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A COMPARATIVE STUDY OF EFFLUENTS AND THEIR CONTROL
FROM FOUR DRY ASH LURGI GASIFICATION PLANTS

By
Mason H. Somerville
James L. Elder
Dorab N. Baria
Yung T. Hung

MASTER

MASTER

July 1978

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Engineering Experiment Station
University of North Dakota
Grand Forks, North Dakota

U. S. DEPARTMENT OF ENERGY

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**Engineering Experiment Station
University of North Dakota
Grand Forks, North Dakota**

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NOTICE

This report consists of three major sections:

- * Executive Summary, A Comparative Study of Effluents and Their Control From Four Dry Ash Lurgi Gasification Plants, Bulletin No. 78-07-EES-01 A
- * A Comparative Study of Effluents and Their Control From Four Dry Ash Lurgi Gasification Plants, Bulletin No. 78-07-EES-01 B
- * Supplementary Data, A Comparative Study of Effluents and Their Control From Four Dry Ash Lurgi Gasification Plants, Bulletin No. 78-07-EES-01 C

The quantity of data collected in the course of this study required that it be handled through the use of a computer program. The data were analyzed utilizing tables formed by this program. On the basis of this analysis, data were selected and reported in the main volume, Bulletin No. 78-07-EES-01 B. The supplementary data volume contains the data that were collected and the computer program used to analyze those data.

ABSTRACT

The four Coal Gasification Plants reviewed in this study are the ones proposed by the El Paso Natural Gas Company, the WESCO Gasification Company in New Mexico, the Natural Gas Pipeline Company of America, and the ANG Coal Gasification Company in North Dakota. This study was undertaken in order to review the nature and the amounts of the effluent emitted into the environment, to determine the cost of controlling undesirable effluents into the environment, to review water treatment facilities and pollution control technologies, to discover the projected capital and operating costs for the plants, and to identify control technology research needs.

The emission of various effluents into the environment from different processes of the four proposed gasification plants are tabulated. The fixed capital investment and the direct operating costs for equipment to control emission of potentially harmful effluents, such as H_2S , SO_2 , hydrocarbons, coal dust, particulates, ashes, sludges, COS , CS_2 , CO , and H_2 were estimated according to the design information provided by the gasification companies. The reuse water treatment systems were reviewed. Little published data was found concerning the influent and effluent characteristics for the water reuse treatment for coal gasification plant systems. Data for the influent stream characteristics was generated from EIS process diagrams and data. Sulfur control within the facility is discussed. Data comparing the composition of Rectisol off gases at SASOL with projected off gases show the streams to be similar. Treatment of these sulfur-bearing gases at SASOL has been

successful. Incineration of tail gases will be required to meet environmental regulations. The EPA guidelines and the regulations for the states of North Dakota and New Mexico are presented. The effluents and operational and capital costs for each facility are presented and compared with one another on a plant-by-plant and division-by-division basis. The biological hazard and reliability of data based upon authors' judgements are presented together with comparison with existing multimedia environmental goals (MEG) hazard ratings.

The work has revealed that the weakest portions of the designs rest in water reuse and sulfur control technology. In the authors' judgements, there is a good probability that existing technology can be utilized to meet the zero liquid discharge and existing gaseous emission requirements for the proposed gasification facilities with minimal upset. However, the technology for internal water reuse is not well established, and these streams can be expected to have characteristics other than those projected. Stretford and Claus technology for sulfur removal exists and in our judgement has a good probability of meeting existing guidelines and regulations. Some operating data are available for high CO_2 , low H_2S , streams; these data are not available in the literature at this time.

Recommendations for research have been made. Research is needed in the basic science areas. Control technology research should be meshed with EPA's MEG's program. A program to establish and characterize the probable odors emitted from a gasification facility should be initiated.

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The principal investigators for each of the areas were:

Project Management	Dr. M. H. Somerville
Emission Spectrum	Dr. J. Elder, Dr. D. Baria
Effluent Regulations	Dr. M. H. Somerville
Sulfur Control Technology	Dr. J. Elder
Water Treatment Technology	Dr. Y. Hung
Effluent Controls and Economics	Dr. D. Baria
Data Analysis	Dr. M. H. Somerville

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LIST OF ABBREVIATIONS

ACGIH	American Conference of Governmental Industrial Hygienists
ADA	anthraquinone disulfic acid
ADIP	Commercial name of SHELL company's H ₂ S concentration process
Ar	argon
BACT	best available control technology
BOD	biochemical oxygen demand
Btu	British thermal unit
°C	degrees centigrade
CaCl ₂	calcium chloride
CaCO ₃	calcium carbonate
Ca(OH) ₂	calcium hydroxide
CaSO ₃	calcium sulfite
CaSO ₄	calcium sulfate
CH ₄	methane
C ₂ H ₄	ethylene
C ₂ H ₆	ethane
C ₃ H ₆	propylene
C ₃ H ₈	propane
CO	carbon monoxide
CO ₂	carbon dioxide
COD	chemical oxygen demand
COS	carbonyl sulfide
CS ₂	carbon disulfide
cu	cubic

LIST OF ABBREVIATIONS (Continued)

DO	dissolved oxygen
DOC	direct operating costs
EHC	non-methane hydrocarbon emissions
EIS	environmental impact statement
EPA	Environmental Protection Agency
ES	total sulfur emissions
F°	Fahrenheit degrees
FCI	fixed capital investment
FPC	Federal Power Commision
ft	feet
gpd	gallons per day
gpm	gallons per minute
H ₂	hydrogen
HCN	hydrogen cyanide
HHV _C	coal heat input based on higher heating value, MW
H ₂ O	water
HP	horsepower
H ₃ PO ₄	hydrogen phosphate
hr	hour
H ₂ S	hydrogen sulfide
H ₂ SO ₄	sulfuric acid
kg	kilograms
kw	kilo-watt
l	liter
lbs	pounds
MEG's	multimedia environmental goals

LIST OF ABBREVIATIONS (Continued)

mg	milligram
mgd	million gallons per day
MgCl ₂	magnesium chloride
MgSO ₄	magnesium sulfate
MLSS	mixed liquor suspended solids
MLVSS	mixed liquor, vapor, and suspended solids
mm	millimeter
MMBTU	million Btu
MMSCFD	million standard cubic feet per day
mhos	conductivity, ohms ⁻¹
MW	mega-watts
N ₂	nitrogen
NaCl	sodium chloride
NaCO ₃	sodium carbonate
NaHCO ₃	sodium bicarbonate
NaHS	sodium bisulfide
NaHSO ₃	sodium bisulfite
NaOH	sodium hydroxide
Na ₂ SO ₃	sodium sulfite
Na ₂ SO ₄	sodium sulfate
Na ₂ S ₂ O ₃	sodium thiosulfite
NaVO ₃	sodium vanadate (V)
Na ₂ V ₄ O ₉	sodium vanadate (IV)
NH ₃	ammonia
NO _x	nitrogen oxides
O ₂	oxygen
P.L.	public law

LIST OF ABBREVIATIONS (Continued)

P_2O_5	phosphate
ppm	parts per million
PSD	prevent significant deterioration
psi	pounds per square inch
psig	pounds per square inch gage
SASOL	South African Coal, Oil, and Gas Corporation Limited
S_c	coal sulfur input
scf	standard cubic feet
scfh	standard cubic feet per hour
scfm	standard cubic feet per minute
SO_2	sulfur dioxide
SNG	synthetic natural gas
SPG	synthetic pipeline gas
TDS	total dissolved solids
TLV	threshold limit values
TOC	total organic compound
yd	yard

1.0 INTRODUCTION

To date the installation of a number of coal gasification plant complexes has been proposed to produce from coal synthetic pipeline gas (SPG) commonly called synthetic natural gas or SNG. This pipeline gas will be equivalent to natural gas; namely, a heating value approaching 1000 Btu per cubic foot and having methane as the primary constituent. The major objective of these installations is to alleviate the nation's growing shortage of known reserves of natural gas and at the same time broadening our energy base by producing a clean gaseous fuel from our large reserves of the solid carbonaceous fuel--coal.

This report deals with four of the coal gasification plant complexes that have been proposed. In each of these cases coal reserves, at least to a major extent, have been provided for by the companies involved. The coal reserves have been assessed as to quality and quantity, and tentative mining plans have been developed. In each case plant engineering contractors have been employed, and tentative designs have been developed for the major coal gasification facility together with the necessary auxiliary supporting installations.

The names and locations of the four gasification plant complexes that are being considered in this project are:

1. El Paso Natural Gas Co., New Mexico
Eng. Contractor - The Lummus Company
2. Western Gasification Co. (WESCO), New Mexico
Eng. Contractor - Fluor Engineers and Constructors, Inc.
3. Natural Gas Pipeline Co. of America, North Dakota
Eng. Contractor - Fluor Engineers and Constructors, Inc.

4. ANG Coal Gasification Co., North Dakota
Eng. Contractor - The Lummus Company

El Paso and WESCO plan on using the subbituminous coal deposits of New Mexico found in San Juan County in the northwestern part of the state. Natural and ANG plan on using the North Dakota lignite found in the west-central part of the state in Dunn and Mercer Counties respectively.

The primary sources of information for the report are: El Paso, FPC 1974, El Paso Int. FES 77-03, 1977; WESCO, Int. FES 76-2, 1976; Natural, Environmental Assessment, 1976; ANG, Int. DES 77-11, 1977; and ANG, Supplemental Application to N.D. State Dept. of Health, 1976.

There are many similarities contained in the tentative plans that have been developed for the four plants. Each of the plant complexes is tentatively designed for the production of a nominal 250 MMSCFD of synthetic pipeline gas (SPG) having a heating value of about 980 Btu per cubic foot and a methane content approaching 97 percent. It appears at this time that the ANG plant in Beulah, North Dakota, will be the first facility built. ANG has formed a consortium of pipeline and other companies to build this facility.

Each of the proposals calls for the development of a large mine-mouth complex and a strip mine to produce the necessary coal for the complex. This will require the movement of water from a moderately distant supply source to the plant site and the transportation of the synthetic gas produced by pipeline to the companies' marketing area.

The four companies studied have selected the dry ash Lurgi pressure gasification process for the production of a crude synthesis gas from coal. Each of the tentative plant designs uses shift conversion to adjust the hydrogen to carbon monoxide ratio. This is followed by the Rectisol

process for removing sulfur compounds and carbon dioxide from the crude gas. Finally, methanation takes place over a high nickel catalyst to produce the final product. In each design the Phenosolvan process is proposed for the recovery of crude phenolics and ammonia from the gas liquor produced in gasification. The designs call for the production of oxygen from air in a cryogenic process, and also for returning the bulk of the solid wastes and sludges to the mine for burial during overburden replacement in the reclamation process. The burial of solid wastes will be done in a manner that will minimize contamination of groundwater. An attempt to hydrologically isolate the wastes from groundwater resources is being made in each case.

Fig 1-1 is a generalized process flow diagram for a typical dry ash Lurgi gasification plant. The naphtha recovery is shown as originating at the Rectisol plant and at the tar, oil, and gas liquor separator. In actual practice, naphtha is recovered in the first methanol wash unit of the Rectisol plant and separated from the methanol by azeotropic distillation. Like phenol, oil, and tar, naphtha is a condensation by-product of the process.

Each of the tentative plant designs plans on zero waste water return to the environment except for water that accompanies the ash and sludges to the mine for burial or that is discharged to evaporation ponds. (The ANG design does include one waste brine stream to be discharged of by deep well injection.)

The major design differences for the four plants lie in the collection and processing of the several waste gas streams from:

1. Rectisol plant vents
2. Phenosolvan plant vents

NOTE: DIAGRAM SHOWS RAW MATERIALS ENTERING PLANT AT LEFT, PRODUCTS AND BY-PRODUCTS LEAVING PLANT AT RIGHT AND EFFLUENTS PASSED TO THE ENVIRONMENT AT TOP AND BOTTOM. THE ARROWS AND LINES SHOW DIRECTION AND PATH OF MATERIAL FLOW INTO, WITHIN AND OUT OF THE PLANT. HOWEVER, SINGLE LINES DO NOT NECESSARILY REPRESENT SINGLE PIPES.

FIGURE I-1
TYPICAL DRY ASH LURGI
GASIFICATION PLANT
PROCESS FLOW DIAGRAM

3. Sulfur recovery plant vents

4. Vents from the tar, oil, gas liquor separation unit.

Differences from plant to plant also occur in the process selection for sulfur recovery, the removal and possible use of hydrocarbons from effluent gas streams, the process water treatment and reuse, and in the selection or production of fuel used in the production of steam for plant use and the generation of some electric power.

There are differences also in the processes used for flue gas desulfurization of the stack gases emitted from the boilers used in the production of steam.

1.1 GASIFICATION BACKGROUND

Each of the companies has selected the Lurgi fixed bed, dry ash, coal gasifier for the production of a crude gas which can be upgraded to SPG by purification and methanation. This process employs steam-oxygen blown, pressurized, gas producers using a downward flowing solid carbonaceous fuel bed with dry ash discharge and operating at approximately 450 psig. The choice of the Lurgi process was made for one or more of the following reasons:

1. The Lurgi pressure gasification process has a good record of commercial operating dependability, some 40 odd years.
2. It operates well on non-caking coals such as subbituminous or lignite which are indigenous to the areas where the four plant installations are contemplated.
3. The oxygen requirements are favorably low when compared to other existing commercial gasifiers.
4. Under conditions of dry ash discharge the methane content of the crude gas is relatively high, accounting for about 40 percent of the methane in the final product.
5. Under conditions of dry ash discharge the hydrogen to carbon monoxide ratio in the crude gasifier gas is about two. This reduces the shift conversion requirements before methanation when compared to the other gasification processes.

Most coal gasifiers, whether oxygen blown or air blown, can be classified into three general types; fixed bed, fluidized bed, and entrained or pulverized coal. They can be designed to operate at atmospheric pressure or high pressure. There are advantages and disadvantages to each type (Fredersdorff and Elliott, 1963; Gronhøvd and others, 1970; Magee, 1976).

In the fixed bed units there is a downward flowing carbonaceous column of broken coal and ash (depending on the location in gasifier),

while there is a counter current flow of gas-making fluids (oxygen and steam). Several reaction zones are established within the gasifier. From the top they are the preheating or drying zone, the carbonization zone, and the ash zone. Heat is transferred from the rising gases to the down-flowing solids, and, with adequate bed depth, the crude gas which is discharged at the top is at a moderate temperature. The oxygen is utilized to burn out the residual carbon entering the ash layer and to provide the heat required by the gasification reactions. The volatile carbonization products (tars, oils, and so on) enter the gas stream with minimal exposure to the high gasification temperatures and are cracked or reformed to a minimum extent. At relatively high gasification temperatures (low steam to oxygen input ratios, such as 1 to 1, as used in slagging operation) the ash is removed as a liquid slag. There is excellent steam decomposition, high gas-making capacity per square foot of cross section and some cracking of volatile hydrocarbons. The crude gas has a hydrogen to carbon monoxide ratio of about 0.5 with a methane content of about 5 percent and relatively low carbon dioxide concentration. At lower gasification temperatures (higher steam to oxygen input ratios; about 6 to 1 as is generally used in dry ash Lurgi operation) there is much less steam decomposition. The ash is removed as a dry solid, the gas-making capacity per square foot of cross section is reduced (possibly to about 1/3 of slagging operation), and the cracking or reforming of volatile hydrocarbons is minimized. The crude gas has a hydrogen to carbon monoxide ratio of about 2. The methane content is usually 9 to 15 percent, and the carbon dioxide content is about 29 percent. The fixed bed gasifiers are characterized by a relatively long overall contact time between reactants, excellent heat transfer between solid and gaseous

constituents resulting in moderate offtake gas temperatures, minimal reaction between volatile carbonization products (tar, oil, and hydrocarbons), and moderate oxygen usage, since the coal volatiles have a minimal chance of reacting with oxygen. The dry ash discharge Lurgi has the advantage of a proven method of ash discharge and the disadvantage of lower rates of gas production, although the hydrogen to carbon monoxide ratio is better than a slagging operation.

The fluidized bed and the entrained or pulverized coal gasifiers are typically exemplified by the Winkler and the Koppers-Totzek gasifiers, respectively, and can be grouped together for the purpose of this discussion. Both methods are characterized by a relatively short overall contact time between solid and gaseous reactants. This results in minimal or no production of unreacted tar, oil, or volatile coal carbonization products since these products are exposed to high gasification temperatures and oxygen. Compared to the Lurgi process this requires greater oxygen usage and provides somewhat increased gas production (about 10 percent) per unit of coal processed. The methane content of the Winkler crude gas is about 2 percent and the Koppers-Totzek crude gas is about 0.1 percent. The hydrogen to carbon monoxide ratio for the Winkler is about 1.1 and for the Koppers-Totzek it is about 0.5. Heat recovery is required at a high temperature in both these systems. The crude hot gas contains a considerable quantity of fly ash and coal particles which can deposit on heat transfer surfaces causing operating problems. Probably both of these systems can be designed for high pressure operation, but the technology of coal feed systems, and possibly ash or slag handling, will be more complex and much less developed than the equivalent systems for dry ash Lurgi operation. The reduction in tar,

oil, and other volatile coal hydrocarbon derivatives as by-products can be advantageous depending on the plant design considerations. These by-products may be marketed as chemical feedstocks or fuel or they can be used as fuel within the plant complex to meet plant requirements. The disadvantages of their production lie in the possible lack of market demand and in the cost and difficulty of producing them.

The oxygen usage of the fixed bed gasifiers (both slagging and dry ash) per unit of coal charged is lower than that of either the fluidized bed or entrained gasifiers. This is primarily due to the fact that the volatile hydrocarbons are not reacted with oxygen as in the case of the fluidized or entrained units.

1.2 EFFLUENT CONTROL BACKGROUND

It is the objective of each of the four plant complex designs examined to eliminate or control the discharge of noxious elements or compounds to acceptable levels so as not to endanger human, animal, or plant life. The costs of control must be kept as low as possible in order that the major product, synthetic natural gas (SNG) can be priced within reach of the ultimate consumer.

The effluents from each complex can be grouped conveniently under a solid, liquid, or gaseous classification system. The major solid effluents will be the coal ash, air borne particulates, the suspended and dissolved solids in raw water, and the chemicals which may be added during processing. The liquid effluent will be water contaminated with soluble derivatives of coal ash, added chemicals, and hydrocarbon materials formed during coal processing. The gaseous effluents will consist of gases discharged from the various plant vents together with water vapor from the cooling tower and evaporation from several ponds.

The crude synthesis gas leaving the offtake of the Lurgi generators is composed mainly of carbon dioxide, carbon monoxide, hydrogen, and methane. This is mixed with appreciable but much smaller quantities of higher hydrocarbons in the C_2 to C_4 range, both saturated and unsaturated; ammonia; hydrogen sulfide; hydrogen cyanide; and organic sulfur compounds, such as carbonyl sulfide and carbon disulfide. As the crude gas leaves the offtake, it is accompanied by condensable vapors including tar vapor, tar oil vapor, naphtha, and steam. In addition, the mixture of gas and vapor is accompanied by coal and char dusts blown over from the fuel bed of the gasifier and by volatile inorganic compounds derived from the mineral matter content of coal. The latter includes the volatile

trace element compounds of the coal. The principal synthesis gas components; CO, H₂, and CH₄, are separated from the rest of the stream by processing and are ultimately present in the primary product of the plant, synthetic pipeline gas or essentially methane. The separated materials are either processed to recover marketable by-products or must be disposed of as waste effluents. In addition to the above materials, the gasifier bottom ash and waste streams from the required auxiliary plants must be disposed.

The offtake of the Lurgi gasifier discharges directly into a scrubber and partial cooling unit (see Figure 1-1). There the temperature of the crude gas stream is reduced to the point where the partial pressure of the water remains high enough to supply sufficient steam to the shift conversion unit. At the same time a large fraction of the condensable portion of the stream is removed as condensate.

The crude gas stream is then divided and about half, or somewhat more, goes to the gas cooling unit. The other portion goes to shift conversion unit where steam is added and the following reaction takes

place:

$$\text{CO} + \text{H}_2\text{O} \xrightarrow[\text{catalyst}]{} \text{H}_2 + \text{CO}_2$$

The catalyst in this unit is sulfur resistant. Minimal catalyst deterioration occurs, although some carbon deposition will require periodic catalyst reactivation. The shifted crude gas then goes to gas cooling where, after cooling, it is repressurized and mixed with the first unshifted cooled portion. The combined stream is the crude synthesis gas and has the hydrogen to carbon monoxide ratio adjusted to about 3.5, which is suitable for subsequent methanation.

At this point in the processing scheme, the coal has been changed to crude synthesis gas which is contaminated with sulfur compounds, such

as H_2S , COS , and CS_2 . In addition, the gas contains uncondensed naphtha vapor, NH_3 , and some HCN . The coal ash has been discharged directly from the gasifier and is ready for ash handling and disposal. The condensed vapor, tar, tar oil, and gas liquor, together with gasifier blow-over dust (coal particles), have been collected and are ready for separation and further processing. There have been no waste gas streams generated other than the vent gas from the coal locks.

The Rectisol plant is the next unit in the processing train and is of major importance in the control of gaseous effluents from the process. It is here that the crude synthesis gas is purified and made ready for the methanation step. The nickel catalyst used in methanation requires that the synthesis gas be virtually sulfur free and imposes the requirement that the Rectisol plant remove all sulfur compounds and provide a clean synthesis gas.

The crude synthesis gas is chilled before entering the prewash tower of the Rectisol unit. In this tower the residual water and naphtha are removed by a cold methanol wash. The naphtha-free gas enters the absorber where H_2S and COS are removed. The heat of absorption is removed by refrigeration, as the temperature of the cold methanol washes are generally maintained at -20°F to -50°F . Some of the absorbed gases are removed from methanol by multi-stage flashes in the flash regenerator, and the remainder is stripped in the hot regenerator. These off-gas streams are collected and sent to the sulfur recovery plant.

The naphtha is recovered from the methanol and water by means of a naphtha extractor and by the use of an azeotrope column. The methanol is recovered by distillation in a methanol-water distillation column.

The Rectisol units are custom-designed in a number of ways depending on the stated process requirements. In one complex, the vapor vent on the naphtha extractor is connected to a water scrubbing column to remove HCN from the released gases and, after scrubbing, these gases are added to the Rectisol off-gas for treatment in the sulfur recovery plant. In two complexes the finished synthetic pipeline gas is put through the first stage of final compression and then returned to the Rectisol unit for a final cold methanol scrub to remove water and reduce CO₂ to as low a limit as feasible in the finished product. This product gas is then sent to second-stage compression before release to the pipeline. In the other two complexes a glycol drying unit is installed after the second stage of compression. This unit removes water but does not change the CO₂ content of the product gas.

From the Rectisol unit the clean synthesis gas feed goes to methanation. This unit converts the relatively low Btu synthesis gas (about 375 to 430 Btu/cu ft) to methane-rich, high-Btu gas (about 980 Btu/cu ft) by the following exothermic reactions:

Other minor reactions which take place are the hydrogenation of ethylene to ethane and the hydrocracking of ethane to methane.

The feed gas entering the methanation reactors is preheated by exchange with product gas and passes through a fixed bed containing a pelleted, reduced-type, nickel catalyst. The temperature rise within a reactor is controlled by the recycling of methanated effluent gas which is mixed with the feed gas. The reaction heat is removed by waste heat exchangers at the outlet of each reactor. The gas leaving the

synthesis loop is passed through a cleanup reactor to completely convert any remaining carbon monoxide. The gas is cooled, the condensed water is separated, and the gas is sent to the gas compression units. The only effluent stream produced is liquid water which is used as boiler feed water.

The product gas leaving methanation goes through first-stage compression. The final moisture and CO₂ removal is accomplished with a second pass through the Rectisol unit (cold methanol wash), or moisture is removed by a glycol dehydration unit following compression. The gas is then ready for pipeline distribution. The product, synthetic pipeline gas, is essentially equivalent to natural gas. It is a clean gaseous fuel suitable for use by the consumer and is essentially free of noxious compounds. The analysis will vary somewhat because of differences in processing in different plants but the following analysis is indicative of the quality of the product.

<u>Component</u>	<u>Mole Percent</u>
Hydrogen	3.00
Carbon monoxide	0.05
Carbon dioxide	0.40
Methane	95.95
Nitrogen & Argon	0.60
	<u>100.00</u>
Btu/cu ft	982

1.2.1 Solid Waste Disposal Background

Most of the solid wastes generated by a gasification complex are derived from the coal feedstock that is used. The waste quantity is directly related to the ash content of the coal. In addition, there are solids derived from raw water treatment and solids derived from the use of chemicals used in various processing steps. Ash is discharged from the Lurgi gasifiers and from boilers used for the production of steam and

power. Also, fly ash is recovered from electrostatic precipitators used on the stack gases from combustion equipment. Where stack gas scrubbing is employed on flue gases, calcium salts of sulfur compounds are produced. These solid wastes, particularly gasifier ash and boiler ash, are often handled in hydraulic sluiceways and delivered to a loading point where they are dewatered and hauled to the mine for burial. They are handled wet to minimize dust evolution; even after dewatering, the material generally contains 20 to 30 percent water. The sludges obtained from raw water treatment and the calcium salts from stack gas scrubbing are handled in much the same manner and are mixed with the ash. The slurries which are not amenable to dewatering are often pumped to lined evaporation ponds, and the solids are ultimately buried. Some of the brines produced by demineralizers, cooling tower blowdown, boiler blowdown, and the like are sent to multiple effect evaporators and the solids recovered are buried with the ash.

The primary method of solid waste disposal is by mine burial, usually at depths of 50 to 100 feet or more below the surface of the reclaimed mine land area. As mine burial takes place, the wastes will be hydrologically isolated as much as possible from the adjacent groundwater system. In this way the possible leaching of compounds from the buried wastes by percolating surface water will have a minimal effect on the quality of the adjacent groundwater systems.

The preceding discussion of solid waste control and disposal has not included dust evolution from coal preparation, handling, and storage facilities. These problems are generally handled by one or more of the following:

1. The use of water sprays which may include a wetting agent

2. The compaction of large long-term storage piles in approximately one-foot lifts possibly including a spray which induces crust formation
3. The use of covered conveyors with adequate ventilation and the passing of discharged air through bag filters and a similar arrangement where the coal is charged to the operating bunkers.
4. Adequate ventilation and baghouse collection of particulate where dry coal crushing and screening operations are being conducted

The collected particulate is disposed of by mine burial.

1.2.2 Liquid Waste Disposal Background

There are virtually no liquid waste streams that are discharged from a gasification plant complex. Each of the four plant complexes was designed for zero waste water discharge to the environment. (The ANG design does include one waste brine stream to be disposed of by deep well injection.) There are a number of condensate streams produced by gasification that must be processed and the values reclaimed.

Tar, tar oil, and gas liquor are produced by gasification and are condensed from the crude gas stream enroute from the gasifiers to the Rectisol plant. These are collected and sent to the separation plant. In the first unit the mixture is pumped into a closed settling tank where the tar that is heavier than water settles to the bottom and is pumped to a tar storage tank. In the second unit the tar oils that are lighter than water, and the remaining gas liquor are allowed to separate; the tar oil is pumped off the top to a tar oil storage tank. In each of these units the condensate contains dissolved crude gas. This is vented from the top of the closed tanks, repressurized and returned to the crude gas stream before it enters the Rectisol plant. The naphtha is recovered in the front end of the Rectisol plant, as has been described,

and is pumped to a storage tank. The gas-liquor water is recovered from the bottom of the tar oil separator and is pumped to the Phenosolvan unit.

The gas liquor contains free and combined ammonia, dissolved acid gases, dissolved phenolics, dissolved fatty acids, and probably many of the salts of inorganic elements found in coal ash that were vaporized during the gasification reactions. The gas liquor stream is filtered at the entrance to the Phenosolvan plant, and counter current extraction is used to remove the phenolics from the water. Isopropyl ether is generally used in the extraction and it transfers the phenolic materials from the water phase to the isopropyl ether phase. After extraction the gas liquor is further processed by heating and stripping to remove CO_2 , H_2S , and NH_3 . The acid gases, CO_2 , and H_2S , are sent to the sulfur recovery plant, and the NH_3 stream is upgraded to anhydrous ammonia and is pumped to storage. The phenol-rich isopropyl ether leaving the extraction section is further processed to obtain crude phenol which is pumped to storage. The lean phenol isopropyl ether that is recovered is recycled back to the extraction section.

The gas liquor water after Phenosolvan plant treatment still contains fatty acids, residual phenols, and various inorganic salts. Other aqueous processing streams from other parts of the plant complex, such as the bottoms from the methanol still of the Rectisol plant, are added to it. These are sent to waste water treatment so that the water can be reused within the plant boundaries for cooling tower makeup, ash handling, and other purposes.

As a result of processing the several process condensate streams, the following materials are recovered and are disposed of as follows:

tar	- either marketed or burned as fuel within the plant

- tar oil - either marketed or burned as fuel within the plant
- naphtha - either marketed or burned as fuel within the plant
- crude phenolics - either marketed or burned as fuel within the plant
- ammonia - marketed

1.2.3 Gaseous Waste Disposal Background

The gaseous effluents are primarily obtained from the vents of the Rectisol plant and the vents of the Phenosolvan plant where the acid gases are stripped from the gas liquor. Since the gaseous effluents originate at several sources (flash gases, hot regenerator overhead, and so on). They have different compositions, and several processing options are available. If these streams are combined they would have an expected composition of about 96 percent carbon dioxide and 1+ percent hydrogen sulfide. The remainder would be hydrogen, carbon monoxide, and hydrocarbons with small quantities of carbonyl sulfide and carbon disulfide. The volume rate of effluent gas can be expected to approach 15 million scfh. The sulfur compounds, carbon monoxide, and hydrocarbons have to be removed from these gases before they are finally vented to the atmosphere.

The four gasification complexes process these effluent gases by two different procedures. Two of the complexes send the hot regenerator overhead acid gases (the effluent containing the highest concentration of hydrogen sulfide) to a hydrocarbon removal unit where hydrocarbons and about 95 percent of the carbon dioxide are separated from the hydrogen sulfide. The hydrocarbons are burned elsewhere in the complex to provide process heat, and the hydrogen sulfide is sent to a Claus sulfur recovery plant where solid sulfur is produced. The

effluent gases of lower hydrogen sulfide content are combined and sent directly to a Stretford sulfur recovery plant where sulfur is produced. The Claus plant in this procedure recovers about 2/3 of the sulfur and the Stretford plant, 1/3. The tail gases from both the Claus plant and the Stretford plant are incinerated. By this procedure the hydrocarbons are completely removed from the effluent gases and any residual sulfur is present as sulfur dioxide. In one of these two complexes the products of combustion are scrubbed to remove most of the residual sulfur dioxide.

In the other two gasification complexes it is planned to combine all of the acid gas vent streams and send them directly to a Stretford sulfur recovery plant where sulfur is produced in marketable form. The tail gases from the Stretford plant (hydrocarbons and residual sulfur compounds) are incinerated either directly to recover as much of the heat of combustion as possible or catalytically to remove hydrocarbons and convert any residual sulfur compounds to sulfur dioxide.

The gaseous effluents also contain particulates which have to be removed from the gas streams before they are vented to the atmosphere. The particulates are mainly emitted in the stack gases from the combustion of coal or coal derived liquid fuels such as tar, tar oils, naphtha or crude phenolics in the boilers. Air borne coal dust is generated in the coal handling and coal preparation areas. Coal dust is also emitted during venting of the coal locks on the gasifiers and gasifier ash particles are emitted during venting of the ash locks on the gasifiers.

The particulate emission in the stack gases from the boilers is controlled by electrostatic precipitators in three plants, the fourth plant burns fuel gas and has no particulate emission from the boilers. The coal dust from the coal handling and preparation areas is controlled

by use of water sprays and baghouse filters in all four plants. The coal dust and the ash particles from the gasifier coal and ash locks are controlled by the use of wet cyclones on the gasifiers.

1.3 ESTIMATED OPERATING COST BACKGROUND FOR A LURGI SNG PLANT COMPLEX

An estimate has been calculated for the approximate average operating cost distribution for a Lurgi coal gasification plant complex having a nominal synthetic natural gas (SNG) production capability of 250 MMSCFD. The operating cost of each of the plant units has been expressed as percentage of the total cost of making SNG.

The operating cost of each of the four gasification plant complexes was estimated individually by plant units using a common basis, and the results were averaged. Table 1-1 gives the average operating cost distribution calculated for each plant complex.

An arbitrary breakdown of the data given in Table 1-1 gives an estimate of the operating cost of the primary processing units and the cost of effluent control. The entire operating cost of Items 1 through 6 and Item 9 are charged to primary processing. Eighty percent of Item 8 and 60 percent of Item 10 are also charged to primary processing. The entire operating cost of Items 7, 11, 12 and 13 is charged to effluent control. In addition, 20 percent of Item 8 and 40 percent of Item 10 are charged to effluent control. Based on this breakdown, the cost of effluent control is 18.2 percent of the total cost, and 81.8 percent of the total cost is charged to primary processing.

TABLE 1-1

AVERAGE OPERATING COST DISTRIBUTION FOR A
LURGI DRY ASH GASIFICATION SNG PLANT COMPLEX

<u>Item</u>	<u>Plant Unit</u>	<u>Percent of Total Cost</u>
1	Gasification	22.3
2	Shift Conversion	2.6
3	Gas Cooling	2.7
4	Gas Purification (Rectisol)	13.5
5	Methanation	6.6
6	SNG Compression	2.0
7	Gas Liquor Separation	2.0
8	Steam and Power Generation	15.5
9	Oxygen Plant	14.7
10	Water System	8.3
11	Ash Dewatering and Transfer	1.6
12	Phenosolvan	5.0
13	Sulfur Recovery	<u>3.2</u>
	Total	100.0

1.4 BACKGROUND: EMISSION REGULATIONS

One of the more important considerations in designing any energy facility is the control of its solid, liquid, and gaseous emissions to the environment. Philosophically, it is desirable to control, by regulation, these emissions at the plant boundaries (three dimensional) as opposed to regulating internal streams. Thus, the definition of the boundaries is often complex and is an important consideration in the design of an energy facility. It is a fact that emission control requires additional equipment and lowers the efficiency of energy production. Consequently, the required controls result in increased capital and operating costs which ultimately result in a higher energy cost to the consumer.

Historically, emission regulations have been written for particular industries and have addressed the actual emissions of those industries which, through experience, are known to exist. To date, the energy industries have been largely composed of the coal, electric, gas, and petro-chemical industries. The gasification industry, if one develops, will become a member of this group. As such, it will share some, but not all, of the environmental considerations that each of the above industries face. One of the principal challenges that the society faces with this industry is to develop a set of environmental guidelines or regulations by which these plants are to be built and operated. The work that has been completed and reported in the following document is an attempt to provide part of the data that will be used to develop such guidelines and to identify research needs in the area of environment control technology.

At the present time there are no federal regulations (new source performance standards) which specifically govern gasification facility emissions. However, at least one state, New Mexico, has developed regulations which control SO_2 , NO_x , and hydrocarbon emissions from gasification facilities. A serious attempt to develop federal gasification regulations was made by the Environmental Protection Agency (EPA) over the last several years. This attempt resulted in two different proposed standards and associated standard support environmental impact statements. These were issued in July and November of 1976. The first standard proposed an emission base similar in concept (mass per unit energy) to the existing sulfur standard for power plants. The second proposal was a total mass based standard. Both of the proposed standards have been withdrawn and guidelines have been issued instead. These guidelines (EPA, March, 1978) suggest numerical limits for the control of the mass of emissions for sulfur and non-methane hydrocarbons.

Control of the minor effluents, substances other than sulfur, NO_x , hydrocarbons, and carbon monoxide, is not discussed in the guidelines. There are many reasons for this, but the principal ones are:

1. The extent of the environmental impact of the minor quantity trace elements and pollutants has not been identified or quantified.
2. The monitoring equipment required has not been developed.
3. The control equipment that would be required has not been developed.
4. The actual extent of trace contaminants in both the solid and gaseous phases is unknown. Only analytical projections based upon scant data are available.
5. The process stream variability of these materials under actual operating conditions is unknown.

Another regulation (EPA, March 15, 1978) governing sulfur emissions from petroleum refinery Claus sulfur plants exists. This regulation may become the performance standard for gasification facilities if gasification operating experience proves that it can be met.

The existing regulations for the states of North Dakota and New Mexico are discussed in more detail in Section 3 as are the Federal guidelines and regulations.

2.0 FACILITY EMISSIONS & FACILITY ECONOMICS

2.1 INTRODUCTION

The design of the four gasification plant complexes that are discussed in this report all follow the general process flow diagram given as Figure 1-1 modified by the exceptions that are noted in the following specific plant descriptions. The primary sources of information for these descriptions are: El Paso, Int. FES 77-03, 1977; El Paso FPC 1974; WESCO, Int. FES 76-2, 1976; Natural, Environmental Assessment, 1976; ANG, Int. DES 77-11, 1977; and ANG, Supplemental Application to N.D. State Dept. of Health, 1976. (Complete information in reference section of report.)

2.1.1 Plant Description, El Paso Natural Gas Company

The tentative El Paso plant complex design follows the generalized process flow diagram (see Figure 1-1) with the following modifications or exceptions.

The design uses separate Lurgi air blown, low Btu, pressurized gasifiers for the production of a clean fuel gas for the generation of steam and power for the complex. The fuel gas, at about 250 psi, is cooled and the condensed tar, oils, and gas liquor are sent to separation. The cooled gas, still at about 250 psi, is scrubbed in a Stretford unit, and the cleaned fuel gas is burned in a gas turbine/boiler plant for power and steam production. The stack gases are not scrubbed for further sulfur removal. The used Stretford solution is treated and regenerated in the main sulfur recovery plant (Stretford process-oxidizers).

The low Btu coal gas concept for steam and power production is, in effect, a "combined cycle" system. It is an efficient system and avoids many of the effluent emission problems inherent with coal-fired boilers. El Paso, in an 18-month test program, has determined that the low Btu coal gas can be burned efficiently in a conventional gas turbine which seems to have several advantages over the use of natural gas.

The acid gases, such as expansion gas, that are relatively low in sulfur and are discharged from vents in the Rectisol plant and other vents, are collected and scrubbed with Stretford solution at 10 psig in the first (lean acid gas) absorber of the main sulfur recovery plant. The vent gases from this absorber and those from the Stretford plant oxidizer are sent to catalytic combustion units where residual hydrocarbons are destroyed and any sulfur compounds are converted to SO_2 before discharge to the atmosphere.

The lock gas and the Rectisol hot regenerator vent gas, which have higher concentrations of both hydrocarbons and sulfur compounds than the other vent gases, are scrubbed with Stretford solution in the second absorber in the sulfur recovery plant. The absorber vent gas is incinerated before discharge to the atmosphere. The sulfur, recovered in saleable form from the Stretford sulfur plant, is estimated at 187 tons per day, which represents about 96 percent of the total coal sulfur entering the plant complex. Less than 2 percent of the coal sulfur is discharged to the atmosphere as sulfur dioxide, and somewhat more than 2 percent of the coal sulfur leaves with by-products and ash. The design uses only the Stretford process for sulfur recovery from the various vent gas streams.

The tentative plant design does not pass the SPG from first-stage compression through a final methanol wash in the Rectisol plant

for dehydration and final CO₂ removal. Instead, a glycol dehydration system is used after second and final compression.

In the El Paso design the liquid condensates from oxygen-blown gasifiers, shift conversion, gas cooling, Rectisol (primarily methanol still bottoms), air-blown gasifiers, and fuel gas cooling are combined and sent to gas liquor, tar, and tar oil separation. After separation the gas liquor is sent to the Phenosolvan plant where the phenols, acid gases, and ammonia, as a 20 percent solution, are separated, and the aqueous effluent is recycled as make-up to the plant cooling water system.

The tentative plant design indicated that raw water treater lime sludge, zeolite softener, and demineralizer blowdown are sent to the ash dewatering and transfer system where wet ash solids are recovered and transferred to the mine for burial. The effluent water plus fine solids are sent to solar evaporation ponds where residual solids are ultimately recovered and buried.

2.1.2 Plant Description, WESCO

The tentative WESCO plant complex design follows the generalized process flow diagram (see Figure 1-1) quite closely.

The complex uses coal-fired steam boilers for the production of steam and emergency electric power and is supplemented with an oil-fired steam superheater. The fuel used in the steam superheater is produced by the gasification plant. The stack gases from the coal-fired boilers are passed through hot electrostatic precipitators for particulate removal and are then scrubbed to remove sulfur compounds.*

* The stack gas desulfurization process has not yet been selected. For this discussion the Chiyoda Thoroughbred 101 Process (Morrison, 1972) has been assumed. This process was under consideration at the time the EIS was prepared. The scrubbing solution is dilute H₂SO₄ with a catalyst. The sulfur product is the calcium salt-gypsum. The stack gas also contains the products of combustion of certain waste gas vent streams since the coal-fired boiler also acts as an incinerator.

In the tentative design, both Claus and Stretford sulfur recovery plants are used to produce sulfur from the various plant processing waste gas vents. The vent gas streams are treated as follows:

1. The hot regenerator vent gas of the Rectisol plant, which contains the largest quantity of sulfur compounds as well as hydrocarbons, is sent through an ADIP hydrocarbon removal process (selective absorption). The high concentration sulfur vent gas resulting (about 80 percent H_2S) is sent to the Claus sulfur recovery unit. The hydrocarbons are incinerated directly in the boiler plant.
2. The vent gas stream from the Rectisol naphtha extractor is sent to the Claus unit for sulfur recovery.
3. The Claus sulfur recovery plant (3 bed unit) recovers about 95 percent of the sulfur entering with the combined streams. The residual 5 percent in the tail gas is incinerated in the boiler plant.
4. The relatively low concentration sulfur flash gas vent streams from the Rectisol plant and the waste gas from the ammonia recovery section of the Phenosan plant (together about 1 percent sulfur concentration) are sent to the Stretford sulfur recovery plant where about 98.5 percent of the sulfur is removed.
5. The Stretford waste tail vent gas is sent to the boiler plant for incineration.
6. The vent gases from the intermittently operating catalyst regeneration unit (shift conversion catalyst) are sent directly to the boiler plant for incineration.
7. The vent gases from gas-liquor separation and from gas-liquor expansion are sent directly to the boiler plant for incineration.
8. The high carbon dioxide concentration, low pressure vent gas streams containing a small quantity of sulfur from the Rectisol plant are incinerated in the steam superheater and, together with the products of combustion of fuel oil, are released to the atmosphere via its stack. This stack gas is not treated further for sulfur removal.
9. Excess coal lock gas is vented to the atmosphere via the steam superheater stack; it is not incinerated. The gas used for pressurizing the coal lock originates as a portion of the high carbon dioxide vent gas from the Rectisol plant and contains only a very small quantity of sulfur.

The combined Claus and Stretford sulfur recovery plants are expected to produce about 202 tons per day of sulfur for sale which represents 78 weight percent of the coal sulfur charged to the plant complex. About 1.9 weight percent of the total sulfur will be discharged to the atmosphere as SO_2 and the remainder, about 20.1 weight percent, will be accounted for in the hydrocarbon by-products and in the ash and sludge waste streams.

In the WESCO plant design the process condensates from the gasifiers, shift conversion, gas cooling, and Rectisol (primarily methanol still bottoms) are combined and are sent to gas liquor, tar, and tar oil separation. After separation the gas liquor is sent to the Phenosolvan plant where phenols, acid gases, and ammonia are separated and the aqueous effluent, together with other miscellaneous plant aqueous effluents and excess storm water, are combined and sent to oil separators, air flotation, and biological treatment. The major portion of the water leaving biological treatment is used as make-up to the process cooling water system. The remainder is sent to selective reuse, such as ash quench, revegetation, road wetting, and other miscellaneous uses at the plant. The tentative plant design indicates that the sludges obtained during raw and process water treatment is dewatered and the water recycled. The wet solids are added to the ash for subsequent disposal during mine burial. The ash and solids discharged by the coal-fired boilers are also added to the gasifier ash for subsequent disposal during mine burial. These solids include bottom ash from the boiler, fly ash from the electrostatic precipitators, and filter cake from stack gas scrubbing. The disposal area will be monitored and probably constructed to avoid leaching and groundwater impacts.

2.1.3 Plant Description, Natural Gas Pipeline Company of America (Natural)

This tentative plant complex design also follows the generalized process flow diagram (see Figure 1-1) quite closely.

The Natural tentative design uses coal-fired steam boilers for the production of steam and electric power, supplemented with an oil-fired steam superheater. The fuel oil used in the steam superheater, or vent gas incinerator as it is presently named, is produced by the gasification plant. The stack gases from the coal-fired boilers are passed through hot electrostatic precipitators for particulate removal and are then scrubbed to remove sulfur compounds.*

In the tentative design, Natural employs both Claus and Stretford sulfur recovery plants to recover sulfur from the various plant processing waste gas vents. The vent gas streams are treated as follows:

1. The hot regenerator overhead gas and the Rectisol plant gas are sent to an ADIP unit for hydrocarbon removal (selective absorption). The vent gas stream (about 78 mole percent H_2S) then goes directly to the Claus plant for sulfur removal. The hydrocarbons removed are incinerated in the steam superheater.
2. The vent gas from the Rectisol pretreatment section for naphtha recovery is rich in sulfur compounds (about 16.5 mole percent). This vent gas, containing hydrocarbons (about 2.7 mole percent) and probably hydrogen cyanide (possible 1.3 mole percent), is sent to the Claus plant.

* The stack gas desulfurization process had not been finally selected at the time the Environmental Assessment was written, but the FMC Alkaline Absorption system (FMC Corporation, 1975) was under serious consideration. The sulfur dioxide is absorbed in a solution of H_2O , Na_2SO_3 , and Na_2SO_4 and reacts with Na_2SO_3 to form $NaHSO_3$. In the solution regeneration phase the sulfite ion is removed by precipitation with $Ca(OH)_2$ forming $CaSO_3$ which is collected and disposed of as a solid waste. The stack gases contain the products of combustion of both coal and coal lock vent gases which are also incinerated in the coal-fired boiler.

This stream is completely incinerated in the Claus plant by a special burner arrangement to destroy both the hydrocarbons and the HCN.

The combined gas stream to the Claus plant (4 bed unit) contains about 66.5 mole percent sulfur compounds and the unit recovers 145.6 tons per day sulfur. The tail gas contains 1.1 tons per day sulfur. The tail gas is burned in a separate oil-fired incinerator to convert any residual combustible compounds to CO_2 , H_2O , and SO_2 before discharge to the atmosphere. The products of combustion from the incinerator are discharged to the atmosphere without further treatment.

3. The expansion gases from the gas liquor buffer tank (gas liquor separation) are scrubbed with Stretford solution and are sent to the vent gas incinerator (superheater).
4. The other Phenosolvan plant vents and the H_2S -rich flash gas streams from the Rectisol plant are sent to a Stretford sulfur recovery plant. The resulting vent gas streams go to the oil-fired vent gas incinerator (superheater) before final discharge to the atmosphere.

The Stretford sulfur recovery plant is designed to remove about 98.5 percent of the sulfur entering, or 76.5 tons per day. Thus, the combined Claus and Stretford sulfur recovery plants produce about 222.1 tons per day sulfur which represents 72.8 weight percent of the coal sulfur entering the plant complex. About 5.7 weight percent of the total sulfur will be discharged to the atmosphere as SO_2 , and the remainder, about 21.5 weight percent, will be accounted for in the hydrocarbon by-products and in the ash and sludge waste streams.

5. The Rectisol plant flash gas vent streams containing an excess of 99 volume percent carbon dioxide and essentially no H_2S are burned in the vent gas incinerator prior to atmospheric discharge.

The combined products of combustion from the oil-fired vent gas incinerator (superheater) are not treated before discharge to the atmosphere.

6. The low pressure vent gas from gas separation and the bio-oxidation vent (process water treating) are discharged to the atmosphere without incineration.

In the Natural plant design the process condensates from the gasifiers, shift conversion, gas cooling, and Rectisol are combined and sent to gas liquor, tar, and tar oil separation. After separation

the gas liquor is sent to the Phenosolvan plant where phenols, acid gases, and ammonia are separated. This aqueous effluent, together with other water streams including storm water from holding facilities are sent to process water treating. Here oil separators, air flotation and biological treatment are employed to remove dissolved and suspended solids as a sludge. A large portion of the water leaving biological treatment is used as make-up to the process cooling water system and the remainder is used selectively within the plant complex.

The tentative plant design indicates that the sludges obtained during raw water clarification treatment, process water treating, cooling tower blowdown, concentrator blowdown, and stack gas scrubbing are all dewatered; the excess water is recycled and the recovered wet solids are added to the coal ash for subsequent disposal by mine burial. The ash and solids discharged during operation of the coal-fired boilers are also added to the gasifier ash for disposal by mine burial.

2.1.4 Plant Description, ANG Coal Gasification Company

The ANG tentative plant complex design follows the generalized process flow diagram (see Figure 1-1) with the following modifications and exceptions.

ANG plans on purchasing all electric power from a nearby electric generating plant with the exception of the installation of standby units for use in an emergency. Sets of steam boilers and steam superheaters will be installed for process steam generation.

The steam boilers are fired with tar and tar oil that are recovered from the gasification train (tar, oil and gas liquor separator). Each boiler is fitted with an electrostatic precipitator to

minimize particulate discharge. The products of combustion from the boilers are piped to the main plant stack for discharge to the atmosphere.

The steam superheaters are fired with gasification train by-products as well as several of the waste gas streams. The superheater fuels include tar oil, not required in the operation of the boiler plant; naphtha, recovered in the Rectisol plant; crude phenols, recovered in the Phenosolvan plant; vent gases from the Stretford sulfur recovery plant; and coal lock gas, discharged from the gasifier coal locks. The steam superheaters are not fitted with electrostatic precipitators, and the products of combustion are discharged to the atmosphere through the main plant stack.

One other small gaseous effluent stream is discharged to the atmosphere through the main stack. This stream is composed of the exhaust from the oil-fired rotary dryer used in recovering sodium sulfate from the bleed stream of the Stretford solution in the Stretford plant. The products of combustion pass through a cyclone for removal of particulate and then enter the main stack.

The products of combustion of the various fuels used in the steam boilers and superheaters are not treated for further sulfur removal and are discharged directly from the main plant stack to the atmosphere.

The ANG complex uses only the Stretford process for recovery of sulfur from the various waste gas effluent streams. As stated, the Stretford tail gas is incinerated in the steam superheaters. It is expected that under average operating conditions the saleable sulfur recovered by the Stretford amounts to about 148 tons per day, which

represents about 77 weight percent of the coal sulfur charged to the plant complex. About 8 weight percent of the coal sulfur is discharged to the atmosphere as sulfur dioxide, and about 15 weight percent of the coal sulfur is present in the solid and sludge wastes.

The treatment of vent gases from the processing units of the plant complex is summarized as follows:

1. The major gas effluent streams (products of combustion from the boilers and superheaters) are discharged to the atmosphere through the main plant stack.
2. The Rectisol plant vent gases, including flash gases and hot regenerator overhead, are sent to the Stretford sulfur recovery plant.
3. The acid gases from the ammonia recovery section of the Phenosan plant are sent to the Stretford sulfur recovery plant.
4. The tail gas from the Stretford sulfur recovery plant is sent to the superheaters for incineration.
5. The Stretford oxidizer vent gases are discharged directly to the atmosphere.
6. The coal lock gas is sent to the superheaters for incineration.
7. A small low pressure vent stream from gas liquor separation is flared and discharged directly to the atmosphere.

The tentative ANG plant design, like the El Paso design, does not pass the synthetic pipeline gas (SPG) from the first stage compression through a final methanol wash in the Rectisol plant for dehydration and final CO_2 removal but uses a glycol dehydration system after final compression, for water removal.

In the ANG plant design the process condensates from the gasifiers, shift conversion, gas cooling, and Rectisol (primarily methanol still bottoms) are sent to gas liquor, tar, and tar oil separation. After separation the gas liquor is sent to the Phenosan

plant where phenols, acid gases, and ammonia are separated, and the aqueous effluent, without biological treatment, is used as make-up to the process water cooling tower. Storm water falling on contaminated paved areas is collected in a retention pond, passed through an oil separator, and clarified by flocculation. This cleaned water is also used as make-up to the process water cooling tower. Waste sanitary water after biological treatment would also be used as make-up to the process cooling system. The blowdown stream from the process water cooling water tower is sent to a multi-effect evaporator, and the reclaimed water is recycled to the low-pressure steam system or ammonia recovery.

The regeneration waste streams from the softener system and the demineralizer system are combined with the blowdown from the low-pressure steam system and sent to deepwell injection for disposal.

The tentative plant design indicates that the underflow of the thickener of the raw water clarification system is sent to the ash handling system. This sludge is combined with the gasifier ash and disposed of by mine burial. The solids discharged by the multi-effect evaporators are also disposed of by mine burial.

2.2 GASEOUS EMISSIONS

The data for the major gaseous effluent discharge from each of the four planned plant complexes have been compiled on a weight basis and are presented in Table 2-1. The hydrocarbon discharges are indicated to be very nearly zero for the El Paso, Natural, and ANG plant complexes, since essentially all effluent gas streams are incinerated. The WESCO plant complex has a small hydrocarbon discharge, primarily C_2H_6 , since one effluent stream entering the superheater stack will not be incinerated. The estimate of NO_x discharges appears to be lowest for the El Paso plant, higher for the WESCO and ANG plants, and highest for the Natural plant. The particulate content of the effluent gases is estimated to be very small from the El Paso plant complex, higher for the WESCO and ANG plant complexes, and largest for the Natural plant complex. The sulfur dioxide content of the gaseous effluent streams is least for the El Paso and WESCO plant complexes and greatest for the Natural and ANG plant complexes.

TABLE 2-1

MAJOR GASEOUS EFFLUENTS FOR EACH OF FOUR GASIFICATION PLANT COMPLEXES,
EACH COMPLEX 250 MMSCFD^(a) OF SYNTHETIC PIPELINE GAS

Plant Source	Components, tons per stream day ^{(b) (c)}																	Total
	N ₂	O ₂	H ₂ O	CO ₂	CO	H ₂	CH ₄	C ₂ H ₆	C ₃ H ₈	C ₂ H ₄	C ₃ H ₆	H ₂ S	SO ₂	COS	CS ₂	NO _x	Parti- culate	
El Paso Natural Gas Co. ^(d)																		
Power Stack	61,140	12,250	3,240	7,740	P	0	0	0	0	0	0	0	4.01	0	0	6.75	0	84,380
Oxygen Plant Vent	18,730	190	120	13	0	0	0	0	0	0	0	0	0	0	0	0	0	19,050
Cooling Towers	A	A	17,820	P	0	0	0	0	0	0	0	P	0	0	0	0	P	17,820
Sulfur Plant Vent (rich-incinerated)	350	17	53	520	P	0	P	P	P	P	P	P	.615	0	0	.10	0	940
Sulfur Plant Vents	3,030	370	650	19,530	P	P	P	P	P	P	P	P	2.59	0	0	0	0	23,580
(lean-catalytic incineration)																		
Total Gaseous Effluent	83,250	12,830	21,880	27,800	P	P	P	P	P	P	P	P	7.22	0	0	6.85	P	145,770
Western Gasification Co. (WESCO) ^(e)																		
Oxygen Plant Vent	19,640	390	150	12	0	0	0	0	0	0	0	0	0	0	0	0	0	20,190
Boiler Plant Stack																		
(after flue gas scrubber)																		
Superheater Stack ^(f)	30,070	1,270	2,640	19,740	P	0	0	0	0	0	0	0	8.86	0	0	17.5	0.82	53,750
Cooling Towers	3,520	60	270	10,640	P	0	P	9.1	1.4	.5	.6	.004	.74	.07	P	1.2	P	14,500
Biological Treating	A	A	13,100	P	0	0	0	0	0	0	0	P	0	0	0	0	P	13,100
	B	B	B	B	B	B	B	B	B	B	B	B	B	B	B	B	B	B
Total Gaseous Effluent	53,230	1,720	16,160	30,392	P	0	P	9.1	1.4	.5	.6	.004	9.60	.07	P	18.7	0.82	101,540
Natural Gas Pipeline Co. of America ^(g)																		
Oxygen Plant Vent	20,460	600	P	P	0	0	0	0	0	0	0	0	0	0	0	0	0	21,060
Cooling Towers	A	A	29,150	P	0	0	0	0	0	0	0	P	0	0	0	0	P	29,150
Boiler Stack (after flue gas scrubbing)	33,340	1,480	6,890	14,300	P	0	0	0	0	0	0	0	22.80	0	0	34.6	4.8	56,070
Superheater Stack	5,930	300	890	19,500	P	0	P	P	P	P	P	P	8.60	0	0	P	P	26,630
Claus Tail Gas Incinerator Stack	420	7	120	300	P	0	P	P	P	P	P	P	3.30	0	0	P	P	850
Low-pressure Atmospheric Vent	210	60	11	0.8	0	P	P	P	P	P	P	P	.053	0	P	0	0	280
Bio-oxidation Vent	A	A	P	170	0	0	P	P	P	P	P	P	.21	0	0	0	0	170
Total Gaseous Effluent	60,360	2,450	37,060	34,270	P	P	P	P	P	P	P	P	.053	34.91	P	34.6	4.8	134,210

TABLE 2-1 (Continued)

Plant Source	N ₂	O ₂	H ₂ O	CO ₂	CO	H ₂	CH ₄	C ₂ H ₆	C ₃ H ₈	C ₂ H ₄	C ₃ H ₆	H ₂ S	SO ₂	COS	CS ₂	NO _x	Particulate	Total
ANG Coal Gasification Co. (h)																		
Main Stack (sum of a,b,c)	15,870	620	1,830	24,080	P	0	P	P	P	P	P	0	30.34	0	0	13.3	2	42,440
a. Stream Boiler Vent (i)	10,240	400	730	2,900	P	0	0	0	0	0	0	0	12.43	0	0	12.2	2	14,300
b. Superheater Vent (i)	5,570	220	1,090	21,170	P	0	P	P	P	P	P	0	17.89	0	0	1.1	P	28,070
c. Stretford Bleed Stream, Dryer Vent	55	2	5	14	P	0	P	P	P	P	P	0	.02	0	0	0	P	76
Stretford Oxidizer	1,680	580	110	290	P	P	P	P	P	P	P	0	0	P	P	0	P	2,660
Gas Liquor, Low Pressure Flare	6	0	2	7	P	P	P	P	P	P	P	P	.21	P	P	P	0	15
Oxygen Plant Vent	18,080	100	P	P	0	0	0	0	0	0	0	0	0	0	0	0	0	18,180
Cooling Towers	A	A	37,410	P	0	0	0	0	0	0	0	0	0	0	0	0	P	37,410
Total Gaseous Effluent	35,640	1,300	39,350	24,380	P	P	P	P	P	P	P	P	30.55	P	P	13.3	2	100,710

(a) Nominal average plant production of synthetic pipeline gas per calendar day. The table does not include intermittent sources such as start up flares.

(b) Atmospheric discharge in tons per day where numbers are shown. Where letters are used, they have the following significance:

P = may be present in very small quantities, possibly detectable

0 = probably absent

A = air used but not estimated: e.g. cooling towers

B = no estimate

(c) Conversion Table

N₂ (tons per day) x 18.763 = scfm (60°F, 30"Hg)
O₂ (tons per day) x 16.424 = scfm (60°F, 30"Hg)
CO₂ (tons per day) x 11.942 = scfm (60°F, 30"Hg)
Air (tons per day) x 18.217 = scfm (60°F, 30"Hg)
H₂O (tons per day) x 0.1664 = gpm
H₂O (tons per day) x 0.2442 = acre ft. per operating year
Operating year = 332 stream days at nominal 275 mmcf/d

(d) Primary Reference: -El Paso Coal Gasification Project, New Mexico, Final Environmental Statement, U.S. Department of the Interior, Bureau of Reclamation, Int. PES 77-03, Feb. 8, 1977, Vols. I & II.

(e) Primary Reference: -Western Gasification Company (WESCO) Coal Gasification Project and Expansion of Navajo Mine by Utah International Inc., New Mexico, Final Environmental Statement, U.S. Department of the Interior, Bureau of Reclamation, Int. PES 76-2, Jan. 14, 1976, Vols. I & II.

(f) This effluent stream also contains 0.35 tons per day CH₃OH, residual solvent from Rectisol.

(g) Primary Reference: -Environmental Assessment of a Coal Gasification Complex in Dunn County, North Dakota, Natural Gas Pipeline Company of America, December, 1976, Vols. I & II.

(h) Primary References: - (a) ANG Coal Gasification Company, North Dakota Project, Draft Environmental Impact Statement, U.S. Department of the Interior, Bureau of Reclamation, Int. DES 77-11, March 17, 1977, and: - (b) ANG Coal Gasification Company, Member of the American National Resources System, Supplemental Application to the North Dakota State Department of Health for a Permit to Construct a Coal Gasification Plant in Mercer County, North Dakota, September, 1976.

(i) Tar, tar oil, naphtha, phenols, Stretford tail gas, and coal lock gas are all being burned in the steam boilers and superheaters. All of these are by-products of the coal being gasified. The yields of these by-products were calculated from the composition of raw gas leaving the gasifiers as reported on pages 1-35 and 1-37 of the reference given in footnote (h)(a) above. The products of combustion (POC) were estimated by the authors and an allowance was made for the possible use of additional supplemental fuel such as fuel oil.

2.3 LIQUID EMISSIONS

Since each of the plants is using the design concept of zero liquid discharge to adjacent surface water, there will be no direct liquid effluent discharge of this nature. In order to meet this design criteria, the water required for the operation of the plant complexes will be treated and recycled within the plant boundaries to the maximum extent possible. The major portion of the aqueous effluent discharged from each plant complex will be evaporated. Cooling tower evaporation will account for about 8.4 percent of this value (see Table 2-1). In addition to evaporative water discharge, liquid will accompany the solids and sludges as well as sediment from evaporation ponds, all of which are returned to the mine for burial. The bulk of the solids (primarily ash) returned to the mine for burial will contain about 18 percent water by weight, but the water content of the sludges returned for burial cannot be estimated with reasonable accuracy from the data available. The data for the major solids and sludges discharged from each of the four planned complexes have been compiled and are presented in Table 2-2.

Besides the aqueous liquid discharges there will be other fluid by-products recovered during synthesis gas production. These liquids and their planned disposition are listed in Table 2-3. None of these materials will be disposed of by direct discharge to the environment.

TABLE 2-2

GASIFICATION PLANT COMPLEXES, MAJOR SOLIDS AND SLUDGES HANDLING,
EACH COMPLEX 250 MMSCFD ^(a) OF SYNTHETIC PIPELINE GAS

		Estimated Quantity of Effluent Per Stream/Day (b)	
Source	Disposition	Total, Solids Plus Water (tons)	Dry Solids (tons)
<u>El Paso Natural Gas Company (c)</u>			
Subbituminous			
Coal Preparation			
Coal (1 3/4" x 2mm)	Synthesis Gas Production	23,256	23,256
Coal (1 3/4" x 2mm)	Fuel Gas Production	4,992	4,992
Clean Coal (2mm x 100 mesh)	Fine Coal to Sales	2,544	2,544
Coal Cleaning Refuse	Return to Mine for Burial	n.a. (d)	1,680
Water Treatment			
Raw Water Supply, Settling Basin	River Sand and Silt - to Gravel Pits	74	
Filter Backwash	To Raw Water Supply	0	
Lime Treater Sludge	To Ash Handling	0 (e)	
Water Softener Blowdown	To Ash Handling	0 (e)	
Cooling Tower Blowdown	To Ash Handling	0 (e)	
Contaminated Gas Liquor	To Ash Handling	0 (e)	
Water from Glycol Regenerator	To Ash Handling	0 (e)	
Ash Handling (Gasifier Ashes & Sludges)			
Coarse Ash and Sludge	Return to Mine for Burial	6,768	5,455 (f)
Fine Ash and Sludge	To Fine Ash Pond - Solar Evaporation and Water Reuse	96	77 (f)
Excess Water (from ash handling)	To Fine Ash Pond - Solar Evaporation	5,400	n.a.
Total Solid Waste Effluent			7,212
<u>Western Gasification Company (WESCO) (g)</u>			
Subbituminous			
Coal Preparation			
Coal (1 1/2" x 7/16")	Synthesis Gas Production	24,820	24,820
Clean Coal (4 x 48mm)	Boiler Plant for Steam Production	3,868	3,868
Clean Coal (4 x 48mm)	Fine Coal to Sales	284	284
Coal Cleaning Refuse	Refuse to Holding Pond	n.a. (d)	2,263
Water Treatment			
Waste Water, Biological Treatment	Lime Sludge to Mine for Burial	48	24
Sanitary Sewage	Sludge to Mine Burial	81	49
Flue Gas Treating	Sludge to Mine Burial or Possibly Land Reclamation	0.3	0.03
Ash Handling	CaSO ₄ · 2H ₂ O & Inerts and Fly Ash	263	231
Gasifier Ash	Return to Mine for Burial	7,684	6,534
Boiler Plant Bottom Ash	Return to Mine for Burial	192	148
Boiler Plant Fly Ash	Return to Mine for Burial	575	443
Total Solid Waste Effluent			9,692

TABLE 2-2 (Continued)

		Estimated Quantity of Effluent Per Stream/Day ^(b)	
Source	Disposition	Total, Solids Plus Water (tons)	Dry Solids (tons)
Lignitic			
<u>Natural Gas Pipeline Company of America</u>^(h)			
Coal Preparation			
Coal (2" x 1/4")	Synthesis Gas Production	28,346	28,346
Coal (-1/4" fines)	Boiler Plant for Steam and Power Production	7,078	7,078
Coal (-1/4" fines)	Fine Coal to Sales	6,304	6,304
Water Treatment			
	Lime Sludge to Mine for Burial	76	34
Waste Water, Biological Treatment	Mine Burial	256	106
Cooling Tower Water Blowdown	Sludges from Cooling Towers to Mine Burial	35	11
Concentrator	Sludges to Mine Burial	64	51
Stack Gas Scrubber	Filter Cake (CaSO ₃ · 2H ₂ O) to Mine Burial	352	196
Ash Handling			
Bottom Ash & Fly Ash	Mine Burial	664	537
Gasifier Ash	Mine Burial	2,691	2,171
Total Solid Waste Effluent			3,106
Lignitic			
<u>ANG Coal Gasification Company</u>⁽ⁱ⁾			
Coal Preparation			
Coal (2" x 1/4")	Synthesis Gas Production	26,840	26,840
Coal (-1/4" fines)	Fine Coal to Sales	15,720	15,720
Water Treatment			
	Lime Sludge to Ash Handling	0 ^(e)	
Cooling Tower Water Blowdown	To Concentrator (Evaporator)	0 ^(e)	
Concentrator	Sludges to Mine Burial	n.a. ^(j)	
Steam System Blowdown and Softner & Demineralizer Regenerator Wastes	Brine or Sludge to Deep Well Injection	1,338	16
Stretford Bleedstream	Na ₂ SO ₄ to Sales		23
Ash Handling			
Boiler Fly Ash	To Mine for Burial	1,980	6
Gasifier Ash	To Mine for Burial		1,656
Total Solid Waste Effluent			1,678 ^(k)

(a) Nominal average plant production of synthetic pipeline gas per calendar day.

(b) Operating year equals 332 stream days. Nominal average plant production per stream day 275 mscfd.

(c) Primary Reference: - El Paso Coal Gasification Project, New Mexico, Final Environmental Statement, U.S. Department of the Interior, Bureau of Reclamation, Int. PES 77-03, February 8, 1977, Vols. I & II.

(d) Water content not available.

(e) There are no effluent solids discharged at this point as the sludges go to the ash handling system.

TABLE 2-2 (Continued)

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- (f) There are about 100 tons per day of dry solids in these two effluent streams which are not derived from coal ash.
- (g) Primary Reference: - Western Gasification Company (WESCO) Coal Gasification Project and Expansion of Navajo Mine by Utah International Inc., New Mexico, Final Environmental Statement, U.S. Department of the Interior, Bureau of Reclamation, Int. FES 76-2, Jan. 14, 1976, Vols. I & II.
- (h) Primary Reference: - Environmental Assessment of a Coal Gasification Complex in Dunn County, North Dakota, Natural Gas Pipeline Company of America, Vols. 1 & 2, December, 1976.
- (i) Primary References: - (a) ANG Coal Gasification Company, North Dakota Project, Draft Environmental Impact Statement, U.S. Department of the Interior, Bureau of Reclamation, Int. DES 77-11, March 17, 1977, and: - (b) ANG Coal Gasification Company, Member of the American Natural Resources System. Supplemental Application to the North Dakota State Department of Health for a Permit to Construct a Coal Gasification Plant in Mercer County, North Dakota, September, 1976.
- (j) n.e., no estimate.
- (k) Does not include concentrator sludges; these probably will be less than 200 tons per day of dry solids.
-

TABLE 2-3

LIQUIDS RECOVERED FROM SYNTHESIS GAS PRODUCTION FOR EACH PLANT COMPLEX

Liquid Effluent	El Paso		WESCO		Natural		ANG	
	Quantity (tons/day)	Disposition	Quantity (tons/day)	Disposition	Quantity (tons/day)	Disposition	Quantity (tons/day)	Disposition
Tar	1066	a	743	a	1117	a	841	b
Tar Oil	583	a	755	c	200	c	142	b
Naphtha	240	a	315	a	153	a	136	b
Ammonia ^d	260	a	204	a	124	a	214	a
Crude Phenols	136	a	102	a	166	a	163	b

a - Recovered for market

b - Used as process fuel

c - Used as process fuel, balance marketed

d - Calculated as hydrous ammonia

2.4 SOLID EMISSIONS

All of the plant complexes plan on using mine burial for the bulk of the solid wastes produced during synthesis gas production (see Table 2-2). In addition to mine burial some of the aqueous effluent containing either fly ash or coal washing refuse is sent to solar evaporation ponds or to holding ponds; the residual sediments are ultimately buried. In this case some of the supernatant carrier liquid is recycled back to the ash handling system for make-up and reuse.

In addition to the above, the ANG plant proposes to dispose of steam system blowdown, water softener, and demineralizer regenerator wastes by deep well injection. The dry solids disposed in this manner are estimated to be in the order of 16 tons per day.

The only other solid waste discharged to the environment is particulate matter which is estimated in Table 2-1 and accompanies the gaseous emission.

2.5 DISCUSSION - EMISSIONS

An examination of the data given on a weight basis and presented in Tables 2-1 and 2-2 indicates that the quantity of gaseous emissions from a synthesis gas production facility is 10 to 60 times that of the solid emissions. For the four plant complexes, the average gaseous emission is about 33 times as large as the average solid emission. The carbon dioxide emission, on a weight basis, varies from 19 to 30 percent of the total gaseous emissions and averages about 25 percent for the four plants. The vaporized water in the stack and cooling tower emissions, on a weight basis, varies from 15 to 39 percent and also averages about 25 percent. The water vapor in the stack and cooling tower emissions for the two North Dakota plants is about twice that estimated for the two New Mexico plants. This is due to the moisture content of the coal being processed (lignitic vs. subbituminous) and because of the methods used for dissipating rejected heat.

The amount of hydrocarbon liquids and ammonia recovered during synthesis gas production for the four plant complexes is compared in Table 2-3. In the El Paso plant complex, steam and power are generated with fuel gas from additional gasifiers. Consequently, the tar, tar oil, crude phenol, and ammonia production should be higher as these by-products are collected from fuel gas production, as well as synthesis gas production. The other variations for the four plants are also influenced by the type of coal being processed (lignitic vs. subbituminous). The yield of tar and related hydrocarbon compounds is related to the so-called tar forming characteristics of the coal substance, and this, in turn, is related to the classification of coal by rank. Carbonization assay

procedures have some value in estimating these yields, especially with respect to Lurgi dry ash gasification processing where cracking and other reactions of the volatile carbonization products of coal are minimized.

In Table 2-4, the sulfur discharges for the four plant complexes are estimated. In the El Paso complex a fuel gas is generated for steam and power production. During processing the crude fuel gas is scrubbed with Stretford solution to reduce the sulfur content. In the WESCO complex the tail gases from the Claus and Stretford recovery plants, together with many other effluent streams are incinerated in the steam boilers, and the stack gases are scrubbed to remove sulfur dioxide. For each of these plants the gaseous discharge of coal sulfur to the atmosphere is reduced to less than 2 percent by weight. In addition, the recovery of coal sulfur as marketable sulfur is increased for the El Paso plant. In the Natural and ANG plant complexes, the gaseous discharge of coal sulfur to the atmosphere is estimated at about 6 and 8 percent by weight, respectively. In these plants, Natural uses stack gas scrubbing on the coal-fired boilers and ANG uses the collected by-products tar, tar oil, naphtha, crude phenols, and Stretford tail gas as fuel to the steam boilers and superheaters. Neither of these plants plan on scrubbing the products of combustion from the incinerators of other effluent streams for sulfur removal.

TABLE 2-4

COAL SULFUR DISTRIBUTION OF EFFLUENTS

Gasification Complex Distribution	El Paso		WESCO		Natural		ANG	
	Sulfur (tons/day) (a)	Weight %	Sulfur (tons/day) (a)	Weight %	Sulfur (tons/day) (a)	Weight %	Sulfur (tons/day) (a)	Weight %
Gaseous Gasification Effluent to Atmosphere	1.60	0.82	1.64	0.63	6.17	2.02	15.29 ^(b)	7.96
Gaseous Effluent from Steam & Power to Atmosphere	2.01	1.03	3.20	1.23	11.34	3.72		
Recovered as by-product, to Sales	187	95.9	202.8	78.0	222.2	72.8	148.1	77.1
In other by-products, solid and sludge wastes	4.35	2.23	52.4	20.1	65.44	21.5	28.71	14.95
Total	195	100.0	260	100.0	305.1	100.0	192.1	100.0

Sulfur in Gaseous Gasification Effluent (lbs per mm Btu in coal to gasification)	.008 ^(c)	.0079 ^(c)	.032 ^(c)	.032 ^{(b) (c)}
Sulfur in Gaseous Steam & Power Effluent (lbs per mm Btu in coal to steam & power)	.046 ^(c)	.0838 ^(c)	.23 ^(c)	(b)
Total Sulfur in Gaseous Effluents from Complex (lbs per mm Btu in coal to complex)	.015 ^(c)	.0198 ^(c)	.072 ^(c)	.079 ^{(b) (c)}

(a) Tons of 2000 pounds per stream day; 332 stream days = 1 operating year.

(b) All fuel burned in boiler and superheater was obtained from gasification effluent streams or gasification combustible by-products. The Stretford tail-gas, burned in the superheater, plus the low pressure flare from gas liquor separation contain 40.73 percent of the total effluent gaseous sulfur.

(c) Multiply by 1.998 to obtain pounds of sulfur dioxide per mm Btu.

2.6 ECONOMIC ANALYSIS OF THE GASIFICATION COMPLEX

An economic analysis was performed on all four gasification plants. The total capital investment, the total operating cost, the total allowable revenue and the revenue per SCF of SNG produced were estimated for each plant. For the El Paso and Natural plants the cost of coal were also computed. Similar processes are proposed to be used in each plant and this provided for a common basis that was used in this economic analysis. The economic analysis of each plant was based on the production of nominally 250MMSCFD of SNG (this actually amounts to the production of 277MMSCFD on a stream day basis). The El Paso and WESCO plants will be located in New Mexico and propose to use sub-bituminous coal and the Natural and ANG plants will be located in North Dakota and propose to use lignite.

The El Paso FPC 1973 filings provided a fairly detailed documentation of cost estimates for the plant and the individual process areas. It also used a systematic method for arriving at various operating costs. Hence it was chosen as the basis for the economic analysis and comparison for the other three plants. All costs are based on 1973 dollars, since the El Paso costs were based on 1973 dollars. Pertinent data required for the economic analysis were taken from El Paso FPC, 1973; WESCO Int. FES 76-2, 1976; Natural Environmental Assessment, 1976; ANG Int. DES 77-11, 1977 and ANG Supplemental Application to N.D. State Dept. of Health, 1976.

2.6.1 Total Capital Investment

A process area cost approach was utilized for each gasification plant to estimate the total installation cost. An itemized list was not generated, since the processes were primarily similar and could be compared on the basis of process areas. The installed equipment cost by process area was available for the El Paso and the ANG plants. The installed

costs for the WESCO and the Natural plants were estimated from the costs for the El Paso plant on the basis of materials being processed in each area.

The total installed costs estimated for the four gasification plants by process area are listed in Table 2-5. The total installed cost includes cost of equipment, installation, contractor's and engineering fees, licenses and state tax. Each plant is divided into 14 main process areas for the estimation of the installed cost. The cost of coal preparation and coal storage area is not included in the estimate for the El Paso, WESCO and Natural plants because it was included in the price of coal. The costs for the various process areas in Table 2-5 are similar due to similar processes being used in all four plants. The differences are due to differences in the amount of material being handled. The major differences among the four plants for the installed costs are in the Gasification Sulfur Recovery, Power and Steam Production and Ash Dewatering and Transfer Areas.

The differences in the costs in the gasification area are due to different number of gasifiers that are proposed to be installed at each plant. El Paso proposes to install 28 gasifiers, WESCO and Natural will probably install 30 gasifiers each and ANG estimates to install 26 gasifiers.

There are major differences among the four plants in the Sulfur Recovery Area. Both the El Paso and ANG plants use the Stretford process only for recovery of sulfur while the WESCO and Natural plants use a combination of the Claus and Stretford processes for sulfur recovery and the ADIP process for the removal of hydrocarbons and the concentration of hydrogen sulfide in the feed to the Claus unit. The differences in the costs are also due to differing amounts of sulfur recovered in each plant.

TABLE 2-5

TOTAL INSTALLATION COSTS FOR THE FOUR GASIFICATION PLANTS
(1973 dollars)

Process Area	Total Installation Cost (MM dollars)			
	El Paso ^{1/}	WESCO ^{2/}	Natural ^{2/}	ANG ^{3/}
1. <u>Coal Preparation and Storage</u>	<u>4/</u>	<u>4/</u>	<u>4/</u>	<u>31.49</u>
2. <u>Gasification</u>	<u>66.37</u>	<u>66.92</u>	<u>66.92</u>	<u>56.26</u>
a. Lurgi Installation	64.45	65.00	65.00	
b. Lock Gas Handling	1.92	1.92	1.92	
3. <u>Shift Conversion</u>	<u>7.68</u>	<u>7.68</u>	<u>7.68</u>	<u>7.22</u>
4. <u>Gas Cooling</u>	<u>8.08</u>	<u>8.08</u>	<u>8.08</u>	<u>6.84</u>
5. <u>Gas Purification - Rectisol</u>	<u>40.64</u>	<u>41.62</u>	<u>41.62</u>	<u>31.60</u>
a. Rectisol Units	31.02	32.00	32.00	
b. Refrigeration	9.62	9.62	9.62	
6. <u>Methane Synthesis</u>	<u>18.55</u>	<u>18.55</u>	<u>18.55</u>	<u>19.33</u>
7. <u>Product Gas Compression</u>	<u>5.66</u>	<u>5.00</u>	<u>5.00</u>	<u>7.41</u>
8. <u>Gas Liquor Separation</u>	<u>5.59</u>	<u>5.14</u>	<u>5.14</u>	<u>6.24</u>
9. <u>Gas Liquor Treatment (Phenosolvan)</u>	<u>13.06</u>	<u>12.01</u>	<u>11.99</u>	<u>19.51</u>
a. Treating	6.98	6.42	6.40	
b. Stripping	6.08	5.59	5.59	
10. <u>Sulfur Recovery</u>	<u>8.16</u>	<u>8.79</u>	<u>9.42</u>	<u>9.77</u>
a. Hydrocarbon Removal	--	2.58	2.58	
b. Claus Plant	--	1.25	1.52	
c. Stretford Plant	8.16	4.96	5.32	
11. <u>Power and Steam Production</u>	<u>60.35</u>	<u>41.24</u>	<u>41.24</u>	<u>36.94</u>
12. <u>Oxygen Plant</u>	<u>46.19</u>	<u>46.95</u>	<u>45.93</u>	<u>32.03</u>
a. Air Compression	17.26	17.26	17.26	
b. O ₂ Production	22.39	22.98	22.19	
c. O ₂ Compression	<u>6.54</u>	<u>6.71</u>	<u>6.48</u>	
13. <u>Water System</u>	<u>26.73</u>	<u>23.20</u>	<u>26.20</u>	<u>19.67</u>
a. River Water Pumping Station and Raw Water Pipeline	12.46	12.60	12.60	
b. Water Storage and Pumping	1.75	1.75	1.75	13.83
c. Raw Water Treating	6.72	5.95	6.33	
d. Cooling Water System	5.80	2.90	5.52	5.84

TABLE 2-5 (Continued)

Process Area	Total Installation Cost (MM dollars)			
	El Paso ^{1/}	WESCO ^{2/}	Natural ^{2/}	ANG ^{3/}
14. <u>Ash Dewatering and Transfer</u>	<u>6.32</u>	<u>6.32</u>	<u>3.38</u>	<u>3.02</u>
15. <u>General Facilities</u>	<u>43.84</u>	<u>42.83</u>	<u>43.07</u>	<u>52.90</u>
a. Site Improvement	7.07	7.07	7.07	10.63
b. Plant Buildup	3.87	3.87	3.87	5.95
c. Plant Equipment				6.00
d. Electrical Distribution	6.82	6.82	6.82	6.54
e. Header System and Interconnecting Piping	10.09	10.09	10.09	6.06
f. Evaporation and Settling Ponds	3.44	3.44	3.44	4.22
g. Storage and Loading	2.63	2.63	2.63	0.86
h. Miscellaneous Plant Utility Systems	5.67	5.67	5.67	0.76
i. Initial Catalyst and Chemicals	4.01	3.00	3.00	1.90
j. Land	0.24	0.24	0.48	1.89
k. Fire Protection				0.89
l. Flare Systems				1.62
m. Pilings				5.57
TOTAL	<u><u>357.22</u></u>	<u><u>334.33</u></u>	<u><u>334.22</u></u>	<u><u>340.23</u></u>

Underlined items are totals for each process area.

1/ From El Paso F PC 1973.

2/ Estimated.

3/ From ANG Application to ND Public Service Commission, 1976.
Corrected to 1973 dollars.

4/ Included in cost of coal.

This is because of the sulfur present in the initial coal and the different processes used to recover the sulfur. Natural and WESCO using the Claus and Stretford processes estimate to recover 222 and 202 t/d of elemental sulfur respectively while El Paso and ANG using the Stretford process only estimate to recover 187 and 151 t/d of sulfur.

Differences also exist in the Power and Steam Production Areas in the four gasification plants. El Paso will use 10 air-blown Lurgi gasifiers to produce clean low Btu fuel gas which, after removing the hydrogen sulfide from it, will be used for steam and electrical power generation. Since the stack gases from the combustion of this gas will not contain any sulfur dioxide or particulates, the El Paso plant will not use any electrostatic precipitators or flue gas desulfurization processes for the clean up of the flue gases. The WESCO and Natural plants propose to use coal fines to fire their boilers and will use electrostatic precipitators and flue gas desulfurization processes to clean up the flue gases. These plants will also produce a sludge from the desulfurization process that will have to be disposed by mine burial. The ANG plant does not propose to generate its own steam or electrical power but will rather purchase it from the neighboring Basin Electric Power Plant to whom it will sell its coal fines. ANG only proposes to have supplementary boilers fired with coal-derived tar, tar oils, naphtha and phenolics and will clean up the stack gases with small electrostatic precipitators.

The installed costs for the Ash Dewatering and Transfer areas are lower at the Natural and ANG plants than at the El Paso and WESCO plants because the Natural and ANG plants will handle lesser amounts of ash than the El Paso and WESCO plants. This is due to the lower ash content of the North Dakota lignites compared to the New Mexico sub-bituminous coals used.

Land costs for sites considered in North Dakota are higher than those in New Mexico.

The cost distribution by process units for the four plants is shown in Table 2-6. The comparison is made by tabulating the percentage of the cost for each process area and the cost of production per 1000 SCF of SNG per process area. It can be seen that gasification constitutes nearly a fourth of the total cost for each plant. Other major cost constituents are the steam and power production, the oxygen plant and the gas purification areas.

The total gross capital investment for each of the four gasification plants is computed in Table 2-7. The method used by El Paso was used for all the plants. Contingency was estimated at 10 percent of the installed equipment cost. Allowance for funds during construction was computed at 8.5 percent compounded semi-annually. General overheads were estimated at 3 percent of installed cost plus contingency; plant startup and other costs were determined at 1/2 percent of the installed cost plus contingency. The working capital was estimated at 2.5 percent of the total property, plant and equipment cost. The total gross capital investment was estimated as $\$491 \times 10^6$ for El Paso, $\$459 \times 10^6$ for WESCO, $\$459 \times 10^6$ for Natural and $\$467 \times 10^6$ for ANG. A ratio of 0.25 to 0.75 was assumed between equity and debt capital, as proposed by El Paso, as a method for financing the plant.

2.6.2 Total Operating Costs and Allowable Revenue

The annual operating cost for each of the four gasification plants is estimated in Table 2-8. They are based on the estimates provided by El Paso and ANG. The estimates provided by El Paso were the basis for the estimate calculated for the WESCO and Natural plants. Each plant is

TABLE 2-6

COST DISTRIBUTION BY PROCESS UNITS FOR THE FOUR GASIFICATION PLANTS
(Does not include General Facilities)

General Facilities Distributed, % Cost/1000 SCF SNG, dollars (1973)									
Process Units	El Paso	WESCO	Natural	ANG	El Paso	WESCO	Natural	ANG	
1. Gasification	21.18	22.95	22.98	22.04	0.294	0.316	0.318	0.292	
2. Shift Conversion	2.45	2.64	2.64	2.86	0.034	0.036	0.037	0.038	
3. Gas Cooling	2.58	2.77	2.77	2.65	0.036	0.038	0.038	0.035	
4. Gas Purification	12.97	14.28	14.30	12.38	0.180	0.197	0.198	0.164	
5. Methane Synthesis	5.92	6.37	6.37	7.55	0.082	0.088	0.088	0.100	
6. Product Gas Compression	1.80	1.71	1.72	2.93	0.025	0.023	0.024	0.039	
7. Gas Liquor Separation	1.78	1.76	1.76	2.45	0.025	0.024	0.024	0.032	
8. Gas Liquor Treatment	4.17	4.12	4.12	7.62	0.058	0.057	0.057	0.101	
9. Sulfur Recovery	2.60	3.02	3.24	3.81	0.036	0.042	0.045	0.051	
10. Power and Steam	19.26	14.15	14.16	14.42	0.267	0.195	0.196	0.191	
11. Oxygen Plant	14.74	16.10	15.78	12.51	0.205	0.222	0.218	0.166	
12. Water System	8.53	7.96	9.00	7.62	0.118	0.110	0.124	0.101	
13. Ash Dewatering and Transfer	2.02	2.17	1.16	1.16	0.028	0.030	0.016	0.015	
TOTAL	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>	<u>1.388^{1/}</u>	<u>1.378^{1/}</u>	<u>1.383^{1/}</u>	<u>1.326^{1/}</u>	

^{1/} From Table 2-9.

TABLE 2-7

TOTAL GROSS CAPITAL INVESTMENT FOR THE FOUR GASIFICATION PLANTS
(in Millions of Dollars)
(1973 Dollars)

Line No.	Item	El Paso ^{1/}	Wesco	Natural	ANG	Source or Basis of Estimate
1.	Installed Equipment, Plant, Property Cost	357.22	334.33	334.22	340.23	Table 2-5
2.	Contingency	<u>35.72</u>	<u>33.43</u>	<u>33.42</u>	<u>34.02</u>	10% of line 1
3.	Installed equipment cost & contingency	<u>392.94</u>	<u>367.76</u>	<u>367.64</u>	<u>374.25</u>	Total of lines 1,2
4.	Allowance for Funds during Construction	70.45	65.94	65.92	48.07 ^{2/}	17.93% of line 3
5.	General Overheads	11.79	11.03	11.03	11.23	3% of line 3
6.	Intangible Plant Start-up Costs	1.96	1.84	1.84	17.15 ^{2/}	0.5% on line 3
7.	Other costs (Organization, etc)	<u>1.96</u>	<u>1.84</u>	<u>1.84</u>	<u>5.78^{2/}</u>	0.5% of line 3
8.	Total Property, Plant, Equipment	479.10	448.41	448.27	456.48	Total of lines 3,4,5,6,7
9.	Working Capital	<u>11.98</u>	<u>11.21</u>	<u>11.21</u>	<u>11.42</u>	2.5% of line 8
10.	Total Gross Capital Investment	<u>491.08</u>	<u>459.62</u>	<u>459.48</u>	<u>467.90</u>	Total of lines 8,9
11.	Equity Capital (25 percent)	122.78	114.91	114.87	116.98	25% of line 10
12.	Debt Capital (75 percent)	368.31	344.71	344.61	350.92	75% of line 10

^{1/} El Paso FPC 1973

^{2/} These values taken from ANG Application to ND Public Service Commission 1976, corrected for 1973 dollars.

TABLE 2-8

ANNUAL OPERATING COSTS FOR THE FOUR GASIFICATION PLANTS
(in Millions of dollars)
(1973 dollars)

Line No.	Item	El Paso ^{1/}	WESCO ^{2/}	Natural ^{2/}	ANG ^{3/}	Source or Basis of Estimate
1.	Estimated Wages	10.00	10.00	10.00	10.49	
2.	Maintenance	10.72	10.03	10.03	7.37	3% of installed equipment cost
3.	Materials and Utilities	4.00	4.00	4.00	8.05	
4.	Chemicals and Catalysts	3.52	3.52	3.52	1.55	
5.	Coal Feed Stock	31.22	33.81	31.90	21.87	
6.	Interest Expense ^{4/}	15.65	14.65	14.64	14.91	
7.	Taxes other than Income Taxes	<u>5.99</u>	<u>5.61</u>	<u>5.60</u>	<u>3.94</u>	1.25% of total Property, Plant, and Equipment
8.	Subtotal	81.10	81.62	79.69	68.18	
9.	Administration and General Expenses	<u>5.92</u>	<u>5.96</u>	<u>5.82</u>	<u>4.98</u>	7.3% of line 8
10.	Total Operating Cost	<u>87.02</u>	<u>87.58</u>	<u>85.51</u>	<u>73.16</u>	

1/ El Paso FPC 1973

2/ Based on El Paso Cost Calculations

3/ ANG Application to ND Public Service Commission, 1976

4/ Average interest per year for useful life of plant of 25 years

approximately about the same type and will employ the same number of people, hence the estimated wages will be the same. Maintenance is assumed to be 3 percent of the installed equipment cost. Materials and utilities will be similar for the El Paso, WESCO and Natural plants. It will be higher at the ANG plant since it will purchase all its steam and electrical power from Basin Electric. Chemicals and catalysts will be approximately the same for all plants.

The coal feed stock cost was estimated from the amount of coal needed for gasification and steam and power generation and the cost of coal for each plant. WESCO has a coal contract for \$0.208 per MMBTU and ANG has a standard coal selling price of \$2.43 per ton. The price of coal for the El Paso and Natural was estimated at \$3.33 and \$2.71 per ton respectively as discussed in Section 2.6.3. The price of coal at WESCO is equivalent to \$3.55 per ton. This was determined by weighting the cost for boiler coal which will be washed and hence have a higher heating value per ton, with the cost for gasifier coal which will not be washed.

Interest was calculated at 8 1/2 percent per annum on the debt capital compounded semi-annually for a useful plant life of 25 years and averaged over 25 years. Property and taxes other than income tax were computed at 1.25 percent of the total property, plant and equipment value. Administration and other general expenses were completed as a percentage of total operating costs.

The annual operating costs were determined as $\$87.02 \times 10^6$ for El Paso, $\$87.58 \times 10^6$ for WESCO, $\$85.51 \times 10^6$ for Natural and $\$73.16 \times 10^6$ for ANG.

Table 2-9 shows the calculations of the estimated annual revenue allowable for each of the four gasification plants and the revenue allowed per 1000 SCF of SNG. Depreciation and amortization was estimated at 4 percent of the total property, plant and equipment value for a 25-year plant life. A 15 percent rate of return was allowed on the equity capital average over a 25 year plant life. Credit taken was by-products that will be sold. Table 2-10 shows the amounts of saleable by-products from each plant and the expected selling price. Income tax was computed at 50 percent and averaged over the 25 year expected life of the plant.

The annual allowable revenue for El Paso was estimated as $\$126.76 \times 10^6$, for WESCO as $\$125.84 \times 10^6$, for Natural as $\$126.33 \times 10^6$ and for ANG as $\$121.02 \times 10^6$. The average allowable selling price per 1000 SCF of SNG averaged over 25 years of useful plant life was estimated at \$1.388 for El Paso, \$1.378 for WESCO, \$1.383 for Natural and \$1.326 for ANG.

2.6.3 Cost of Coal at El Paso and Natural Plants

The average annual cost of the coal feed stock was estimated for the El Paso and Natural gasification plants. This was based on an average of 25 years of mine life. The gross capital investment, the total annual operating expenses and the annual cost of coal feedstock was estimated by methods similar to those used for the cost estimation of the gasification plant. Credit was taken for the expected sale of coal fines. The costs include the costs at the mine and the coal preparation and storage areas. Table 2-11 lists the computation of the capital investment, the annual operating expenses, and the cost of coal per ton delivered to the gasification plant. The gross capital investment was estimated as $\$115 \times 10^6$ for El Paso and $\$103 \times 10^6$ for Natural. The annual cost of coal delivered was estimated as $\$31.22 \times 10^6$ for El Paso and $\$31.90$ for Natural.

TABLE 2-9

ESTIMATED ANNUAL COSTS AND ANNUAL REVENUES
ALLOWABLE FOR THE FOUR GASIFICATION PLANTS
(IN MILLIONS OF DOLLARS)
(1973 DOLLARS)

Line No.	Item	<u>1/</u> El Paso	<u>2/</u> WESCO	<u>2/</u> Natural	<u>2/</u> ANG	Source or Basis of Estimate
1.	Total Operating Costs	87.02	87.58	85.51	73.16	Table 2-8
2.	Depreciation and Amortization	19.16	17.94	17.93	18.26	4% of total property, plant & equipment
3.	Return on Equity	18.42	17.24	17.23	17.55	15% of Equity capital
4.	By-Product Revenue	(16.23)	(14.16)	(11.57)	(5.50)	
5.	Income Tax ^{3/}	<u>18.42</u>	<u>17.24</u>	<u>17.23</u>	<u>17.55</u>	
6.	Total Allowable Revenue	<u>126.76</u>	<u>125.84</u>	<u>126.33</u>	<u>121.02</u>	
7.	Revenue Allowed per MSCF of SNG, \$	1.388	1.378	1.383	1.326	Based on 250 MMSCFD of SNG

1/ El Paso FPC 1973

2/ Based on El Paso calculations

3/ Average annual income tax for useful life of plant of 25 years.

TABLE 2-10

**AMOUNT OF SALEABLE BY-PRODUCTS
AND ESTIMATED SELLING PRICE**

By-Products	Price	<u>Amount Produced, tons/day</u>			
		El Paso	WESCO	Natural	ANG
Tar	\$0.04/gal	1066	743	1117	- <u>2/</u>
Tar Oil	\$0.06/gal	583	530 <u>1/</u>	200	- <u>2/</u>
Naphtha	\$0.07/gal	240	315	153	- <u>2/</u>
Phenolics	\$0.14/gal	135	102	166	- <u>2/</u>
Ammonia	\$ 62/ton	257	204	124	214
Sulfur	\$ 22/ton	187	202	222	151

1/ Additional amounts used as fuel in plant

2/ Used as fuel in plant

TABLE 2-11

CAPITAL INVESTMENT, OPERATING EXPENSES FOR
MINE AND COAL HANDLING AREAS AND COST OF COAL
FOR EL PASO AND NATURAL GASIFICATION PLANTS
(1973 DOLLARS)

Item	El Paso (MM dollars)	Natural (MM dollars)
<u>Capital Investment for Mine and Coal Handling</u>		
1. Capital Investment +10% Contingency	73.27	78.55
2. Allowance for funds used in Construction (8.5% compounded semi-annually)	14.58	15.63
3. Overhead (3% of line 1)	2.20	2.36
4. Intangible costs (Pre-production development, startup and leasehold costs)	21.95	4.00
5. Other costs (organization, etc) (0.5% of line 1)	<u>0.37</u>	<u>0.39</u>
6. Total costs	112.37	100.93
7. Working Capital (2 1/2% of line 6)	<u>2.81</u>	<u>2.52</u>
8. Total Gross Capital Investment	<u>115.18</u>	<u>103.45</u>
9. Equity Capital (25% of line 8)	28.80	25.86
10. Debt Capital (75% of line 8)	86.38	77.59
<u>Operating Expenses</u>		
11. Direct Mining Expenses (Wages, Materials, Supplies, Utilities)	12.04	17.45
12. Interest Expense (85% compounded semiannually on debt capital)	3.81	3.30
13. Administration and General expenses	1.75	1.59
14. Taxes other than Income Tax (1% of line 6)	<u>1.12</u>	<u>1.01</u>
15. Total Operating Expenses	18.72	23.35
16. Depreciation, Amortization and Depletion (average over 25 year mine life)	5.25	3.74
17. Royalty on Coal (.20 per ton coal mined)	2.16	2.72
18. Return on Common Equity (15 percent rate of return)	4.46	3.88
19. Allowance for Income Tax	4.46	3.88

TABLE 2-11 (Continued)

Item	El Paso (MM dollars)	Natural (MM dollars)
20. Sale of Coal Fines	<u>(3.83)</u>	<u>(5.67)</u>
21. Total Estimated Cost	<u>31.22</u>	<u>31.90</u>
22. Coal delivered to Gasification Plant, MM tons/year	9.378	11.761
23. Cost of Coal, \$/ton	3.329	2.712

3.0 EFFLUENT GUIDELINES AND STANDARDS

3.1 INTRODUCTION

The current projections are that five coal gasification plants will be built during the 1980's. If the effluents of these facilities were entirely uncontrolled they would emit in one year approximately 750,000 tons of particulate, approximately 550,000 tons of sulfur compounds (2/3 of which would be H_2S), approximately 80,000 tons of nitrogen oxides (NO_x), and approximately 35,000 tons of carbon monoxide (EPA, March, 1978). Obviously, these emissions would be unacceptable under existing national air quality standards (NAQS). In addition, a few states have developed regulations which prevent significant deterioration (PSD) of the air quality (42 FR 57479 and Section 127 of the Clean Air Act Amendments of 1977). Areas that do not meet NAQS must meet new source review and emission offset regulations (41 FR 55525 as amended by Section 129 of the Clean Air Act Amendments of 1977). Coal gasification plants must also meet the "best available control technology" (BACT) section of PSD. Assuming that the five plants meet the above requirements, the emissions per year would be reduced to approximately: 15,000 tons of particulates, 110,000 tons of sulfur compounds (mostly SO_2), 50,000 tons of NO_x , and some 3,000 tons of carbon monoxide and non-methane hydrocarbons. Clearly, gasification plants have the potential to become significant emission sources of particulates, sulfur compounds, NO_x , non-methane hydrocarbons, and carbon monoxide (HEW, no date). This report addresses the effluent characteristics of four of the proposed five plants. The effluent control systems for each of these plants are also discussed.

A typical gasification facility (Figure 3-1) consists of two major plants: a power plant which at least produces steam and, in some cases, electricity, and a gasification plant. The power plant emissions are limited under the current new source performance standards and as a result are not discussed in this report. The emissions from the gasification plants, however, are not limited by new source performance standards and are addressed in this report.

Setting new source performance standards is a difficult task for a major gasification facility. Figure 3-1 identifies the major gaseous effluent sources for a gasification facility. The task of setting standards to control these emissions is complicated by several facts:

1. The physical separation distance of the plant units can be significant (1000 meters or more (1/2 mile)).
2. Process design differences, even with Lurgi technology, can change the emission control equipment requirements and the effluent characteristics (e.g., a Claus/Stretford sulfur recovery unit instead of just a Stretford unit).
3. An obvious design choice is to combine power plant emissions with those from the gasification plant, for treatment. This makes the task of monitoring and control more difficult.
4. The setting of standards for only one of the gasification technologies may establish a precedent that is not appropriate for other and new gasification technologies.
5. No commercial gasification plants currently exist in this country. As a result, an operational data base is absent.
6. The sulfur effluent control system units (Stretford, Stretford/Claus, and Claus) are well established technologies. However, there has been little experience with these technologies in a gasification plant environment. Consequently, there is little question as to whether these systems will work; only as to how well they will work. These systems are discussed in detail in Section 4.

Because of the above reasons and several others, the Environmental Protection Agency has decided to issue guidelines (EPA, March 1978) for the emissions from gasification facilities rather than promulgate standards.

FIGURE 3-1: GASEOUS EMISSION AND EMISSION SOURCES FOR A TYPICAL COAL GASIFICATION FACILITY.

Standards do exist for the control of particulates from the coal handling and pre-treatment unit and limit particulate emissions to 20 percent capacity (Federal Register, January 18, 1976). This is important because drying may be required for some of the lignitic coals. New source performance standards have recently been set for new petroleum refinery Claus sulfur recovery plants (Federal Register, March 15, 1978). These regulations are probably not appropriate because of the variance in input stream conditions that a gasification Claus sulfur plant may experience. Additionally, the EPA's current opinion is that a gasification guideline or standard should be set on the basis of total (mass) emissions rather than the concentration basis used for the petroleum refinery Claus plants.

The sulfur emissions from a gasification plant are controlled in Claus and/or Stretford units. These units are discussed in more detail in Section 4 of this report. Carbon monoxide and non-methane hydrocarbons are controlled by combustion (oxidation); consequently, setting a standard to control one (the hydrocarbons) automatically controls the other. The guidelines and standards that control the above emissions are discussed in the following subsections.

Most of the major gasification gaseous effluents (in terms of quantity) are controlled under EPA's guidelines (March, 1978). The solid wastes are uncontrolled and are usually buried in the mined area. Much of the current research effort that is ongoing is directed to the more minor (quantity) trace elements and trace compounds. The EPA has established multimedia environmental goals (MEG) to be used for environmental assessments (EPA, November, 1977).

These goals define levels of significant contaminants or degradents of concern for fossil energy processes and are organized into 85

chemical categories covering essentially all compound classes. Individual MEG charts are planned for 650 substances; 216 have been published (EPA, November, 1977). The most comprehensive existing set of emission goals is the Threshold Limit Values (TLV) established by the American Conference of Governmental Industrial Hygienists (ACGIH). Although ACGIH recommends that these only be used in the practice of industrial hygiene, EPA has relied upon these in the calculation of the MEG's. Table 3-1 contains a listing of the substances analyzed to date by EPA in decreasing order of hazard level. The "category" column refers to the MEG category (EPA, November, 1977). The hazard potential is a number assigned by EPA based upon estimated permissible concentrations (EPC) and a weighting factor. The higher the hazard potential number the more hazardous the substance is thought to be. A triple x, "xxx," indicates the most hazardous substances; a double x, "xx," very hazardous; a single x, "x," hazardous; and a blank indicates the relatively non-hazardous substances. EPA expects to be issuing the supplement to this report with all 650 MEG's shortly. A copy of the multimedia environmental goals chart for methane is shown in Figure 3-2. Two hundred sixteen of these charts have been published. How and to what extent these goals will be incorporated into the standards setting procedure is unclear at this time.

TABLE 3-1

HAZARD RANKING OF COMPOUNDS PRESENTLY ADDRESSED BY MEG CHARTS

<u>Category</u>	<u>Compound</u>	<u>Hazard Potential</u>	<u>Indicator</u>
22	3-Methylcholanthrene	30	xxx
32	Beryllium	30	xxx
68	Chromium	30	xxx
82	Cadmium	30	xxx
83	Mercury	30	xxx
21	Dibenz (a,h) anthracene	28	xxx
12	N-Nitrosodimethylamine	27.5	xxx
76	Nickel	26	xxx
21	7,12-Dimethylbenz (a) anthracene	26	xxx
21	Benzo (a) pyrene	26	xxx
50C	Antimony trioxide	26	xxx
54	Selenium	26	xxx
49	Arsenic	25	xxx
49C	Arsine	25	xxx
49C	Arsenic trioxide	25	xxx
21	Benz (a) anthracene	24	xx
21	Dibenzo (a,i) pyrene	24	xx
74	Cobalt	24	xx
76B	Nickel carbonyl	24	xx
11	N,N'-Dimethylhydrazine	23.5	xx
11	Diazomethane	22	xx
46	Lead	22	xx
16A	Polychlorinated biphenyls	20	xx
20	4,6-Dinitro-o-cresol	20	xx
20	2,4,6-Trinitrophenol	20	xx
26A	Tetramethyllead	20	xx
26A	Alkyl mercury	20	xx
26A	Organotin	20	xx
41	Thallium	20	xx
48	Phosphorus	20	xx
48B	Phosphine	20	xx
50	Antimony	20	xx
51	Bismuth	20	xx
54C	Hydrogen selenide	20	xx
78	Copper	20	xx
85	Uranium	20	xx
10B	Ethyleneimine	19.5	xx
12	N-Nitrosodiethylamine	19.5	xx
47B	Hydrazine	19.5	xx

TABLE 3-1 (Continued)

<u>Category</u>	<u>Compound</u>	<u>Hazard Potential</u>	<u>Indicator</u>
11	Monomethylhydrazine	18	x
23B	Dibenz (a,j) acridine	18	x
23B	Dibenz (a,h) acridine	18	x
23C	Dibenzo (c,g) carbazole	18	x
26A	Tetraethyllead	18	x
10C	Aminotoluenes	17	x
10C	1-Aminonaphthalene	17	x
10C	2-Aminonaphthalene	17	x
7A	Acrolein	16	x
27	Lithium	16	x
27	Lithium hydride	16	x
36	Barium	16	x
44	Germanium	16	x
55	Tellurium	16	x
65	Vanadium	16	x
7A	Formaldehyde	15.5	x
26B	Nickelocene	15.5	x
8D	Phthalate esters	15	x
11	N,N-Dimethylhydrazine	15	x
11	1,2-Diphenylhydrazine	15	x
17	Nitrobenzene	15	x
17	1-Chloro-2-nitrobenzene	15	x
17	Dinitrotoluenes	15	x
18A	Xylenols	15	x
20	3-Nitrophenol	15	x
20	4-Nitrophenol	15	x
20	Dinitrophenols	15	x
23A	Pyridine	15	x
39	Gallium	15	x
47B	Hydrogen cyanide	15	x
71	Manganese	15	x
26C	Copper-8-hydroxyquinoline	14	x
79	Silver	14	x
10C	4-Aminobiphenyl	13	x
15	Benzene	13	x
17	4-Nitrobiphenyl	13	x
19	2,4-Dichlorophenol	13	x
5B	1-Phenyl ethanol	12	
6A	Ethylene glycol	12	
8A	Formic acid	12	
8A	Phthalic acid	12	
9	Tetramethylsuccinonitrile	12	
10A	Ethanolamine	12	
10A	Butylamines	12	
11	p-Dimethylaminoazobenzene	12	
13A	Methanethiol	12	
13A	Ethanethiol	12	

TABLE 3-1 (Continued)

<u>Category</u>	<u>Compound</u>	<u>Hazard Potential</u>	<u>Indicator</u>
13A	n-Butanethiol	12	
15	Biphenyl	12	
21	Phenanthrene	12	
21	Chrysene	12	
21	Methylchrysenes	12	
21	Benzo (e) pyrene	12	
21	Picene	12	
21	Dibenzo (a,h) pyrene	12	
21	Dibenzo (a,l) pyrene	12	
22	Benzo (j) fluoranthene	12	
22	Benzo (b) fluoranthene	12	
22	Indeno (1,2,3-cd) pyrene	12	
23B	Quinoline, isoquinoline	12	
23C	Pyrrole	12	
23C	Dibenzo (a,g) carbazole	12	
25	Thiophene	12	
25	Methyl thiophenes	12	
29	Potassium	12	
33	Magnesium	12	
33B	Magnesium oxide	12	
35	Strontium	12	
37	Boron	12	
37	Boron oxide	12	
38	Aluminum	12	
38B	Aluminum oxide	12	
47A	Alkali cyanide	12	
53D	Hydrogen sulfide	12	
62	Titanium	12	
69	Molybdenum	12	
70	Tungsten	12	
81	Zinc	12	
10C	Benzidine	11.5	
16B	a-Chlorotoluene	11.5	
2B	Vinyl chloride	10.5	
18A	Phenyl phenols	10.5	
7B	Isophorone	10	
8C	Formamide	10	
10C	Aniline	10	
18A	Phenol	10	
18A	Cresols	10	
18A	Alkyl cresols	10	
18B	Catechol	10	
19	2-Chlorophenol	10	
20	2-Nitrophenol	10	
6B	1-Chloro-2,3-epoxy propane	9	
21	Naphthalene	9	

TABLE 3-1 (Continued)

<u>Category</u>	<u>Compound</u>	<u>Hazard Potential</u>	<u>Indicator</u>
4	2,2'-Dichloroethyl ether	8	
5C	Tertiary pentanol	8	
7A	Propionaldehyde	8	
7B	Benzaldehyde	8	
8A	Acetic acid	8	
8B	Hydroxyacetic acid	8	
9	Acetonitrile	8	
9	Acrylonitrile	8	
9	Benzonitrile	8	
10A	Ethylamine	8	
10A	Cyclohexylamine	8	
10B	Dimethylamine	8	
10C	Dimethylaniline	8	
10D	N,N-Dimethylaniline	8	
14	Benzenesulfonic acid	8	
15	Indene	8	
17	Nitrotoluenes	8	
22	Fluoranthene	8	
23A	Picolines	8	
23A	Collidines	8	
23B	Methylquinolines, methylisoquinolines	8	
23C	Acridine	8	
23C	Carbazole	8	
25	Benzo(b)thiophene	8	
26B	Ferrocene	8	
42C	Carbon monoxide	8	
47B	Ammonia	8	
52	Ozone	8	
53D	Carbon disulfide	8	
60	Scandium	8	
21	Anthracene	6	
21	Benzo(c)phenanthrene	6	
21	Pyrene	6	
21	Benzo(g)chrysene	6	
21	Dibenz(a,c)anthracene	6	
23B	Benz(c)acridine	6	
23B	Dibenz(c,h)acridine	6	
23C	Dibenzo(a,i)carbazole	6	
5A	Methanol	5	
5A	Ethanol	5	
16A	1,4-Dichlorobenzene	5	
18C	Indanols	5	
24	Tetrahydrofuran	5	
1A	Methane	4	
1A	Ethane	4	

TABLE 3-1 (Continued)

<u>Category</u>	<u>Compound</u>	<u>Hazard Potential</u>	<u>Indicator</u>
1A	Propane	4	
1A	Butanes	4	
1B	Ethylene	4	
1B	Propylene	4	
1C	Acetylene	4	
2A	Methyl chloride	4	
2A	Methylene chloride	4	
3	1,4-Dioxane	4	
5A	1-Propanol	4	
5A	n-Butanols	4	
5A	Isobutyl alcohol	4	
5A	Pentanols (primary)	4	
5B	2-Propanol	4	
5B	2-Butanol	4	
5B	Pentanols (secondary)	4	
5C	Tert-butanol	4	
7A	Acetaldehyde	4	
7A	Butyraldehyde	4	
8A	Benzoic acid	4	
15	Toluene	4	
15	Ethyl benzene	4	
15	Indan	4	
15	Xylenes	4	
15	Tetrahydronaphthalene	4	
16A	Chlorobenzene	4	
16A	1,2-Dichlorobenzene	4	
16A	2-Chlorotoluene	4	
42C	Carbon dioxide	4	
53C	Carbonyl sulfide	4	

The following compounds have not been assigned hazard potential values:

21	Naphthacene
21	Triphenylene
21	Dimethyl pyrenes
21	Perylene
21	Benzo(g,h,i)perylene
21	Coronene
22	Fluorene
23B	2,3-Benz-4-azafluorene
48A	Phosphate

FIGURE 3-2.

MULTIMEDIA ENVIRONMENTAL GOAL CHART FOR METHANE

EMISSION LEVEL GOALS							
	I. Based on Best Technology		II. Based on Ambient Factors				
	A. Existing Standards	B. Developing Technology	A. Minimum Acute Toxicity Effluent		B. Ambient Level Goal*		C. Elimination of Discharge
	NSPS, BPT, BAT	Engineering Estimates (R&D Goals)	Based on Health Effects	Based on Ecological Effects	Based on Health Effects	Based on Ecological Effects	Natural Background*
Air, $\mu\text{g}/\text{m}^3$ (ppm Vol)			3.27E6 (5,000)		7,800 (11.9)		
Water, $\mu\text{g}/\text{l}$ (ppm Wt)			4.9E7	>1.0E5	45,000	>50,000	
Land, $\mu\text{g}/\text{g}$ (ppm Wt)							

*To be multiplied by dilution factor

AMBIENT LEVEL GOALS					
	I. Current or Proposed Ambient Standards or Criteria		II. Toxicity Based Estimated Permissible Concentration		III. Zero Threshold Pollutants Estimated Permissible Concentration
	A. Based on Health Effects	B. Based on Ecological Effects	A. Based on Health Effects	B. Based on Ecological Effects	Based on Health Effects
Air, $\mu\text{g}/\text{m}^3$ (ppm Vol)			7,800 (11.9)		
Water, $\mu\text{g}/\text{l}$ (ppm Wt)			45,000	>50,000	
Land, $\mu\text{g}/\text{g}$ (ppm Wt)					

FIGURE 3-2 (Continued)

CATEGORY: 1A

WLN:

ETHANE: C_2H_6 (bimethyl, methylmethane, dimethyl, ethyl hydride). STRUCTURE:
A colorless, flammable, odorless gas.

PROPERTIES:

Molecular wt: 30; mp: -172° ; bp: -88.6° ; d: 0.572_4^{108} ;
vap. d: 1.04; slightly soluble; vap. press.: 760 mm at -88.6° .

NATURAL OCCURRENCE, CHARACTERISTICS, ASSOCIATED COMPOUNDS:

Rural concentration in air is reported as 3.6 ppbc (ref. 1). This is equivalent to $2.2 \mu g/m^3$.
Ethane participates to a very limited extent in photooxidation reactions (ref. 3).

TOXIC PROPERTIES, HEALTH EFFECTS:

No significant physiologic effects are reported for exposed workers.

REGULATORY ACTIONS, STANDARDS, CRITERIA, RECOGNITION, CANDIDATE STATUS FOR SPECIFIC REGULATION:

Classified by ACGIH as a simple asphyxiant.
 $TLV_{SA} = 5,000 \text{ ppm or } 6,122 \text{ mg/m}^3$.

MINIMUM ACUTE TOXICITY CONCENTRATIONS:

Air, Health: $6.12 \times 10^6 \mu g/m^3$ (5,000 ppm)
Water, Health: $15 \times 6.12 \times 10^6 = 9.2 \times 10^7 \mu g/l$
Land, Health:

Air, Ecology:
Water, Ecology:
Land, Ecology:

ESTIMATED PERMISSIBLE CONCENTRATIONS:

$EPC_{AH1} = 10^3 \times 6,122/420 = 14,600 \mu g/m^3$
 $EPC_{AH1a} = 5,000/420 = 11.9 \text{ ppm}$
 $EPC_{WH1} = 15 \times 14,600 = 2.2 \times 10^5 \mu g/l$
 $EPC_{WH2} = 13.8 \times 6,122 = 8.4 \times 10^4 \mu g/l$

3.2 FEDERAL GUIDELINES

The current federal guidelines for emissions from gasification plants are based upon best available control technology (BACT). Essentially two system choices exist for the control of sulfur. These choices are shown in Figures 3-3 and 3-4.

System I (Figure 3-3) represents the system that could be installed today if no federal or state guidelines or new source performance standards existed. The sulfur emissions from this system are estimated to be (EPA, March, 1978):

$$ES = 0.7(S_c)^{0.85} (HHV_c)^{0.15} \quad (3-1)$$

where:

ES = total sulfur emissions, kg/hr

S_c = coal sulfur input to gasifier, kg/hr

HHV_c = coal gasifier higher heating value
heat input, MW.

The BACT system, System II (Figure 3-4), has estimated emission characteristics given by:

$$ES = 0.032F(S_c)^{0.75} (HHV_c)^{0.25} \quad (3-2)$$

where F is a correction factor (1.0 to 1.6) based upon organic sulfur content. EPA's guideline (EPA, March, 1978) recommends that Equation 3-2 be used as a guideline for states that wish to establish a sulfur standard. It should be noted that the addition of tail gas scrubbing to the Claus unit or an all-Stretford control system results in a significant reduction of emissions. The ratio of ES as calculated by Equation 3-1 to that calculated by Equation 3-2 is:

FIGURE 3-3 TYPICAL SULFUR EMISSION CONTROL SYSTEM (SYSTEM I)

FIGURE 3-4 BEST AVAILABLE TECHNOLOGY SULFUR EMISSION CONTROL (SYSTEM II)

$$R = \frac{ES_{3-1}}{ES_{3-2}} = \frac{21.88}{F} (S_c)^{.10} (HHV_c)^{-.10} \quad (3-3)$$

where R is the ratio of uncontrolled (no standard) emissions to controlled (guideline) emissions.

For typical values of S_c (7.5×10^3 P, where P is percent by weight sulfur) and HHV_c (0.488 HHV, where HHV is the higher heating value in Btu per pound), R has a value of approximately 20. Thus, System II removes approximately 95 percent of the sulfur that System I would emit to the atmosphere. Partial documentation of Equations 3-1 and 3-2 is provided in the guideline document (EPA, March, 1978). The EPA believes that System II represents best available control technology.

Control of the hydrocarbons is achieved by combustion which also controls carbon-monoxide emissions. The recommended guideline for non-methane hydrocarbon emissions is:

$$EHC = 0.07 HHV_c \quad (3-4)$$

where:

EHC = emissions of non-methane hydrocarbons, kg/hr

HHV_c = coal heat input based on the higher heating value of gasifier feed, MW.

3.3 NORTH DAKOTA REGULATIONS

There are no existing state standards for gasification plant emissions. The state is using the PSD and air quality regulations as its principal guideline. ANG, the only gasification plant with permits, was granted its construction permit on the basis of the PSD and air quality regulations and the use of mathematical models. North Dakota had not established plans to incorporate the federal guidelines at the time of the writing of this report.

3.4 NEW MEXICO REGULATIONS

The New Mexico gasification regulations are quite stringent. The regulations (New Mexico, 1967) are summarized in Table 3-2 and are considerably more restrictive than the federal guidelines.

It is worth noting that New Mexico has chosen to omit a standard for hydrocarbons. The reason for the omission is that H_2S is limited to 10 ppm in all effluent streams. This requirement forces the designer to incinerate nearly all steams and, thus, virtually eliminate hydrocarbon emissions.

The Navajo tribe has been considering regulations but has not issued any standards as of the writing of this report. Taxation based upon effluent quantity has been considered. There is also some question as to the legal authority of the tribe with respect to issuing regulations.

TABLE 3-2

NEW MEXICO GASIFICATION EMISSION REGULATIONS

<u>Effluent</u>	<u>N.M. Emission Regulations</u>
$H_2S + CS_2 + COS$	less than 100 ppm
H_2S	less than 10 ppm
HCN	less than 10 ppm
HCl	less than 5 ppm
Particulate	less than .03 grains/SCF
NH_3	less than 25 ppm
Particulates (gas burning boilers)	less than .03 lbs/MMBTU
SO_2 (gas burning boilers)	less than 0.16 lbs SO_2 /MMBTU
Sulfur (gasification plant)	less than 0.008 lbs S/MMBTU

3.5 SUMMARY OF SULFUR EMISSIONS

The projected sulfur emissions for each plant are given in Table 3-3 and compared with both state and federal guidelines. All of the proposed designs meet or exceed the standards or guidelines. It is worth noting that the New Mexico limits are quite stringent and, in the opinion of the authors, it is questionable whether these guidelines can be met. In the opinion of the authors, there is a high probability that the federal sulfur guidelines can be met.

TABLE 3-3

PLANT SULFUR EMISSIONS - TONS PER STREAM DAY

I. El PasoBoiler, Superheater and Power Generation

	<u>Standards</u>		<u>Design</u>
	New Mexico	Federal	
SO ₂	4.95	39.40	4.01
NO _x	6.18	23.0	6.75
Parti- culates	.927	3.28	NIL

Total Gasification (High & Low Btu Trains)

	<u>Standards</u>		<u>Design</u>
	New Mexico	Federal	
Total Sulfur	1.96	6.37	1.606

II. WESCOBoiler and Superheater

	<u>Standards</u>		<u>Design</u>
	New Mexico	Federal	
SO ₂	13.31	51.34	9.6
NO _x	16.96	30.01	18.70
Parti- culates	1.83	4.29	0.82

Total Gasification (High & Low Btu Trains)

	<u>Standards</u>		<u>Design</u>
	New Mexico	Federal	
Total Sulfur	1.65	5.57	0.0 ^(c)

TABLE 3-3 (Continued)

III. Natural

Boiler and Superheater

	<u>Standards</u>		<u>Design</u>
	North Dakota	Federal (b)	
SO ₂	- (d)	64.50	31.40
NO _x	- (d)	37.72	34.60
Parti- culates	- (d)	5.39	4.80

Total Gasification (High & Low Btu Trains)

	<u>Maximum Allowable</u>		<u>Design</u>
	North Dakota	Federal	
Total S	- (d)	6.82	1.86

IV. ANG

Main Stack

	<u>Standards</u>		<u>Design</u>
	North Dakota	Federal	
SO ₂	- (4)	30.3	30.55 (e)
NO _x	- (4)	17.7	13.3
Parti- culates	- (4)	2.53	2.

Total Gasification (High & Low Btu Trains)

	<u>Standards</u>		<u>Design</u>
	North Dakota	Federal	
Total S	- (4)	6.28	0.0 (c)

(a) Federal Guidelines - March 1978 - see text of report.

(b) 40 CFR 60.

(c) All gasification plant waste streams to boiler and superheater.

(d) Have adopted federal standards, but removed lignite exemptions.

(e) Total allowed sulfur emissions would be: $(30.3 + 6.28) = 36.58$ TPD

3.6 DISCUSSION

In the view of the authors, there is a high probability that the existing federal guidelines can be met with existing best available control technology (BACT). This technology consists of treating (by combustion) the tail gases of both the Stretford and Claus plants. It is highly probable that the tail gas of Claus incinerator will have to be scrubbed. This is discussed in more detail in Section 4.

Some uncertainty in the sulfur control system exists due to the variability of sulfur in the coal feed to the gasifiers. This variability has the potential to cause operational difficulties in the Claus plant. The organic sulfur compounds (CS_2 and COS) tend to go to the sulfur recovery system and are reacted to SO_2 in the tail gas incinerator. The general lack of industrial experience with variable H_2S Claus unit feeds and the actual behavior of the organic sulfur compounds appear to be the major uncertainties in the sulfur system.

Control of hydrocarbons and carbon monoxide by combustion is the best available technology, is reliable, and has a high probability of meeting existing standards or guidelines. Control of NO_x and particulates for power plants is established and will meet existing standards.

There are many substances (see Table 3-2) which are presently uncontrolled. Which elements or compounds are likely to receive attention first is, at this time, an open question. Part of EPA's rationale in establishing the MEG program was to establish a data base that will assist them in establishing controls on key substances, compounds, and elements. Control methods and the accompanying technology have not been

established on an industrial scale for the vast majority of the 650 compounds contained on the original MEG list. Many of the trace metals are contained in this list.

In short, the major gaseous effluents (SO_2 , NO_x , non-methane hydrocarbons, H_2S , CO , and particulates) are all controllable and have existing guidelines or standards at least at the federal level. There are no liquid emissions, with the exception of one small stream from ANG, that will be disposed of by deep well injection. The solid wastes and sludges at this time are uncontrolled and will be disposed of in the mined area. There is a potential for groundwater pollution from these wastes, but the extent is unknown and will be strongly site specific. The minor (by weight) constituents are, by in large, uncontrollable. At this time it is difficult, if not impossible, to project what these effluents will be. In most cases, it is likely that the monitoring and control technology will be absent for most of these compounds.

4.0 SULFUR CONTROL TECHNOLOGY

4.1 INTRODUCTION

Sulfur nominally occurs in coal in three forms: sulfate, pyritic, and organic. The relative percentages of each form vary from mine to mine, and even from one part of a bed to another. For instance, in the lignitic coal beds of Mercer County, North Dakota, (Sondreal, Kube, and Elder, 1968), on the basis of 37 samples it has been found that the sulfur in the coal was distributed as follows: 47.7 percent pyritic, 47.2 percent organic, and 5.1 percent sulfate. The deviation from the mean for this set of samples taken from different locations was approximately ± 100 percent for both the pyritic and sulfate forms and approximately ± 30 percent for the organic. The form of the sulfur in the coal influences not only the percentage of sulfur that remains with the ash, but the reactivity of the sulfur and, in gasification, the sulfur compounds formed.

The steam plant which provides steam and power to the complex produces gaseous sulfur compounds under oxidizing conditions. There is no measurable organic sulfur in the flue gases. The sulfur remaining in the ash is divided between the two ash streams; some is removed from the boiler as bottom ash or slag, while some is carried with the flue gases and is collected as fly ash. The sulfur which remains with the fly ash is primarily $\text{SO}_4^{=}$ and is quite water soluble. The sulfur in the bottom ash is at least partially fused integrally with the solid residue.

Lurgi dry ash gasifiers operate under mixed oxidizing and reducing conditions and relatively low (1800°F or less) effective reaction temperatures and reduce principally CO and H₂. Because of these factors the raw gas sulfur is organically bound in tars and oils that condense as liquids and are present as reduced sulfur compounds in the gas phase going to purification.

The gaseous sulfur, H₂S, and organic sulfides (COS and CS₂) remain with the raw gas until the raw gas clean-up process. All contemplated U.S. gasification proposals consist of a Rectisol unit (cold methanol scrub) for a raw gas clean-up. The principal sulfur compound is H₂S. Carbonyl sulfide production varies depending upon the gasifier operating conditions and possibly upon the form of the coal sulfur. Probably both the high organic sulfur content and the gasifier equivalent reaction temperature contribute to the percentage of sulfur going to carbonyl sulfide.

In the Lurgi gasifier the equivalent or effective reaction temperature (apparent equilibrium temperature) is important in determining the $\frac{\text{H}_2\text{S} + \text{COS}}{\text{H}_2\text{S}}$ mole ratio in the raw gas. The reactivity of the coal substance, the limitation imposed by the ash fusion temperature of the coal ash, and the steam to oxygen ratio all influence the effective reaction temperature that can be achieved during gasification. A comparison of data from several gasification processes (Magee, 1976) having apparent equilibrium temperatures, varying from an estimated 1400°F to 2700°F, indicates that the mole ratio, $\frac{\text{H}_2\text{S} + \text{COS}}{\text{H}_2\text{S}}$, in the raw gas increases as the apparent equilibrium temperature increases (about 10 percent over the temperature range from 1650°F to 2700°F).

Carbonyl sulfide and CS₂ are not appreciably removed from waste gases by the Stretford process. This is also true for Claus units

using bauxite or alumina catalysts (Atkins and Thomas, 1976), although with either special operating conditions and/or new catalysts some removal may be accomplished. Carbonyl sulfide and CS_2 can account for 50 percent or more of the gaseous sulfur emitted by a Stretford and should be incinerated in most cases. The tail gases from the Claus generally require further treatment, either incineration and removal of SO_2 or hydrogenation of sulfur compounds to H_2S followed by absorption and recovery of sulfur. An example of the latter process is the Beavon sulfur removal process followed by the Stretford (Cheremisinoff and Young, 1975; Beavon, 1977; Beavon and Vaell, 1972).

4.2 SULFUR CONTENT IN THE SOLID EFFLUENT

In all of the contemplated installations, gasifier ash, boiler bottom ash, and boiler fly ash, as applicable, are disposed of together by mine burial. These solid wastes all contain a certain amount of sulfur which is derived from the original coal sulfur content. In the Lurgi gasification process most of the sulfur reacts and vaporizes in the reducing zones, and only a fraction reaches the oxidation zone where carbon is burned out. It is estimated that 3 to 10 percent of the coal sulfur will be discharged with the ash, probably as sulfates and complex sulfates of inorganic elements. Under the oxidizing conditions of coal-fired boiler installations, the sulfur retention by the ash varies greatly depending on the method of firing and the chemical nature of the ash (basic or acidic). For pulverized coal firing one can roughly estimate that 20 percent of the coal sulfur will be retained in the ash. This sulfur will probably be present as sulfates and complex sulfates of the inorganic elements. In the utility industry no serious environmental hazards from this disposal technique have been encountered.

The companies contemplating construction of gasification facilities are making investigations of the interaction of buried solid refuse (ash) with infiltration of water and of the possible uptake of elements in the ash by plants seeded during reclamation; these generally take the form of various leachability studies of the ash and of replaced overburden and plant growth tests. (It should be noted that there are other solid wastes in addition to the ash that are disposed of in the mined area.) In addition, monitoring wells will be installed at the perimeters of reclaimed areas, and the effect of leaching of solids by groundwater will be determined over extended time periods.

4.3 SULFUR CONTENT IN THE GASEOUS EFFLUENT

Effluent gas clean-up has, deservedly, received the most attention. The air we breathe is perhaps the most easily contaminated and the most difficult to clean of the three physical forms; particulate, entrained liquid, and gaseous. Gasification plants have a significant challenge in controlling gaseous sulfur emissions. There is SO_2 in the steam plant emissions, and H_2S , COS, and organic sulfides, such as CS_2 , in the gasifier crude gas. In addition, the crude gas contains gaseous hydrocarbons and compounds, such as HCN. The crude gas is processed by washing, shift conversion, and cooling, and is then purified in a Rectisol plant. The Rectisol off-gases (vent waste gases) contain the sulfur compounds of the crude gas, residual hydrocarbons, and a large quantity of carbon dioxide. The HCN component can be largely eliminated by water washing the vent gases from the naphtha extractor of the Rectisol plant (ANG, 1976). An analysis of the combined Rectisol off-gas has been calculated from ANG data (ANG, 1977) and is presented in Table 4-1. This is based on large scale mass balance gasification tests of a North Dakota lignite in a Lurgi dry ash gasifier at SASOL. The sulfur forms in the Rectisol off-gas have been modified by consideration of data derived from sources (Magee, 1976) previously mentioned. The calculated analysis of the lignite derived combined Rectisol off-gas is compared to the combined Rectisol off-gas from South African coal reported by South African Coal, Oil, and Gas Corporation Limited (SASOL, 1974).

The Rectisol gas purification plant design can be modified in a number of ways to better fit the requirements of the gasification

TABLE 4-1

COMPOSITION OF COMBINED RECTISOL OFF-GAS

<u>Component</u>	<u>Lignite Derived, Calculated (Mole %)</u>	<u>Reported by SASOL, South African Coal (Mole %)</u>
H ₂	1.08	1.31
CO	.64	1.34
CO ₂	96.53	93.52
Hydrocarbons:		
CH ₄	0.65	2.13
C ₂ +	0.05	0.75
H ₂ S	1.03	0.76
COS	0.01	-
CS ₂	0.01	-
N ₂ + Ar	-	0.19
Total:	100.00	100.00
Quantity (mole/hr)	38,600	11,570

plant complex. The reported analysis only represents the combined vent gas streams. The individual vent gas streams from a Rectisol unit vary in H_2S content. It is possible, by a selective absorption process, such as the Shell ADIP, to produce a high concentration H_2S stream from the richest (H_2S) streams that would be very suitable for a Claus plant sulfur recovery system. The streams may also be combined and sent directly to a Stretford sulfur recovery system. The choice is a matter of economics. If the recovery and use of residual hydrocarbons economically warrants the concentration step, then the Claus plant for the bulk sulfur recovery may be justified. Even so, large Claus plants now operate on a feed gas of about 8 percent H_2S , using proprietary techniques that may ultimately permit an extension to about 1 percent H_2S feed concentration.

It is emphasized that the Rectisol off-gas analyses reported in Table 4-1 do not include any vent gas streams obtained from tar, tar oil, gas liquor separation, or gas liquor treatment (Phenosolvan plant). These also contain identical components but in varying concentrations. The Rectisol off-gases represent the major quantity. The combination of all vent gas streams must be primarily treated by the Stretford sulfur recovery process, the Claus sulfur recovery process, or a combination of the two processes. The choice will probably be made on economic considerations rather than on technical limitations. In any event, the final gaseous effluent discharge to the atmosphere may require incineration of tail gases and scrubbing of combustion products in order to meet ever more restrictive regulations. This will virtually eliminate residual hydrocarbon discharge and minimize SO_2 emissions. The contemplated plant installations all include provisions for final incineration of most, if not all, of the waste gas streams.

4.4 STRETFORD TECHNOLOGY

4.4.1 Background

The Stretford process was developed by the Northwest Gas Board, Manchester, England, as a continuous liquid phase process for H₂S removal. The process has operated successfully in Britain and Europe since the early sixties. The technology was first applied to town gas, coke oven gas, refinery gas, and other gas streams with moderate (<1% H₂S) concentrations. The first United States use of the process was in the East Wilmington field at Long Beach, California. It was chosen there because of low cost and high reliability.

The Stretford technology was operated historically on coke oven or similar gases with a typical feed of 40 percent CO₂, 1 percent H₂S, and 0.1 percent HCN. Each Stretford absorption column was about 10 MMCFD. The outlet H₂S concentration was typically 0.5 to 1 ppm for the gases treated.

More recently, Stretford systems have been designed and are operating satisfactorily with feed gas containing more than 90 percent CO₂. Operation with a high concentration of CO₂ has been demonstrated on a large industrial scale, but these operations are not yet reported in the literature.

4.4.2 Chemical Reactions

The overall Stretford reaction is:

In the initial process development, sodium salts of 2,6- and 2,7- anthraquinone disulfonic acid (ADA) acted as an oxidizing agent. Long residence times for the oxidation reaction as well as high chemical costs caused by excessive thiosulfate formation resulted in modification of the process to include metavanadate salts. Sodium vanadate (NaVO_3) causes the oxygen to speed the formation of free sulfur. The ADA then oxidizes the $\text{Na}_2\text{V}_4\text{O}_9$. The reactions are:

The use of metavanadate sodium salts as well as determination of optimum operating conditions has reduced holding time requirements in the absorber and solution holding sections from 30 minutes to 2 or 3 minutes.

These improvements have not totally eliminated the thiosulfate reaction:

This reaction can be minimized by stabilizing the pH near 8.7 and the temperature near 80°F. Fortunately, the thiosulfate has no detrimental effect on process efficiency and can build up to quite high levels. Levels of 25 weight percent have been reported. A purge for thiosulfate and other compounds results in chemical losses that must be made up. This purge of thiosulfate and sulfate sodium salts is the only significant system chemical loss.

In the past there were reagent loss problems in the final sulfur removal step. Sulfur-liquor separation was achieved by filtration. The filter cake was more of a sulfur sludge than a cake. This was caused by high liquor retention (about 60 weight percent) in the cake. Excessive chemical reagent losses resulted from this high liquor loss.

Reagent losses were subsequently reduced by various combinations of centrifugation, filtering, cake washing, and batch autoclaves set at about 270°F under sufficient pressure to maintain the water and sulfur in a liquid form. Presently, many of the plants incorporate continuous melting of the sulfur under pressure, returning the supernatant aqueous solution to the Stretford system.

4.4.3 Physical Description

The Stretford process may be broken down into four processing steps: 1. H_2S absorption (Reaction 4-2); 2. Solution holding (Reactions 4-3 and 4-4 begin in step 1 and go to completion in step 2); 3. Oxidation of the reduced ADA (Reaction 4-5); and 4. Sulfur recovery. This breakdown provides an overview of the process and permits a general understanding of the steps involved.

1. In the absorber the actual transfer of the H_2S from the gas phase to the liquid phase takes place. Conventional Stretford absorber towers use splash tray packing in which the gas phase is continuous throughout the column. The liquid rains from one deck of boards to the next lower deck. In normal operation practice the liquid composition and flow rate are maintained at the design values and are independent of the gas flow rate. A possible objection to the use of a splash tray absorber exclusively is the fact that it requires quite a long residence time. The long residence time gives CO_2 ample opportunity to dissolve in the Stretford solution; this lowers the pH and slows the rate of H_2S uptake. It has been demonstrated industrially (Ralph M. Parsons Company, 1977) that with the use of an ejector Venturi, up to 99.95 percent of the inlet H_2S can be extracted in about one second of contact time (as opposed to one minute or less using a splash tray packing column). The ejector Venturi is

capable of extensive removal of H_2S while operating at a favorably high pH. Even so, the new Stretford unit at SASOL is now reportedly operating satisfactorily on 99 percent CO_2 feed gas using only splash tray contacting. The SASOL Stretford absorber is 272 ft high (Atkins, 1976) to accommodate the high $\frac{CO_2}{H_2S}$ ratio in the feed gas, as opposed to the

generally used Stretford absorber columns, 60 to 70 ft high, operating on much lower $\frac{CO_2}{H_2S}$ ratios in the feed gas.

2. In the solution holding section, Reaction 4-3 is completed with the formation of free sulfur. Free sulfur begins to form in the absorber. The oxidation of the vanadium salt and reduction of ADA (Reaction 4-4) also starts in the absorber and is completed in the holding section.
3. In the oxidizer section the ADA is usually reoxidized (Reaction 4-5) by air sparging, although oxygen-enriched air or pure oxygen could be used if desired.
4. The liquor-bearing sulfur froth from the oxidizer passes to the sulfur recovery section. The remainder of the reoxidized liquor is recycled to the Stretford absorber. In the sulfur recovery section the sulfur can be recovered by several methods. The liquor-bearing sulfur froth can be pressurized to about 30 psig and heated to about $270^{\circ}F$ in a continuous process. The sulfur is withdrawn as a liquid, and the supernatant aqueous solution is cooled and returned to the Stretford liquor feed. This is exemplified by the Parson's continuous autoclaving method. The liquor-bearing sulfur froth can also be centrifuged and/or filtered, and the cake melted to recover sulfur. The liquor would be returned to the Stretford unit. In any method of sulfur recovery a bleed stream will probably have to be removed from the recycled Stretford solution to control build-up of thiosulfate and other non-regenerable chemical formation in the Stretford solution, as in the reaction:

Following this sulfate removal the stream will probably be sent to water treatment.

4.4.4 Discussion

The Stretford process has been proven to be reliable for the removal of H_2S from sour gas streams. At the present time the Stretford process operates at high efficiency on an industrial scale using a feed containing more than 90 percent CO_2 . The Northwest Gas Board, original

developer of the Stretford, estimates that 10 ppm H_2S is achievable at the Stretford outlet, while 100 ppm H_2S at the outlet is a normal operating effluent concentration when Rectisol off-gas is being treated.

Table 4-2, "Calculated Concentration of Sulfur Forms in Stretford Off-Gas and Total Sulfur Removal as a Function of H_2S Removal," was calculated from the data given in Table 4-1 using the estimated composition of combined Rectisol off-gas derived from lignite as the input to the Stretford. The table indicates the composition of the off-gas and the total sulfur recovery expected from a Stretford unit operating with excellent absorber efficiency on H_2S removal--99.04 percent H_2S removal with the off-gas containing 100 ppm H_2S , 229 ppm $COS + CS_2$, and total sulfur removal of 96.16 percent. The other components of the Stretford off-gas would consist of CO_2 , hydrocarbons, and other constituents of the input, all virtually unchanged.

In operating the Stretford process there is a gaseous effluent produced in the oxidizer section where ADA is reoxidized by air sparging (Reaction 4-5). This stream is composed of air with a reduced oxygen content and carbon dioxide. Virtually no sulfur or hydrocarbon compounds, with the possible exception of a small quantity of entrained sulfur froth, are present. If the gaseous effluent proves to be objectionable, it can be combined with the Stretford off-gas for further treatment.

The following references may be consulted for further information concerning the Stretford process: Miller, 1972; Ellwood, 1964; Atkinson, 1976; Stecker, no date; Cheremisinoff, 1975; Beavon, 1977; and Beavon and Vaell, 1972.

TABLE 4-2

CALCULATED CONCENTRATION OF SULFUR FORMS IN
STRETTFORD OFF-GAS AND TOTAL SULFUR REMOVAL AS A
FUNCTION OF H_2S REMOVAL

H_2S Removed in Stretford (%)	Concentration of Sulfur Forms in Stretford Off-Gas (ppm)		Total Sulfur Removed by Stretford (%)
	H_2S	$COS + CS_2$	
100	0	229	97.09
99.99	1	229	97.08
99.90	10	229	97.00
99.04	100*	229	96.16*
98.08	200	229	95.22
97.12	300	229	94.29

*Normal operating effluent concentration when Rectisol off-gas is
being treated, Northwest Gas Board Estimate.

4.5 CLAUS TECHNOLOGY

4.5.1 Background

Claus technology is, at present, perhaps the most commonly used H_2S removal system. The operating conditions are well-defined and the design parameters known well enough that skid mounted Claus plants have been produced and used.

In about 1880, Claus (Cheremisinoff, 1975) discovered that H_2S produces good yields of sulfur when mixed with air and passed over an iron or bauxite catalyst at elevated temperatures (Cheremisinoff and Young, 1975). The reaction is exothermic, and completion is opposed by high temperatures so that the amount of conversion in a fixed bed of uncooled catalyst is relatively low. About 1937, I.G. Farbenindustrie developed the modified Claus process and approached the problem of heat removal by first burning 1/3 of the hydrogen sulfide with air in a boiler, in which about 80 percent of the overall heat of reaction was removed by generating steam. After condensing sulfur from the cooled gases, the reaction was carried further by heating the gases from 400 to 500°F and passing them over a Claus catalyst, usually bauxite or alumina. It is customary to use two or more catalyst beds for cooling, condensation, removal of produced sulfur, and reheating of the gas stream after each bed.

In the past modified Claus plants were normally used on input gas streams having 15 or more percent H_2S in the feed gas, and probably the best overall operation was at high feed gas concentrations of H_2S , such as 45 percent or more. Since the feed gas concentrations of sulfur

were relatively high and sulfur recovery usually varied from about 90 to 97 percent, depending on plant design, the tail gases emitted were generally higher in sulfur concentration than desired for present environmental considerations. Consequently, these streams usually require additional treatment.

At the present time large industrial Claus plants operate on a feed gas of about 8 percent H_2S using proprietary techniques that may ultimately permit an extension to about 1 percent H_2S feed concentration.

4.5.2 Chemical Reactions

The overall Claus reaction is the same as the overall Stretford reaction mentioned previously.

The following reactions take place in sequence in the processing units of the Claus plant:

Reaction 4-7 takes place in the Claus furnace and reheaters of the plant where theoretically 1/3 of the H_2S entering the furnace is burned and Reaction 4-8 is partly completed. Reaction 4-8 is carried toward completion in the catalytic reactors after cooling and removal of the sulfur that is formed. The temperature of the catalytic reactors is maintained at a value favoring completion of Reaction 4-8, usually 400 to 500°F, when using bauxite or alumina catalysts.

4.5.3 Physical Description

There are essentially two reaction areas in the usual Claus sulfur recovery plant, the furnace, and the catalytic converters.

Generally, two to four converters are used. The bulk of the sour feed gas is burned stoichiometrically in the combustion zone of the furnace so that $1/3$ of the H_2S is oxidized to SO_2 (Reaction 4-7) and the residual $2/3$ of the H_2S remains unchanged. Temperature is controlled by the waste heat boiler section, and Reaction 4-8 is initiated. The liquid elemental sulfur formed is separated from the gas beyond the cold end of the boiler and goes to storage while the gas is reheated by stoichiometric combustion of an increment of the sour feed gas so that the $\frac{H_2S}{SO_2}$ mole ratio is maintained at $2/1$. The reheated gas then passes through the first stage catalytic converter to drive Reaction 4-8 towards completion. The gas is cooled to a temperature between 260 and $300^\circ F$, the liquid sulfur is separated, and the gas is reheated in a similar manner for the next pass through a catalytic converter. The processes of cooling, sulfur recovery, reheating, and passing through a catalytic converter cycle are repeated several times until the H_2S content of the tail gas is reduced as much as is economically practical.

4.5.4 Discussion

Normally the heating value requirement of the Claus furnace and the reheaters sets the lower limit of about 18 percent H_2S concentration in the feed gas to the Claus sulfur recovery plant. As has been mentioned, the H_2S rich off-gas streams of the Rectisol plant can be concentrated with respect to H_2S . A number of proprietary processes are available. Generally, the H_2S is selectively absorbed in an amine solution which is subsequently steam stripped, and the concentrated H_2S stream is sent to the Claus plant. This procedure has the advantage of separating the H_2S from any residual hydrocarbons in the Rectisol off-gas, and the hydrocarbons can be used elsewhere in the plant

complex for supplemental heat. However, the cost of the separation may overbalance the value of the hydrocarbons for supplemental heating.

Table 4-3 gives some estimated overall data on the operating characteristics of a Claus plant using four catalytic converters. For the purpose of this estimate the H_2S rich off-gas streams from the Rectisol plant were concentrated by a proprietary selective absorption procedure and mixed with vent sour gas from the Phenosolvan plant.

In the Claus furnace, the temperature is 2000 to 2500°F, and the conversion of the H_2S to sulfur by Reactions 4-7 and 4-8 is about 70 percent (Atkins, 1976). In the catalytic converters with bauxite or alumina catalysts, a temperature of 400 to 500°F results in 90 to 97 percent conversion to sulfur. At temperatures above 600°F, the percentage of conversion falls off rapidly and reaches a minimum at about 1000°F. Both of the sulfur compounds COS and CS_2 require temperatures of 600°F or more for appreciable conversion, and thus, the Claus is usually not too effective for removing these compounds. Some success has been achieved using newer catalysts for removal of COS, but this is not the case for CS_2 (Atkins, 1976).

The presence of hydrocarbons in the Claus feed can cause carbon deposition that fouls the catalyst surface and discolors the sulfur product. In addition, the combustion of hydrocarbon material requires extra air and can cause operating problems in maintaining a mole ratio of 2/1 for H_2S to SO_2 .

Generally, the instrumentation required for operating a Claus sulfur recovery plant consists of a coordinated system of one or more ratio analyzers ($\text{H}_2\text{S}/\text{SO}_2$) installed on tail gases together with flow, temperature and pressure controllers/recorders on air and feed gas.

TABLE 4-3

ESTIMATED OPERATING DATA FOR A CLAUS PLANT^a
WITH FOUR CATALYTIC CONVERTERS

Constituent	Feed Gas (Mole %, Dry)	Tail Gas (Mole %, Dry)
CO ₂	52.27	35.41
H ₂ S	47.23	.17
COS	.01	.05
CS ₂	-	.01
SO ₂	-	.09
Sulfur	-	.01 ^b
C ₃ + C ₄ Hydrocarbons	.31	-
HCN	.18	-
CO	-	.24
H ₂	-	.02
N ₂	-	64.00
Total	100.00	100.00
Sulfur Gases (ppm)	472,400	3,300
Heating Values ^c (Btu/cu ft)	306	-
H ₂ S Removal (%)		99.5
Sulfur Removal (%)		98.8
Input (scfm wet)	6,640	
Tail Gas (scfm wet)		12,070

^a Claus feed gas consists of H₂S rich Rectisol off-gas streams with H₂S concentrated and hydrocarbons removed by a proprietary selective absorption system then mixed with vent sour gases from a Phenosolvan plant.

^b Entrained mist.

^c Sulfur gases only.

streams to the furnace, and reheaters. The operating control problem is difficult but has been reasonably well solved for commercial operation of Claus plants.

The concentration of sulfur and its forms in the tail gas from a Claus sulfur recovery plant depends on the sulfur removal efficiency of the plant. In a well operated plant the concentration will probably be about 3300 ppm (see Table 4-3). The sulfur concentration in this effluent stream is too high for direct discharge to the environment, and it must be reduced by one of the three available procedures.

The first is dilution by mixing the tail gas with another gaseous plant effluent, which is either sulfur free or very low in sulfur. A ratio of one part of tail gas to 10 or 20 parts of additive gas in the combined effluent stream reduces the concentration of sulfur compounds to more acceptable limits. It is doubtful if even this will be acceptable under future federal and state regulations; although, after this dilution the concentration would be quite comparable to the expected sulfur concentration of the tail gas from a Stretford sulfur recovery plant used in a gasification complex.

The second procedure is to oxidize the sulfur in the tail gas by incineration in a boiler plant, superheater, or separate incinerator (catalytic or other) so that all sulfur is produced in the form of SO_2 , probably the least objectionable form. If stack gas scrubber is installed to treat the products of combustion then about 70 to 90 percent of the SO_2 can be removed as a salt. This salt can be disposed of by mine burial or by marketing, depending upon the treatment methods used and the salt formed. Alternately, the SO_2 resulting from incineration can be concentrated and recycled to the Claus plant for further sulfur recovery.

The final alternative is to hydrogenate all or most of the sulfur forms in the tail gas to H_2S and then recover sulfur. This depends on a choice between two general procedures. In the first the sulfur compounds in the tail gas are selectively absorbed by scrubbing with a solvent. In the liquid phase, the sulfur is converted to H_2S by hydrogenation and/or hydrolysis. Elemental sulfur is subsequently formed and recovered. In the second the sulfur forms in the tail gas are hydrogenated in the gas phase, with a reducing gas, to H_2S . The gas is then passed through a Stretford plant. An example of this second procedure is the Beavon sulfur removal process.

The following references can be consulted for further information concerning the Claus process and for additional methods of removing H_2S or SO_2 : Slack, 1971; Stecker, no date; Gas Producers Association, no date; Goar, 1974; Goar, no date; and Raymont, 1975.

4.6 APPLICATION

All four proposals for construction of coal gasification complexes that will produce methane rich gas include either Stretford or Claus and Stretford units for sulfur recovery and primary removal of sulfur from the vent gases. There are other H_2S removal processes (Stecker, no date) but the Claus and Stretford appear to be the most applicable. Neither the Claus nor the Stretford removes all of the sulfur from vent gases, particularly compounds such as COS and CS_2 . Also, hydrocarbons are not removed by the Stretford process and can interfere with the operation of the Claus process. It appears feasible to collect and pass all vent gas streams through a Stretford system (relatively low concentration H_2S), but the Claus appears to be well suited to operation with relatively high concentration H_2S streams. Thus, a combination of Claus and Stretford units may be required to handle all of the vent streams if a Claus unit is used.

In order to meet all of the foreseeable federal and state sulfur control standards, it is likely that the tail gases from sulfur recovery (either process) should be incinerated and the products of combustion scrubbed to remove most of the SO_2 formed. Incineration destroys residual hydrocarbons and converts COS, CS_2 , and residual H_2S to SO_2 , probably the least objectionable form of sulfur emitted to the atmosphere. Stack gas scrubbing can be used to reduce the SO_2 content to within regulated limits if required. The various stack gas scrubbing systems usually remove the SO_2 as a salt of either calcium or sodium which can be disposed of by mine burial, or possibly used to some extent. Table 4-4

TABLE 4-4

COMPARISON OF SULFUR RECOVERY SYSTEMS FOR A 250 MMSCFD
GASIFICATION COMPLEX WITH RESPECT TO GASEOUS
EMISSION OF SULFUR IN EFFLUENT GASES

	North Dakota Lignite ^a	New Mexico Subbituminous ^b
Coal Feed (lb sulfur per MMBTU)	1.11	.987
Sulfur in Waste Gases to Sulfur Recovery ^c (lb sulfur per MMBTU)	1.033	.918
<u>Sulfur Recovery System Choices</u>		
I. No Tail Gas Treatment		
a. Stretford only (96.16% S removal, Table 4-2) Output: lb sulfur per MMBTU	.040	.035
b. Claus only (98.8% S removal, Table 4-3) Output: lb sulfur per MMBTU	.012	.011
c. 33% of waste gas sulfur to Claus, 67% to Stretford Output: lb sulfur per MMBTU	.031	.027
d. 50% of waste gas sulfur to Claus, 50% to Stretford Output: lb sulfur per MMBTU	.026	.023
e. 67% of waste gas sulfur to Claus, 33% to Stretford Output: lb sulfur per MMBTU	.021	.019
II. Sulfur Recovery Plant Tail Gases of Section I Incinerated and followed by Stack Gas Scrubbing at 70% Sulfur Removal		
a-1 Output: lb sulfur per MMBTU	.012	.011
b-1 Output: lb sulfur per MMBTU	.004	.003
c-1 Output: lb sulfur per MMBTU	.009	.008
d-1 Output: lb sulfur per MMBTU	.008	.007
e-1 Output: lb sulfur per MMBTU	.006	.006
<u>Federal Sulfur Effluent Guidelines</u>		
a. Pound per hour sulfur ^d	503	470
b. Pound Sulfur per MMBTU ^d	.0310	.0282

^aNorth Dakota Lignite: As received, 0.76% sulfur, 6839 Btu/lb,
coal feed 2369×10^3 lb/hr

^bNew Mexico Subbituminous: As received, 0.82% sulfur, 8304 Btu/lb,
coal feed 2005×10^3 lb/hr

^cAssumption: 7% of input sulfur is discharged with ash + tar + tar oil + naphtha

^dCalculated from the EPA guidelines:

$$ES = 0.032(S_c)^{.75} (HHV_c)^{.25}$$

ES = kg/hr sulfur emission, calculated as elemental sulfur

S_c = coal sulfur to gasifier, kg/hr

HHV_c = higher heating value of coal to gasifier, MW

compares several sulfur removal schemes that could be used with nominal 250 MMSCFD gasification plants using either North Dakota lignite or New Mexico subbituminous coal as feed stock. The expected effluent sulfur discharge is calculated as pounds of sulfur per MMBTU input.

In Table 4-4 the Stretford estimate appears to be more conservative than the Claus estimate; however, much of this is a function of the degree of COS removal, and possibly CS_2 , in a Claus system. The COS, and possibly CS_2 removal, in the Claus depends on the operating temperature of the first catalytic converter. If this temperature approaches $600^{\circ}F$ instead of the normal 400 to $500^{\circ}F$, and one of the new catalysts is used, some COS but little, if any, CS_2 is removed. The apparent advantage of the Claus over the Stretford with regard to effluent sulfur as shown on Table 4-4 is questionable. However, either system is capable of higher sulfur removal if well designed and carefully operated.

If a federal standard for mass rate sulfur emission, as defined by the equation, $ES = 0.032(S_c)^{.75} (HHV_c)^{.25}$, is established, the use of either a Stretford system treating all waste effluent gases or of a combination of a Claus system treating highly concentrated H_2S gases and a Stretford system treating low concentration H_2S gases results in tail gases that approach and may meet the mass rate standard (see Table 4-4). The tail gases from the Stretford should meet the suggested federal concentration standard of 500 ppm sulfur but Claus tail gases will not. Neither of the systems, without subsequent tail gas treatment, will meet the New Mexico sulfur emission standard of 0.008 lb sulfur per MMBTU.

Foreseeable sulfur emission standards can probably be attained when the tail gases from either of the sulfur recovery systems

mentioned in the previous paragraph are incinerated and the products of combustion are scrubbed to remove SO_2 . Even in this instance the New Mexico standard will be difficult to attain.

The technology exists to reduce sulfur emissions from a gasification complex to an acceptable level. The cost-benefit ratio will rapidly increase as standards requirements increase. Incineration and stack gas scrubbing following primary sulfur recovery will appreciably increase the cost of synthetic pipeline gas, but incineration will insure virtual elimination of hydrocarbons and other toxic gases as well as conversion of sulfur to sulfur dioxide.

5.0 WATER TREATMENT, REUSE, CONTROL, AND ECONOMICS

5.1 INTRODUCTION

Coal conversion by gasification produces pollutants as liquid, gaseous, and solid wastes. Air pollution control and solid waste disposal in the gasification plants are dealt with in other sections of this report. This section deals with water treatment, reuse, control, and economics.

The information contained in this section is primarily based on the reports of the Environmental Impact Assessment prepared by the following companies: Natural Gas Pipeline Company of America (Natural, 1976); ANG Coal Gasification Company (ANG, 1977); El Paso Natural Gas Company (El Paso, 1977); and Western Gasification Company (WESCO, 1976). The literature pertaining to the treatment of coke plant water process streams is also used because of the similarity to coal gasification process streams.

All of the four plants cited have incorporated the concept of zero liquid effluent discharge in their plant designs to meet the stipulations in P.L. 92-500; consequently, no liquid effluent discharge into surface waters is planned. For Natural, El Paso, and WESCO, the only liquid effluent leaving the plant will be the water contained in ashes and in sludges to be buried on the mine sites. In the case of ANG, other liquid effluent streams released to the environment will be the water treatment effluent streams and boiler blowdown streams, which are to be disposed of in deep wells.

All plants emphasize in-plant water reuse. Since all of the plants will be located in semi-arid or arid climates, water conservation and reuse will help to alleviate the impact of high water demand on the region, as well as to achieve the goal of zero pollutant discharge requirements. Major items of water reuse include cooling water make-up, and ash quenching and handling.

In two of the proposed designs, Natural and WESCO, biological treatment of aqueous effluent from the Phenosolvan plant has been proposed before reuse as cooling water make-up and in the other two, ANG and El Paso, this effluent will be used directly as cooling water make-up. This use particularly, without treatment, represents a major uncertainty and potential environmental concern.

All four gasification plants propose to use surface water for their source of water supply. The Natural and ANG plants utilize water from Lake Sakakawea, while El Paso and WESCO obtain their water from the San Juan River. The characteristics of the water supply for these plants are shown in Table 5-1. The raw water for the El Paso plant has the highest concentration of total dissolved solids (TDS), 2609 mg/l; sodium, 631 mg/l; sulfate, 1384 mg/l; and total alkalinity, 347 mg/l. The Natural raw water also contains high concentrations of TDS, 1179 mg/l; and sulfate, 553 mg/l. The WESCO and ANG raw water contain less than 225 mg/l sulfate, and less than 500 mg/l TDS. The turbidity of Lake Sakakawea waters is much lower than San Juan River waters. Some of the impurities in the water supply, such as suspended solids, calcium, magnesium, turbidity, and total dissolved solids, will be removed by the water treatment processes and will be present in the water treatment plant sludges for mine burial.

TABLE 5-1

RAW WATER QUALITY DATA OF WATER SOURCES FOR
FOUR GASIFICATION PLANTS^a

	<u>Natural</u> ^b	<u>ANG</u> ^c	<u>El Paso</u> ^d	<u>WESCO</u> ^e
Temperature (°C)	-	18.6	-	13
Conductivity (µmhos)	-	689.5	-	663
Total Alkalinity (mg/l)	272	165	347	144
Chloride (mg/l)	9	9.8	53	-
Sulfate (mg/l)	553	132.6	1,384	209
Calcium (mg/l)	72	-	153	72
Magnesium (mg/l)	34	-	31	13
Sodium (mg/l)	221	-	631	54
Total Dissolved Solids (mg/l)	1,179	454.7	2,609	452
pH	7.8	8.3	7.68	7.8
Suspended Solids (mg/l)	500	-	-	5,830
Nitrate (mg/l)	1	0.01	-	3.2
Phosphate (mg/l)	-	0.025	-	0.08
Turbidity (mg/l)	-	1	-	496
COD (mg/l)	-	10.4	-	-
BOD (mg/l)	-	1	-	-

^aData Sources are Environmental Impact Statements for each plant.^bNatural Gas Pipeline Company, 1976.^cANG Coal Gasification Company, 1977.^dEl Paso Natural Gas Company, 1977.^eWestern Gasification Company, 1976.

5.2 PROPOSED SYSTEMS AND EFFLUENT CHARACTERISTICS

The water treatment systems as proposed by the four coal gasification plants and the water stream characteristics as contained in reports of Environmental Impact Statements are described below.

Natural Plant - The 67 gpm of sanitary wastes are treated in a package waste treatment unit. The 4528 gpm of Phenosolvan effluent and a portion of the utility and storm waters of the 50 gpm flow are treated in a process water treating unit where an activated sludge process is employed to remove organics present in the liquid streams. The water treatment facilities are shown in Figure 5-1. A characterization of the influent and effluent process water streams to the treating unit, as listed in the Natural EIS report, are shown in Table 5-2.

ANG Plant - The sanitary wastes are treated in a package biological treatment unit. The Phenosolvan effluent does not receive any further treatment and is used, together with treated sanitary wastes, as cooling make-up water. Biological treatment of the Phenosolvan effluent is not proposed for the ANG Plant. The water treatment system is shown in Figure 5-2. Deep well disposal has been proposed in the ANG's EIS report for the disposal of 90 gpm of regeneration streams from the softener and 174 gpm of blowdown stream from the low pressure steam system. The 479 gpm of water streams going to deep well disposal is 17 percent of the total liquid streams produced in the ANG Plant. The composition of liquid streams for deep well disposal is listed in Table 5-3. The characterization of Phenosolvan effluent is not provided in the ANG EIS report.

FIGURE 5-1. WATER STREAMS AND TREATMENT SYSTEMS, NATURAL PLANT.

TABLE 5-2

CHARACTERIZATION OF PROCESS WATER TREATING UNIT
INFLUENT AND EFFLUENT FOR THE NATURAL PLANT

Component	Influent Concentration (mg/l)	Effluent Concentration (mg/l)
Ca	1,261	188
Mg	-	2
Na	52	52
NH ₄	158	100
HCO ₃	-	140
Cl	326	326
SO ₄	-	47
NO ₃	-	182
Free CO ₂	-	25
Total PO ₄	-	22
Si	-	1
Total Dissolved Solids	-	1,093
CN	10	5
Phenols	237	94
Fatty Acids	2,970	75
NH ₃	100	-
pH	10	6

NOTE: Characterization data based on Natural's EIS report.

FIGURE 5-2. WATER STREAMS AND TREATMENT SYSTEMS, ANG PLANT.

TABLE 5-3

COMPOSITION OF LIQUID STREAMS FOR
DEEP WELL DISPOSAL FOR ANG PLANT

<u>Constituents</u>	<u>Concentration (mg/l)</u>
CaSO ₄	540
MgSO ₄	460
Na ₂ SO ₄	6,460
NaCl	2,770
NaHCO ₃	110
CaCl ₂	860
MgCl ₂	730

El Paso Plant - The El Paso Phenosolvan Unit receives gas liquors from both oxygen gasification and fuel gas production. The Phenosolvan effluent flows to a steam stripping unit for the removal of ammonia from the gas liquor. The flow rate for the stripped gas liquor is 2706 gpm, of which 2377 gpm will be used as cooling water make-up and 329 gpm is used as ash handling water. Characterization of the stripped gas liquor is not available in the El Paso EIS report. Biological treatment or other secondary treatment is not proposed for the El Paso plant. Figure 5-3 depicts the water treatment systems of the El Paso plant.

WESCO Plant - The Phenosolvan effluent stream (2810 gpm), combined with sewer flows and excess storm water, will first be treated in oil separators, to be followed by air flotation and biological treatment. Removal of entrained oils is achieved in the oil separators and the air flotation units. Organics will be removed in a biological

FIGURE 5-3. WATER STREAMS AND TREATMENT SYSTEMS, EL PASO PLANT.

treatment unit. A portion of the biological treatment unit effluent (2680 gpm) is to be used for process cooling. The balance of the biological treatment effluent is used for ash quenching, revegetation, road wetting, sulfur pelletizing, and other mine uses. The characterization of biological treatment unit effluent is not available in the WESCO EIS report. The water treatment system for the WESCO plant is shown in Figure 5-4.

FIGURE 5-4. WATER STREAMS AND TREATMENT SYSTEMS, WESCO PLANT.

5.3. LITERATURE PERTINENT TO WATER USE

In the EIS reports prepared for the four proposed plants, little or no literature is cited that deals with coal gasification process water treatment. In fact, there are limited data published concerning the treatment of coal gasification waters. A literature review of the treatment methods for coal gasification and other similar waters is presented below.

Biological treatment is the most widely used method for the treatment of domestic and industrial wastewaters. In this process, the dissolved and colloidal organic matter is converted by microorganisms into carbon dioxide, simple inorganic compounds, and a biological sludge containing both living and dead microorganisms. In addition to reducing the biochemical oxygen demand (BOD), the chemical oxygen demand (COD), and the total organic carbon (TOC), biological treatment can also be used as a means for nitrification and denitrification. In the nitrification process ammonia is converted to nitrite and then to nitrate, while in the denitrification process nitrate is reduced to nitrogen gas.

Cook and Graham (1965) have reported a study on the biological purification of the Lurgi coal gasification effluent. Bromel (1976) has conducted research on the isolation and utilization of microbial isolates from North Dakota soil and water for the biological oxidation of wastewaters from the Lurgi plant of the South African Coal, Oil and Gas Corporation (SASOL) at Sasolburg, South Africa. The three bacterial genera most efficient for the phenol oxidation were identified as *Pseudomonas*, *Arthrobacter*, and *Micrococcus*. The best COD reduction

for the SASOL wastewaters was 70 percent, which is less than the 70 to 90 percent COD reduction for phenolic wastes reported in the literature. Characterization of SASOL wastes revealed that fatty acids, phenols, and amines were the major compounds found in the Lurgi process waters, and therefore are similar to those found in ammoniacal liquor. The differences in the composition of coal from different mines or deposits will have some effect on the variations in the concentration of specific chemicals in the wastewater produced. Data describing the coal variation effect are generally absent.

There is considerable information available in the literature concerning the biological treatment of coke plant wastes which have constituents similar to the coal gasification waters. Rudolfs (1953) gave an excellent summary on the biological treatment of coke wastes prior to 1953. The earliest studies dealt with Phenolics removal from the combined wastewaters of still wastes and municipal wastes. Frankland and Silvester (1907) employed trickling filters and bacterial contact beds successfully for treating a mixture containing nine percent ammonia still waste in municipal waste. A trickling filter of crushed clinker with a recirculation ratio of nine to one was used to treat ammonia liquor without the use of an external diluent (Fowler and Holton, 1911). Rudolfs (1953) described the first use of the activated sludge process in this country for the treatment of still wastes by the Milwaukee Sewerage Commission. Mixtures of 15 percent still waste in municipal sewage were treated satisfactorily for the removal of phenolic compounds. A treatment study of mixtures of still waste in municipal sewage was also conducted by the Chicago Sanitary District (Mohlman, 1929 and 1947). The allowable influent phenolics concentration of the mixtures was found to be 30 to 40 mg/l. The removal of

phenolic compounds increased with increased temperature. Mathews (1952) has reported the use of the activated sludge process in the treatment of still wastes from the U.S. Steel Company. With a minimum dilution factor of 1 in 40, and an influent phenolics concentration of 20 mg/l, the effluent phenolics concentration was found to be less than 1 mg/l. A later series of experiments was conducted during 1966-67 for the same still wastes (Muller and Coventry, 1968). Mixtures of 40 mgd of domestic sewage and 400,000 gpd of still wastes were treated by the activated sludge process, at an aeration time of nine hours. The phenolics removal was essentially complete, and the cyanide removal was 85 percent complete.

A U.S. Steel report (Morgan, Knudson, and Swaney, 1954) described the use of a large-scale pilot plant for a treatability study of still wastes containing various concentrations of phenolics without dilution with domestic wastes. To obtain an effluent phenolics concentration of less than one mg/l, the detention times required in the aeration tank were 9.4, 25, and 100 hours for the initial phenolic concentrations of 10, 40, and 300 mg/l, respectively. Kostenbader and Flecksteiner (1969) reported a treatment study of ammoniacal liquor at the Bethlehem Steel Corporation. It was observed that phenolic loadings of 30 lbs/day/100 cu ft of aeration capacity could be treated satisfactorily at a mixed liquor suspended solids (MLSS) concentration of 5700 mg/l, and at an aeration time of 17.5 hours. Due to the difficulty encountered in operating the system, loading rates of this magnitude were not recommended. A good removal of phenolics was obtained at phenolic loading rates below 12 lbs/day/100 cu ft, and at food-to-microorganism ratios below 0.7 lbs phenol/day/lb of sludge. The

important treatment parameters found included tar, ammonia, temperature, nutrient requirements, and pH. For the successful operation of the waste treatment system the following conditions were recommended:

1. Tar removal ahead of the aeration tank by storage of the ammoniacal liquor at ambient temperature.
2. Maximum ammonia concentration of 2000 mg/l in the operation tank.
3. Aeration tank temperature of 80-95°F.
4. Phosphorus addition to maintain a phenol to phosphorus ratio of 70 to 1.
5. Effluent pH maintained at 6-8.

In 1962 a full-scale plant designed on these recommendations was put on stream. The plant consisted of an equalization tank, an aeration tank, and a settling tank. The equalization tank had a detention of nine days for equalization and tar removal. This effluent was then diluted with water to keep an ammonia concentration of less than 2000 mg/l. It was also dosed with phosphoric acid to provide the necessary phosphorus nutrient and was steam heated to maintain temperatures of 80-95°F. The detention time in the aeration tank was 56 hours, based on the undiluted discharge of weak ammonia liquor. The sludge separated in the settling tank was mostly returned to the aeration tank to maintain the proper level of MLSS, and the excess sludge discharges went to the city sewer system. The design capacity of this plant was more than 4000 lb of phenol/day, while the average phenol load was only 1300 lb/day. The removal efficiency of BOD was 85-95 percent. Thiocyanate removals ranged from 20-99 percent with an average of 70 percent. The effluent phenol concentration had remained below 0.1 mg/l at most times. In order to improve the plant's capacity for thiocyanate oxidation and cyanide removal, a slag trickling filter in

series with an activated sludge system was tested on a pilot plant scale. Both thiocyanate removal of 2.7 lb/day per 100 cu ft filter media and cyanide removal of 50-65 percent were observed in the slag trickling filter.

The activated sludge treatment of ammonia still waste liquor at the Lone Star Steel Company in Texas was described by Horne and Hurse (1963). The plant was designed to reduce influent concentrations of phenols of 100-800 mg/l to less than 1 mg/l for a waste flow of 50,000 gpd. The treatment system included a pretreatment storage pond, an aeration tank, and a settling tank. The detention time in the aeration tank was 24 hours. The temperature of the aeration tank content was maintained above 70°F by a heating unit, and the pH was kept between 7 and 8. Phosphorus acid was added to provide the phosphorus nutrient requirement. From the pilot plant studies conducted to develop design criteria, it was observed that dissolved oxygen (DO) concentration exceeding 0.5 mg/l in the aeration tank did not enhance the treatment efficiency. Optimum removal efficiency was obtained at a phenolic load of 0.2 to 0.25 lb/day/lb of MLSS, and at a MLSS level of 2500 to 3500 mg/l. In the full-scale activated sludge plant operation, influent phenolic concentrations of 250 to 475 mg/l were reduced to between 0.1 and 0.3 mg/l with partial removal of cyanides.

Ludberg and Nicks (1969) described the activated sludge plant for treating ammoniacal liquor from Dominion Foundries and Steel of Hamilton, Ontario, Canada. The plant consisted of an equalization tank of 2.5-days detention time, an aeration tank of 37-hours detention time based on undiluted waste, and a settling tank with a return sludge rate

equal to the flow of diluted waste. The equalization tank effluent was diluted to 50 percent strength to maintain ammonia concentrations in the aeration tank to less than 1200 mg/l. The plant has effectively reduced the diluted waste concentration of phenolics from 260-400 mg/l to 0.8-3.6 mg/l.

The Koppers Company has conducted laboratory investigations to determine the treatment necessary to process crude ammonia liquor, free ammonia liquor, and ammonia still waste (Cousins and Mindler, 1970). Complete-mix activated sludge units were used in the study. The units provided an aeration time of 24 hours for a waste diluted to 25 percent for ammonia control. It was noted that treatability varied among the three waste streams, and that different design criteria needed to be developed for each stream.

Pretreatment of ammoniacal liquors for the ammonia and cyanide removal prior to biological treatment by stripping, chemical precipitation, and coagulation was investigated at the International Hydronics Corporation (Cousins and Mindler, 1970). The pretreatment rendered wastewater amenable to biological treatment without dilution.

The effect of effluent constituents on the complete-mix activated sludge treatment of carbonization effluents was investigated by Ashmore, Catchpole, and Cooper (1967). The criteria for successful treatment were: the reduction of the 4-hour permanganate value by 90 to 95 percent and the removal of phenolics, thiocyanate, and thiosulfate to a few mg/l. The limiting concentration of chlorides that could be tolerated by the treatment system was 2000 mg/l. At ammonium chloride levels of 10,000 mg/l as chloride, the maximum thiocyanate concentration which could be effectively treated was 1000 mg/l, and this figure fell to 500 mg/l at a chloride concentration of 20,000 mg/l. The chloride

effect was found to be more important in the presence of phenolics. For a given concentration of thiocyanate, the chloride concentration, which could be tolerated in the aeration tank for the total thiocyanate removal, decreased with increasing phenol concentration in the aeration tank. For instance, an influent containing 1000 mg/l of thiocyanate could be treated in the presence of 10,000 mg/l of chloride, but only 2500 mg/l of chloride could be tolerated at an influent phenolic concentration of 1100 mg/l. Recommended ranges of pH in the aeration tank were 6.7 to 7.3. Cyanide above a concentration of about 40 mg/l was inhibitory. The refractory organics present after treatment would influence the dilution necessary for efficient treatment. For effective waste treatment the plant operation needs to be in the endogenous respiration phase with sludge wastage of up to 10 percent per day.

Barker and Thompson (1973) reported the pilot plant treatment study of coke plant wastes at Armco Steel Corporation's Houston, Texas, Works. For the removal of carbon compounds and ammonia from diluted excess raw ammonia liquor, three stages of treatment were used:

1. carbon removal, 2. nitrification, and 3. denitrification.

Raw wastes contained 3000 mg/l of COD and 600 mg/l of phenolics. The carbon removal unit employing the activated sludge process removed 75 percent of COD, and essentially all of the phenolics from raw waters. The aeration time was 24 hours, and the temperature was between 75 and 90°F in the carbon removal unit. The treatment efficiency improved at higher temperatures. Thiocyanate, a major constituent of ammonia liquor, was only partially removed in the carbon removal unit. The major portion of the COS in the carbon removal unit was from residual thiocyanate. The average cyanide removal efficiency was only 57 percent.

In the nitrification unit 90 percent of the ammonia was oxidized to nitrate when the waste was diluted to a strength of 12 percent. The optimum operating condition included a pH range of 6.8 to 8.2 and temperatures of 90-95°F. The denitrification unit removed 95 to 100 percent of the oxidized nitrogen present in the nitrification unit effluent up to a concentration of 600 mg/l. The complete three-stage treatment plant, under optimum operating conditions, could remove over 99 percent of the phenolics, 90 percent of the organic carbon, 70 percent of the COD, and 90 percent of the ammonia present in the coke plant wastes.

Adams, Stein, and Eckenfelder (1974) reported a laboratory treatability study of coke plant wastewaters. The treatment processes that were evaluated included the activated sludge process and the aerated lagoon process. Both systems removed more than 95 percent BOD, 75 percent COD, and 70 percent TOC. Overflow rates of 600 to 900 gpd/sq ft were recommended for the design of the final settling tank. The operating parameters for the best-operated bench-scale activated sludge unit operating parameters were: 1. 2592 mg/l of MLVSS, 2. 0.61 lb BOD/day/lb MLVSS, and 3. 2.6 days of aeration time. The effluents contained 107 mg/l of BOD, 303 mg/l of TOC, 128 mg/l of $\text{NH}_3\text{-N}$, 0.93 mg/l of cyanide, and 179 mg/l of phenolics.

The treatment process for coke plant waste liquor at the Alan Wood Steel Company included ammonia stripping, multi-effect evaporation, biological treatment, and incineration. The wastes contained 300-4000 mg/l phenolics, 3900-6000 mg/l NH_3 , 10-100 mg/l cyanide, 50-500 mg/l thiocyanate, 20-40 mg/l oils and tars, 30-120 mg/l suspended solids, and 4000-13,000 mg/l total dissolved solids. The wastes first entered

a downflow pressure filter for the removal of oils and tars, then a stripping column for ammonia removal, followed by a multi-effect evaporator for separating the concentrate from the distillate. Next, the wastes enter a biological treatment system for oxidizing the phenols in the distillate. Finally the wastes enter an ozone or activated carbon unit for removal of residual phenol in the distillate. There were two incinerators at the end of the process. The first incinerator was for phenol destruction, while the second one was for thermal oxidation of the contaminants in the concentrate. Hydrochloric acid was a by-product from the second incinerator. The distillate was used as a cooling-tower make-up or boiler feed.

In conclusion, various biological treatment processes, which have been employed successfully in the treatment of coke plant wastes, could possibly be applicable to the coal gasification water treatment. It appears that stripping and tailored biological treatment trains with carbon polishing will be able to render the waste suitable for cooling towers and the main issue would be the necessity and cost acceptability for such a scheme.

5.4 PROJECTED WATER CHARACTERIZATION

This section deals with the source of liquid and solid effluents, the characteristics of influent and effluent of the Phenosolvan unit, and the projected water characterization of the biologically treated effluent in the proposed gasification plants. Design criteria for the water treatment unit based on coke plant waste data are also described in this section.

Several waste streams are produced in the Lurgi coal gasification facilities. Gaseous emissions are described in another chapter of this report. Major liquid and solid waste streams include gas liquors, ashes, sludges, and blowdowns from various units. A list of solid and liquid waste streams is shown in Table 5-4.

The major liquid waste stream in a Lurgi gasification plant is the gas liquor, which has a high concentration of contaminants. In the four proposed plants the gas liquor is treated in the Phenosolvan unit for phenol removal. Since all plants are currently in the planning stage, the actual waste samples are not available for laboratory characterization. As mentioned in Section 5.1, Natural's EIS report contains a partial listing of characterization data for influent and effluent of the water treating unit, while the other EIS reports do not contain the characterization data. For the purpose of this report, estimates of the constituents of influent and effluent streams of the Phenosolvan unit for the four proposed plants were calculated by the authors. These estimated data are summarized in Table 5-5 and are based from data generated elsewhere in this report.

TABLE 5-4

SOLID AND LIQUID WASTE STREAMS FROM LURGI GASIFICATION PLANT

<u>Stream No.</u>	<u>Description</u>	<u>Natural</u>	<u>ANG</u>	<u>El Paso</u>	<u>WESCO</u>
1	Gas Liquor	P	P	P	P
2	Bio-Sludge	P	-	-	P
3	Stack Gas Scrubber Sludge	P	-	-	-
4	Water Treatment Sludge	P	P	P	P
5	Reverse Osmosis Reject	P	-	-	-
6	Water Softener Blowdown	-	P	-	-
7	Demineralizer Blowdown	-	P	P	P
8	Cooling Water Blowdown	P	P	P	P
9	Concentrator Blowdown	P	P	-	-
10	Boiler Blowdown	P	P	P	P
11	Gasifier Ash	P	P	P	P
12	Boiler Ash	P	P	P	P

P = Stream present within the facility.

TABLE 5-5

ESTIMATED COMPOSITION OF INFLUENT AND
EFFLUENT STREAMS OF A PHENOSOLVAN UNIT

Parameters	Phenosolvan Influent (mg/l)	Phenosolvan Effluent (mg/l)
S	63	63
Cl	34	34
NH ₃	8,200	80
Phenolics	6,600	430
Fatty Acids	1,900	1,900
HCN	4.2	4.2
Na	45	45
P ₂ O ₅ as H ₃ PO ₄	4.8	4.8

The Phenosolvan influent contains 6600 mg/l of phenolics and 1900 mg/l of fatty acids. About 93 percent of phenolics are estimated to be recovered in the Phenosolvan unit. Effluent from the Phenosolvan unit still contains 430 mg/l of phenolics and 1900 mg/l of fatty acids. An estimated theoretical oxygen demand for various constituents of the Phenosolvan effluent is listed in Table 5-6. Table 5-7 lists the characterization data of actual water samples from the Phenosolvan unit of the SASOL plant in South Africa (EPA, 1974). The SASOL Phenosolvan effluent contained higher concentration of ammonia, and lower concentrations of phenolics and fatty acids, than the estimated data for the four proposed plants.

TABLE 5-6

ESTIMATED THEORETICAL OXYGEN DEMAND FOR
CONSTITUENTS OF PHENOSOLVAN EFFLUENT

Compounds	Formulae	Estimated Concentra- tion (mg/l)	Theoretical Oxygen Demand (mg/l)
Phenolics			
Phenol	$C_6 H_6 O$	190	470
o-cresol	$C_7 H_8 O$		
m-cresol	$C_7 H_8 O$	190	590
p-cresol	$C_7 H_8 O$		
Xylenol	$C_8 H_{10} O$	54	180
	Phenolics	434	1,240
Fatty Acids			
Acetic Acid	$C_2 H_4 O_2$	1,200	1,900
Propanoic Acid	$C_3 H_6 O_2$	290	620
Butanoic Acid	$C_4 H_8 O_2$	150	390
2-methylpropionic Acid	$C_4 H_9 O_2$	46	130
Pentanoic Acid	$C_5 H_{10} O_2$	67	190
Methylbutanoic Acid	$C_5 H_{11} O_2$	46	140
Hexanoic Acid	$C_6 H_{12} O_2$	78	240
	Fatty Acids	1,877	3,610
Sulfur	S	63	95
Ammonia	NH_3	80	260
Cyanide	HCN	4.2	11
	Overall Total		5,216

TABLE 5-7

CHARACTERIZATION OF PHENOSOLVAN UNIT EFFLUENT
OF SASOL PLANT, SOUTH AFRICA

Parameters	Values	Units
Conductivity	1,000-1,800	mhos/cm
pH	8.4	-
F	56	mg/l
COD	1,100	mg/l
NH ₃ -N	220	mg/l
Cl	25	mg/l
H ₂ S	12	mg/l
CN	1	mg/l
Phenol (steam volatile)	1	mg/l
Phenol (bound)	160	mg/l
Fatty Acids (as C ₇ H ₄ O ₂)	560	mg/l
TDS	880	mg/l
TSS	21	mg/l
Ca	18	mg/l
Fe	1	mg/l
PO ₄ -P	2.5	mg/l

In the EIS reports of four plants the information pertaining to the design criteria and the sizes of water treatment units is lacking, as is the projected water characterization. The purpose of this section is to fill in this information gap based on current available technology by designing a hypothetical treatment system for a gasification plant. Although little information is available in the literature regarding coal gasification water treatment, the information on similar wastewaters, such as coke plant wastes, is readily available. Table 5-8 compares the characteristics of coke plant waters with those of a coal gasification plant. Both waters contain ammonia, phenolics, cyanide and residual sulfur, although the concentrations are somewhat different. Some typical design criteria for biological treatment of coke plant waters are shown in Table 5-9. These criteria are useful for coal gasification water treatment in the absence of specific criteria for coal gasification waters because of the similarity between the two waters. Consequently, selected information from the literature of coke waste treatment has been used as the design criteria for coal gasification waters and is presented in Table 5-10. These selected data infer that the hypothetical treatment system includes an equalization tank, an aeration tank, a settling tank with return sludge, an air flotation sludge thickener, and a vacuum filter. Cakes from the vacuum filter are usually disposed of at mine sites. The design flow rates exiting the Phenosolvan units are 4578 gpm for the Natural plant, 2810 gpm for the ANG plant, 4450 gpm for the El Paso plant, and 2877 gpm for the WESCO plant. The constituents of the Phenosolvan effluent which contribute to BOD are shown in Table 5-10. The theoretical oxygen demand is 5216 mg/l. Assuming the ratio of 5-day BOD to theoretical oxygen

TABLE 5-8

COMPARISON OF CHARACTERISTICS OF COKE WASTES AND GASIFICATION WATERS

Parameters	Excess Ammonia Liquor (a)	Weak Ammonia Liquor (b)	Gas Liquor (c)
Total Dissolved Solids (mg/l)	15,000	5,740	1,100 (d)
BOD (mg/l)	3,600	4,600	-
COD (mg/l)	5,800	-	1,100 (e)
Ammonia (mg/l)	3,200	27	80
Cyanide (mg/l)	24	5.1	4.2
Chloride (mg/l)	-	2,400	34
Phenolics (mg/l)	950	2,800	430
Fatty Acids (mg/l)	-	34	1,900
Sulfur (mg/l)	3.7	-	64
P ₂ O ₅ as H ₃ PO ₄ (mg/l)	-	-	4.8
pH	8.6	8.6	8.4

(a) J.E. Barker and R.J. Thompson, 1973.

(b) C.E. Adams, 1974.

(c) ANG Gasification Company, 1977.

(d) From Table 5.0-1 of this report.

(e) Anonymous, 1974.

TABLE 5-9

TYPICAL DESIGN CRITERIA FOR
BIOLOGICAL TREATMENT OF COKE
PLANT WASTES^(a)

Parameters	b	c		d		e
		Plant A	Plant B	Plant A	Plant B	
(1) Influent Dilution	Yes	-	-	-	-	-
(2) NH ₃ Concentration in Aeration Tank (mg/l)	-	130	220	-	-	-
(3) pH	8.5-9.1	7.8	7.7	-	-	7.5-7.6
(4) Water Temperature in Aeration Tank (°F)	75-90	95-100	95-100	-	-	90
(5) F/M (lb BOD/lb MLSS/day)	-	0.6	0.2	0.3	0.16	-
(6) MLVSS (mg/l)	-	2,600	2,400	-	-	-
(7) Aeration Time (hrs)	24	62	98	77	37	1.6
(8) Influent Phenol Concentration (mg/l)	100	-	-	-	-	3,700
(9) Effluent Phenol Concentration (mg/l)	1	-	-	-	-	0.5
(10) Influent BOD, (mg/l)	-	880	4,100	-	-	3,700
(11) Effluent BOD (mg/l)	-	65	150	-	-	0.5
(12) BOD Removal (%)	-	96.5	96.5	-	-	99.9

(a) According to plant descriptions in references listed.

(b) J.E. Baker and R.J. Thompson, 1973.

(c) C.E. Adams, 1974.

(d) R. Jablin and G.P. Chanko, 1973.

(e) P.D. Kostenbader and J.W. Flecksteiner, 1969.

TABLE 5-10

DESIGN CRITERIA FOR COAL GASIFICATION
WATER TREATMENT BASED UPON COKE PLANT
WASTE TREATMENT DATA

Treatment Unit	Design Criteria	Value
(1) Equalization tank	Detention time	7.4 days
(2) Aeration tank	Detention time	24 hours
	BOD removal	90%
	Sludge production	0.2 lb sludge produced /lb BOD removed
	HP requirement	45 lb BOD/day/HP
(3) Settling tank	Overflow rate	750 gpd/ft ²
	Return sludge flow	50% of plant inflow
	Waste sludge flow	14% of plant inflow
	Solid concentration in waste sludge	9500 mg/l
(4) Air flotation sludge thickener	Solid loading rate	20 lb dry solids/ft ² /day
(5) Vacuum filter	Solid loading rate	120 lb dry solid/ft ² /day

demand of 0.5, the 5-day BOD of Phenosolvan effluent will be 2608 mg/l, which is used as the influent BOD to the wastewater treatment units of the four coal gasification plants. Based on the design criteria listed in Table 5-9, the hypothetical designs of the activated sludge plants for the proposed gasification plants are summarized in Figures 5-5, 5-6, 5-7, and 5-8. The vacuum filter cakes to be disposed of vary from 7.85 tons of dry solids/day for the ANG plant to 12.78 tons of dry solids/day for the Natural plant. Since the coal gasification wastes are nutrient deficient, nitrogen and phosphorus have to be added to the aeration tank to maintain a BOD:N:P ratio of 100:5:1. Surface aerators are used to provide oxygen for biological oxidation. Based on the coke plant waste data, the estimated horsepower requirements for surface aerators range from 1743 HP for the ANG plant to 2840 HP for the Natural plant. The estimated composition of activated sludge plant effluent is shown in Table 5-11. Removal efficiency of organics is assumed to be 90 percent. Since the influent BOD is 2608 mg/l, the effluent would still contain 261 mg/l of BOD after the activated sludge treatment.

NOTE: MGD = 10^6 GALLONS/DAY

FIGURE 5-5 HYPOTHETICAL ACTIVATED SLUDGE SYSTEM FOR NATURAL PLANT

NOTE : MGD = 10^6 GALLONS/ DAY

FIGURE 5-6. HYPOTHETICAL ACTIVATED SLUDGE SYSTEM FOR ANG PLANT.

NOTE: MDG = 10^6 GALLONS/DAY

FIGURE 5-7 HYPOTHETICAL ACTIVATED SLUDGE SYSTEM FOR EL PASO PLANT

NOTE: MGD = 10^6 GALLONS/ DAY

FIGURE 5-8. HYPOTHETICAL ACTIVATED SLUDGE SYSTEM FOR WESCO PLANT

TABLE 5-11

ESTIMATED GASIFICATION PLANT INFLUENT AND
EFFLUENT CHARACTERISTICS OF AN ACTIVATED SLUDGE
SYSTEM BASED UPON COKE PLANT WASTE DATA

<u>Parameters</u>	<u>Influent Concentration (mg/l)</u>	<u>% Removal</u>	<u>Effluent Concentration (mg/l)</u>
Sulfur	63	95	3.2
Chlorides	34	0	34
NH ₃	80	50	40
Phenolics	430	90	43.0
Fatty Acids	1,900	90	190
HCN	4.2	80	0.8
Na	45	0	45
P ₂ O ₅ as H ₃ PO ₄	4.8	100	0

5.5 ECONOMICS OF WATER REUSE AND CONTROL

The capital and the operating costs for the hypothetical water treatment systems for the proposed gasification plants are computed and presented in this section. All cost data are based upon 1973 dollars.

The following values are used in the cost estimates: \$170/cu yd of concrete, \$424/installed HP of surface aerators, \$0.014/kw-hr for 8000 hrs/year of electricity, and \$0.30/lb of phosphorus. Capital costs of vacuum filtration and dissolved air flotation are obtained from Figure 5-9 (AWARE, Inc., 1974). Capital costs of settling tanks are obtained from Figure 5-10 (Goldstein and Yung, 1977). The operating costs for the amortization and other capital related items are estimated to be 15 percent of the capital costs per year. The annual costs for maintenance of the concrete tank and the machinery are estimated at 1 and 2 percent of their respective capital costs. Tables 5-12 and 5-13 show the capital costs and operating costs for the four plants. The capital costs vary from 4.83 million dollars for the ANG plant to 7.07 million dollars for the Natural plant, while the operating costs range 1.11 million dollars a year for the ANG plant to 1.65 million dollars a year for the Natural plant. The estimated treatment cost using the activated sludge process is 69 cents per 1000 gallon of treated water.

FIGURE 5-9. CAPITAL COST OF VACUUM FILTRATION AND DISSOLVED AIR FLOTATION.

FIGURE 5-10. CLARIFIER COSTS

TABLE 5-12

ESTIMATED CAPITAL COSTS OF THE HYPOTHETICAL ACTIVATED
SLUDGE SYSTEMS FOR THE FOUR GASIFICATION PLANTS

<u>Item</u>	<u>Capital Cost (10⁶ \$)</u>			
	<u>Natural</u>	<u>ANG</u>	<u>El Paso</u>	<u>WESCO</u>
1. Equalization Tank	4.34	2.71	4.23	2.77
2. Aeration Tank	0.75	0.70	0.73	0.72
3. Surface Aerators	1.20	0.74	1.17	0.76
4. Settling Tank	0.45	0.42	0.45	0.42
5. Air-Flotation Sludge Thickener	0.17	0.13	0.17	0.13
6. Vacuum Filter	0.16	0.13	0.16	0.13
Total Capital Cost	7.07	4.83	6.91	4.93

TABLE 5-13

ESTIMATED OPERATING COSTS OF THE HYPOTHETICAL ACTIVATED
SLUDGE SYSTEMS FOR THE FOUR GASIFICATION PLANTS

<u>Item</u>	<u>Operating Cost (10⁶ \$)</u>			
	<u>Natural</u>	<u>ANG</u>	<u>El Paso</u>	<u>WESCO</u>
1. Amortization and Other Capital-Related Items	1.06	0.72	1.04	0.74
2. Maintenance				
Concrete Tank	0.07	0.05	0.07	0.05
Machinery	0.14	0.10	0.14	0.10
3. Electricity	0.24	0.15	0.23	0.15
4. Chemical (Phosphorus)	0.14	0.09	0.14	0.09
Total Operating Cost	1.65	1.11	1.62	1.13

5.6 DISCUSSION

The EIS reports of the four proposed gasification plants contain limited information on the water treatment system and characterization data of the treated water. All of the plants have included the concept of in-plant water reuse in their plant design, although degrees of water treatment vary according to plants. For the Natural and WESCO plants, the biological treatment has been proposed for treating the Phenosolvan effluent. Biological treatment effluent is to be used as cooling make-up water. For the ANG and El Paso plants, the Phenosolvan effluent will be used as cooling make-up water without going through the biological treatment. The effect of quality of cooling make-up water on the cooling system is not discussed in the EIS report. Leaching of organics and inorganics from buried ashes is probably minimal (Natural 1976) but sludges buried in the mine sites could possibly cause pollution of ground water and have not been experimentally investigated. Therefore, the disposal sites for ashes and sludges need to be carefully selected so that the impact on surface and ground water could be minimized. ANG proposes to use a deep well to dispose of the regeneration wastes from the softener and demineralizer system, and the blowdown from the low pressure steam system. This waste stream contains a high concentration of total dissolved solids. In the EIS report ANG claims that the impact of this waste stream on the groundwater is minimal.

As per intended use as stated in the EIS reports, the current water treatment technology is adequate to treat liquid streams from the gasification plants as proposed by the four plants; there will be no liquid effluent discharge into the receiving waters. Waters leaving

the plant site will include water contained in the ashes and sludges, which possibly will be disposed of at the mine site, and water evaporated from the cooling towers. The major in-plant water reuse is for the cooling make-up water. The use of the cooling tower as a means of disposal of the impaired-quality water in the gasification plants might help to meet the "zero effluent discharge" goal if enforced. But the impact on the environment resulting from the air pollutants in the evaporated water needs to be studied. Other uses of treated water as boiler feed water and process waters will require water treatment systems beyond the Phenosolvan unit and the biological treatment.

There is an apparent difference of technical opinion concerning the need for biological treatment of Phenosolvan effluent waters. Future designs will probably use Phenosolvan effluent as cooling tower make-up if this practice does not result in unacceptable environmental impact and equipment deterioration. However, these impacts are difficult to quantify. Consequently, the use of hypothetical activated sludge systems for Phenosolvan water treatment has been investigated as the natural alternative should the proposed scheme to use Phenosolvan effluent directly not prove successful.

Operating data for the water treatment system in the plants is lacking at this time. In all likelihood the operation of such a treatment system will be quite reliable and will meet the plant water-reuse objectives. Only a possibility of upsets of the water treatment system exists for coal gasification plants, as well as for other industrial plants. In case of upsets, the release of primary or secondary treated waters into the environment might become unavoidable. The impact on the receiving waters would be much greater than the industrial wastes which

have received tertiary treatment. Retention ponds to hold water in case of upsets could be one of the solutions to this problem.

In this report the ANG influent and effluent characterization data for the Phenosolvan unit have been estimated. These data were also used for the other three gasification plants in estimating quality of their treated waters. A more precise estimate of the Phenosolvan influent and effluent characterization could be done for each individual plant, with consideration given to variations in the coal composition and raw water quality, but was judged to be not warranted for this report.

6.0 EFFLUENT CONTROL ECONOMICS

6.1 INTRODUCTION

Because of their large production capacities, coal gasification plants will also produce large amounts of effluents, which, if not controlled, will be discharged into the environment. Some of the effluents are not known to be harmful to the environment; others may be harmful when present in larger quantities; and others may be detrimental to the environment even in very small concentrations. Hence, all gasification plants will have processes which will control the emission of the hazardous effluents into the environment in order to meet federal, state, and local emission standards wherever they are applicable. These processes are not needed directly for the production of SNG, and thus add to the price of the final product.

The emission of hazardous effluents will be controlled by the best available technology by converting these effluents into substances that may be emitted without harming the environment or substances that can be recovered and utilized as a by-product.

Effluents, whose emission into the atmosphere will be controlled to various degrees by the best available technology are H_2S , SO_2 , hydrocarbons, CO , H_2 , COS , CS_2 , particulates, and coal dust. Ash, sludges, and water containing very high concentrations of salts are effluents which will be controlled by burial in the mine. In this chapter, emission of all effluents into the environment is determined. The effluents that will be controlled and the control processes are identified. Cost of control of these effluents is then estimated to give an indication of cost of pollution control equipment relative to the final cost of the plant.

6.2 DIVISION OF GASIFICATION PLANT

Each of the proposed four gasification plants, in general, are divided into 19 divisions or units selected because effluents are emitted into the environment or because the unit will be used for effluent control. Not all units may be present in a particular gasification plant depending on the process selected. Table 6-1 illustrates the numbering system used. The division numbers are used to designate the unit or division in the effluent data tables in Appendix A.

TABLE 6-1

LIST OF DIVISIONS OR UNITS UTILIZED FOR ESTIMATING
EFFLUENTS FROM COAL GASIFICATION FACILITY

<u>Unit or Division Number</u>	<u>Unit or Division</u>
1	Coal Storage Area
2	Coal Preparation Area
3	Raw Water Treatment Plant
4	Boiler Plant
5	Oxygen Plant
6	Gasifiers
7	Ash Dewatering and Transferring Facility
8	ADIP Plant
9	Claus Sulfur Plant
10	Stretford Sulfur Plant
11	Claus Incinerator
12	Vent Gas Incinerator
13	Catalytic Incinerator
14	Untreated Stack Gas Vent
15	Stack Gas Treatment Plant
16	Waste Water Concentrator
17	Biological Waste Water Treatment Plant
18	Evaporation and Ash Ponds
19	Cooling Towers

6.3 EMISSION OF EFFLUENTS

In reporting the emission of effluents, only those that are emitted from within the actual boundaries of the coal gasification plant will be considered. Emissions from outside the boundaries of the plant have not been considered. For each gasification plant, the emission of different effluents into the atmosphere were calculated or estimated for the various divisions present in that plant. Emissions of various effluents were also calculated or estimated for all the effluent control divisions, even if not discharged into the environment. The quantity of each effluent entering a division being controlled and leaving the division was also calculated. The disposition of an effluent whether emitted into the environment or transferred to another process or division was noted. This information is tabulated in the effluent data tables that are given in Appendix A along with biological hazard information for each effluent.

The effluent data tables for each plant were compiled from data provided in the Environmental Impact Statements (EIS) or the Federal Power Commission (FPC) filings prepared by the gasification company. For the El Paso plant, the data were taken from the EPC filings (El Paso, 1973) and the EIS (El Paso, 1977). The WESCO plant information was taken from its EPC filing (WESCO, 1973) and the EIS (WESCO, 1976). Data for the Natural plant were from the environmental assessment report (Natural, 1976) and that for the ANG plant was from its EIS (ANG, 1977) and the supplemental application to the North Dakota State Department of Health (ANG, 1976). Effluent emission data were calculated from flow rates of streams as given in the flow sheets included in the documents. For the ANG plant,

values for utilization of coal having the maximum sulfur content was used. In cases where information was not available from the filed documents, emissions were calculated from material balances and by comparison with similar processes.

Table 6-2 gives a summary of the various effluents emitted into the environment from different units or divisions for the four gasification plants. Variations occur because of the different processes being used for effluent control with differing qualities of coal feed. The various effluent control processes are discussed later in this chapter. There will be no boiler ash or fly ash emitted from the El Paso plant because low Btu gas will be used to fire the boilers. The ANG plant will buy most of its steam from Basin Electric Power Cooperative. Some steam will be raised from supplementary boilers using tar, tar oils, and naphtha which are by-products from the plant and hence some fly ash will be emitted from this source. The Natural and ANG plants will have refuse buried in the mine. Details are not reported since no data was available. Similarly no data was provided for emission of unreacted carbon from gasifiers for the WESCO, Natural, and ANG plants. The presence of CaSO_4 , CaSO_3 , CaCO_3 , Na_2SO_4 , and Na_2SO_3 in the table depends on the flue gas desulfurization process used. The El Paso and ANG plants will not have any flue gas desulfurization process and, hence, will not emit these sulfates, sulfites, and carbonates. Sulfur vapor emission was reported only for the Natural plant.

The EIS of all four gasification plants did not consider the emission to the atmosphere of the coal-lock gas that will be displaced from the coal-lock of the gasifier during coal charging. Emission to the atmosphere of trace compounds vaporized in the water cooling towers

TABLE 6-2

SUMMARY OF ESTIMATED EMISSIONS OF VARIOUS EFFLUENTS
FROM THE FOUR GASIFICATION FACILITIES
(tons/day)

<u>Effluent</u>	<u>El Paso</u>		<u>WESCO</u>		<u>Natural</u>		<u>ANG</u>		<u>To Deep Well Injection</u>
	<u>To Atm</u>	<u>To Mine</u>	<u>To Atm</u>	<u>To Mine</u>	<u>To Atm</u>	<u>To Mine</u>	<u>To Atm</u>	<u>To Mine</u>	
Coal Dust	0.1412	-	0.0124	-	0.1473	-	1.2192	-	-
Refuse	-	1,680	-	2,263	-	-	-	-	-
Sludge + Water	-	1,147	-	1,413	-	437	-	740	3,052
Boiler Ash	-	-	-	135	-	151	-	-	-
Fly Ash	-	-	-	411	-	361	-	6.24	-
Gasifier Ash	-	5,439	-	6,534	-	2,159	-	1,763	-
Unreacted C	-	286	-	-	-	-	-	-	-
Particulates	0.5530	-	1.2160	-	2.177	-	1.5688	-	-
CaSO ₄ ·2H ₂ O	-	-	-	215	-	-	-	-	-
CaSO ₃ ·2H ₂ O	-	-	-	-	-	179	-	-	-
CaCO ₃	-	-	-	53	-	-	-	-	-
Na ₂ SO ₃	-	-	-	-	-	2.5	-	-	-
Na ₂ SO ₄	-	-	-	-	-	9.6	-	-	-
O ₂	12,540	-	1,723	-	2,391	-	1,761	-	-
N ₂	82,544	-	53,135	-	60,148	-	40,840	-	-
H ₂ O Vapor	31,644	-	29,712	-	39,968	-	30,399	-	-
CO ₂	27,805	-	30,399	-	34,171	-	26,945	-	-

TABLE 6-2 (Continued)

	<u>El Paso</u>		<u>WESCO</u>		<u>Natural</u>		<u>ANG</u>		
<u>Effluent</u>	<u>To Atm</u>	<u>To Mine</u>	<u>To Atm</u>	<u>To Mine</u>	<u>To Atm</u>	<u>To Mine</u>	<u>To Atm</u>	<u>To Mine</u>	<u>To Deep Well Injection</u>
Naphtha	0.224	-	-	-	-	-	-	-	-
Fatty Acids ^(b)	1.0707	-	0.3867	-	0.7626	-	-	-	-
Phenolics ^(c)	0.1165	-	0.0033	-	0.3648	-	-	-	-
Pyridines ^(d)	0.0067	-	-	-	-	-	-	-	-
Thiocyanates ^(e)	0.0893	-	0.0032	-	0.179	-	-	-	-

(a) Estimated as NO₂

(b) Estimated as acetic acid

(c) Estimated as phenol

(d) Estimated as pyridine

(e) Estimated as HSCN

and evaporation ponds are also not reported. It is important to know the extent of emissions from both these sources since the compounds emitted to the atmosphere could possibly be hazardous depending on the concentrations and quantities emitted.

Discharges from the coal lock were estimated from the gas composition, the amount of coal to be used in the gasifiers, and the number of gasifiers in each plant. El Paso and ANG plants will use the raw gas after cooling as coal-lock gas while the WESCO and Natural plants will be using a CO₂-rich effluent gas from the Rectisol plant as lock-gas. Table 6-3 lists the effluents and their estimated emission quantities to the atmosphere from coal-lock hoppers for all plants.

In order to estimate the emission of trace compounds to the atmosphere from cooling towers, the composition of the circulating cooling water entering the cooling system had to be known. These data were reported only for the Natural plant (Natural, 1976). The cooling water is made up of effluent water from different sources within each plant and contains various compounds, such as fatty acids, phenolics, ammonia, pyridines, thiocyanates, and other dissolved solids in small quantities. Some of these compounds will be vaporized and emitted into the air. Most of these compounds do have an odor when present even in minute quantities in the atmosphere.

The composition of cooling water for the El Paso and WESCO plants was estimated by comparing the water flow diagrams of these plants with that of the Natural plant. It must be understood that the composition of water obtained in this manner is not precise since the water quality will differ greatly due to different sources of raw water and varying qualities of coal being gasified. Emissions estimated serve only the

TABLE 6-3

ESTIMATED EMISSIONS OF EFFLUENTS FROM THE GASIFIER
COAL LOCK TO THE ATMOSPHERE WHILE CHARGING THE COAL
LOCK WITH COAL FOR THE FOUR GASIFICATION FACILITIES

Estimated Emission (ton/day)

<u>Effluent</u>	<u>El Paso</u>	<u>WESCO</u>	<u>Natural</u>	<u>ANG</u>
CO ₂	14.646	50.00	56.7	13.848
H ₂ S	0.153	0.0044	0.0005	0.1508
Hydrocarbons	2.447	0.380	0.294	1.8698
CO	7.153	-	-	4.241
H ₂	0.945	-	-	0.7502
N ₂	2.567	-	-	-
Naphtha	0.224	-	-	-
H ₂ O	0.112	-	-	4.941
COS	-	0.0012	0.0014	-

purpose of providing an indication of the kind of emissions that could be obtained from the cooling towers. This estimate was not made for the ANG plant because of insufficient information. The calculations were made knowing the mean air temperature, the amount of water vaporized, and the amount of cooling achieved. A similar estimate was made for emission from the evaporation pond in the El Paso plant. No estimate was made for evaporation ponds of the other plants since they will be outside the plant limit. However, these would be included in an environmental analysis of the facility. Table 6-4 lists the estimated emissions from cooling towers and evaporation ponds for the El Paso, WESCO, and Natural gasification plants.

TABLE 6-4

ESTIMATED EMISSIONS OF TRACE COMPOUNDS FROM
COOLING TOWERS OF THREE GASIFICATION FACILITIES
AND EVAPORATION POND OF EL PASO

<u>Effluent</u>	<u>Emissions from Cooling Towers (tons/day)</u>			<u>Emission from Cooling Pond (tons/day)</u>
	<u>El Paso</u>	<u>WESCO</u>	<u>Natural</u>	<u>El Paso</u>
Fatty Acids (a)	0.3826	0.3867	0.7626	0.574
Phenolics (b)	0.1161	0.0033	0.3648	0.00031
Pyridines (c)	0.0067	0.0032	-	-
Thiocyanates (d)	0.0893	-	0.1790	-
NH ₃	4.562	2.544	9.16	-
CO ₂	-	-	18.0	-
HCN	-	-	-	0.572
Particulates	0.5244	0.344	0.923	-

(a) Estimated as acetic acid

(b) Estimated as phenol

(c) Estimated as pyridine

(d) Estimated as HSCN

6.4 CONTROL OF EFFLUENTS

The main effluents that will be controlled are H_2S , SO_2 , hydrocarbons, particulates, coal dust, and CO. Secondary gaseous effluents controlled are H_2 , COS, CS_2 , and HCN. Hydrocarbons, H_2S , CO, H_2 , COS, and CS_2 will be present in the effluent streams from the Rectisol unit, the Phenosolvan unit, and the gas-liquor separation unit. Particulates and SO_2 will be mainly present in the flue-gases from the boilers, and coal dust will be present in the coal storage and coal handling areas.

Gasifier ash, boiler ash, fly ash, various water sludges from different water purification units, and sludges from flue gas desulfurization units will be disposed of by burial in the mine.

6.4.1 Control of H_2S

H_2S is removed from the main product gas stream in the Rectisol unit in all four gasification plants. The H_2S containing off-gases from the Rectisol unit cannot be emitted into the atmosphere directly as its concentration and quantity will exceed standards. The H_2S will be controlled by conversion to elemental sulfur using either the Claus process or the Stretford process or by a combination process. In the El Paso and ANG plant designs the H_2S -rich and the H_2S -lean off-gases from the Rectisol unit will be combined and sent to the Stretford process. The gaseous effluents from the Stretford process will be sent to incineration. In case of the WESCO and Natural plants, the H_2S will be controlled by a combination of the Stretford and Claus units. The hot-regenerator, H_2S lean, overhead gas from the Rectisol plant will be concentrated in

H₂S before being sent to the Claus unit using the ADIP process. This process separates the gas into two streams, one containing all the hydrocarbons, COS, and most of the CO₂ and the other containing most of the H₂S. The ADIP unit will be considered as a part of the H₂S control process. The hydrocarbon-rich gas from the ADIP unit will be sent to the incinerator. The H₂S-rich stream will be sent to the Claus unit for recovery of sulfur. The Claus tail gas will contain residual amounts of H₂S, SO₂, COS, CO, and CS₂ along with N₂, O₂, CO₂, and H₂O. This stream will be incinerated. The Stretford unit will be used to recover sulfur from H₂S in the H₂S-rich flash gases from the Rectisol unit, the off-gas from the Phenosolvan plant, and the expansion gases. The vent gas from the Stretford unit will be incinerated.

6.4.2 Control of Hydrocarbons, CO, H₂, COS, CS₂, and Residual H₂S

The vent gases from the ADIP, Claus, and Stretford processes will contain hydrocarbons, CO, H₂, residual H₂S, COS, and CS₂. These combustible gases are most easily controlled by incineration. This is usually done very conveniently by burning the gases in either the combustion chamber of the boiler or the superheater along with the regular fuel. The gases are incinerated in the boiler or superheater because of high temperatures in the combustion chambers and there is need of very little additional fuel for incineration. In some instances the combustible gases are burned by themselves in an incinerator. When the heating value of the gas stream is not above 100 Btu/SCF the gas will not maintain combustion without additional fuel. Control of combustible gases may also be done by means of incineration over a catalyst at much lower temperatures. Irrespective of what method is used to incinerate the gases, excess air must be supplied for complete combustion.

In the El Paso plant, the absorber off-gases from the Stretford unit will be incinerated. This stream will have a high enough heating value so that no extra fuel will be necessary to maintain combustion. Another absorber off-gas stream and the oxidizer off-gas stream from the Stretford unit will be burned in a catalytic incinerator.

In the WESCO design the hydrocarbon-rich gases from the hydrocarbon removal process will be sent to the boiler. The Claus and Stretford tail gases containing residual amounts of H_2S will also be sent to the boiler for incineration. The CO_2 -rich vent gas containing residual amounts of H_2S from the Rectisol unit will be burned in the combustion chamber of the steam superheater. Coal will be used as a fuel in the boiler and fuel oil, a by-product of the gasification plant, will be used as a fuel in the superheater section. The flue gases from the boiler, after particulate control, will be sent to a flue gas desulfurization unit for SO_2 removal while the flue gas from the superheater will be emitted into the atmosphere.

In the Natural plant, the hydrocarbon-rich gas from the ADIP process and the vent gases containing residual H_2S from the Stretford process will be incinerated. The Claus tail gases containing residual H_2S will be incinerated in a separate Claus incinerator. Both incinerators will burn fuel oil produced in the gasification plant. The flue gases will be emitted into the atmosphere.

In case of the ANG plant, the Stretford tail gas will be incinerated in the superheater. Tar, tar oil, and naphtha produced as by-products in the plant will be used as the fuel. The flue gases will be emitted directly into the atmosphere.

6.4.3 Control of SO₂

Control of SO₂ emission in the flue gases becomes important in gasification plants that burn coal in the boilers. The emission of SO₂ is relatively small in the flue gases from the steam superheaters of all four gasification plants, since either liquid or gaseous fuels containing little or no sulfur will be used and SO₂ emission control will not be necessary.

The El Paso and ANG gasification plants will not have any flue gas desulfurization unit for SO₂ control. El Paso will use low Btu sulfur-free gas produced from air-fired coal gasifiers to fuel its boilers and superheaters and, hence, SO₂ control is not needed. ANG plant avoids using any SO₂ control unit by not having any major boilers in the plant complex. Most of the steam requirements will be purchased from Basin Electric Power Cooperative to be located in the immediate vicinity. Basin Electric will use the coal fines from the coal preparation. ANG proposes to use low sulfur tar, tar oil, and naptha, produced in the plant as fuel in supplementary boilers and superheaters without flue gas desulfurization.

The WESCO gasification plant will use coal as fuel for its steam boilers and SO₂ control for the flue gases, but at the time of publication of the latest EIS (WESCO, 1976) WESCO had not decided on the flue gas desulfurization process to be used as an example of the SO₂ control. The Chiyoda Thoroughbred 101 Process had been used as an example of the SO₂ control method in the EIS. The steam superheaters will be fired with low sulfur fuel oil produced in the plant and will not need SO₂ control.

The Natural plant will use the FMC process for control of SO₂ emission from the flue gases from coal-fired boilers. The incinerators

and superheaters will be fired with low sulfur fuel oil and no SO₂ control will be needed.

6.4.4 Control of Particulates and Coal Dust

Emission of coal dust needs to be controlled in the coal storage and coal preparation areas. This dust will be controlled by using water sprays and bag filters. Wet cyclones will be used to control coal dust emission from coal lock hoppers from the decompression cycle during charging. Particles emitted from the ash-lock of the gasifiers during the decompression cycle will also be removed with wet cyclones.

Emission of particulates (fly ash) into the atmosphere from the flue gases from boilers when coal is used does not meet federal emission standards. These particulates will be removed using hot electrostatic precipitators. Since the El Paso plant will be using low Btu fuel gas in its boilers and superheaters no particulate control will be necessary. WESCO and Natural gasification plants will use coal in their boilers and ANG plant will be using tar, tar oil, and naphtha as fuel for their supplementary boilers and need hot electro-static precipitators for control of emission of particulates (fly ash). The flue-gas desulfurization process used by WESCO and Natural plants also will remove particulates.

6.4.5 Control of Ash

The major source of ash production will be from the gasifiers. Ash will also be obtained from the boilers, in the form of boiler ash or bottom ash and fly ash, when coal or tar is used as fuel in the boilers. Ash from these sources will be removed by sluicing with waste water to an ash dewatering and transfer unit. The ash dewatering

and transfer unit separates the water from the ash and stores the ash in silos or in ash piles. From here the ash will be loaded into trucks using a front end loader for final disposal in the mine. There will be different designs of the ash dewatering and transfer unit proposed for the four gasification plants. Each plant will have this unit.

6.4.6 Control of Liquid Sludges and Waste Water

All gasification plants will be operating on the principle of zero discharge of water and other liquid wastes. Such operation implies that waste water containing high concentrations of dissolved solids and sludges will have to be disposed of in some manner other than discharge to the drainage system. Raw water treatment processes, cooling tower blowdowns, waste water concentrators, and biological water treatment processes all produce waste water and sludges that are highly concentrated in dissolved solids. This waste water will be used to sluice the gasifier and boiler ash to ash dewatering and transfer units. The water and the sludges will then be sent along with the ash to the mine for final disposal. The El Paso plant, due to its location in New Mexico, also makes use of solar evaporation to get rid of excess waste water. The ANG plant also plans to dispose of sludges by deep well injection.

6.4.7 Uncontrolled Gases

There are some vent gas streams that will be emitted into the atmosphere without being incinerated or otherwise treated. These gas streams will be high in CO_2 and low in combustibles and cannot be burned. However, the El Paso plant will have no unincinerated stream released to the atmosphere. In the WESCO plant, the coal-lock gas

which is very rich in CO_2 will be emitted into the atmosphere without incineration through the superheater stack. In the Natural plant, part of the flue gas from the boiler will by-pass (if allowed under NSPS) the flue gas desulfurization unit and will be used to reheat the treated flue gas and increase its buoyancy. In the ANG plant, the oxidizer vent from the Stretford unit will be emitted into the atmosphere untreated since it does not contain any combustible gases.

6.5 COST OF UTILITIES

In order to estimate operating costs for the various effluent controls, the cost of utilities, such as electricity, steam, process water, cooling water, and fuel, has to be known. In most instances this information is not directly available for the four gasification plants and has to be estimated otherwise. These costs are summarized in Table 6-5 for each of the four gasification plants.

The cost of electricity was given for the El Paso plant (El Paso, 1973) and was assumed to be the same for the other three plants. The cost of process water was obtained by estimating the cost of raw water and adding the costs of pumping, transferring to the plant, and water treatment. The cost of raw water was known for El Paso, WESCO, and ANG plants (El Paso, 1973; WESCO, 1973; and ANG, 1976). For the Natural plant it was assumed that the cost was the same as for the ANG plant since they will be obtaining water from the same source. The cost of pumping and transfer and water treatment was estimated by assuming that the operating cost of these units were proportional to the fixed capital investments of these units that are known for El Paso and ANG plants (El Paso, 1973 and ANG, 1976). The final fixed capital investment for the complete plant was also known and, hence, the cost of treated water could be estimated. The cost of cooling water was determined by estimating the expense of operating the cooling tower and the cost of make-up water. The cost of steam was estimated in a similar manner by calculating the operating cost for the steam and power plant and adding the cost of boiler make-up water. The cost of electrical power is subtracted if generated in the plant. The cost of diesel fuel was estimated from the present market value of the fuel.

TABLE 6-5

COST OF UTILITIES FOR THE FOUR GASIFI-
CATION FACILITIES (1973 DOLLARS)

<u>Utility</u>	<u>Units</u>	<u>El Paso</u>	<u>WESCO</u>	<u>Natural</u>	<u>ANG</u>
Electricity	\$/KW hr	0.0140	0.0140	0.0140	0.0140
Steam	\$/MM Btu	0.7860	0.8213	0.5844	0.580
Process Water	\$/1,000 gal	3.0440	3.4488	3.4599	2.509
Cooling Water	\$/MM Btu	0.3155	0.7104	0.6271	-
Diesel Fuel	\$/MM Btu	3.339	3.339	3.339	3.339

6.6 FIXED CAPITAL INVESTMENT AND DIRECT OPERATING COSTS

The fixed capital investment (FCI) and the direct operating costs (DOC) were estimated in 1973 dollars¹ for pollution control equipment for all four gasification plants. The FCI includes the cost of process equipment, material of construction, initial catalyst and chemical supplies, land, direct field labor and supervision, payroll taxes, construction supplies, temporary facilities, craft benefits, construction equipment, engineering, contractors' overheads and fees, process license fees, and state sales tax. The FCI costs for most of the effluent control units for the El Paso plant were obtained from the FPC filings (El Paso, 1973). For the other plants, the capital investment costs for individual control units are estimated either by scaling from values known for the El Paso plant or by estimating the installed equipment costs from literature sources together with factors given by Peters and Timmerhaus (1968). In such cases the FCI was estimated between 184 and 192 percent of the installed equipment cost depending upon the system. Where more than one effluent was controlled in the same unit, the FCI for that unit for controlling the different effluents was arrived at by taking the total FCI for the unit and multiplying it by the fraction of the various controlled effluents.

The DOC for each unit was made up of the following costs:

1. Material
2. Operating Labor
3. Operating supervision (15 percent of operating labor)

¹1973 dollars were chosen because of the availability of the El Paso data (the first plant) on that basis. All other data occurred at a later date.

4. Utilities
5. Maintenance and repairs (5-9 percent of FCI)
6. Operating supplies (15 percent of maintenance and repairs)
7. Laboratory charges (10-20 percent of operating labor)

The percentages in parentheses are the ones suggested by Peters and Timmerhaus (1968). The cost of material, utilities and labor were estimated directly. Operating labor was charged at \$16,700/man-year including fringe benefits, as suggested in the El Paso FPC filings (El Paso, 1973). The DOC does not include interest charges and depreciation. Where more than one effluent was controlled by a unit, the DOC for control of each effluent was proportional to the fraction of the controlled effluent.

The FCI and various elements used in calculating the DOC, such as electrical, steam, cooling water and fuel requirements, cost of labor material, maintenance, and other items, are tabulated in the effluent data tables in Appendix A.

6.6.1 Cooling Towers

A cooling tower may be assumed as a means of heat release from the plant into the atmosphere and as a process for controlling thermal pollution. Table 6-6 summarizes the costs for the cooling towers for the four gasification plants along with their total energy requirements and water vapor emission rates. The FCI for the cooling tower for the El Paso plant was obtained from FPC filings (El Paso, 1973). The costs for the other plants were estimated by comparing the values for the El Paso and the other gasification plants.

TABLE 6-6

FIXED CAPITAL INVESTMENT, DIRECT OPERATING COSTS,
TOTAL ENERGY REQUIREMENT, AND AMOUNT OF WATER
VAPORIZED FOR COOLING TOWER FOR THE FOUR
GASIFICATION FACILITIES

<u>Plant</u>	<u>Fixed Capital Investment, MM dollars 1973 dollars</u>	<u>Direct Operating Costs, MM dollars 1973 dollars</u>	<u>Energy Requirements, (MM Btu/day)</u>	<u>Water Vaporized (tons/day)</u>
El Paso	5.8	1.56	730.9	17,844
WESCO	2.657	4.278	199.1	23,437
Natural	8.426	12.074	1,361.9	29,149
ANG	10.325	3.206	678.4	27,484

6.6.2 Control of Ash and Sludges

Solid and liquid effluents consisting of refuse, ash, and sludges from flue gas desulfurization units, water treatment units, and cooling tower blowdowns will be sent to the mine for disposal by burial and will be monitored as required by state and federal regulations. The cost for control of these effluents that have been considered are the costs for the ash dewatering and transfer, units and the costs associated with loading the ash and sludges into ash trucks for transport to the mine. The costs of transfer by trucks and the mine disposal are not included since these operations will not be within the boundaries of the gasification plant. The FCI, DOC, energy requirements and amounts controlled for the individual components being sent to the mine are shown in Table 6-7 for the four gasification plants. The energy requirements per ton of solids and sludges controlled and the DOC per ton of solids and sludges controlled are also tabulated in Table 6-7. From the tables it is observed that the DOC per ton and the energy requirements per ton are higher for the Natural and ANG plants than for the El Paso and WESCO plants. The costs for the El Paso plant were obtained from the FPC filings (El Paso, 1973) while those for the other facilities were estimated by comparison with El Paso's costs.

6.6.3 Control of Coal Dust and Particulates

The cost of control of coal dust includes the cost of water sprays, bag filters, and wet cyclones. The cost of particulate control includes costs for electrostatic precipitators and wet cyclones. The cost data for water sprays was arrived at by making many assumptions about the system since no other data was available. The cost data for bag filters, wet cyclones, and electrostatic precipitators were obtained from published data (HEW, 1969). Table 6-8 compares the FCI, DOC, total

TABLE 6-7

FIXED CAPITAL INVESTMENT (FCI), DIRECT OPERATING COSTS (DOC),
ENERGY REQUIREMENTS, AND AMOUNT HANDLED FOR CONTROLLING ASH
AND SLUDGES FROM THE FOUR GASIFICATION PLANTS

<u>Effluent</u>	<u>FCI, MM dollars (1973 dollars)</u>	<u>DOC, MM dollars (1973 dollars)</u>	<u>Energy Requirements (MMBTU/day)</u>	<u>Quantity Controlled (tons/day)</u>	<u>DOC/Quantity Controlled (\$/ton)</u>	<u>Energy/Qty Controlled (MMBTU/ton)</u>
<u>El Paso</u>						
Refuse	0.308	0.064	5.51	1,680	0.115	0.0033
Water + Sludge	0	0	0	1,147	0	0
Gasifier Ash	7.182	1.088	114.6	5,439	0.603	0.0211
Unreacted C	<u>0.378</u>	<u>0.057</u>	<u>6.06</u>	<u>286</u>	<u>0.600</u>	<u>0.0212</u>
Total	7.868	1.209	126.17	8,552	0.426 ^(a)	0.0147 ^(a)
<u>WESCO</u>						
Refuse	0.355	0.0689	6.74	2,263	0.917	0.00298
Water + Sludge	0.0071	0.00159	0.216	1,413	0.0034	0.00153
Boiler Ash	0.161	0.0151	3.064	135	0.337	0.0227
Fly Ash	0.484	0.0808	9.275	411	0.592	0.0226
Gasifier Ash	6.918	1.145	132.8	6,534	0.528	0.0203
CaSO ₄ ·2H ₂ O	0.039	0.00816	0.780	215	0.114	0.00363
CaCO ₃	0.012	0.00257	0.252	42	0.184	0.0060
CaCO ₃	<u>0</u>	<u>0</u>	<u>0</u>	<u>11</u>	<u>0</u>	<u>0</u>
Total	7.976	1.322	153.127	11,024	0.361 ^(a)	0.0139 ^(a)

TABLE 6-7 (Continued)

<u>Effluent</u>	<u>FIC, MM dollars (1973 dollars)</u>	<u>DOC, MM dollars (1973 dollars)</u>	<u>Energy Requirement (MMBTU/day)</u>	<u>Quantity Controlled (tons/day)</u>	<u>DOC/Quantity Controlled (\$/ton)</u>	<u>Energy/Qty Controlled (MMBTU/ton)</u>
<u>Natural</u>						
Water & Sludge	0.1503	0.0382	8.817	437	0.263	0.0202
Boiler Ash	0.254	0.0517	8.596	151	1.031	0.0569
Fly Ash	0.612	0.124	20.690	361	1.035	0.0573
Gasifier Ash	3.645	0.740	123.24	2,159	1.032	0.0571
CaSO ₃ ·2H ₂ O	0.085	0.0277	7.947	179	0.466	0.0444
Na ₂ SO ₃	0	0	0	2.5	0	0
Na ₂ SO ₄	0	0	0	9.6	0	0
Total	4.746	0.9816	169.290	3,299	0.896 ^(a)	0.0513 ^(a)
<u>ANG</u>						
Water & Sludge	0.584	0.0983	14.439	740	0.400	0.0195
Fly Ash	0.0115	0.00195	0.256	6.24	0.941	0.0410
Gasifier Ash	3.327	0.547	80.16	1,763	0.935	0.0455
Total	3.923	0.647	94.86	2,509	0.788 ^(a)	0.0378 ^(a)

(a) The total represents the average number for the individual components.

TABLE 6-8

FIXED CAPITAL INVESTMENT (FCI), DIRECT OPERATING COSTS (DOC), ENERGY REQUIREMENTS, AND AMOUNT CONTROLLED FOR CONTROL OF COAL DUST AND PARTICULATES FOR THE FOUR GASIFICATION PLANTS

<u>Effluent</u>	<u>FCI, MM dollars (1973 dollars)</u>	<u>DOC, MM dollars (1973 dollars)</u>	<u>Energy Requirements (MMBTU/day)</u>	<u>Quantity Controlled, (tons/day)</u>	<u>Percent Controlled</u>	<u>DOC/Qty Controlled (\$/ton)</u>	<u>Energy/Qty Controlled, (MMBTU/ton)</u>
<u>El Paso</u>							
Coal Dust	0.231	0.645	45.589	13.98	99.00	138.97	3.12
Particulates	<u>0.145</u>	<u>0.0531</u>	<u>6.719</u>	<u>2.833</u>	<u>98.99</u>	<u>56.46</u>	<u>2.37</u>
Total	0.376	0.698	50.31	16.812	99.00	125.05 ^(a)	2.99 ^(a)
<u>WESCO</u>							
Coal Dust	0.289	0.723	25.072	12.41	99.90	175.48	2.02
Particulates	<u>6.627</u>	<u>0.312</u>	<u>80.543</u>	<u>409.23</u>	<u>98.55</u>	<u>2.30</u>	<u>0.197</u>
Total	6.916	1.035	105.62	421.64	98.59	7.39 ^(a)	0.250 ^(a)
<u>Natural</u>							
Coal Dust	0.334	0.651	40.476	14.031	99.00	139.75	2.88
Particulates	<u>7.138</u>	<u>0.322</u>	<u>83.329</u>	<u>362.06</u>	<u>98.69</u>	<u>2.68</u>	<u>0.230</u>
Total	7.472	0.973	123.85	376.1	98.70	7.79 ^(a)	0.329 ^(a)
<u>ANG</u>							
Coal Dust	1.245	0.740	77.102	13.286	99.00	167.76	5.80
Particulates	<u>2.806</u>	<u>0.175</u>	<u>24.417</u>	<u>7.113</u>	<u>81.93</u>	<u>74.10</u>	<u>3.43</u>
Total	4.051	0.915	101.52	20.4	92.30	140.41 ^(a)	4.97 ^(a)

(a) The total represents the average number for the individual components.

energy consumption, the quantity and percentage controlled for the coal dust, and the particulate control equipment for the four gasification plants. It also compares the DOC per ton and the energy required per ton for the four plants.

6.6.4 Control of H_2S

The cost estimate for the Stretford process for the El Paso plant was obtained from the FPC filings (El Paso, 1973). The costs of the Stretford, Claus, and ADIP units for the WESCO, Natural, and ANG plants were arrived at by using information provided by the Environmental Protection Agency (EPA, 1977). The costs for incineration processes were calculated from published data for incinerators (HEW, 1969). The various costs, the energy requirements, the quantity and percentage of H_2S controlled, the DOC per ton H_2S controlled, and the energy requirements per ton H_2S controlled are shown in Table 6-9 for the four gasification plants. No costs have been assigned for WESCO and ANG incineration units since they were part of the steam superheater in the plant and their main function was superheating the steam.

6.6.5 Control of SO_2

Flue gas desulfurization units will be present only in the WESCO and the Natural gasification plants. The cost data for the Chiyoda Thoroughbred 101 process for the WESCO plant was estimated from published data (Tamaki, 1975). The cost data for the FMC process for use in the natural plant was obtained from vendor information (FMC, 1973). The FCI, the DOC along with the energy requirements, the quantity and percentage of SO_2 controlled, the DOC per ton of SO_2 controlled, and the energy requirements per ton SO_2 controlled are tabulated in Table 6-10 for the WESCO and Natural plants.

TABLE 6-9

FIXED CAPITAL INVESTMENT (FCI), DIRECT OPERATING COSTS (DOC), ENERGY REQUIREMENTS, AND AMOUNT CONTROLLED FOR H₂S CONTROL BY VARIOUS METHODS FOR THE FOUR GASIFICATION PLANTS:

Plant	FCI, MM dollars (1973 dollars)	DOC, MM dollars (1973 dollars)	Energy Requirements (MMBTU/day)	Quantity Controlled (tons/day)	Percent Controlled	DOC/Qty Controlled (\$/ton)	Energy/Qty Controlled, (MMBTU/ton)
<u>Stretford Process</u>							
El Paso	8.61	5.959	2998.5	200.656	99.93	89.45	14.94
WESCO	9.3	1.355	376.2	66.28	98.02	61.58	5.68
Natural	10.288	1.592	435.96	81.334	99.85	58.96	5.36
ANG	22.241	4.269	1259.5	234.7	99.24	54.7	5.37
<u>Claus Process</u>							
WESCO	2.295	0.259	204.1	146.4	95.00	5.33	1.39
Natural	2.302	0.235	132.9	155.2	99.46	4.56	0.86
<u>ADIP Process</u>							
WESCO	3.698	0.556	1288.5	116.3	99.91	14.40	11.08
Natural	4.294	0.560	1648.0	149.07	99.89	11.32	11.06
<u>Incineration</u>							
El Paso	0.00199	0.000302	0.00835	0.4582	98.75	1.99	0.0182
WESCO	0	0	0	0.071	100.00	0	0
Natural	0.154	0.0158	0.254	1.216	100.00	39.14	0.209
ANG	0	0	0	1.807	100.00	0	0

TABLE 6-10

FIXED CAPITAL INVESTMENT (FCI), DIRECT OPERATING COSTS
(DOC), ENERGY REQUIREMENT, AND AMOUNT CONTROLLED FOR
SO₂ CONTROL FOR TWO GASIFICATION PLANTS

6-30

<u>Plant (Process)</u>	<u>FCI, MM dollars (1973 dollars)</u>	<u>DOC, MM dollars (1973 dollars)</u>	<u>Energy Requirements (MMBTU/day)</u>	<u>Quantity Controlled (tons/day)</u>	<u>Percent Controlled</u>	<u>DOC/Qty Controlled (\$/ton)</u>	<u>Energy/Qty Controlled (MMBTU/ton)</u>
WESCO (Chiyoda thoroughbred process)	78.243	5.236	854	81.45	90.00	193.63	10.49
Natural (FMC process)	27.10	3.251	659	75.58	90.12	129.56	8.72

6.6.6 Control of Hydrocarbons, H_2 , CO, COS, CS_2 , and Other Combustibles

The costs of control of combustible gases in incinerators were obtained from published data (HEW, 1969). No costs and energy requirements were estimated when the incineration will be done in boilers and superheaters. The cost of fuel and the energy provided by the fuel was not taken into account since the fuels used for incineration will be by-products from the gasification plants and they represent utilization of internal resources. Table 6-11 lists the costs, energy requirements, and amounts controlled for the combustibles by incineration for the four gasification plants. The unit DOC and the unit energy requirements are also shown in the table.

TABLE 6-11

FIXED CAPITAL INVESTMENT (FCI), DIRECT OPERATING COSTS (DOC), ENERGY REQUIREMENTS, AMOUNT CONTROLLED FOR CONTROL OF HYDROCARBONS, H₂, CO, COS, CS₂, HCN, AND S VAPOR BY INCINERATION FOR THE FOUR GASIFICATION PLANTS

Plant	FCI, MM dollars (1973 dollars)	DOC, MM dollars (1973 dollars)	Energy Requirements (MMBTU/day)	Quantity Controlled (tons/day)	Percent Controlled	DOC/Qty Controlled (\$/ton)	Energy/Qty Controlled (MMBTU/ton)
<u>Hydrocarbons</u>							
El Paso	1.545	0.235	6.375	110.4	96.17	6.41	0.0610
WESCO	0	0	0	218.98	100	0	0
Natural	1.286	0.126	7.047	267.6	100	1.42	0.0263
ANG	0	0	0	266.56	99.79	0	0
<u>H₂</u>							
El Paso	0.725	0.107	3.114	6.816	97.7	47.28	0.457
WESCO	0	0	0	19.8	100	0	0
Natural	0.183	0.0181	0.926	2.255	100	25.18	0.411
ANG	0	0	0	0.749	100	0	0
<u>CO</u>							
El Paso	0.318	0.0476	1.393	52.56	99.17	2.73	0.0265
WESCO	0	0	0	130.7	100	0	0
Natural	0.0822	0.00814	0.413	14.81	100	1.66	0.0279
ANG	0	0	0	6.72	68.97	0	0

TABLE 6-11 (Continued)

<u>Plant</u>	<u>FCI, MM dollars (1973 dollars)</u>	<u>DOC, MM dollars (1973 dollars)</u>	<u>Energy Requirements (MMBTU/day)</u>	<u>Quantity Controlled (tons/day)</u>	<u>Percent Controlled</u>	<u>DOC/Qty Controlled (\$/ton)</u>	<u>Energy/Qty Controlled (MMBTU/ton)</u>
<u>COS</u>							
El Paso	0.0190	0.00157	0.049	1.9814	96.00	2.39	0.0247
WESCO	0	0	0	3.712	100	0	0
Natural	0.0450	0.00471	0.139	4.430	100	3.20	0.0314
ANG	0	0	0	6.185	100	0	0
<u>CS₂</u>							
El Paso	0.00032	0.000050	0.0016	0.0691	95.97	2.14	0.0232
Natural	0.0037	0.00035	0.00819	0.2836	100	3.47	0.0289
ANG	0	0	0	2.444	100	0	0
<u>HCN</u>							
WESCO	0	0	0	0.38	100	0	0
<u>S Vapor</u>							
Natural	0.046	0.0048	0.0819	0.238	100	60.75	0.344

6.7 SUMMARY

The FCI, DOC, and quantity of effluent controlled for the four gasification plants is summarized in Table 6-12 for the different effluents. Table 6-13 shows the same FCI and DOC for effluent control as percentages of the total FCI and total DOC for each of the complete gasification plants. The effluent control costs for the WESCO plant are the highest and also constitute the largest fraction of the total plant costs. This is due to the very high cost for SO_2 control. El Paso has the lowest cost because it does not have any flue gas desulfurization units or electrostatic precipitators. The ANG plant without any flue gas desulfurization and with only small electrostatic precipitators has the next lowest cost. This indicates that the plants that have been designed to eliminate the problem of SO_2 emission will have lower emission control costs, but the costs of the whole plant will not be lowered since, as in the El Paso plant, extra gasifiers will be used to produce low sulfur fuel gas for use in the boilers.

TABLE 6-12

SUMMARY OF THE FIXED CAPITAL INVESTMENT (FCI), YEARLY DIRECT OPERATING COSTS
(DOC) FOR EFFLUENT CONTROL, AND THE AMOUNT OF EFFLUENT CONTROLLED FOR
GASIFICATION PLANTS

(FCI and Yearly DOC in MM dollars, 1973 dollars)

Effluents	El Paso		Qty Control- ed (ton/day)	WESCO		Qty Control- ed (ton/day)	Natural		Qty Control- ed (ton/day)	ANG		Qty Control- ed (tons/day)
	FCI	DOC		FCI	DOC		FCI	DOC		FCI	DOC	
Ash & Sludge	7.868	1.209	8552	7.956	1.322	11024	4.746	0.981	3299	3.923	0.648	2509 ^(a)
Coal Dust & Particulates	0.376	0.698	16.812	6.916	1.035	421.64	7.472	0.973	376.1	4.051	0.915	20.4
H ₂ S	8.612	5.959	201.114	15.293	2.170	212.75	16.978	2.403	237.75	22.241	4.269	236.51
SO ₂	-	-	0.0	78.243	5.236	81.45	27.1	3.251	75.58	-	-	0.0
Hydrocarbons	1.545	0.235	110.4	0	0	218.98	1.286	0.126	267.6	0	0	266.56
CO	0.318	0.0476	52.56	0	0	130.7	0.0822	0.00814	14.81	0	0	6.72
H ₂	0.725	0.107	6.816	0	0	19.8	0.183	0.0181	2.255	0	0	0.749
COS	0.019	0.00157	1.981	0	0	3.712	0.045	0.0047	4.43	0	0	6.185
CS ₂	0.00032	0.00005	0.0691	0	0	0.0	0.0035	0.00033	0.284	0	0	3.47
S Vapor	-	-	0.0	-	-	0.0	0.046	0.0048	0.238	-	-	0.0
Total	19.463	8.257		108.408	9.763		57.942	7.770		30.215	5.832	

(a) Does not include 3052 tons/day of sludge and water sent to deep well injection.

TABLE 6-13

SUMMARY OF THE FIXED CAPITAL INVESTMENT (FCI) AND YEARLY DIRECT OPERATING COSTS (DOC) FOR EFFLUENT CONTROL EXPRESSED AS PERCENTAGE OF TOTAL COSTS FOR THE FOUR GASIFICATION PLANTS

	<u>El. Paso</u>		<u>WESCO</u>		<u>Natural</u>		<u>ANG</u>	
	<u>FCI (%)</u>	<u>DOC (%)</u>	<u>FCI (%)</u>	<u>DOC (%)</u>	<u>FCI (%)</u>	<u>DOC (%)</u>	<u>FCI (%)</u>	<u>DOC (%)</u>
Ash & Sludges	2.203	1.941	2.380	2.155	1.420	1.635	1.153	1.314
Coal Dust & Particulates	0.105	1.121	2.069	1.687	2.236	1.622	1.191	1.855
H ₂ S	2.411	9.568	4.574	3.537	5.080	4.005	6.537	8.654
SO ₂	-	-	23.403	8.533	8.108	5.418	-	-
Hydrocarbons	0.433	0.377	0	0	0.385	0.210	0	0
CO	0.089	0.076	0	0	0.025	0.0136	0	0
H ₂	0.203	0.172	0	0	0.055	0.0302	0	0
COS	0.005	0.003	0	0	0.014	0.008	0	0
CS ₂	0.000	0.000	0	0	0.001	0.001	0	0
S Vapor	0	0	0	0	0.014	0.008	0	0
Total	5.449	13.258	32.426	15.912	17.338	12.951	8.881	11.823

7.0 DATA ANALYSIS

7.1 INTRODUCTION

This section analyzes much of the data presented in previous sections. Section 2 presented the overall emission data for all four plants. Section 3 discussed the environmental regulations that currently exist. Claus and Stretford sulfur recovery technology was explained in Section 4. Water treatment reuse, control systems, and economics were presented in Section 5. The gaseous and solid effluents installed and the operating control costs were presented and discussed in Section 6. A number of questions can be raised in dealing with these data:

1. What are the biological hazards associated with gasification effluents?
2. How do the effluents from one facility compare with another?
3. Is one design concept inherently better than another?
4. What are the relative costs of effluent control?
5. What is the reliability of the data base?
6. Is there anything to be learned by comparing the effluent characteristics of the four plants?

These and other questions are addressed below.

Extensive data were collected describing all four plants. The data were not only compiled, but were also compared with one another through a computer program. In addition to quantitative data and comparisons, subjective information concerning the reliability and biological hazard associated with the effluents is given. The data presented in this chapter are a summary of the computer processed data and are presented for the ease of reading. The complete data sets are contained

TABLE 7-1

DEFINITION OF SYMBOLS USED IN COMPUTER GENERATED TABLES

<u>DIVISION # AND MEANING</u>		<u>BIOLOGICAL HAZARDS</u>	<u>DISPOSITION CODES</u>
1	Coal Storage Area	NK - None Known	1 - to mine
2	Coal Preparation Area	MN - Minor	2 - to atmosphere
3	Raw Water Treatment	PH - Possible Hazard	3 - to surface water
4	Boiler Plant	HZ - Hazard	4 - to deep well disposal
5	Oxygen Plant	TX - Toxic	5 - to Claus unit
6	Gasifiers		6 - to incineration
7	Ash Dewatering and Transfer Facility		7 - to stack gas treatment unit
8	ADIP Plant		8 - to ash handling
9	Claus Sulfur Plant		9 - to boiler
10	Stretford Sulfur Plant		0 - to superheater
11	Claus Incinerator		
12	Vent Gas Incinerator		
13	Catalytic Incinerator		
14	Untreated Stack Gas Vent		
15	Stack Gas Treatment		
16	Waste Water Concentrator		
17	Biological Waste Water Treatment		
18	Evaporation and Ash Ponds		
19	Cooling Towers		
20	Total Emissions		
		<u>QUANTITY CODES</u>	<u>NATURE CODES</u>
		SM - Small	S - Solid
		MIN - Minor	L - Liquid
		NIL - Nil	G - Gas
		N - None Emitted	SL - Sludge
		NR - None Reported	
<u>PLANT IDENTIFICATION</u>		<u>RELIABILITY LEVELS</u>	
Plant #1 - El Paso, New Mexico		A Good Reliability	-A- Refer to Reliability = A
Plant #2 - Natural, North Dakota		B Fair Reliability	-B- Refer to Reliability = B
Plant #3 - WESCO, New Mexico		C Poor Reliability	-C- Refer to Reliability = C
Plant #4 - ANG, North Dakota			

in the appendix to this chapter and in a second volume to this report which contains five appendices (A through E). The effluent and cost data even processed on a plant-by-plant basis for twenty divisions in each plant for 60 effluents. The computerized data sheets are coded for the sake of compactness. Table 7-1 contains the code used in data sheets. The data presented in this chapter use only the plant and division numbers, the biological hazard level, and the reliability level. The letter "N" means that no emission of that effluent from that division of that plant is expected.

The data that are presented in this chapter and its appendix are based upon the data reported in the second volume to this report with its five appendices. The raw data used as input to the programs are presented in Appendix A. Appendix B contains the descriptions of the computer programs and a program-by-program instruction sheet, flow chart, and listing. An effluent-by-effluent breakdown for all four plants and 20 divisions is presented in Appendix C. Appendix D contains an alphabetized list of all footnotes used in the computer processed tables. Table 7-1 contains the definitions of the symbols used in Tables A7-1 through A7-15 and in Appendices A, B, C, and D. This table is repeated at the beginning of each appendix for ease of reading the data.

7.2 GENERALIZED EFFLUENT CHARACTERISTICS

The appendix to this chapter contains a matrix cross-referencing each of the 60 effluents with each plant division for each plant (Tables A7-1 through A7-15). The effluents are grouped by nature--solid, liquid, gaseous, or sludge--with the exception of sulfur which is a gaseous emission. " Al_2O_3 " through "unreacted carbon" (numbers 1 through 30) are all, except "sulfur" (number 28), solid emissions. The liquid emissions are covered by the "chlorides" through "thiocyanates" (numbers 31 through 38) and the gaseous emissions are "CO" through "thiocyanates" (numbers 39 through 57). The three sludges listed, (58 through 60), are from raw water treatment, biological waste water treatment, and cooling tower blowdown, respectively. An "N" has been inserted wherever there is no effluent present or expected; consequently, a typographical error by omission has been precluded. It should also be noted that the total column does not represent the sum of each division. The reason is that one division may process a stream but not emit the entire stream to the atmosphere. Similarly, not all plants contain all 19 divisions because of design differences between facilities. The footnotes for Tables A7-1 through A7-4 are listed by order of reference at the end of Table A7-4.

Table 7-2 contains the values of the ratios between the minimum quantity of effluent in that division for all four plants to the effluent quantities for the non-minimum plants. The number 1.0 means the plant has the minimum flow of that effluent for that division, while 2.0 means that the plant has twice the minimum flow. For example, particulates

TABLE 7-2

COMPARATIVE MATRIX FOR EFFLUENT QUANTITIES FROM EACH GASIFICATION FACILITY SHOWING
THE RATIO VALUE TO MINIMUM NON-ZERO EFFLUENT FOR THAT DIVISION FOR ALL FOUR PLANTS

Effluent	Division	Ratios				Division	Ratios			
		1	2	3	4		1	2	3	4
Boiler Ash	4	N	1.11	1.00	N	7	N	1.11	1.00	N
CaCO ₃	15	N	N	1.00	N	17	N	N	1.00	N
CaSO ₃ ·2H ₂ O	15	N	1.00	N	N					
CaSO ₄ ·2H ₂ O	15	N	N	1.00	N					
Coal Dust	1	SM	SM	SM	SM	2	SM	SM	SM	1.00
Coal Dust	6	11.38	11.87	1.00	10.82					
Fly Ash	4	N	57.85	65.06	1.00	7	N	57.85	65.06	1.00
Fly Ash	15	N	N	1.00	N					
Gasifier Ash	6	3.08	1.22	3.70	1.00	7	3.08	1.22	3.70	1.00
Na ₂ SO ₃	15	N	1.00	N	N					
Na ₂ SO ₄	15	N	1.00	N	N					
Particulates	4	MIN	3.07	3.73	1.00	6	3.25	2.04	3.71	1.00
Particulates	12	N	N	1.00	N	14	N	1.00	N	N
Particulates	15	N	1.00	22.77	N	19	1.52	2.68	1.00	N
Refuse	2	1.00	N	1.34	N	7	1.00	N	N	N
Sulphur	11	N	0	N	N					
Susp. Solids	7	N	1.00	N	N	16	N	1.00	N	N
Unreacted C	6	1.00	N	N	N	7	1.00	N	N	N
H ₂ O-Liquid	3	21.08	1.75	1.00	N	4	N	N	1.00	N
H ₂ O-Liquid	6	1.00	N	1.00	N	7	3.60	2.07	4.16	1.00
H ₂ O-Liquid	15	N	4.87	1.00	N	16	N	1.00	N	2.00
H ₂ O-Liquid	17	N	4.62	1.00	N	19	82.45	1.00	N	N
CO	4	N	N	NIL	1.00	6	1.68	N	N	1.00
CO	9	N	1.00	N	N	10	5.43	1.51	N	1.00
CO	12	NIL	0	N	1.00	13	1.00	N	N	N

TABLE 7-2 (Continued)

Effluent	Division	Ratios				Division	Ratios			
		1	2	3	4		1	2	3	4
COS	4	N	0	NIL	N	6	N	1.13	1.00	N
COS	8	N	1.27	1.00	N	9	N	1.00	0	N
COS	10	1.06	1.00	1.00	3.18	11	N	0	N	N
COS	12	N	0	0	0	13	1.00	N	N	N
COS	14	N	N	1.00	N					
CO ₂	4	2.67	4.93	6.80	1.00	5	1.04	N	1.00	N
CO ₂	6	1.05	4.09	3.61	1.00	8	N	1.28	1.00	N
CO ₂	9	N	1.00	1.48	N	10	2.11	1.08	1.00	1.34
CO ₂	11	N	1.00	N	N	12	1.00	37.86	17.26	46.11
CO ₂	13	1.00	N	N	N	14	N	7.47	6.08	1.00
CO ₂	15	N	1.00	1.62	N	19	N	1.00	N	N
CS ₂	9	N	1.00	N	N	10	1.00	N	N	33.94
CS ₂	11	N	0	N	N	12	N	N	0	0
CS ₂	13	1.00	N	N	N					
Fatty Acids	7	1.00	N	N	N	18	1.00	N	N	N
Fatty Acids	19	1.03	2.06	1.00	N					
HCN	7	1.00	N	N	N	9	N	N	0	N
HCN	18	1.00	N	N	N					
Hydrocarbons	4	N	0	NIL	1.00	6	8.32	1.00	1.29	6.35
Hydrocarbons	8	N	1.27	1.00	N	9	N	N	0	N
Hydrocarbons	10	1.35	1.04	1.00	3.18	12	NIL	0	0	1.00
Hydrocarbons	13	1.00	N	N	N	14	N	N	1.00	N
H ₂	4	N	N	NIL	N	6	1.25	N	N	1.00
H ₂	9	N	1.00	N	N	10	9.34	3.00	N	1.00
H ₂	11	N	0	N	N	12	NIL	0	N	0
H ₂	13	1.00	N	N	N					
H ₂ O-Gaseous	3	1.00	N	2.33	N	4	6.18	2.20	2.88	1.00
H ₂ O-Gaseous	5	1.00	N	N	N	6	1.00	17.85	30.35	44.11

TABLE 7-2 (Continued)

Effluent	Division	Ratios				Division	Ratios			
		1	2	3	4		1	2	3	4
H ₂ O-Gaseous	7	4.71	2.34	N	1.00	8	N	1.28	1.00	N
H ₂ O-Gaseous	9	N	1.07	1.00	N	10	2.51	1.00	N	3.17
H ₂ O-Gaseous	11	N	1.00	N	N	12	1.00	16.83	5.03	32.15
H ₂ O-Gaseous	13	1.00	N	N	N	14	N	6.56	N	1.00
H ₂ O-Gaseous	15	N	2.36	1.00	N	16	N	1.00	N	N
H ₂ O-Gaseous	18	1.00	N	N	N	19	1.00	1.63	1.31	1.54
H ₂ S	4	N	0	NIL	N	6	6.39	1.00	8.80	1.59
H ₂ S	8	N	1.27	1.00	N	9	N	1.00	0	N
H ₂ S	10	3.77	1.00	10.97	14.69	11	N	0	N	N
H ₂ S	12	NIL	0	0	0	13	1.00	N	N	N
H ₂ S	14	N	N	1.00	N					
Naptha	6	1.00	N	N	N					
NH ₃	19	1.79	3.60	1.00	N					
NOX	4	1.00	9.36	2.59	1.39	12	1.00	N	12.08	5.00
NOX	14	N	1.00	N	N	15	N	1.63	1.00	N
N ₂	4	6.01	9.70	2.98	1.00	5	1.03	1.13	1.08	1.00
N ₂	6	1.00	N	N	N	9	N	1.00	1.14	N
N ₂	10	0.45	N	N	1.00	11	N	1.00	N	N
N ₂	12	1.00	15.89	8.56	30.95	13	1.00	N	N	N
N ₂	14	N	2.97	N	1.00	15	N	1.00	1.07	N
O ₂	4	30.24	3.66	3.14	1.00	5	1.79	5.79	3.76	1.00
O ₂	9	N	1.00	N	N	10	1.00	N	N	N
O ₂	11	N	1.00	N	N	12	1.00	17.47	3.41	39.29
O ₂	13	1.00	N	N	N	14	N	1.00	N	2.60
O ₂	15	N	1.00	1.01	N					
Phenolics	7	1.00	N	N	N	18	1.00	N	N	N
Phenolics	19	35.18	10.54	1.00	N					
Pyridines	19	1.00	N	N	N					

TABLE 7-2 (Continued)

<u>Effluent</u>	<u>Division</u>	<u>Ratios</u>				<u>Division</u>	<u>Ratios</u>			
		<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>		<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>
SO ₂	4	1.00	24.59	22.70	3.02	9	N	1.00	20.74	N
SO ₂	10	N	N	N	1.00	11	N	1.00	N	N
SO ₂	12	1.00	13.95	1.20	31.54	13	1.00	N	N	N
SO ₂	14	N	1.00	N	N	15	N	1.00	1.09	N
Thiocyanates	19	27.91	55.93	1.00	N					
Sludge (RWT)	3	N	1.33	1.00	21.28					
Sludge (BWWT)	17	N	16.11	1.00	55.52					
Sludge (CTB)	19	N	1.00	N	N					

are emitted from all four plants in only two divisions (#4 - boiler plant and #6 - the gasifiers). Other divisions have particulate emissions in only some of the plants (e.g., #15 - stack gas treatment).

The data of Table 7-2 indicate that ANG (Plant #4) emits minimum particulate quantity, while WESCO (#3) and Natural (#2) emit 3.7 and 3.1 times as much particulate as ANG does. The El Paso calculation was not reported because a numerical quantity was not reported even though a minimum one is expected. If an effluent is not expected to occur in that plant and division, as indicated by the letter "N," then the calculation was not done. The number 1.0 with three "N's" reported means that only that plant emits that effluent in that division.

The data of 7-2 show that there is considerable variability between the four facilities in terms of plant design and specific effluent characteristics. This is, of course, to be expected because of the variability of the coal found at the four plant sites and the different design philosophies used in trying to meet both the production, economic, and environmental constraints.

Table 7-3 contains the ratios of the total effluent quantities for all four divisions. It is apparent from Table 7-3 that the variability of the effluent quantities is large (values as high as 65.9). The high ratio values are indicative of three basic facts:

1. There is a large variation in the basic design characteristics of the facilities (such as boiler vs. low Btu gasifier, vs. procured power).
2. The variability in the coal feed characteristics have a pronounced impact upon emissions (e.g., a gasifier ash ratio of 1 to 3.70).
3. The local effluent regulations have a pronounced impact on effluents used and the basic design chosen (e.g., SO₂ ratios of 1 to 4.38).

TABLE 7-3

COMPARATIVE MATRIX FOR TOTAL EFFLUENT QUANTITY RATIOS FROM
EACH GASIFICATION FACILITY BASED UPON MINIMUM EFFLUENT QUANTITY

Effluent	TOTAL			
	Plant #1	Plant #2	Plant #3	Plant #4
Boiler Ash	N	1.11	1.00	N
CaCO ₃	N	N	1.00	N
CaSO ₃ ·2H ₂ O	N	1.00	N	N
CaSO ₄ ·2H ₂ O	N	N	1.00	N
Coal Dust	11.38	11.87	1.00	98.32
Fly Ash	N	57.85	65.86	1.00
Gasifier Ash	3.08	1.22	3.70	1.00
Na ₂ SO ₃	N	1.00	N	N
Na ₂ SO ₄	N	1.00	N	N
Particulates	1.00	3.93	2.19	2.83
Refuse	1.00	N	1.34	N
Sulphur	N	0	N	N
Susp. Solids	N	1.00	N	N
Unreacted C	1.00	N	N	N
H ₂ O-Liquid	1.87	1.68	2.30	1.00
CO	1.00	0	N	1.07
COS	60.66	1.00	31.69	0
CO ₂	1.03	1.26	1.12	1.00
CS ₂	1.00	0	0	0
Fatty Acids	2.76	1.97	1.00	N
HCN	1.00	N	N	N
Hydrocarbons	23.05	1.00	32.24	10.89
H ₂	1.47	0	N	1.00
H ₂ O-Gaseous	1.05	1.34	1.00	1.02
H ₂ S	18.00	1.00	39.60	1.59
Naptha	1.00	N	N	N
NH ₃	1.79	3.60	1.00	N
NOX	1.00	5.06	2.72	1.44
N ₂	2.02	1.47	1.30	1.00
O ₂	7.27	1.38	1.00	1.02
Phenolics	35.29	10.54	1.00	N
Pyridines	1.00	N	N	N
SO ₂	1.00	4.83	1.37	4.61
Thiocyanates	27.91	55.93	1.00	N
Sludge (RWT)	N	1.33	1.00	N
Sludge (BWWT)	N	16.11	1.00	55.52
Sludge (CTB)	N	1.00	N	N

7.3 OPERATIONAL COSTS AND EFFLUENT CONTROL ENERGY USAGE

Section 6 presented the installed cost data for each facility.

The operational costs are addressed here. Table 7-4 presents the energy used for effluent control and the operational costs on an effluent basis. It is clear from these data that there are significant design differences. For example, ANG and El Paso do not have coal-fired boilers and, thus, do not have to control boiler ash. Excess hydrocarbons do not exist for ANG (Plant #4) and WESCO (Plant #3) and, thus, do not have to be controlled. It is also apparent that there are significant data gaps. For example, all four facilities have to handle suspended solids coming into raw water treatment but only one facility, Natural (Plant #2), reports it. Generally, the largest energy consumption and operating cost is taken up by cooling; followed by SO₂ control and ash handling. These data also show that effluent control requires energy which, of course, reduces the plant's efficiency.

TABLE 7-4

COMPARATIVE EFFLUENT CONTROL COST AND EFFLUENT CONSUMPTION

Controlled Effluent	Plant #1		Plant #2		Plant #3		Plant #4	
	Total Operating Cost \$/Yr	Total Energy Consumed MM Btu/D	Total Operating Cost \$/Yr	Total Energy Consumed MM Btu/D	Total Operating Cost \$/Yr	Total Energy Consumed MM Btu/D	Total Operating Cost \$/Yr	Total Energy Consumed MM Btu/D
Boiler Ash	N	N	51,721	9	15,122	3	NR	NR
CaCO ₃	N	N	NR	NR	2,571	0	NR	NR
CaSO ₃ ·2H ₂ O	N	N	27,716	8	NR	NR	NR	NR
CaSO ₄ ·2H ₂ O	N	N	NR	NR	8,159	1	NR	NR
Coal Dust	645,026	44	651,257	40	639,065	25	739,570	77
Fly Ash	N	N	123,972	21	80,279	9	1,946	0
Gasifier Ash	1,087,792	115	739,627	123	1,144,681	133	547,222	80
Na ₂ SO ₃	N	N	0	0	N	N	N	N
Na ₂ SO ₄	N	N	0	0	N	N	N	N
Particulates	53,095	7	25,900	3	28,235	5	174,952	24
Refuse	64,099	6	NR	NR	68,850	7	NR	NR
Sulphur	NR	NR	4,812	0	NR	NR	NR	NR
Susp. Solids	NR	NR	17,926	3	NR	NR	NR	NR
Unreacted C	57,024	6	NR	NR	NR	NR	NR	NR
H ₂ O-Liquid	NR	NR	0	0	0	0	98,329	14
CO	47,646	1	8,142	0	NR	NR	0	0
COS	1,577	0	4,710	0	0	0	0	0
CS ₂	49	0	381	0	0	0	0	0
Hydrocarbons	234,505	7	126,093	7	0	0	0	0
H ₂	106,649	3	18,126	1	NR	NR	0	0
H ₂ O-Gaseous	2,629,764	735	2,074,217	1,362	4,278,071	199	3,205,550	678
H ₂ S	302	0	16,156	0	0	0	NR	NR
SO ₂	NR	NR	3,251,013	659	5,236,270	854	NR	NR
Sludge (RWT)	NR	NR	4,516	1	1,591	0	NR	NR
Sludge (BWWT)	NR	NR	15,537	4	0	0	NR	NR
Sludge (CTB)	NR	NR	183	0	NR	NR	NR	NR

7.4 EFFLUENT AND COST DATA RELIABILITY

The reliability level of a data base is one of the most important qualifying characteristics that a data base can have. Consequently, the authors have made an attempt to judge the reliability or quality of the data that has been generated. Since there is no operational data base against which the data can be compared, the reliability ratings given below are purely subjective. That is, the reliability levels given represent the authors' judgements of how good the data are. Good, fair, and poor reliability correspond to levels A, B, and C, respectively.

Table 7-5 presents a breakdown by plant of how "good" the installed cost data are; Table 7-6 presents a similar breakdown for operating costs. The majority of the cost data have "A" or "B" reliability ratings which implies that the data are reasonably good. A similar analysis was done for the effluent quantity emitted. The results of this analysis are presented in the appendix to this chapter in Tables A7-5 (reliability A), A7-6 (reliability B) and A7-7 (reliability C). Most of the effluent data have been given an "A" or "B" rating indicating that in the judgement of the authors the data are reasonable projections of what will probably be emitted.

TABLE 7-5

INSTALLED COST MATRIX FOR PLANT #1

<u>Effluent</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>
Coal Dust	29,000	1	C	116,100	2	B
Coal Dust	86,000	6	B	231,100	total	B
Gasifier Ash	7,182,000	7	A	7,182,000	total	A
Particulates	145,000	6	B	145,000	total	B
Refuse	4,300,000	2	A	308,000	7	A
Refuse	308,000	total	A			
Unreacted C	378,000	7	A	378,000	total	A
CO	75,100	12	B	242,600	13	B
CO	317,700	total	B			
COS	10,900	13	B	10,900	total	B
CS ₂	320	13	B	320	total	B
Hydrocarbons	25,000	12	B	1,520,000	13	B
Hydrocarbons	1,545,000	total	B			
H ₂	100,000	12	B	625,000	13	B
H ₂	725,000	total	B			
H ₂ O	3,440,000	18	A	5,800,000	19	A
H ₂ O	9,240,000	total	A			
H ₂ S	8,610,000	10	A	640	12	B
H ₂ S	1,350	13	B	1,990	total	B

TABLE 7-5 (Continued)

INSTALLED COST MATRIX FOR PLANT #2

Effluent	Cost	Division	Reliability	Cost	Division	Reliability
Boiler Ash	254,000	7	B	254,000	total	B
CaSO ₃ ·2H ₂ O	85,000	15	B	85,000	total	B
Coal Dust	29,000	1	C	116,100	2	C
Coal Dust	189,000	6	B	334,000	total	B
Fly Ash	612,000	7	B	612,000	total	B
Gasifier Ash	3,645,000	7	B	3,645,000	total	B
Na ₂ SO ₃	0	15	A	0	total	A
Na ₂ SO ₄	0	15	A	0	total	A
Particulates	7,040,000	4	A	98,000	6	B
Particulates	98,000	total	B			
Sulphur	46,000	11	B	46,000	total	B
Susp. Solids	88,000	7	B	88,000	total	B
H ₂ O-Liquid	0	3	A	0	total	A
CO	2,240	11	B	80,000	12	A
CO	82,240	total	A			
COS	0	4	A	35,000	11	B
COS	10,000	12	A	45,000	total	B
CS ₂	3,700	11	B	3,700	total	B
Hydrocarbons	0	4	A	1,286,000	12	A
Hydrocarbons	1,286,000	total	A			
H ₂	15,300	11	B	168,000	12	A
H ₂	183,300	total	A			
H ₂ O-Gaseous	8,426,000	19	B	8,426,000	total	B
H ₂ S	0	4	A	4,294,000	8	A
H ₂ S	2,302,000	9	A	10,228,000	10	A
H ₂ S	152,000	11	B	1,700	12	A
H ₂ S	153,700	total	B			
SO ₂	27,100,000	15	A	27,100,000	total	A
Sludge (RWT)	13,700	3	B	13,700	total	B
Sludge (BWWT)	48,000	17	B	48,000	total	B
Sludge (CTB)	550	19	B	550	total	B

TABLE 7-5 (Continued)

INSTALLED COST MATRIX FOR PLANT #3

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<u>Effluent</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>
Boiler Ash	161,000	7	B	161,000	total	B
CaCO ₃	0	15	A	12,000	17	B
CaCO ₃	12,000	total	B			
CaSO ₄ .2H ₂ O	39,000	15	B	39,000	total	B
Coal Dust	29,000	1	C	116,100	2	B
Coal Dust	144,000	6	B	289,100	total	B
Fly Ash	484,000	7	B	0	15	A
Fly Ash	484,000	total	B			
Gasifier Ash	6,918,000	7	B	6,918,000	total	B
Particulates	6,548,000	4	A	79,000	6	B
Particulates	0	15	A	79,000	total	B
Refuse	335,000	2	B	335,000	total	B
H ₂ O-Liquid	0	15	A	0	17	A
H ₂ O-Liquid	0	total	A			
CO	0	4	A		total	N
COS	0	4	A	0	9	A
COS	0	12	A	0	total	A
CS ₂	0	12	A	0	total	A
HCN	0	9	A		total	N
Hydrocarbons	0	4	A	0	9	A
Hydrocarbons	0	12	A	0	total	A
H ₂	0	4	A		total	N
H ₂ O-Gaseous	2,657,000	19	B	2,657,000	total	B
H ₂ S	0	4	A	3,698,000	8	A
H ₂ S	2,295,000	9	A	9,300,000	10	A
H ₂ S	0	12	A	0	total	A
SO ₂	78,243,000	15	A	78,243,000	total	A
Sludge (RWT)	7,100	3	C	7,100	total	C
Sludge (BWWT)	0	17	A	0	total	A

TABLE 7-5 (Continued)

INSTALLED COST MATRIX FOR PLANT #4

<u>Effluent</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>
Coal Dust	29,000	1	C	1,027,000	2	B
Coal Dust	189,000	6	C	1,245,000	total	B
Fly Ash	11,500	7	A	11,500	total	A
Gasifier Ash	3,327,000	7	A	3,327,000	total	A
Particulates	2,708,000	4	B	98,000	6	C
Particulates	2,806,000	total	B			
H ₂ O-Liquid	583,600	7	A	583,600	total	A
CO	0	12	A	0	total	A
COS	0	12	A	0	total	A
CS ₂	0	12	A	0	total	A
Hydrocarbons	0	12	A	0	total	A
H ₂	0	12	A	0	total	A
H ₂ O-Gaseous	10,325,000	19	A	10,325,000	total	A
H ₂ S	22,241,000	10	A	0	12	A
H ₂ S		total	N			

TABLE 7-6

OPERATING COST MATRIX FOR PLANT #1

<u>Effluent</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>
Coal Dust	251,423	1	C	292,434	2	C
Coal Dust	101,168	6	B	645,026	total	C
Gasifier Ash	1,087,792	7	B	1,087,792	total	B
Particulates	53,095	6	B	53,095	total	B
Refuse	752,326	2	B	64,099	7	B
Refuse	64,099	total	B			
Unreacted C	57,024	7	B	57,024	total	B
CO	12,616	12	C	35,030	13	B
CO	47,646	total	B			
COS	1,577	13	B	1,577	total	B
CS ₂	49	13	B	49	total	B
Hydrocarbons	4,059	12	C	230,416	13	B
Hydrocarbons	234,505	total	B			
H ₂	16,763	12	C	89,881	13	B
H ₂	106,649	total	B			
H ₂ O	85,320	18	B	2,544,444	19	B
H ₂ O	2,629,764	total	B			
H ₂ S	5,959,250	10	A	108	12	C
H ₂ S	195	13	B	302	total	B

TABLE 7-6 (Continued)

OPERATING COST MATRIX FOR PLANT #2

<u>Effluent</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>
Boiler Ash	51,721	7	B	51,721	total	B
CaSO ₃ ·2H ₂ O	27,716	15	B	27,716	total	B
Coal Dust	272,423	1	C	314,404	2	C
Coal Dust	64,429	6	B	651,257	total	C
Fly Ash	123,972	7	B	123,972	total	B
Gasifier Ash	739,627	7	B	739,627	total	B
Na ₂ SO ₃	0	15	A	0	total	A
Na ₂ SO ₄	0	15	A	0	total	A
Particulates	295,879	4	A	25,900	6	C
Particulates	0	15	A	25,900	total	C
Sulphur	4,812	11	C	4,812	total	C
Susp. Solids	17,926	7	B	17,926	total	B
H ₂ O-Liquid	0	3	A	0	total	A
CO	234	11	C	7,908	12	A
CO	8,142	total	A			
COS	0	4	A	3,688	11	C
COS	1,022	12	A	4,710	total	B
CS ₂	381	11	C	381	total	C
Hydrocarbons	0	4	A	126,093	12	A
Hydrocarbons	126,093	total	A			
H ₂	1,598	11	C	16,527	12	A
H ₂	18,128	total	A			
H ₂ O-Gaseous	2,074,217	19	A	2,074,217	total	A
H ₂ S	0	4	A	560,067	8	A
H ₂ S	235,200	9	A	1,592,182	10	A
H ₂ S	15,985	11	C	171	12	A
H ₂ S	16,156	total	C			
SO ₂	3,251,013	15	A	3,251,013	total	A
Sludge (RWT)	4,516	3	B	4,516	total	B
Sludge (BWWT)	15,537	17	B	15,537	total	B
Sludge (CTB)	183	19	C	183	total	C

TABLE 7-6 (Continued)

OPERATING COST MATRIX FOR PLANT #3

7-2C

<u>Effluent</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>
Boiler Ash	15,122	7	C	15,122	total	C
CaCO ₃	0	15	A	2,571	17	B
CaCO ₃	2,571	total	B			
CaSO ₄ ·2H ₂ O	8,159	15	B	8,159	total	B
Coal Dust	272,423	1	C	314,204	2	C
Coal Dust	52,437	6	B	639,065	total	B
Fly Ash	80,279	7	B	0	15	A
Fly Ash	80,279	total	B			
Gasifier Ash	1,144,681	7	B	1,144,681	total	B
Particulates	284,120	4	A	28,235	6	C
Particulates	0	15	A	28,235	total	C
Refuse	68,850	2	B	68,850	total	B
H ₂ O-Liquid	0	15	A	0	17	A
H ₂ O-Liquid	0	total	A			
CO	0	4	A		total	N
COS	0	4	A	0	9	A
COS	0	12	A	0	total	A
CS ₂	0	12	A	0	total	A
HCN	0	9	A		total	N
Hydrocarbons	0	4	A	0	9	A
Hydrocarbons	0	12	A	0	total	A
H ₂	0	4	A		total	N
H ₂ O-Gaseous	4,278,071	19	B	4,278,071	total	B
H ₂ S	0	4	A	556,298	8	A
H ₂ S	259,329	9	A	1,354,555	10	A
H ₂ S	0	12	A	0	total	A
SO ₂	5,236,270	15	A	5,236,270	total	A
Sludge (RWT)	1,591	3	C	1,591	total	C
Sludge (BWWT)	0	17	A	0	total	A

TABLE 7-6 (Continued)

OPERATING COST MATRIX FOR PLANT #4

<u>Effluent</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>	<u>Cost</u>	<u>Division</u>	<u>Reliability</u>
Coal Dust	222,473	1	C	448,457	2	C
Coal Dust	68,640	6	C	739,570	total	C
Fly Ash	1,946	7	B	1,946	total	B
Gasifier Ash	547,222	7	B	547,222	total	B
Particulates	149,473	4	C	25,480	6	C
Particulates	174,952	total	C			
H ₂ O-Liquid	98,329	7	B	98,329	total	B
CO	0	12	A	0	total	A
COS	0	12	A	0	total	A
CS ₂	0	12	A	0	total	A
Hydrocarbons	0	12	A	0	total	A
H ₂	0	12	A	0	total	A
H ₂ O-Gaseous	3,205,550	19	A	3,205,550	total	A
H ₂ S	4,269,143	10	A	0	12	A
H ₂ S		total	N			

7.5 EFFLUENT HAZARD LEVELS

The establishment of the hazard level of a substance is a difficult and highly subjective task. The EPA has made a serious attempt to quantify the hazard potential through the use of LD₅₀ rates, threshold limit values (TLV), National Institute for Occupational Safety and Health (NIOSH) recommendations for maximum concentrations, and several others (EPA, November, 1977). EPA has used these models to derive estimated permissible concentrations (EPC) and minimum acute toxicity effluent (MATE) values. The EPC's are used as a model for the ambient level goals and the MATE values are used as a model for emission level goals. MATE concentrations describe approximate levels of contaminants which will not evoke significant, harmful, or irreversible responses in exposed humans or in ecology where those exposures are limited to short duration (less than 8 hours per day). MATE values are reported for humans and for three categories of ecology; land, air, and water. The EPA sees the MATE levels ultimately being goals for control technology. The MATE values currently available are based upon very limited research and are subject to revision.

In addition to the EPA data base, the authors have drawn upon their experience and subjectively rated the hazard potential of the projected effluents. The ratings used by the authors were:

NK	None known
MN	Minimum hazard
PH	Probable hazard
HZ	Hazardous
TX	Toxic to humans

The effluents reported in this study have been compared with both of the above hazard potential systems. The authors' subjective judgements of each effluent's hazard potential are reported in Table 7-7 for each reliability level, A, B, and C, respectively.

The EPA's list of 216 MEG compounds for which detailed information is available was scanned for compounds projected to exist in the gasification plant's effluent stream. The compounds common to both streams are presented in Table 7-8 where its EPA hazard potential and MET category are identified. The most hazardous substances have potentials of 30-XXX. Table 7-9 lists the location of the effluent, its quantity, the reliability of the quantity level, the EPA hazard potential, and the authors' estimated hazard potential. All of the effluents listed in Table 7-9 are gaseous and emitted to the atmosphere. Fortunately, most of the hazardous effluent emission rates are small. Because the reliability of the data in Table 7-9 is generally poor, there is little value in comparing the projected effluent value to its associate MATE value. Consequently this was not done.

TABLE 7-7

BIOLOGICAL HAZARD MATRIX FOR PLANT #1

<u>Effluent</u>	<u>Hazard*</u> <u>Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard</u> <u>Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard</u> <u>Level</u>	<u>Division</u>	<u>Footnote</u>
Coal Dust	PH-A	1	A1	PH-A	2	A1	PH-A	6	A1
Gasifier Ash	PH-A	6		PH-A	7	B0			
Particulates	PH-A	4		PH-A	6		PH-A	19	
Refuse	PH-C	2	A2	PH-A	7	A2			
Unreacted C	MN-A	6	B1	PH-A	7				
H ₂ O-Liquid	PH-A	3	A5	MN-A	6	B1	MN-A	7	B1
H ₂ O-Liquid	MN-A	18	D6						
CO	TX-A	6	B6	TX-A	10	B6	TX-A	12	B6
CO	TX-A	13	B6						
COS	HZ-A	10		HZ-A	13				
CO ₂	NK-A	4		NK-A	5		NK-B	6	
CO ₂	NK-A	10		NK-A	12		NK-B	13	
CS ₂	HZ-A	10	C8	HZ-A	13	C8			
Fatty Acids	HZ-B	7	C2	HZ-B	18	C2	HZ-B	19	C2
HCN	TX-A	7	C0	TX-A	18	C0			
Hydrocarbons	MN-B	6		MN-B	10		MN-B	12	
Hydrocarbons	MN-B	13							
H ₂	MN-B	6		MN-B	10		MN-A	12	
H ₂	MN-A	13							
H ₂ O-Gaseous	NK-A	3		NK-A	14		NK-A	5	
H ₂ O-Gaseous	NK-A	6		NK-A	7		NK-A	10	
H ₂ O-Gaseous	NK-A	12		NK-A	13		NK-A	18	
H ₂ O-Gaseous	NK-A	19							
H ₂ S	TX-A	6	B5	TX-A	10	B5	TX-A	12	B5
H ₂ S	TX-A	13	B5						
Naptha	MN-B	6							

*A = Reliability A; B = Reliability B; C = Reliability C

TABLE 7-7 (Continued)

<u>Effluent</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>
NH ₃	HZ-A	19	B0						
NOX	PH-A	4	A7	PH-A	12	A7	HZ-A	19	E0
N ₂	NK-A	4		NK-A	5		NK-A	6	
N ₂	NK-A	10		NK-A	12		NK-A	13	
O ₂	NK-A	4		NK-A	5		NK-A	10	
O ₂	NK-A	12		NK-A	13				
Phenolics	HZ-B	7	C4	HZ-B	18	C4	HZ-A	19	C9
Pyridines	HZ-A	19	D8						
SO ₂	PH-A	4	A7	PH-A	12	A7	PH-A	13	A7
Thiocyanates	HZ-A	19							

TABLE 7-7 (Continued)

BIOLOGICAL HAZARD MATRIX FOR PLANT #2

<u>Effluent</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>
Boiler Ash	PH-A	4	L5	PH-A	7	L5			
CaSO ₃ ·2H ₂ O	PH-A	15	P1						
Coal Dust	PH-A	1	L1	PH-A	2	L1	PH-A	6	L1
Fly Ash	PH-A	4	L5	PH-A	7	L5			
Gasifier Ash	PH-A	6	L5	PH-A	7	L5			
Na ₂ SO ₃	PH-A	15	P1						
Na ₂ SO ₄	PH-A	15	P1						
Particulates	PH-A	4	L5	PH-A	6		PH-A	14	
Particulates	PH-A	15		PH-A	19				
Sulphur	PH-A	11							
Susp. Solids	PH-A	7	M8	PH-A	16	M8			
H ₂ O-Liquid	PH-A	3	L3	PH-A	7	M9	PH-A	15	P2
H ₂ O-Liquid	PH-A	16	M8	PH-A	17	P2	PH-A	19	P2
CO	TX-A	9	N4	TX-A	10	N4	TX-A	11	N4
CO	TX-A	12	N4						
COS	HZ-A	4		HZ-A	6		HZ-A	8	
COS	HZ-A	9		HZ-A	10		HZ-A	11	
COS	HZ-A	12							
CO ₂	NK-A	4		NK-A	6		NK-A	8	
CO ₂	NK-A	9		NK-A	10		NK-A	11	
CO ₂	NK-A	12		NK-A	14		NK-A	15	
CO ₂	NK-A	19							
CS ₂	HZ-A	9	N6	HZ-A	11	N9			
Fatty Acids	HZ-B	19	P6						
Hydrocarbons	MN-B	4		MN-B	6		MN-B	8	
Hydrocarbons	MN-B	10		MN-B	12				

TABLE 7-7 (Continued)

<u>Effluent</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>
H ₂	MN-B	9		MN-B	10		MN-B	11	
H ₂	MN-B	12							
H ₂ O-Gaseous	NK-A	4		NK-A	6		NK-A	7	
H ₂ O-Gaseous	NK-A	8		NK-A	9		NK-A	10	
H ₂ O-Gaseous	NK-A	11		NK-A	12		NK-A	14	
H ₂ O-Gaseous	NK-A	15		NK-A	16		NK-A	19	
H ₂ S	TX-A	4	M1	TX-A	6	M1	TX-A	8	M1
H ₂ S	TX-A	9	M1	TX-A	10	M1	TX-A	11	M1
H ₂ S	TX-A	12	M1						
NH ₃	HZ-A	19	P9						
NOX	PH-A	4	L8	PH-A	14	R3	PH-A	15	R3
N ₂	NK-A	4		NK-A	5		NK-A	9	
N ₂	NK-A	11		NK-A	12		NK-A	14	
N ₂	NK-A	15							
O ₂	NK-A	4		NK-A	5		NK-A	9	
O ₂	NK-A	11		NK-A	12		NK-A	14	
O ₂	NK-A	15							
Phenolics	HZ-B	19	P8						
SO ₂	PH-A	4	L8	PH-A	9	L8	PH-A	11	L8
SO ₂	PH-A	12	L8	PH-A	14	L8	PH-A	15	L8
Thiocyanates	HZ-A	19							
Sludge (RWT)	PH-A	3	L3						
Sludge (BWWT)	PH-A	17	L5						
Sludge (CTB)	PH-A	19	L3						

TABLE 7-7 (Continued)

BIOLOGICAL HAZARD MATRIX FOR PLANT #3

<u>Effluent</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>
Boiler Ash	PH-A	4	G5	PH-A	7	G5			
CaCO ₃	PH-A	15	I8	PH-A	17	I8			
CaSO ₄ ·2H ₂ O	PH-B	15	I8						
Coal Dust	PH-A	1	G1	PH-C	2	G1	PH-A	6	G1
Fly Ash	PH-A	4	G5	PH-A	7	G5	PH-A	15	G5
Gasifier Ash	PH-A	6	G5	PH-A	7	G5			
Particulates	PH-A	4	G2	PH-A	6		PH-A	12	
Particulates	PH-A	15		PH-A	19				
Refuse	PH-C	2	G2						
H ₂ O-Liquid	PH-A	3	G3	PH-A	4	G7	PH-A	6	G7
H ₂ O-Liquid	PH-A	7	G7	PH-A	15	I9	PH-A	17	G3
CO	TX-A	4	H1						
COS	HZ-A	4		HZ-A	6		HZ-A	8	
COS	HZ-A	9		HZ-A	10		HZ-A	12	
COS	HZ-A	14							
CO ₂	NK-A	4		NK-A	5		NK-A	6	
CO ₂	NK-A	8		NK-A	9		NK-A	10	
CO ₂	NK-A	12		NK-A	14		NK-A	15	
CS ₂	HZ-A	12	I6						
Fatty Acids	HZ-B	19	J4						
HCN	TX-A	9	I4						
Hydrocarbons	MN-B	4		MN-B	6		MN-B	8	
Hydrocarbons	MN-B	9		MN-B	10		MN-B	12	
Hydrocarbons	MN-B	14							
H ₂	MN-B	4							

TABLE 7-7 (Continued)

<u>Effluent</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>
H ₂ O-Gaseous	NK-A	3		NK-A	4		NK-A	6	
H ₂ O-Gaseous	NK-A	8		NK-A	9		NK-A	12	
H ₂ O-Gaseous	NK-A	15		NK-A	19				
H ₂ S	TX-A	4	H0	TX-A	6	H0	TX-A	8	H0
H ₂ S	TX-A	9	H0	TX-A	10	H0	TX-A	12	H0
H ₂ S	TX-A	14	H0						
NH ₃	HZ-A	19	J8						
NOX	PH-A	4	H3	PH-A	12	H3	PH-A	15	H3
N ₂	NK-A	4		NK-A	5		NK-A	9	
N ₂	NK-A	12		NK-A	15				
O ₂	NK-A	4		NK-A	5		NK-A	12	
O ₂	NK-A	15							
Phenolics	HZ-B	19	J6						
SO ₂	PH-A	4	H3	PH-A	9	H3	PH-A	12	H3
SO ₂	PH-A	15	H3						
Thiocyanates	HZ-A	19							
Sludge (RWT)	PH-A	3	G3						
Sludge (BWWT)	PH-A	17	G3						

TABLE 7-7 (Continued)

BIOLOGICAL HAZARD MATRIX FOR PLANT #4

<u>Effluent</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>	<u>Hazard Level</u>	<u>Division</u>	<u>Footnote</u>
Coal Dust	PH-A	1	S1	PH-A	2	S1	PH-A	6	S1
Fly Ash	PH-A	4	S3	PH-A	7	S3			
Gasifier Ash	PH-A	6	S3	PH-A	7	S3			
Particulates	PH-A	4	S3	PH-A	6				
H ₂ O-Liquid	PH-A	7	T1	PH-A	16	T9			
CO	TX-A	4	S4	TX-A	6	S4	TX-A	10	S4
CO	TX-A	12	S4						
COS	HZ-A	10		HZ-A	12				
CO ₂	NK-A	4		NK-A	6		NK-A	10	
CO ₂	NK-A	12		NK-A	14				
CS ₂	HZ-A	10	T5	HZ-A	12	T5			
Hydrocarbons	MN-B	4		MN-B	6		MN-B	10	
Hydrocarbons	MN-B	12							
H ₂	MN-B	6		MN-B	10		MN-B	12	
H ₂ O-Gaseous	NK-A	4		NK-A	6		NK-A	7	
H ₂ O-Gaseous	NK-A	10		NK-A	12		NK-A	14	
H ₂ O-Gaseous	PH-B	19	U1						
H ₂ S	TX-A	6	S9	TX-A	10	S9	TX-A	12	S9
NOX	PH-A	4	S5	PH-A	12	S5			
N ₂	NK-A	4		NK-A	5		NK-A	10	
N ₂	NK-A	12		NK-A	14				
O ₂	NK-A	4		NK-A	5		NK-A	12	
O ₂	NK-A	14							
SO ₂	PH-A	4	S5	PH-A	10	S5	PH-A	12	S5
Sludge (RWT)	PH-B	3	S2						
Sludge (BWWT)	PH-A	17	T9						

FOOTNOTES TO TABLE 7-7

The following footnotes were referenced:

- 7-31
- A1 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 10 MG/M3 in the environment.
 - A2 -- Judged to be possibly hazardous to vegetation in case of acid mine drainage.
 - A5 -- Potentially hazardous since it contains salts and other water treatment chemicals.
 - A7 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 5 PPM in the environment. Federal and New Mexico state air quality and emission standards are also applicable.
 - B0 -- Potentially hazardous due to some elements and compounds present which can be leached by water.
 - B1 -- Potentially hazardous because it may contain some elements and compounds leached out from the ash.
 - B5 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment. Federal and New Mexico are also applicable.
 - B6 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 50 PPM in the environment. Federal and New Mexico are also applicable.
 - C0 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 10 PPM in the environment. New Mexico state air emission standards are also applicable.
 - C2 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 10 PPM in the environment.
 - C4 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 5 PPM in the environment.
 - C8 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment. New Mexico state air emissions standards are also applicable.
 - C9 -- Consists of 2540 TPD to catalytic incinerator and 70 TPD to vent gas incinerator.
 - D6 -- Potentially hazardous due to cooling tower chemicals in it.

FOOTNOTES TO TABLE 7-7 (Continued)

- 7-32
- D8 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 5 PPM in the environment.
- E0 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment. New Mexico state air emission standards are also applicable.
- G1 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 10 MG/M3 in the environment.
- G2 -- Judged to be possibly hazardous to vegetation in case of acid mine drainage.
- G3 -- Potentially hazardous since it contains salts and other water treatment chemicals.
- G5 -- Potentially hazardous due to some elements and compounds present which can be leached by water.
- G7 -- Potentially hazardous because it may contain some elements and compounds leached out from the ash.
- H0 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment. Federal and New Mexico state air quality and emission standards are also applicable.
- H1 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 50 PPM in the environment. Federal and New Mexico state air quality and emission standards are also applicable.
- H3 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 50 PPM in the environment. New Mexico state air emission standards are also applicable.
- I4 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 10 PPM in the environment. New Mexico state air emission standards are also applicable.
- I6 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment. New Mexico state air emission standards are also applicable.
- I9 -- Potentially hazardous because it may contain Ca ions leached out from the sludge.
- J4 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 10 PPM in the environment.
- J6 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 5 PPM in the environment.

FOOTNOTES TO TABLE 7-7 (Continued)

- J8 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 50 PPM in the environment. New Mexico state air emission standards are also applicable.
- L1 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 10 MG/M3 in the environment.
- L3 -- Potentially hazardous since it contains salts and other water treatment chemicals.
- L5 -- Potentially hazardous due to some elements and compounds present which can be leached by water.
- L8 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 5 PPM in the environment. Federal and North Dakota state air quality and federal emission standards are also applicable.
- M1 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment. Federal and North Dakota state air quality and federal emission standards are also applicable.
- M8 -- Potentially hazardous due to the presence of cyanides, phenols, fatty acids and metal ions that could be leached by water.
- M9 -- Potentially hazardous because it may contain some elements and compounds leached out from ash and sludge.
- N4 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 50 PPM in the environment. Federal and North Dakota state air quality standards are also applicable.
- N6 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment.
- N9 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment.
- P1 -- Potentially hazardous since it may be leached by water.
- P2 -- Potentially hazardous since it may contain sodium and calcium ions leached out from salts.
- P6 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 10 PPM in the environment.

FOOTNOTES TO TABLE 7-7 (Continued)

- P8 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 5 PPM in the environment.
- P9 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 50 PPM in the environment.
- R3 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 5 PPM in the environment. Federal and North Dakota state air quality and federal emission standards are also applicable. Estimated as NO₂.
- S1 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 10 MG/M3 in the environment.
- S2 -- Potentially hazardous due to water treatment chemicals that may be present.
- S3 -- Potentially hazardous due to elements or compounds present which can be leached by water.
- S4 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 50 PPM in the environment. Federal and North Dakota state air quality standards are also applicable.
- S5 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 5 PPM in the environment. Federal and North Dakota air quality and federal emission standards are also applicable.
- S9 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment. Federal and North Dakota state air quality and federal emission standards are also applicable.
- T1 -- Potentially hazardous due to elements and compounds which may be leached from ash.
- T5 -- OSHA standards do not permit prolonged exposure of an employee to a concentration greater than 20 PPM in the environment.
- T8 -- Potentially hazardous because Ca ions may be leached by water.
- T9 -- Potentially hazardous since it contains high concentrations of dissolved salts and other chemicals.
- U1 -- Potentially hazardous since it contains fatty acids, ammonia, etc.

TABLE 7-8
SUSPECTED GASIFICATION ATMOSPHERIC EFFLUENTS
WHICH HAVE AN IDENTIFIED MEG HAZARD POTENTIAL

<u>Substance</u>	<u>EPA MEG Catagory</u>	<u>EPA Hazard Potential</u>	<u>Effluent number in Table 7-18</u>
Pyridine	23A	15-X	55
Hydrogen Cyanide	47B	15-X	44
Hydrogen Sulfide	53D	12	48
Phenol	18A	10	36.54
Carbon Monoxide	42C	8	39
Ammonia	47B	8	35.50
Carbon Disulfide	53D	8	42
Carbonyl Sulfide	53C	4	40

TABLE 7-9

EFFLUENT QUANTITIES AND DISPOSITIONS THAT HAVE MEG VALUES

<u>Effluent</u>	<u>Plant/ Division</u>	<u>Quantity (TPD)</u>	<u>Quantity Reliability</u>	<u>EPA Hazard Potential</u>	<u>UND Estimated Hazard</u>
#55 Pyridine	1/19	0.00665	C	15-X	HZ
#44 Hydrogen Cyanide	1/07	0.1143	C		
			C	15-X	TX
	1/18	0.572	C		
#48 Hydrogen Sulfide	1/06	0.1532	C		
	2/06	0.0005	C	12	TX
	3/06	0.0044	C		
	4/06	0.1508	C		
	1/13	0.0058	C		
	3/14	0.0154	A		
#54 Phenols	1/07	0.00006	C	10	HZ
	1/18	0.00031	C		
	1/19	0.1161	C		
	2/19	0.3648	C		
	3/19	0.0033	C		
#39 Carbon Monoxide	4/04	1.344	B	8	TX
	1/06	7.1530	C		
	4/06	4.2409	C		
	4/12	3.024	A		
	1/13	0.856	B		
#50 Ammonia	1/19	4.562	C	8	HZ
	2/19	9.160	C		
	3/19	2.544	C		
#42 Carbon Disulfide	1/13	0.00288	C	8	HZ
#40 Carbonyl Sulfide	2/06	0.00136	C	4	HZ
	3/06	0.00120	C		
	1/13	0.0825	C		
	3/14	0.0419	B		

7.6 DISCUSSION OF DATA

It is apparent from the data presented that it is difficult and perhaps impossible to identify clear or precise effluent control technology needs for the gasification industry. The variability of the feed coal, the water, the regions' climates, local regulations, and politics cause each plant to have a significantly different design than any other facility. This is true even for facilities that are geographically close to one another (El Paso and WESCO, Natural and ANG). What has evolved is that there are no serious omissions with regard to effluents that have been identified and quantified in the design process and the authors' analyses. It is likely that the analyses available today cover some 99 percent by weight of the emissions that will be generated. The material balances presented in the EIS statements check; this lends some credibility to the analyses. Although more design analysis can be done, it is very doubtful if it is warranted. The next logical step is to gather operational data from a commercial 250 MMSCFD Lurgi plant. The existing control technology is, in the opinion of the authors, adequate to justify taking this step.

Control technology needs should be identified in the areas related to pyridine, hydrogen cyanide, and phenols. Oxidation of these effluents by incineration may be adequate.

APPENDIX A7

COMPUTER GENERATED COMPARATIVE
MATRICS OF EFFLUENT QUANTITY,
COST, AND RELIABILITY DATA

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TABLE 7-1

DEFINITION OF SYMBOLS USED IN COMPUTER GENERATED TABLES

<u>DIVISION # AND MEANING</u>		<u>BIOLOGICAL HAZARDS</u>	<u>DISPOSITION CODES</u>
1	Coal Storage Area	NK - None Known	1 - to mine
2	Coal Preparation Area	MM - Minor	2 - to atmosphere
3	Raw Water Treatment	PH - Possible Hazard	3 - to surface water
4	Boiler Plant	HZ - Hazard	4 - to deep well disposal
5	Oxygen Plant	TX - Toxic	5 - to Claus unit
6	Gasifiers		6 - to incineration
7	Ash Dewatering and Transfer Facility		7 - to stack gas treatment unit
8	ADIP Plant		8 - to ash handling
9	Claus Sulfur Plant		9 - to boiler
10	Stretford Sulfur Plant		0 - to superheater
11	Claus Incinerator		
12	Vent Gas Incinerator	<u>QUANTITY CODES</u>	
13	Catalytic Incinerator	SM - Small	
14	Untreated Stack Gas Vent	MIN - Minor	
15	Stack Gas Treatment	NIL - Nil	<u>NATURE CODES</u>
16	Waste Water Concentrator	N - None Emitted	S - Solid
17	Biological Waste Water Treatment	NR - None Reported	L - Liquid
18	Evaporation and Ash Ponds		G - Gas
19	Cooling Towers		SL - Sludge
20	Total Emissions		
<u>PLANT IDENTIFICATION</u>		<u>RELIABILITY LEVELS</u>	
Plant #1 - El Paso, New Mexico		A Good Reliability	-A- Refer to Reliability = A
Plant #2 - Natural, North Dakota		B Fair Reliability	-B- Refer to Reliability = B
Plant #3 - WESCO, New Mexico		C Poor Reliability	-C- Refer to Reliability = C
Plant #4 - ANG, North Dakota			

TABLE A7-1

EFFLUENT QUANTITY MATRIX FOR PLANT #1																			
(ALL NUMERICAL QJANTITIES GIVEN IN TONS/DAY)																			
EFFLUENT NAME	D I V I S I O N																		TOTAL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAC03	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAS03.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAS04.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	SM	SM	N	N	N	0.1412 OF7	N	N	N	N	N	N	N	N	N	N	N	N	0.1412
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PLY ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
GASIFIER ASH	N	N	N	N	N	5438.7 *A9	5438.7 *B7	N	N	N	N	N	N	N	N	N	N	N	5438.7
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA23	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-1 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #1																			
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																			
EFFLUENT NAME	DIVISION #																		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	TOTAL
PARTICULATES	N	N	N	MIN	N	0.0246 *F8	N	N	N	N	N	N	N	N	N	N	N	0.5244 *E1	0.553
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	1680	N	N	N	N	1680	N	N	N	N	N	N	N	N	N	N	N	1680
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SR02	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNREACTED C	N	N	N	N	N	286.0 *A9	286 *B7	N	N	N	N	N	N	N	N	N	N	N	286
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HClN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	2906 *A4	N	N	1147.3 *A9	1147 *B7	N	N	N	N	N	N	N	N	N	N	1970 *B5	1147
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	N	7.153 *F0	N	N	N	53 *D1	N	NIL	0.856	N	N	N	N	N	8.003
CO2	N	N	N	N	N	N	N	N	N	2.664 *C7	N	N	0.0825	N	N	N	N	N	0.0825

TABLE A7-1 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #1																			
(ALL NUMERICAL QANTITIES GIVEN IN TONS/DAY)																			
EFFLUENT NAME	DIVISION																		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
TOTAL																			
CO2	N	N	N	7744	12.6	14.646 *F0		N	N	N	19225 *C6	N	515	19519	N	N	N	N	N
CS2	N	N	N	N	N	N	N	N	N	N	0.072 *C7	N	N	0.00288	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	0.1141 *F1	N	N	N	N	N	N	N	N	N	0.574 *C1	0.3826 *F3
HCN	N	N	N	N	N	N	N	0.1143 *B9	N	N	N	N	N	N	N	N	N	0.572	N
HYDROCARBONS	N	N	N	N	N	2.447 *F0		N	N	N	114 *D2	N	NIL	4.33	N	N	N	N	N
H2	N	N	N	N	N	0.945 *F0		N	N	N	7 *D0	N	NIL	0.159	N	N	N	N	N
H2O	N	N	1051 *A3	5599 *A6	119.9	0.112 *F0		907 *B8	N	N	427 *D3	N	53	639	N	N	N	N	5411
H2S	N	N	N	N	N	0.1532 *F0		N	N	N	0.464 *C5	N	NIL	0.0058	N	N	N	N	N
NAPHTHA	N	N	N	N	N	0.224 *F0		N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N		N	N	N	N	N	N	N	N	N	N	N	4.562 *D4
NOX	N	N	N	6.74	N	N		N	N	N	N	N	0.096	N	N	N	N	N	N
N2	N	N	N	61444	18730.4	2.537 *F0		N	N	N	1610 *C9	N	351	2016	N	N	N	N	N
O2	N	N	N	12250	186.6	N		N	N	N	373 *C7	N	17	86	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	0.000001 *F2	N	N	N	N	N	N	N	N	N	N	0.00031 *C3	0.1161 *F4
PYRIDINES	N	N	N	N	N	N		N	N	N	N	N	N	N	N	N	N	0.00655 *F5	N
SO2	N	N	N	N	N	N		N	N	N	N	N	0.615	2.49	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N		N	N	N	N	N	N	N	N	N	N	N	0.06533 *F6
SLUDGE (PWT)	N	N	N	N	N	N		N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (BWT)	N	N	N	N	N	N		N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (CTB)	N	N	N	N	N	N		N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-2

EFFLUENT QUANTITY MATRIX FOR PLANT # 2																				
(ALL NUMERICAL QJANTITIES GIVEN IN TONS/DAY)																				
D I V I S I O N																				
EFFLUENT NAME	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	TOTAL
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	151 #L4	N	N	151 #L4	N	N	N	N	N	N	N	N	N	N	N	N	151
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	173.9 #P0	N	N	N	N	173.9
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	SM	SM	N	N	N	0.1473	N	N	N	N	N	N	N	N	N	N	N	N	N	0.1473
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	361 #L6	N	N	361 #L6	N	N	N	N	N	N	N	N	N	N	N	N	361
GASIFIER ASH	N	N	N	N	N	2159 #L4	2159 #L4	N	N	N	N	N	N	N	N	N	N	N	N	2159
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	2.5 #P0	N	N	N	N	2.5
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	9.6 #P0	N	N	N	N	9.6

TABLE A7-2 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT # 2																				
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																				
EFFLUENT NAME	DIVISION																			TOTAL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
PARTICULATES	N	N	N	4.8 0.17	N	0.018 0.04	N	N	N	N	N	N	N	1.2	0.035	N	N	N	0.923 0.01	2.177
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
S102	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
S03	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
S04	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
S002	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	0 0.08	N	N	N	N	N	N	N	N	0
SUSP. SOLIDS	N	N	N	N	N	N	52 0.47	N	N	N	N	N	N	N	N	52 0.47	N	N	N	52
UNREACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCM	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	42	N	N	N	640	N	N	N	N	N	N	N	156 0.00	210	156 0.00	N	24 0.00	1032
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	N	N	N	N	0.0101	14.8	0	0	0	N	N	N	N	N	N	0
COS	N	N	N	0 0.00	N	0.00136 0.00	N	1.93	0.333	1.94	0	0	0	N	N	N	N	N	N	0.00136

TABLE A7-2 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT # 2																				
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																				
EFFLUENT NAME	D I V I S I O N																			TOTAL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
CO2	N	N	N	14299	N	56.7 #M6	N	701.7 #N1	81.5	10050	297	19499	N	2146	12154	N	N	N	18 #P4	34171
CS2	N	N	N	N	N	N	N	N	0.0456	N	0	N	N	N	N	N	N	N	N	0
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0.7626 #P4	0.7626
HCN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HYDROCARBONS	N	N	N	0 #P4	N	0.294 #M6	N	127.7	N	87.8	N	0	N	N	N	N	N	N	N	0.294
H2	N	N	N	N	N	N	N	N	0.0035	2.25	0	0	N	N	N	N	N	N	N	0
H2O	N	N	N	1995 #R1	N	450 #M5	450	16.8	92.7	169.8	117.4	892	N	722	6163	30	N	N	29149 #P4	39908
H2S	N	N	N	0 #M0	N	0.0005 #M0	N	0.163 #M0	0.84 #P3	0.123	0	0	N	N	N	N	N	N	N	0.0005
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	9.16
NOX	N	N	N	63.1 #L9	N	N	N	N	N	N	N	N	N	6.02	29.6	N	N	N	N	34.62
N2	N	N	N	99203	20464	N	N	N	266.2	N	423	5929	N	5000	28332	N	N	N	N	60148
O2	N	N	N	1484	603	N	N	N	0.0384	N	7.3	297	N	224	1260	N	N	N	N	2391
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0.3648 #R5	0.3648
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO2	N	N	N	93.4	N	N	N	N	0.699 #R2	N	3.34	8.58	N	14.5	8.29	N	N	N	N	34.71
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0.179 #K0	0.179
SLUDGE (RWT)	N	N	32.1 #L2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	32.1
SLUDGE (RWWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	108 #P3	N	N	108
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	12.5 #O2	12.5

TABLE A7-3

EFFLUENT QUANTITY MATRIX FOR PLANT # 3																				
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																				
EFFLUENT NAME	D I V I S I O N #																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	TOTAL
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CaCARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
ROILER ASH	N	N	N	135	N	N	135	N	N	N	N	N	N	N	N	N	N	N	N	135
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	11 *17	N	42 *11	N	N	53
CaO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	215 *17	N	N	N	N	215
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	SM	SM	N	N	N	0.0124 *HS	N	N	N	N	N	N	N	N	N	N	N	N	N	0.0124
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	40% *G8	N	N	406	N	N	N	N	N	N	N	5 *17	N	N	N	N	411
GASIFIER ASH	N	N	N	N	N	6534	6534	N	N	N	N	N	N	N	N	N	N	N	N	6534
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-3 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #3																				
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																				
EFFLUENT NAME	DIVISION																			TOTAL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
PARTICULATES	N	N	N	5.82 *G9	N	0.0327 *K0	N	N	N	N	N	0.0193	N	N	0.82	N	N	N	0.346 *J9	1.216
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	2263	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	2263
S102	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
S03	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
S04	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SR02	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNREACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	24	176 *G6	N	1150	1326 *H9	N	N	N	N	N	N	N	32 *I7	N	32.4 *J1	N	N	1414.4
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	NIL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COS	N	N	N	NIL	N	0.0012 *H8	N	1.51	0	1.95	N	0	N	0.0419	N	N	N	N	N	0.0431

TABLE A7-3 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #3																			
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																			
EFFLUENT NAME	DIVISION #																		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
																			TOTAL
CO2	N	N	N	19704	12	50 #H8	N	547.3 #I1	120.9	9270	N	8890	N	1747	19700	N	N	N	N
CS2	N	N	N	N	N	N	N	N	N	N	N	0	N	N	N	N	N	N	0
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0.3667 #K1	0.3667
HCN	N	N	N	N	N	N	N	N	0	N	N	N	N	N	N	N	N	N	N
HYDROCARBONS	N	N	N	NIL	N	0.380 #H8	N	99.9	0	83.5	N	0	N	9.1	N	N	N	N	9.48
H2	N	N	N	NIL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	2523 #G4	2611	N	877 #H7	N	13.1 #I2	86.2	N	N	267	N	N	2608	N	N	N	23437 #J2
H2S	N	N	N	NIL	N	0.0044 #H9	N	0.128 #I0	0	1.35	N	0	N	0.0154	N	N	N	N	0.0198
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	2.544 #J2	2.544
NOX	N	N	N	17.5 #H6	N	N	N	N	N	N	N	1.140 #H4	N	N	17.5 #H4	N	N	N	18.66
N2	N	N	N	30502	19634	N	N	N	294.5	N	N	3008	N	N	30491	N	N	N	53135
O2	N	N	N	1273	302	N	N	N	N	N	N	58	N	N	1273	N	N	N	1723
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0.0033 #J2	0.0033
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO2	N	N	N	90.83 #H2	N	N	N	N	14.5 #I3	N	N	0.74	N	N	9.05	N	N	N	9.79
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0.0032 #K3	0.0032
SLUDGE (RWT)	N	N	24	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	24
SLUDGE (BWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	6.7 #J1	N	6.7
SLUDGE (CTD)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

A7-10

TABLE A7-4

EFFLUENT QUANTITY MATRIX FOR PLANT #4
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)

EFFLUENT NAME	DIVISION																			TOTAL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAC03	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAS03.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAS04.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	54 1.085		N	N	N 0.1342 0.57		N	N	N	N	N	N	N	N	N	N	N	N	N	1.2192
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N 6.24	N	N	N 6.24	N	N	N	N	N	N	N	N	N	N	N	N	N	6.24
GASIFIER ASH	N	N	N	N	N	1763	1763	N	N	N	N	N	N	N	N	N	N	N	N	1763
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-4 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #4																				
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																				
EFFLUENT NAME	CIVISION #																			TOTAL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
PARTICULATES	N	N	N	1.56	N	0.0088 *70	N	N	N	N	N	N	N	N	N	N	N	N	N	1.5688
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SRO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNREACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HClN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	318.5	N	N	N	N	N	N	N	N	421	N	N	N	613.3
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	1.344	N	4.2409 *58	N	N	N	9.744	N	3.024 *17	N	N	N	N	N	N	N	8.6089
CO2	N	N	N	N	N	N	N	N	N	6.185	N	0	N	N	N	N	N	N	N	0

TABLE A7-4 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #4																			
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																			
EFFLUENT NAME	DIVISION																		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
																			TOTAL
CO2	N	N	N	2897	N	13.848 *58	N	N	N	12500 *13	N	23747 *17	N	287 *18	N	N	N	N	N
CS2	N	N	N	N	N	N	N	N	N	2.444 *14	N	0	N	N	N	N	N	N	0
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HClN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HYDROCARBONS	N	N	N	0.8	N	1.8698 *58	N	N	N	267.1	N	0.534 *17	N	N	N	N	N	N	3.2038
H2	N	N	N	N	N	0.7502 *58	N	N	N	0.745	N	0 *17	N	N	N	N	N	N	0.7502
H2O	N	N	N	904	N	4.9409 *58	192.3	N	N	539	N	1704 *17	N	110 *18	N	N	N	N	27484 *10
H2S	N	N	N	N	N	0.1508 *58	N	N	N	1.807	N	0	N	N	N	N	N	N	0.1508
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NOX	N	N	N	9.4 *56	N	N	N	N	N	N	N	0.48 *10	N	N	N	N	N	N	9.86
N2	N	N	N	10218	18075	N	N	N	N	16.027	N	10865 *17	N	1692 *18	N	N	N	N	40840
O2	N	N	N	405	104	N	N	N	N	N	N	668 *17	N	584 *18	N	N	N	N	1761
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO2	N	N	N	12.1	N	N	N	N	N	1.2 *16	N	19.4 *17	N	N	N	N	N	N	32.8
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (RWT)	N	N	510.8	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (MWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	3052	N	N	3052
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

A7-13

FOOTNOTES TO TABLES 7A-1 TO 7A-4

THE FOLLOWING FOOTNOTES WERE REFERENCED:

- P7 *** EMISSION FROM HIGH BTU AND LOW HTU GASIFIERS. ESTIMATED USING EMISSION FACTORS
- A9 *** EMISSION FROM HIGH BTU AND LOW HTU GASIFIERS.
- B7 *** GASIFIER ASH. UNREACTED CARBON AND WATER ARE IN THE FORM OF A SLUDGE.
- P8 *** EMISSION FROM HIGH HTU AND LOW HTU GASIFIERS. CONSISTS MAINLY OF GASIFIER PARTICLES. ESTIMATED USING EMISSION FACTORS.
- F1 *** CONSISTS OF DISSOLVED SOLIDS IN COOLING WATER WHICH ARE EMITTED IN THE DRIFT.
- A4 *** IN THE FORM OF SLUDGE FROM LINE TREATMENT. DEMINERALIZER AND ZEOLITE SOFTNER.
- D5 *** IN THE FORM OF SLUDGE.
- F0 *** EMISSION FROM HIGH BTU AND LOW HTU GASIFIERS. EMISSION DUE TO LOCK GAS DISPLACED FROM COAL LOCKS BY COAL DURING CHARGING OF COAL LOCKS.
- D1 *** CONSISTS OF 21 TPD TO CATALYTIC INCINERATOR AND 32 TPD TO VENT GAS INCINERATOR.
- C7 *** TO CATALYTIC INCINERATOR.
- C6 *** CONSISTS 019178 TPD TO CATALYTIC INCINERATOR AND 447 TPD TO VENT GAS INCINERATOR.
- F1 *** EVAPORATED INTO ATMOSPHERE ALONG WITH WATER FROM FINE ASH POND. ESTIMATED AS ACETIC ACID.
- C1 *** ESTIMATED AS ACETIC ACID.
- F3 *** ESTIMATED AS ACETIC ACID. CONSISTS OF DRIFT AND EVAPORATION LOSSES.
- B9 *** EVAPORATED INTO ATMOSPHERE ALONG WITH WATER FROM FINE ASH POND.
- D2 *** CONSISTS OF 107.5 TPD TO CATALYTIC INCINERATOR AND 6.5 TPD TO VENT GAS INCINERATOR.
- D0 *** CONSISTS OF 4 TPD TO CATALYTIC INCINERATOR AND 3 TPD TO VENT GAS INCINERATOR.
- A3 *** CONSISTS OF 871 TPD. DUE TO EVAPORATION FROM RAW WATER STORAGE AND 210 TPD FROM DEGASER VENTS.
- A6 *** INCLUDES STEAM LOSSES IN DEAERATOR VENTS, LEAKS AND OTHER LOSSES FROM BOILER AND ITS PIPING.
- B8 *** CONSISTS OF EVAPORATION TO ATMOSPHERE FROM FINE ASH POND.
- D3 *** CONSISTS OF 415 TPD TO CATALYTIC INCINERATOR AND 12 TPD TO VENT GAS INCINERATOR.
- D4 *** CONSISTS OF DRIFT AND EVAPORATION LOSSES.
- C5 *** CONSISTS OF 0.144 TPD TO CATALYTIC INCINERATOR AND 0.32 TPD TO VENT GAS INCINERATOR.
- C9 *** CONSISTS OF 2540 TPD TO CATALYTIC INCINERATOR AND 70 TPD TO VENT GAS INCINERATOR.
- F2 *** EVAPORATED INTO ATMOSPHERE ALONG WITH WATER FROM FINE ASH POND. ESTIMATED AS PHENOL.
- C3 *** ESTIMATED AS PHENOL.

FOOTNOTES TO TABLES A7-1 TO A7-4 (Continued)

- F4 *** ESTIMATED AS PHENOL. CONSISTS OF DRIFT AND EVAPORATION LOSSES.
- F5 *** OSHA STANDARDS DO NOT PERMIT PROLONGED EXPOSURE OF AN EMPLOYEE TO A CONCENTRATION GREATER THAN 5 PPM IN THE ENVIRONMENT. CONSISTS OF DRIFT AND EVAPORATION LOSSES.
- F6 *** ESTIMATED AS HSCN. CONSISTS OF DRIFT AND EVAPORATION LOSSES.
- L4 *** CONSISTS OF 14.4% AL₂O₃, 25.9% CAO, 11.8% MGO, 3.6% NA₂O, 5.2% SO₃, 26.9% SiO₂, 1.5% SR₂O AND 1.2% K₂O.
- P0 *** EMITTED AS A SLUDGE.
- L6 *** CONSISTS OF 32.3% SiO₂, 27.7% CAO, 17.0% AL₂O₃, 5.1% NA₂O, 10.0% MGO, 1.0% K₂O, 5.3% Fe₂O₃ AND 1.1% TiO₂.
- L7 *** PARTICULATES ARE FLY ASH PARTICLES.
- M4 *** CONSISTS MAINLY OF GASIFIER ASH PARTICLES.
- O1 *** CONSISTS OF DISSOLVED SOLIDS IN COOLING WATER WHICH ARE EMITTED IN THE DRIFT.
- N8 *** SULPHUR IS IN VAPOR STATE.
- M7 *** CONSISTS OF SOLIDS FROM THE TRIPLE EFFECT EVAPORATER CONCENTRATOR CONTAINING CYANIDES, PHENOLS, FATTY ACIDS AND METAL IONS.
- M0 *** PART OF THE COAL LOCK GAS INCINERATED IN THE BOILER.
- M6 *** EMISSION DUE TO LOCK GAS DISPLACED FROM COAL LOCKS BY COAL DURING CHARGING OF COAL LOCKS.
- N1 *** DOES NOT INCLUDE 34.05TPD CO₂ IN THE H₂S RICH GAS VENT TO CLAUS UNIT.
- P4 *** CONSISTS OF EVAPORATION AND DRIFT LOSSES.
- P4 *** CONSISTS OF EVAPORATION AND DRIFT LOSSES. ESTIMATED AS ACETIC ACID.
- R1 *** AN ADDITIONAL 4823TPD OF H₂O VAPOR IS EMITTED TO THE STAG GAS TREATMENT UNIT. CONSISTS OF LEAKS AND STEAM VENTS TO THE ATMOSPHERE FROM THE STEAM LINE.
- M5 *** FROM ASH QUENCH.
- N0 *** DOES NOT INCLUDE 149.1TPD H₂S IN THE H₂S RICH GAS SENT TO CLAUS PLANT.
- N3 *** SOME OF THE CONTROLLED H₂S LEAVES THE CLAUS UNIT AS SO₂.
- L9 *** ESTIMATED AS NC₂.
- R5 *** CONSISTS OF EVAPORATION AND DRIFT LOSSES. ESTIMATED AS PHENOL.
- R2 *** SOME OF THE UNCONTROLLED H₂S LEAVES THE CLAUS UNIT AS SO₂. AN ADDITIONAL 0.238TPD OF SULFUR IN THE VAPOR PHASE IS EMITTED FROM THE CLAUS PROCESS.
- R6 *** CONSISTS OF EVAPORATION AND DRIFT LOSSES. ESTIMATED AS HSCN.
- L2 *** SLUDGE CONSISTS OF 13.5TPD CaCO₃, 0.42TPD Mg(OH)₂, 0.77TPD Al₂(SO₄)₃ AND 17.4TPD SUSPENDED SOLIDS.
- P3 *** CONSISTS OF 66.7% CaCO₃, 15.3% ORGANIC MATTER FOR BICREATING, 8.0% CALCIUM SALTS OF PHENOLS, 5.8% CALCIUM SALTS OF FATTY ACIDS AND 4.2% OTHER INORGANIC CALCIUM SALTS.
- O2 *** CONSISTS OF 86.4% CaCO₃, 9.6% Mg(OH)₂ AND 4.0% Al₂(SO₄)₃.

FOOTNOTES TO TABLES A7-1 TO A7-4 (Continued)

- I7 *** IT IS A PART OF THE SLUDGE SENT TO THE MINE. COST IS ONLY ALLOCATED TO $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ SINCE IT IS THE MAJOR COMPONENT.
- J1 *** PART OF THE SLUDGE FROM THE BIOLOGICAL WASTE WATER SLUDGE SENT TO MINE. COST IS ALLOCATED ONLY TO CaCO_3 SINCE IT IS A MAJOR COMPONENT.
- M5 *** ESTIMATED USING EMISSION FACTORS.
- G8 *** CONSISTS OF FLY ASH COLLECTED BY THE ELECTROSTATIC PRECIPITATOR.
- G9 *** CONSISTS OF FLY ASH PARTICLES.
- K0 *** ESTIMATED USING EMISSION FACTORS. CONSISTS OF GASIFIER ASH PARTICLES.
- J9 *** CONSISTS OF DISSOLVED SOLIDS IN COOLING WATER WHICH ARE EMITTED IN THE DRIFT.
- G6 *** CONSISTS OF 44TPD OF WATER ACCOMPANYING THE BOILER ASH AND 132TPD OF WATER ACCOMPANYING THE FLY ASH.
- M9 *** ASH AND WATER ARE IN THE FORM OF A SLUDGE.
- M8 *** EMISSION DUE TO LOCK GAS DISPLACED FROM COAL LOCKS BY COAL DURING CHARGING OF COAL LOCKS.
- I1 *** DOES NOT INCLUDE 26.5TPD CO_2 IN THE H_2S RICH GAS SENT TO THE CLAUS PLANT.
- K1 *** CONSISTS OF DRIFT AND EVAPORATION LOSSES. ESTIMATED AS ACETIC ACID.
- G4 *** CONSISTS OF EVAPORATION FROM RA- WATER STORAGE.
- M7 *** CONSISTS OF WATER VAPOR FROM ASH QUENCHING OPERATION.
- I2 *** DOES NOT INCLUDE 6.8TPD H_2O IN THE H_2S RICH GAS SENT TO THE CLAUS PLANT.
- J2 *** CONSISTS OF DRIFT AND EVAPORATION LOSSES.
- I0 *** DOES NOT INCLUDE 116.6TPD H_2S IN THE H_2S RICH GAS SENT TO CLAUS PLANT.
- I3 *** ALL THE H_2S IS OXIDIZED TO SO_2 . ANY UNCONTROLLED H_2S LEAVES THE CLAUS UNIT AS SO_2 .
- M4 *** ESTIMATED AS NO_2 .
- K2 *** CONSISTS OF DRIFT AND EVAPORATION LOSSES. ESTIMATED AS PHENCL.
- M2 *** FORMED IN BOILER DUE TO COMBUSTION OF COAL, H_2S AND COS .
- K3 *** CONSISTS OF DRIFT AND EVAPORATION LOSSES. ESTIMATED AS HSCN.
- S7 *** ESTIMATED USING EMISSION FACTORS.
- T0 *** CONSISTS MAINLY OF GASIFIER ASH PARTICLES. ESTIMATED USING EMISSION FACTORS.
- S8 *** EMISSION DUE TO LOCK GAS DISPLACED FROM COAL LOCKS BY COAL DURING CHARGING OF COAL LOCKS.
- T7 *** INCINERATION IS DONE IN A STEAM SUPERHEATER WITH TAR OIL, NAPHTHA AND PHENOLICS AS FUEL.
- T3 *** AN ADDITIONAL 1.3TPD OF CO_2 IS EMITTED TO THE ATMOSPHERE IN THE STRETFORD BLEED STREAM.
- T8 *** EMITTED AS STRETFORD OXIDIZER EFFLUENT.
- T4 *** REPORTED BY ANG AS ORGANIC SULFUR.

FOOTNOTES TO TABLES A7-1 TO A7-4 (Continued)

UO *** MAY CONTAIN FATTY ACIDS, AMMONIA, PHENOLICS, OTHER VOLATILE CONTAMINANTS AND
DISSOLVED SOLIDS WHICH ARE EMITTED ALONG WITH THE DRIFT.

SA *** ESTIMATED AS NO₂.

VO *** ESTIMATED AS NO₂. INCINERATION IS DONE IN A STEAM SUPERHEATER WITH TAR OIL,
NAPHTHA AND PHENOLICS AS FUEL.

T6 *** STRETFORD BLEED STREAM.

TABLE A7-5

EFFLUENT QUANTITY MATRIX FOR PLANT #1 (RELIABILITY = A)
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)

EFFLUENT NAME	DIVISION																			TOTAL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	SM	SM	N	N	N	-C-	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
GASIFIER ASH	N	N	N	N	N	5438.7	5438.7	N	N	N	N	N	N	N	N	N	N	N	N	5438.7
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	N	N	-C-	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	-B-	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	1680
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SR02	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNREFACTED C	N	N	N	N	N	286.0	286	N	N	N	N	N	N	N	N	N	N	N	N	286
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HClN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	2906	N	N	1147.3	1147	N	N	N	N	N	N	N	N	N	N	N	1979	1147
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	N	-C-	N	N	N	N	53	NIL	-B-	N	N	N	N	N	N	-C-
CO5	N	N	N	N	N	-C-	N	N	N	N	-C-	N	-C-	N	N	N	N	N	N	-C-
CO2	N	N	N	7744	12.6	-C-	N	N	N	1925	515	-C-	-C-	N	N	N	N	N	N	-C-
CS2	N	N	N	N	N	N	N	N	N	-C-	N	N	-C-	N	N	N	N	N	N	-C-
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
HClN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
HYDROCARBONS	N	N	N	N	N	N	N	N	N	114	NIL	-C-	N	N	N	N	N	N	N	-C-
H2	N	N	N	N	N	N	N	N	N	7	NIL	-B-	N	N	N	N	N	N	N	-C-
H2O	N	N	1081	5589	119.9	N	907	N	N	427	53	-B-	N	N	N	N	N	5411	17844	31644
H2S	N	N	N	N	N	N	N	N	N	-B-	NIL	-C-	N	N	N	N	N	N	N	-C-
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
NOX	N	N	N	N	N	N	N	N	N	N	N	-C-	N	N	N	N	N	N	N	-C-
H2	N	N	N	61444	18730.4	-C-	N	N	N	1610	N	-B-	-B-	N	N	N	N	N	N	82444
O2	N	N	N	12250	186.6	N	N	N	N	373	N	17	-C-	N	N	N	N	N	N	12536
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
SO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
THIOCYANATES	N	N	N	-B-	N	N	N	N	N	N	N	-B-	-B-	N	N	N	N	N	N	-B-
SLUDGE (RWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
SLUDGE (RWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-5 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #2 (RELIABILITY = A)																			
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																			
EFFLUENT NAME	DIVISION																		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
																			TOTAL
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
OTCARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
GASIFIER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SR02	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SILPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNREACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CS2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HYDROCARBONS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2S	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NOX	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
O2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (RWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (RWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-5 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #3 (RELIABILITY = A)																			
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																			
DIVISION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
EFFLUENT NAME	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
TOTAL																			
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	135	N	N	135	N	N	N	N	N	N	N	N	N	N	N	135
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-	N	-B-	N	-B-
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-D-	N	N	N	-B-
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	SM	SM	N	N	N	-C-	N	N	N	N	N	N	N	N	N	N	N	N	-C-
FF2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	406	N	N	406	N	N	N	N	N	N	N	-B-	N	N	N	411
GASIFIER ASH	N	N	N	N	N	6534	6534	N	N	N	N	N	N	N	N	N	N	N	6534
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	5.82	N	-C-	N	N	N	N	N	N	-B-	N	-B-	N	N	-C-	-B-
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	-B-	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-B-
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SRO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNPEAKED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	-B-	176	N	1150	1326	N	N	N	N	N	N	N	-B-	N	-B-	N	1414.4
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	NIL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO2	N	N	N	NIL	N	-C-	N	N	N	N	N	N	N	N	N	N	N	N	-B-
CS2	N	N	N	19704	12	-C-	N	547.3	120.9	9270	N	8890	N	1747	19700	N	N	N	30399
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
HYDROCARBONS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0.48
H2	N	N	N	NIL	N	-C-	N	99.9	0	83.5	N	0	N	9.1	N	N	N	N	N
H2O	N	N	-B-	2611	N	-B-	N	13.1	86.2	N	N	267	N	N	2608	N	N	N	23437
H2S	N	N	N	NIL	N	-C-	N	0.128	-B-	1.35	N	0	N	0.0154	N	N	N	N	0.0198
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NOX	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
V2	N	N	N	-B-	N	N	N	N	N	N	N	-B-	N	N	-C-	N	N	N	-C-
O2	N	N	N	30502	19634	N	N	N	N	294.5	N	3008	N	N	-B-	N	N	N	-B-
PHENOLICS	N	N	N	1273	302	N	N	N	N	N	N	58	N	N	-B-	N	N	N	-C-
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO2	N	N	N	-B-	N	N	N	N	14.5	N	N	-B-	N	N	9.05	N	N	N	9.79
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
SLUDGE (RWT)	N	N	-B-	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-B-
SLUDGE (BWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-B-
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-5 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT 64 (RELIABILITY = A)																				
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																				
D I V I S I O N																				
EFFLUENT NAME	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	TOTAL
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
GASIFIER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
WAXES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNPEAKED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CS2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HYDROCARBONS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2S	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NOX	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
O2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (RWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (RWY)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-6

EFFLUENT QUANTITY MATRIX FOR PLANT #1 (RELIABILITY = 8)
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)

EFFLUENT NAME	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	TOTAL
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
RICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	-A	-A	N	N	N	-C	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
GASIFIER ASH	N	N	N	N	N	-A	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
PARTICULATES	N	N	N	N	N	-C	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
REFUSE	N	1680	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SR02	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
UNREACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
HCN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
CO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
CO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
CO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
CS2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
HCN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
HYDROCARBONS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
H2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
H2S	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
NOX	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
N2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
OP	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
SO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
SLUDGE (PWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (EWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-6 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #2 (RELIABILITY = 8)																				
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																				
..... DIVISION #																				
EFFLUENT NAME	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	TOTAL
.....																				
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	-A	N	N	-A	N	N	N	N	N	N	N	N	N	N	N	N	-A
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A	N	N	N	N	-A
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	-A	-A	N	N	N	-C	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	-A	N	N	-A	-A	N	N	N	N	N	N	N	N	N	N	N	-A
GASIFIER ASH	N	N	N	N	N	-A	-A	N	N	N	N	N	N	N	N	N	N	N	N	-A
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A	N	N	N	N	-A
Na2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A	N	N	N	N	-A
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	4.9	N	-C	N	N	N	N	N	N	N	1.2	0.036	N	N	N	-C	2.177
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SRO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	-A	N	N	N	N	N	N	N	N	-A
SUSP. SOLIDS	N	N	N	N	N	N	-A	N	N	N	N	N	N	N	N	-A	N	N	N	-A
UNFACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	-A	N	N	N	-A	N	N	N	N	N	N	N	-A	-A	-A	N	-A	-A
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	N	N	N	N	0.0101	-A	-A	-A	N	N	N	N	N	N	N	-A
CO5	N	N	N	-A	N	-C	N	-A	-A	-A	-A	-A	N	N	N	N	N	N	N	-A
CO2	N	N	N	-A	N	-C	N	-A	-A	-A	-A	-A	N	-A	-A	N	N	N	-C	-A
CS2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
HYDROCARBONS	N	N	N	-A	N	-C	N	-A	N	-A	-A	-A	N	N	N	N	N	N	N	-A
H2	N	N	N	N	N	N	N	N	-A	-A	-A	-A	-A	N	N	N	N	N	N	-C
H2O	N	N	N	-A	N	450	-A	-A	-A	-A	-A	-A	N	-A	-A	30	N	N	-A	-A
H2S	N	N	N	-A	N	-C	N	-A	-A	-A	-A	-A	N	-A	-A	N	N	N	N	-A
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NOX	N	N	N	63.1	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
N2	N	N	N	-A	N	-A	N	N	N	N	N	N	N	6.02	28.6	N	N	N	N	34.62
O2	N	N	N	-A	N	-A	N	N	N	N	N	N	N	-A	-A	N	N	N	N	-A
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
SO2	N	N	N	-A	N	N	N	N	-A	N	-A	-A	N	-A	-A	N	N	N	N	-A
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
SLUDGE (RMT)	N	N	N	-A	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C
SLUDGE (BMT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A	N	N	-A

TABLE A7-6 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #3 (RELIABILITY = 8)
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)

D I V I S I O N																				
EFFLUENT NAME	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	TOTAL
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	N	-A-	N	N	N	-A-	N	N	N	N	N	-C-	N	42	N	N	-A-
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	53
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	215	N	N	N	N	215
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
COAL DUST	-A-	-A-	N	N	N	-C-	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	5	N	N	N	N	-A-
FLY ASH	N	N	N	N	-A-	N	N	N	-A-	N	N	N	N	N	N	N	N	N	N	-A-
GASIFIER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	N	-A-	N	N	N	N	N	N	N	N	N	N	N	N	N	N	1.216
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	2263
REFUSE	N	2263	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SHO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNREACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCN	N	N	24	-A-	N	-A-	-A-	N	N	N	N	N	N	N	32	N	32.4	N	N	-A-
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	-A-	N	N	N	N	N	N	N	N	N	0.0419	N	N	N	N	0.0431
COS	N	N	N	N	-A-	N	N	1.51	-A-	1.92	N	-A-	N	N	-A-	N	N	N	N	-A-
CO2	N	N	N	N	-A-	N	N	-A-	-A-	-A-	N	-A-	N	N	N	N	N	N	N	-A-
CS2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-A-
HCN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HYDROCARBONS	N	N	N	N	-A-	N	N	N	-A-	-A-	N	-A-	N	N	-A-	N	N	N	N	-A-
H2O	N	N	2523	-A-	N	877	N	N	-A-	0	-A-	N	N	N	-A-	N	N	N	N	29712
H2S	N	N	N	N	-A-	N	N	N	-A-	N	N	-A-	N	N	N	N	N	N	N	-A-
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-C-
NOX	N	N	N	N	17.5	-A-	N	N	N	N	N	1.160	N	N	N	N	N	N	N	53135
N2	N	N	N	N	-A-	N	N	N	N	N	N	-A-	N	N	304.91	N	N	N	N	1723
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	1273	N	N	N	N	-C-
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N				

TABLE A7-6 (Continued)

[illegible]

A7-26

EFFLUENT QUANTITY MATRIX FOR PLANT #1 (RELIABILITY = C)																	
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																	
EFFLUENT NAME	DIVISION																TOTAL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
RICARBOATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
ROLLER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Ca(OH)2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CaO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL CLST	-A	-A	N	N	0.1412	N	N	N	N	N	N	N	N	N	N	N	0.1412
CO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
GASIFIER ASH	N	N	N	N	-A	-A	N	N	N	N	N	N	N	N	N	N	-A
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Na2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	-A	N	0.0280	N	N	N	N	N	N	N	N	N	0.52	0.52
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PERFUSE	N	-B	N	N	N	N	N	-B	N	N	N	N	N	N	N	N	-A
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SILICUMUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNREACTED C	N	N	N	N	-A	-A	N	-A	N	N	N	N	N	N	N	N	-A
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	-A	N	N	-A	-A	N	N	N	N	N	N	N	N	-A	-A
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SILICUMUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	N	7.153	N	N	N	-A	-B	N	N	N	N	N	N
CO2	N	N	-A	-A	14.546	N	N	N	2.025	N	0.0325	N	N	N	N	N	0.3625
CS2	N	N	N	N	N	N	N	N	-A	-A	-U	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	0.172	N	0.00288	N	N	N	N	N	0.00288
HCl	N	N	N	N	N	0.1141	N	N	N	N	N	N	N	N	0.574	0.3820	1.0707
HCl	N	N	N	N	N	0.1143	N	N	N	N	N	N	N	N	0.572	N	0.583
HYDROCARBONS	N	N	N	N	N	2.447	N	N	-A	-A	4.33	N	N	N	N	N	0.777
H2	N	N	-A	N	N	0.945	N	N	-A	-A	-B	N	N	N	N	N	1.04
H2O	N	N	-A	-A	N	0.112	-A	N	-A	-A	-B	N	N	N	-A	-A	-A
H2S	N	N	N	N	N	0.1532	N	N	-B	N	0.0039	N	N	N	N	N	0.153
NAPHTHA	N	N	N	N	N	0.224	N	N	N	N	N	N	N	N	N	N	0.224
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	4.562	4.562
NO4	N	N	N	N	N	N	N	N	N	0.096	N	N	N	N	N	N	0.096
N2	N	N	N	-A	-B	2.547	N	N	-A	-B	-B	N	N	N	N	N	2.547
O2	N	N	N	-A	-A	N	N	N	-A	-A	-B	N	N	N	N	N	-A
PHENOLICS	N	N	N	N	N	0.000061	N	N	N	N	N	N	N	N	0.000031	0.1101	0.11047
HYDIOINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	0.00065	0.0065
SiO2	N	N	N	-B	N	N	N	N	N	-B	-B	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLODGE (DWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLODGE (DWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLODGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-7 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #2 (RELIABILITY = C)
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)

EFFLUENT NAME	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	TOTAL
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BILK ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	-A-	-A-	N	N	N	0.1473	N	N	N	N	N	N	N	N	N	N	N	N	N	0.1473
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
GASIFIER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO1	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SIO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO5	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNFRACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HYDROCARBONS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2S	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO1	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
N2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
O2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULFIDE (F&T)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULFIDE (P&T)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULFIDE (CTF)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

TABLE A7-7 (Continued)

EFFLUENT QUANTITY MATRIX FOR PLANT #3 (RELIABILITY = C)																			
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																			
EFFLUENT NAME	DIVISION #																		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
TOTAL																			
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BOILER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CACD3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CAO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COAL DUST	-A	-A	N	N	N	0.0124	N	N	N	N	N	N	N	N	N	N	N	N	0.0124
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
GASIFIER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SR02	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNREACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Cl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CS2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCl	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HYDROCARBONS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2S	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NAPHTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NOX	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
N2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
O2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (BWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (BWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

A-7-29

EFFLUENT QUANTITY MATRIX FOR PLANT #4 (RELIABILITY = C)																			
(ALL NUMERICAL QUANTITIES GIVEN IN TONS/DAY)																			
EFFLUENT NAME	DIVISION #																		
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	TOTAL
AL2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL(OH)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
AL2(SO4)3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
BICARBONATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
DRILLER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CACO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
C40	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO3.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CASO4.2H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHAL DUST	-A	-B	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	-B
FE2O3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FLY ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
GASIFIER ASH	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
K2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
MGO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NA2SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PARTICULATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHOSPHATE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
REFUSE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SiO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SO4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SR02	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SUSP. SOLIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
UNREACTED C	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CHLORIDES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HI3	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SULPHUR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
CO2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COS2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
FATTY ACIDS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HCN	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
HYDROCARBONS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2O	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
H2S	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
KARPTHA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NH4	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
NOX	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
N2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
O2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PHENOLICS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
PYRIDINES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SD2	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
THIOCYANATES	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (RWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (PWT)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SLUDGE (CTB)	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

8.0 CONCLUSIONS AND RECOMMENDATIONS

8.1 CURRENT EFFLUENT CONTROL STATUS

Liquid wastes are "controlled" in the sense that there are none. There are no waste water streams from any of the facilities with the exception of ANG's deep well which will be used for brine disposal. All of the water is either treated for reuse or evaporated. There is little published data concerning the characteristics of water reuse treatment systems for coal gasification facilities. There is a high probability that the existing technology can be used to meet the zero discharge requirement and provide water for reuse. Upsets due to this system should be minimal; however, accurate prediction of internal water reuse streams is difficult during steady state operation and impossible during upsets.

Gaseous emissions are under relatively tight state standards in New Mexico and Federal standards and guidelines in North Dakota. Controlled substances are NO_x , non-methane Hydrocarbons (HC), COS, SO_2 , CO, and particulates. There is a good probability that the Federal sulfur standards and guidelines can be met or exceeded (lower emission) with satisfactory operational characteristics. The New Mexico sulfur standards are considerably tighter and will be difficult to meet or exceed with existing equipment while maintaining satisfactory operating characteristics and reasonable cost. Hydrocarbon (HC) and carbon-monoxide emissions guidelines and standards (both Federal and state) are somewhat easier to meet than the sulfur standards. The control method is by oxidation which can exact a penalty in operating efficiency due

to the fuel gas requirement. Claus and Stretford tail gas streams in New Mexico will have to be scrubbed both for COS and SO₂ control. A Stretford system has been installed in SASOL and operated successfully on the Rectisol off-gas. The SASOL Rectisol off-gas stream is similar to the streams projected for the four gasification plants examined in this report. Additional operating data are available for high CO₂, low H₂S streams; however, these data are not available in the literature at this time. Both the SASOL data and unpublished data indicate that a Stretford can be operated in a gasification environment.

Solid wastes and sludges are, at this time, uncontrolled. There is, however, significant research being conducted to establish the probable impact of solid waste disposal and to establish techniques to minimize the potential impact. The only control implemented at this time is through the permitting requirements which force examination of and approve the mining solid waste disposal, and reclamation plans. The potential disposing of some of the plant's waste water in the sludges in the mined area is high; if this practice was implemented, it would probably cause the states to implement controls on sludge disposal. Existing waste water treatment technology could probably treat sludge additive liquids to acceptable limits prior to disposal. Technology for post-disposal treatment does not exist.

8.2. CONSIDERATIONS AND REQUIREMENTS FOR FUTURE EFFLUENT CONTROL TECHNOLOGY

The future needs of control technology are difficult to name and virtually impossible to quantify. In fact, it is the latter characteristic, the lack of quantification of emission levels, that makes the future applicability of existing control technology uncertain. Several general areas that must be considered in examining gasification effluent control research needs are:

1. Social-economic characteristics of effluent control.
2. Operational considerations.
3. Technical considerations.

Each of these areas is discussed below. Upon examining these problems one must keep in mind the trade-off between production of energy and non-pollution of the environment. The basic problem is, of course, to find a satisfactory balance between these two that permits an acceptable environment and a reasonable level of energy production.

8.2.1 Social, Political, and Economic Considerations

Social pressures for a clean environment are, in the view of the authors, likely to remain in place. Local politics particularly at the town, county, and state levels are likely to cause serious delays in the permitting process for gasification facilities to be constructed. This is particularly true of the western coals which are largely politically controlled by an agriculturally based economy. In addition, the air quality level in the western regions is likely to be Class I or Class II. Both of these factors will tend to force plants in the West to utilize

best available control technology and may cause some retrofitting. Trace metals have high visibility both at the state and national (EPA) levels. Although sound justification for controlling trace element emissions is absent at this time, proposals are being made (particularly by plant opponents) that such emissions, if they occur, be controlled.

Another tool now being widely used by the government to make permit decisions is atmospheric computer modeling. The emission requirements from coal burning/processing facilities are being specified by the air quality requirements rather than by the emission standards for the facility. In the case of North Dakota, the air quality space (Class II) for a good portion of the state is already used. Natural's plant (Dunn County) may not be permitted because of projected violation of the air quality in Theodore Roosevelt National Park (Class I) based upon the computer model results. This approach may represent a serious hindrance to both the development of appropriate control technology and development of the industry itself. Foreign policy also has a pronounced impact and may force coal development ahead of control technology development, although this seems unlikely at this time.

The economics of controlling the effluents from a gasification facility are summarized in Table 8-1. On the average, the fixed capital investment is 50 million dollars (1973) which accounts for about 16 percent of the total fixed capital investment. Direct operating costs average 13 percent of the plant's operating costs. Consequently, the consumer must, on the average, pay a 10 to 15 percent incremental cost increase for environmental control of these facilities. A serious and important question deals with how much of an incremental change in price the consumer is willing to pay for control of a given effluent.

TABLE 8-1

SUMMARY OF FIXED CAPITAL INVESTMENT (FCI) AND
DIRECT OPERATING COSTS (DOC) FOR
EACH GASIFICATION FACILITY (1973 DOLLARS)

	<u>El Paso</u>	<u>Natural</u>	<u>WESCO</u>	<u>ANG</u>
FCI (MM \$)	19.463	108.408	57.942	30.215
FCI (% of total)	5.449	32.426	17.338	8.881
DOC (MM \$)	8.257	9763.	7.770	5.832
DOC (% of total)	13.258	15.912	12.951	11.823

This question is presently answered in the hearings that set standards and determine what "best available control technology" is. Because of this, it is likely that standards will follow control technology development rather than lead it. Consequently, the predominant social, political, and economic considerations are those that control construction permitting process and the techniques that are used to predict air quality conditions for permitting purposes.

8.2.2. Operational Considerations

A 250 MMSCFD coal gasification facility is a huge, complex, facility. The care with which it is operated will determine its environmental acceptability. The control technologies being used to control gaseous emissions are well established, but are relatively unproven in the gasification environment. A delicate operational balance between process and sulfur environmental control requirements may exist. This problem is partially handled by mine blending techniques.

Mine blending refers to the practice of blending different qualities of coal to smooth out coal feedstock composition variations. This is widely practiced in steam plants for several reasons, one of which is to keep the percent of sodium in the coal low enough to control boiler tube fouling. The same practice can be utilized in a gasification plant to reduce sulfur variations in the feed to sulfur recovery plants.

There is a twofold advantage to blending. Feedstock sulfur variations can be reduced from ± 50 percent to perhaps as low as ± 10 percent (see Figure 8-1). This reduces the control problems of a Claus unit. The second advantage is a smoothing of constituent variations in the raw gasifier gas and minimizing control problems of other process units.

Coal feedstock to a gasification plant can vary in sulfur content by as much as ± 50 percent. This depends on variations in the composition of the coal, with respect to sulfur, at various locations within the coal bed and is often accentuated by mining methods, such as multiple bed mining, and the actual location of the mining equipment within the coal resource area. Good conservation of natural resources calls for removing essentially all of the coal within the resources. The practice of sending the mined coal to relatively large live stockpiles and then properly reclaiming it from the stockpile for plant use will tend to flatten the peaks and valleys of composition variation. Figure 8-1 is a general graphical estimation of what may be expected. This figure is based on Lurgi crude gas containing 0.5 mole percent of sulfur as H_2S resulting from assumed mining schedules and storage reclamation procedures. Refinery Claus sulfur recovery plants commonly encounter variations in H_2S feed for short periods. Control instrumentation presently handles this type of variation.

British Gas has completed some studies on Stretford plants at the laboratory scale with favorable results under these operating schemes. Consequently, the mining plan and coal blending scheme used has an impact on the selection, design, and operation of sulfur recovery equipment. This fact should be considered in the promulgation of regulations, particularly at the state level. That is, a state's regulations could reflect the variability of the sulfur content of its coal.

8.2.3 Technical Considerations

Areas of technical concern that are germane to environmental control technology are:

1. Odor control.
2. Control of biologically hazardous materials.
3. Control of volatile trace element and trace compound effluents.
4. Development of the multimedia environmental goals (MEG's).
5. Solid waste and sludge disposal.
6. Water treatment and reuse.

At the present time the federal government is actively involved in all of the above areas. None, with the possible exception of the first, is likely to impact plant operation.

Biologically hazardous materials can usually be controlled by combustion or containment. It is likely that the trace element compounds that are volatile could be removed by tail gas scrubbing units, although these units are not ordinarily used for this purpose. Development of the MEG's is an extremely important step and is likely to point out control technology needs clearly once a plant has been built and a good characterization of its effluent streams is available. Solid waste and sludge dis-

posol techniques are currently being investigated. Hydrological isolation techniques either exist or can probably be developed should an impact be found due to leaching or sludge liquid drainage. Water treatment techniques for internal water reuse will probably work but will need the development work that is currently being carried out within the office of Environmental Division of Environmental Control Technology and the Office of Energy Technology.

Of all of the above areas, odor control is perhaps the most innocuous. The effluent quantities and concentrations involved are extremely small and in some cases difficult to measure. It is clear that there will be an odor associated with the plants. What it will be and how it is to be controlled are unknown.

8.3 RECOMMENDATIONS

The following recommendations represent the opinions of the authors. They do not infer that the existing control technology being proposed for the four plants is inadequate. In fact, it is the authors' opinions that the existing control technology is adequate and that it can and probably will meet existing regulations and guidelines. The recommendations given below are based upon current research and the state of knowledge dealing with effluents.

- *It is recommended that a program be implemented to mesh the MEG's with the characterization program from the DOE gasification program. The goal of this program should be to prioritize effluents as candidates for control based impact upon MEG data and quantity considerations.

- *A serious investigation into the verification and use of air quality modeling programs is needed if they are to become the limiting element in the permitting process.

- *Basic research in the biological sciences is needed to ensure that appropriate gasification related EPC's and MATE's are generated. DOE and EPA should cooperate in this area and utilize DOE's gasification program as a source of effluents.

- *A program should be initiated to establish and characterize the probable odors from a gasification facility.

- *The best available control technology for pyridine, HCN, and phenols needs to be identified and examined with respect to potential gasification needs.

- *The use treated wastewater as cooling tower make-up should be substantiated with field tests. The problem of cooling tower "drift" requires special assessment and will impact air quality.

- *CaSO₃ based sludges associated with limestone scrubbing operations for the boiler plant (which may be hazardous under RCRA) tend to be "muds" which fluidize when wet. Precautionary blending and perhaps fixation procedures will be required when these materials are disposed with mine tailings. Field to verification of these procedures should be completed.

*The use of evaporation ponds poses a series of potential problems: (1) odor and release of trace volatiles contained by the wastes, (2) effectiveness and use during severe cold spells, and (3) ultimate disposal of bottom sludges during normal plant operation and at the decommissioning of the plant. These potential difficulties need to be addressed through field experimentation and verification.

*The Stretford and Claus units will be operating at conditions somewhat beyond their standard ranges (high for Stretford and low for Claus). They deserve special characterization and study.

*Disposal of wastewater treatment sludges and other process wastes in mine restoration operations requires close scrutiny. Attention should be given to the effect of leachable constituents associated with the disposal of blowdown sludges.

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