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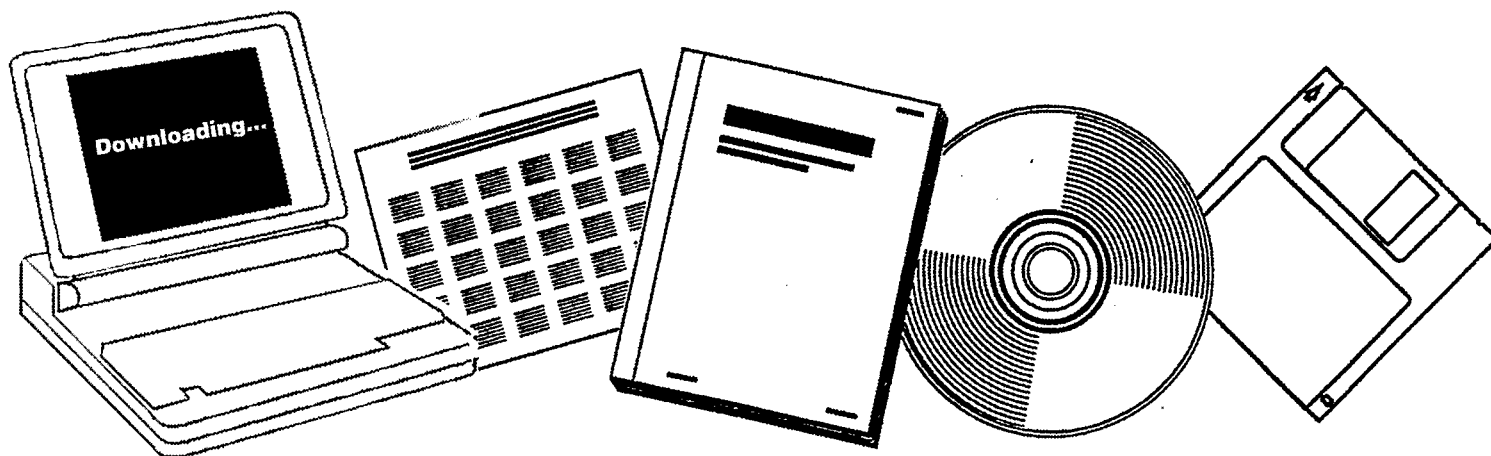
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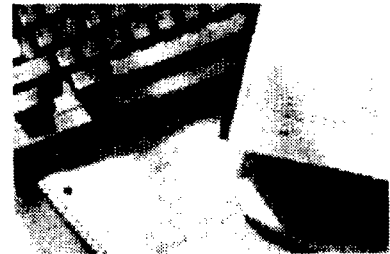EXXON RESEARCH AND ENGINEERING CO.,
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EPA-650/2-74-009-1

EVALUATION OF POLLUTION CONTROL IN FOSSIL FUEL CONVERSION PROCESSES

ANALYTICAL TEST PLAN

by

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TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-650/2-74-009-1	2.	3. RECIPIENT'S ACCESSION NO. PB-249 845
4. TITLE AND SUBTITLE Evaluation of Pollution Control in Fossil Fuel Conversion Processes (Analytical Test Plan)		5. REPORT DATE October 1975
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) C. D. Kalfadelis, E. M. Magee, G. E. Milliman, and T. D. Searl		8. PERFORMING ORGANIZATION REPORT N Exxon/GRU.13DJ.75
9. PERFORMING ORGANIZATION NAME AND ADDRESS Exxon Research and Engineering Company P. O. Box 8 Linden, New Jersey 07036		10. PROGRAM ELEMENT NO. 1AB013; ROAP 21ADD-023
		11. CONTRACT/GRANT NO. 68-02-0629
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERE Task Final
		14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

16. ABSTRACT   The report gives results of a preliminary definition of those streams which require analysis to permit an assessment of the pollution potential of the processes i the light of current environmental standards, using a coal gasification process (Lurgi) and a coal liquefaction process (COED) as a basis. It defines methods for sampling indicated streams and analytical procedures which are required to obtain the data. These summaries may be readily modified or adapted to other processes, and expanded to include additional polluting constituents or improvements in analytical procedures.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution Coal Gasification Coal Liquefaction Conversion Testing Sampling Analyzing	Air Pollution Control Stationary Sources Pollution Potential Lurgi Process COED Process	13B 13H 21D 07D 14B

PRICES SUBJECT TO CHANGE

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES
	20. SECURITY CLASS *(This page)* Unclassified	

EPA Form 2220-1 (9-73)

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SUMMARY

A coal gasification process (Lurgi) and a coal liquefaction process (COED) have been used as the basis for preliminary definition of those streams which require analysis to permit an assessment of the pollution potential of the processes in the light of current environmental standards. Methods for sampling indicated streams and analytical procedures which are required to obtain the data have been defined. These summaries may be readily modified or adapted to other processes, and expanded to include additional polluting constituents or improvements in analytical procedures.

TABLE OF CONVERSION UNITS

To Convert From	To	Multiply By
Btu	Calories, kg	0.25198
Btu/pound	Calories, kilogram	0.5552
Cubic feet/day	Cubic meters/day	0.028317
Feet	Meters	0.30480
Gallons/minute	Cubic meters/minute	0.0037854
Inches	Centimeters	2.5400
Pounds	Kilograms	0.45359
Pounds/Btu	Kilograms/calorie, kg	1.8001
Pounds/hour	Kilograms/hour	0.45359
Pounds/square inch	Kilograms/square centimeter	0.070307
Tons	Metric tons	0.90719
Tons/day	Metric tons/day	0.90719

INTRODUCTION

The Environmental Protection Agency has anticipated the pollution potential of fossil-fuel conversion processes and has attempted to define the extent of controls which may have to be applied in the conversion of naturally occurring "dirty" fuels. Thus, a particular goal is to insure that contemplated fuel conversion plants do not themselves become sources of environmental pollution.

Accordingly, the Environmental Protection Agency has awarded Contract No. EPA-68-02-0629 to Exxon Research and Engineering Company to evaluate the current status of fossil fuel conversion and/or treatment processes with respect to pollution control and thermal efficiency. Specifically, Exxon Research and Engineering Company is performing a detailed pollution control assessment of representative processes using nonproprietary information. As a result of this study the "technology' needs" to minimize pollution will be delineated in order to allow sufficient time for research, development, and design of adequate pollution control equipment for coal conversion processes.

Few developers of conversion processes have so far seriously addressed pollution control requirements for their process, reflecting the fact that no significant commercial system has yet been constructed in the United States. In general, the thrust of the work which has been reported has been directed to basic process development, including hardware development and yield improvement. And, until recently, much of the developmental effort had been conducted on so small a scale as to make suspect extrapolations of analytical results to commercial systems.

A particular difficulty with fossil fuel systems, and for coal in particular, is the complexity of the composition of streams within the system. Coal has a very complex, vaguely defined organic structure superposed on an equally complex mineral or inorganic base. Thermal processing of such materials gives rise to myriad reaction products whose form and stability are a function of the temperature of processing and of the atmosphere in which the processing is conducted.

The coal itself and many of the primary products of coal conversion plants are unstable in a normal atmosphere. Coal begins to lose occluded gases, and its surface begins to oxidize as it is broken out of the earth. The coal feeds to conversion processes and chars obtained from conversion systems are pyrophoric to some degree. Coal liquids require considerable processing to produce stable end products.

The primary pollutant which most conversion processes intend to control is sulfur. However, most other elements exist in coal, and the opportunity to produce almost every pollutant or pollutant form for which controls have been established is present in most integrated coal conversion systems. It is clear that the list of controlled pollutants will grow, and the probability that new legislation will impact on coal systems is high.

There is, of course, no body of Federal environmental legislation which is specifically directed to coal conversion systems. However, many of the component operations envisioned for such systems are subject to existing regulations, and it is probable that further specific regulations will be enacted as systems come into existence. In fact, it is possible that the "coal conversion industry" may represent the first instance of an industry which is essentially regulated before any substantial industry exists.

The purpose of this study is to establish a baseline for the system of analysis which may be required to assess the pollution potential of a coal conversion facility. It is, of course, geared to present environmental standards and employs established or state-of-the-art sampling and analytical methods. It is obvious that analysis of all relevant streams around an integrated system will constitute a major undertaking in terms of labor and time and will require significant investment in analytical facilities and materials.

1. GENERAL PHILOSOPHY AND APPROACH

1.1 Goals of an Analytical Test Plan

It should be realized at the outset that a coal gasification or liquefaction plant is very complex. Such a plant consists of many units in the main processing stream with numerous auxiliary units necessary for clean, efficient operation. The nature of the central unit for coal conversion differs from process to process. The emerging primary stream is different in each case and this leads to major differences in subsequent processing units.

An example of these differences is very apparent in a comparison of the Lurgi and Koppers-Totzek gasification processes. The Lurgi process (4) operates at intermediate pressures, relatively low temperatures and uses a fairly large sized coal feed. The Koppers-Totzek process (17), on the other hand, operates at low pressure and high temperature and uses a fine sized coal feed. The higher pressure and low temperature of the Lurgi process produces tars, oils and organic compounds containing sulfur and oxygen. The presence of these materials in the Lurgi raw product gas introduces complexities into the clean-up systems that are absent from the Koppers-Totzek process. The presence of low molecular weight paraffins can have an effect on subsequent acid gas removal; the presence of organic oxygen and sulfur compounds introduces restrictions and requirements on dirty process water treatment that have an effect downstream on ultimate water disposal. The large quantity of small particulate matter in the latter process requires special considerations for removal that are absent in the Lurgi process. The need for larger sized feed coal in the Lurgi process causes a special problem of fines disposal from the grinding operation.

The many alternatives existing for subsequent gas treatment and auxiliary units leads to further overall complexity. For example, numerous processes exist for acid gas removal (necessary in all gasification and liquefaction schemes). (For more details see, for example, reference 52:) There are processes utilizing absorption and reaction of the acid gases with a suitable basic solution (e.g., hot carbonate; amines) followed by regeneration. Other processes use low temperature absorption with a suitable solvent (e.g., methanol, propylene carbonate, etc.) followed by desorption. A third technique involves absorption of hydrogen sulfide into an oxidizing solution where the hydrogen sulfide is converted to sulfur. Still a further variation involves removal of the sulfur in situ with an appropriate solid basic material such as limestone or dolomite (25). All of these alternatives lead to further options or requirements on subsequent treatment of the acid gases to remove sulfur.

In the case of auxiliary units many different alternatives exist depending on the initial gasification or liquefaction technique. An example is the fuel to be used in steam production. Coal can be used as fuel with appropriate stack gas scrubbing. Some processes produce chars that are available for fuel; some processes produce liquid products that can be burned.

Another alternative is the use of clean product gas or liquid; sulfur removal from stack gases is thus avoided. Another example of an auxiliary unit with many alternatives is the treatment of waste water. Alternatives such as biox ponds, adsorption with solids, etc. again add complexity to the subject of environmental control.

The myriad of alternatives available for coal conversion plants makes it essentially impossible and certainly non-productive to attempt to anticipate all permutations and combinations of process units in an analytical test plan. Such a test package would be so large that it would confuse rather than aid in the gathering of meaningful analytical data.

The approach taken in devising the analytical test plan presented here was to choose "representative" processes that exemplify the three basic requirements for obtaining a satisfactory description of the flow of materials. These requirements are choice of process streams, choice of stream components to be determined and method of analysis.

Two major levels of information are available from the choice of streams: those streams may be chosen that give an overall material balance for the plant or the streams can be chosen to give, besides an overall balance, a balance around each major unit of the plant. For environmental purposes it is only necessary to know what goes into the plant and what comes out of the plant. This should offer the lowest cost assessment of the plants effect on the environment. Realistically however, a number of factors make such a simple determination very difficult. An example of the difficulties is a determination of cooling tower effluents (in vaporization and drift). Since the wind velocity and direction affect the spot concentration of effluents, sampling and data treatment are very inaccurate. Because cooling tower effluent is very large, errors in the determination of the composition of the effluent can seriously affect the overall plant material balance.

In this analytical test plan, the problem of overall vs. unit material balances has been addressed in a way that will minimize costs for a given objective. First, those streams have been identified that would give an overall plant material balance. Should the balance be closed on appropriate analysis of these streams then that is sufficient. In all probability this will not be the case. Therefore, those units around which a material balance should then be made have been listed individually with an indication of streams to be analyzed. This will allow a determination of the source of errors in the overall balance and appropriate corrections can be made. It should be pointed out that the judiciousness of the choice of units where errors will appear can have a major effect on the costs associated with this endeavor. Experience is invaluable in making a decision as to what units should be examined in detail.

As indicated earlier, it is next to impossible to document all streams for every combination of plant units. It is believed, however, that the examples included in this test plan are sufficiently general that an experienced person can make the necessary revisions to fit the plant under evaluation. This analytical test plan is therefore designed for use by such skilled personnel. Only minor modifications, together with a few added or deleted streams, will be necessary for a specific plant.

The choice of stream components for which analyses are necessary is very subjective. Again, costs may be the limiting factor in making this choice. The list of components in this test plan for which analyses are to be made represents what is felt to be a reasonable choice that should be determined and that can be determined without an inordinate expenditure of funds. However, there is almost no limit to additions that can be made to the list. (A few deletions may also be made in some cases.)

The choice of sampling and analytical techniques to be used in determining the concentration of selected components in the streams is somewhat arbitrary. The techniques outlined in this test plan were selected on the basis of the five considerations detailed in Section 7.1 and the experience and knowledge of the factors involved in such determinations. In all such work however, the techniques may have to be changed to fit a specific situation. These changes may be necessary due to interference from other components in the stream, unusual concentration ranges, or others and can only be recommended for very specific cases by experienced personnel.

The goal of this analytical test plan is to supply sufficient information for example process and analytical techniques to allow experienced personnel to rapidly and easily modify the plan to fit the process of interest. Streams comparable to those in the present test plan can be identified, and additions and deletions can be made where appropriate. The decision should be made as to what components are necessary for the desired material balance and what other components are of interest, and appropriate sampling and analyses can then be performed. A trial plant material balance should be made. If this balance cannot be made, then individual units will have to be investigated to determine the source of errors. Once the source and magnitude of errors have been identified, a complete balance should be possible. Future balances are then much simplier since errors are known before hand.

In some cases, for environmental control purposes or for other reasons, it may be necessary to extend the analyses to include all input and output streams from one particular unit. This could be the case, for example, when comparisons need to be made between two types of control technology. Then, all streams around that unit would be sampled and analyzed according to the test plan. No attempt is made in this plan to point out such units as they will vary from case to case.

It is anticipated that an analytical test plan, modeled along the lines outlined in this report, will furnish accountability for all pollutants of interest that may enter the plant in the coal, water, chemicals, etc., or that may be formed during processing.

1.2 Specific Approach

Two processes, one for coal gasification and one for coal liquefaction, have been chosen as representative of their respective classes for the purpose of establishing a baseline analytical system. These processes are the Lurgi process as representative of gasification and the COED process of FMC for liquefaction.

In the case of gasification, the Lurgi process was chosen because environmental impact statements have been prepared by domestic concerns who propose to construct integrated commercial facilities (1,2,3), because the process was reviewed in an earlier phase of this program (4), because a number of commercial facilities are in operation in other countries (5), and because almost all units of gasification processes are present. This information provided an opportunity to assess the environmental impact and the effectiveness of controls in widely differing situations.

There is unfortunately no such clear-cut candidate for a coal liquefaction system. The COED (pyrolysis) process was chosen because of the large body of information which is available in the public literature (6-15), because this process was also reviewed in an earlier phase of this program (16), and because an integrated COED facility would probably include most component operations required by other proposed coal lique-faction schemes.

Each component operation of each process is described, including the approximate composition of incoming and outgoing streams, where these are known. The process descriptions are not intended to be taken as definitive, and much more detailed information is available in the references cited. Streams which may be analyzed, especially those streams which may impact on the environment, are indicated. Sampling procedures, sample treatment, and analytical methods are described using established or state-of-the-art technology.

The Lurgi process streams impacting on the environment are out-lined in detail, with quantities of material where available. Information is included on actual analysis of some of these streams together with analyses of comparable streams from other processes where available. Included for information and comparison are existing or proposed state and Federal regulations concerning quantities of pollutants allowed. A discussion of problem areas is given with an indication of other streams for which analytical data may be necessary for an accurate asses-sment of environmental impact. A sample data sheet is included that will serve as a guide in data acquisition.

The COED process streams are similarly treated as an example of liquefaction. The amount of information available is much less for the COED process than for the Lurgi process since no commercial plant is yet in operation. Information in the Lurgi section can, by analogy, be applied to the COED process.

1.3 Operating Conditions and Flow Rates

Information on typical operating conditions and flow rates are given for each unit of interest. If more detailed information is required, references have been given to process reports giving this information in detail. Differences in operating conditions and flow rates will not affect the testing procedures in most cases. If quantities of potential pollutants are less than can be determined by the procedures outlined in this test plan, then they may be insignificant. If it is eventually decided that extremely low concentrations must be determined then that particular concentration range must become a research program itself.

1.4 Determination of Effect on Environmental Factors of Altered Operating Conditions

In some cases it may be of interest to determine what effect, if any, altered operating conditions may have on environmental factors. For example, hydrogen cyanide and ammonia formation will be affected by reactor temperature and pressure. In most cases, limits exist as to the change in operating conditions that can be effected. These limits are set by such factors as reaction rate, materials of construction, etc., and, for a given design, are narrow.

To obtain a good picture of the effect of operating variables on pollutant production, it is necessary that the conditions be changed sufficiently so that the change in pollutant concentration is significantly measurable and that three levels of concentration be measured. It is thus suggested that operating conditions be changed by at least $\pm$ 10% and that the pollutant concentrations be determined at these levels. Thus, if the reactor normally operates at 1000°F, then data should also be collected at 900°F and 1100°F. In pilot unit operation, such changes will normally be a part of the program in process development. In commercial plant operation, efficiency could well be affected by changes from the design optimum.

It frequently will be necessary to change two or more variables simultaneously when a change is desired. Thus, lowering the temperature must usually be accompanied by a decrease in feed rate since reactions are slower. Each such change must be examined individually and in detail to assure process operation.

Variables that may be changed to determine the effect on pollutants may be summarized. In the reactor, the temperature, pressure, oxygen-steam-coal ratios and feed rate may be altered. A change in the ratio of raw gas to quench liquid may cause a change in pollutant output. In the shift section, changes in operating temperature, pressure, and residence time may be significant. Also, when part of the gas by-passes the shift reactors, it would be of interest to determine the effect of changing the ratio of by-pass gas to reacted gas. (The total CO/H_2 ratio must, of course, remain approximately the same.)

In the gas purification section, altering the temperature, pressure and gas to absorbent ratio could be informative. It is doubtful if useful environmental data could be obtained by varying conditions in the methanation section.

It will be of definite interest to change the coal feed to the process. At present, the prediction of sulfur forms in the raw gas seems not to be feasible and the same may hold true for trace elements. Therefore, predictions of the fate of these materials can only be determined empirically. With sufficient data, a correlation might be possible.

2. COAL GASIFICATION

2.1 System Basis

The Lurgi process has been chosen as representative of the class of systems which may be used to produce primarily clean gaseous fuels from coal. There is of course a very wide range of processing conditions which may be applied to coal to generate gas. These range from virtually standard atmosphere and temperature, as in diminution of total pressure on some coals to recover occluded methane, to virtually complete gasification of all organic matter at high temperature, as in the 3300°F steam-oxygen atmosphere of a Koppers-Totzek gasifier (17). The number of proposed processing schemes is large (18,19,20), and the range of products which may issue from the various systems, in addition to noncondensable gases, is extremely broad. It is in fact this broad product spectrum, common to all processing schemes excepting those which operate at very high temperatures, which gives rise to much of the indicated control which must be included in the processing sequence. If an objective is to conserve or produce the high energy-density constituents which may be derived from coal, such as coal liquids or methane equivalent, then processing conditions must be less vigorous than those which decompose or destroy these materials; and, in general, the processing sequence is rendered more complex, the pollution potential is higher, and the conversion efficiency is reduced.

There are a number of variants of the Lurgi process depending on feed and on end-use requirements, and the processing elements, including the gasifiers (21), are undergoing almost constant development. We have chosen the processing scheme proposed for the El Paso Burnham complex (1,2,22) as the particular example of an integrated Lurgi system which may be designed to meet domestic energy/environmental standards. The system proposed by Wesco (23) is practically identical, utilizing essentially the same feed coal and producing the same end products. For purposes of illustration only, we have indicated throughout Section 3 the magnitude of the streams as indicated in El Paso's proposal.

2.2 Process Basis

Figure 1 is a schematic representation of the overall processing scheme. The Burnham complex is designed to produce 288 MM scfd of synthetic pipeline gas (954 Btu/scf) from Navajo coal using Lurgi coal gasification. purification, and enrichment technology. Specifically, Lurgi supplied the process design basis for the operations of coal gasification, shift conversion, gas cooling, gas purification, gas liquor treatment, and methanation. In addition, commercial air-separation processing will be included to produce 98 percent purity oxygen for the Lurgi gasifiers, and the Stretford process (British Gas Council) will be used to remove H_2S from acid gases separated from product gas in the gas purification section.

FIGURE 1

LURGI GASIFICATION

AFTER EL PASO BURNHAM COMPLEX

REFER TO TEXT FOR STREAM DETAILS

COAL ①

WEATHER ②   FUMES & DUST ④   AIR ⑦   N₂ ⑧

COAL PREP'N.   ③   OXYGEN PLANT

⑥ COAL FINES PRODUCT   RUNOFF   ⑨ O₂   ⑩ CONDENSATE

SIZED COAL   ⑤

LURGI GASIFICATION   ⑮ ⑭   SHIFT CONVERSION   ㉑   GAS COOLING   ㉓   PURIFI-CATION   ㉘   METHANE SYNTHESIS   ㉛   COMPRESSION & DEHYDRATION   ㉝ SYNTHETIC GAS PRODUCT

⑬   ⑲ BFW   ⑳ FUEL GAS

⑰ COAL TAR PRODUCT   ⑪   STEAM   ⑯   ⑱

STACK GAS ㉒   TAR NAPHTHA PRODUCT ㉔   BFW ㉖   NAPHTHA PRODUCT ㉚

⑫   ㉕   GAS LIQUOR ㉙   ㉗   ㉜

GAS LIQUOR TO PHENOSOLVAN

ASH TO ASH DISPOSAL

ACID GASES

STEAM   VENT �

㊹   ㊼   MAKE-UP ⑦①   STEAM ⑦②   VENT ㉛ STACK GASES ㉒   TO PONDS ㊳   ⑯ ㉕ ㉟

⑤   FUEL GAS PRODUCTION   ㊺   FUEL GAS TREATING   PURGE ㊽   STEAM & POWER   ㊿   ASH DISPOSAL   ㊻   GAS LIQUOR TREATMENT   ㊶ CRUDE PHENOL PRODUCT   ㊸ AMMONIA SOLN. PRODUCT

AIR ㊺   ④⓪   BFW ㊾   BLOWDOWN   ⑥⑨ ⑥⑧ ㊾ ㊽   ASH TO MINE ⑥⑦   BLOWDOWN   ㊷   CHEMICALS ㊾ EVAPORATION & DRIFT ⑥⑤

㊱   OFF-GAS ㊲   ELECTRICITY TO PLANT   CHEMICALS ㊴ ㉜   ⑥⓪

CDK 2/75   ㉟   SULFUR RECOVERY   ㉗ ACID GASES   ㊳ ABSORBER OFF-GAS TO INCINERATION   ㊳⑧   RAW WATER TREATMENT   ⑥① FROM O₂ PLANT   ⑥② FROM PLANT   COOLING WATER SYSTEM   ⑥③ TO PLANT   ⑥④ TO O₂ PLANT

㊴⑨ LIQUID SULFUR PRODUCT   ㉝ RAW WATER   VENT ㊻⑥   WATER TO PLANT ㊵⑤

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Analysis of the feed coal for the complex is shown in table 1 including two estimates of trace element composition.

In addition to product SNG, the complex will produce the following byproducts:

Product	Quantity
Coal Tar	239,250 GPD
Tar Oil	157,370 GPD
Naphtha	74,900 GPD
Crude Phenol	32,470 GPD
Sulfur	167 TPD
Ammonia Solution	332,550 GPD

The system is designed to be self-sufficient with respect to utilities:

Water

Raw water will be supplied from the San Juan River at a location approximately 40 miles from the plant site. Pipeline and pumping facilities will be provided to transfer the water to the complex where it will be stored and used as required.

Electricity

On-site power generation will be used to supply all power requirements for the complex. Power for the mining operations and the river water pumping systems will be purchased. Power required for crushing and screening of the coal will be exported to the mine.

Steam

Steam will be used in the complex both as a motive force and as a reactant in the gasification processes. All steam generation will be done onsite with a combination of heat recovery and gas-fired boilers.

Fuel Gas Production

Low Btu -content fuel gas will be produced in the complex for use in gas turbines, process heaters, steam superheaters, and power boilers. Airblown Lurgi gasifiers will be utilized in the fuel gas production.

<u>Table 1</u>

<u>NAVAJO SUB-BITUMINOUS COAL (1)</u>

<u>Feed to Burnham Complex</u>

<u>Proximate Analysis</u>	<u>Weight %</u>
DAF coal	66.2
Ash	17.3
Moisture	16.5

<u>Component Analysis (DAF Coal)</u>

C	76.72
H	5.71
N	1.37
S	0.95
O	15.21
Trace compounds	0.04

HHV range 7500 To 10,250 Btu/lb

	Trace Elements ppm by weight (1)		IGS data*
	<u>Minimum</u>	<u>Maximum</u>	
Sb	0.30	1.20	0.3
As	0.10	3.00	1.3
Bi	0.00	0.20	---
B	60.00	150.00	17.
Br	0.40	18.00	0.4
Cd	0.20	0.40	< 0.2
F	200.00	780.00	39.
Ga	0.50	8.00	1.6
Ge	0.06	0.50	2.
Pb	1.40	4.00	4.
Hg	0.20	0.35	0.06
Ni	3.00	30.00	5.
Se	0.08	0.21	1.2
Zn	1.10	27.00	15.
Be	---	---	0.2
Co	---	---	7.
Cr	---	---	5.
Cu	---	---	22.
Mn	---	---	6.
Mo	---	---	2.
P	---	---	125.
Sn	---	---	< 2.
V	---	---	17.
TOTAL	267.3	1023	

* Data furnished by EPA from Illinois State Geological
  Survey Analyses of Navajo County Red Seam Coal.

Miscellaneous

Other utilities, such as sewage facilities, fire protection
facilities, instrument air, etc., will all be provided in the
utility systems to ensure self-sufficiency for the complex.
The mine office will be provided potable water, fuel gas,
electricity, and sewage facilities from the complex.

3. GASIFICATION PROCESS DESCRIPTION

3.1 Qualifications

Although El Paso's design for the Burnham Coal Gasification Complex (1) has been chosen as the basis for the coal gasification analytical system, most gasification processes (20) will require many of the same major and auxiliary operations provided in the integrated Lurgi plant. Relatively minor modification will be required to adapt this environmental test system to many of the most well-known candidates for coal gasification, assuming that a realistic integrated design is available. Hence, an integrated Synthane design (24) differs primarily in the pressure regime and mode of operation of the gasifiers, required coal communition, and in the particular methanation procedure that is proposed. Other processes may be less complex, especially if methanation facilities are not included or if only low-Btu gas is produced, cf Koppers-Totzek Process (17). And some processes may prove more complex, requiring additions to the analytical scheme, cf. CO_2 Acceptor Process (25) which requires additional facilities for preparing and moving limestone or dolomite through the process. The modifications to the analytical scheme which may be required for a particular process or design will be readily apparent in most instances.

Each processing step or operation in the Lurgi/El Paso design is briefly described below. Significant input and output streams around each operation are described, and the particular streams requiring analysis are designated. The suggested analytical procedures for each stream are referenced to the Analytical Section via table 18.

Note that the plant operator will require other additional analyses to facilitate his operations and insure product specifications. Our concern is only with potential pollutants which may impact on the environment.

Each operator of a coal conversion facility may ultimately be required to account for the disposition of elements present in feed coals whose toxicity or ultimate impact on the environment warrants control. Particular sanctions relating to such potentially toxic discharges, including those relating to atmospheric discharges, discharges to waterways, disposition of solid wastes, and limiting concentrations in work areas, are still in process of formulation (26,27,28,29). However, it is almost certain that the list of controlled substances will grow and that permissible levels in effluents will continue to be limited.

We have accordingly indicated that all generated effluent streams, including products, be analyzed for particular trace element composition, along with feed coal, to permit a gross indication of the disposition of such elements. Streams to be analyzed are shown in the following figures and tables with an asterisk (*). We caution that overall balances for particular elements may be extremely difficult and costly to obtain around an operating system of the type and size under consideration. The complexity of the chemical system, the difficulties associated with representative sampling of very large streams, and the imprecision of available sensors or test methods for the monitoring of trace elements all militate against achievement of

perfect balances. Moreover, the capacity of a large physical system
to trap out various elements or compounds, as by chemical combination
with materials of construction or through physical condensation or
deposition introduces another order of complexity, especially if process
changes can result in sudden large emissions.

The "time constant" of the contemplated systems may be very
large indeed, and the time rate of change associated with processing
conditions for a particular unit will have to be taken into consideration
by the analyst if his objective is to obtain a consistent overview of the
process. The "steady-state" condition implied in this analytical scheme
is very difficult to obtain in practice, especially if batch-type or step-
function operations, such as the step-wise addition of coal to the gasifiers,
are superposed on an otherwise continuously operating flow train. And
it may ultimately be necessary to examine the materials of construction
and to physically examine the interiors of vessels or piping for deposited
matter to close the balances in some cases.

All facilities of the type under consideration will include a
flare system to handle emergency discharges from pressurized vessels
and piping. To insure compliance with hydrocarbon emission rates in the
future, it may be necessary to size the flare system to handle the entire
plant output. The analytical scheme assumes zero discharge at the flare.

Similarly, all such systems will include tankage for storage of
liquid byproducts. Presumably standards of performance now imposed on
storage vessels for gasoline, crude oil, or petroleum distillates (30)
to limit hydrocarbon emissions will apply.

Finally, the operator of a physical plant will be aware that
there may be hundreds of valves, packing glands, seals, and other closures
through which harmful pollutants may be accidentally discharged. There
is no practical remedy for such eventualities except vigilance.

3.2 Coal Preparation (Figure 2 and Table 2)

Coal preparation for the gasification plant will consist of stockpiling, secondary screening, reclaiming, and sampling facilities. The mine will have facilities, for receiving coal from trucks, crushing, and primary screening. The facilities at the mine will be interconnected to those at the gasification plant by a continuous belt conveyor.

Coal, sized at the mine to 1-3/4" x 0", will be received by a conveyor belt connecting the mine and the gasification plant and will be distributed by stacker/reclaimer conveyors for blending and storage.

The coal sampling and stockpiling facilities, which operate less than 24 hours per day, are sized for 3600 tons per hour (tph), while the reclaiming and screening facilities are sized for 1500 tph. The gasification plant will require 1180 tph when operating at full load, and the fuel gas production area will require 208 tph additional.

Six storage areas, each 1750 feet long by 124 feet wide and containing 120,000 tons of coal, will provide blending for Btu control of gasifier feed and approximately 12 days live storage at full capacity operation.

The original design (1) included facilities for briquetting coal fines (<3/16") separated in the screening operations. The briquetting plant included facilities for mixing coal fines with gasifier tar binder and compacting the mix into briquettes which could be charged to the gasifiers along with sized coal. This system has been deleted in the revised design (2), and it is implied that coal fines will issue as a saleable additional product. Fines are generated at the rate of 176 tph.

Prior to sale, the fines are (2) indicated to be directed to a cleaning plant which will separate some 70 tph of refuse. Refuse will be sent to the coal mines for reburial along with gasifier ash. Facilities for collection and/or storage of the product fines has not been specified.

The original design also included emergency stockpile and reclaiming facilities for 650,000 tons of additional sized coal; this emergency storage has been deleted in the revised design.

Wet-scrubber dust collectors will be installed in the secondary screening plant to eliminate dust and fume emissions. Sprays will be used at transfer points for dust suppression.

Influence
Of Weather On
Stockpiles

*Dust and Fumes

(2)

(4)

COAL
PREPARATION
AND
STORAGE

(5) *Sized Coal
to Gasifiers

Coal   (1)
1-3/4" x 0"

Product
Coal Fines
(6) (<3/16")

<

(3) Runoff
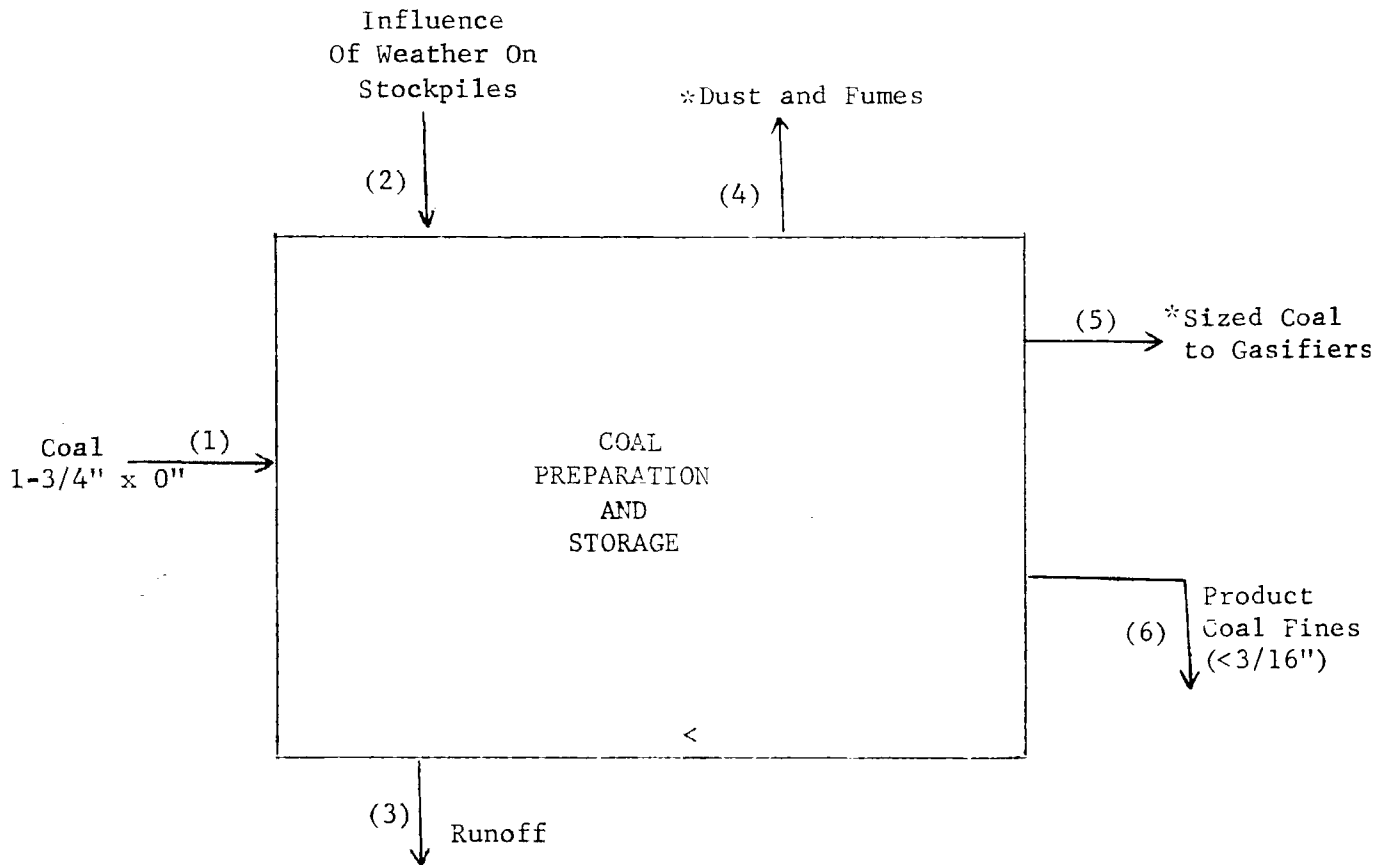
Figure 2

Coal Preparation for Lurgi Plant

Table 2

Coal Preparation for Lurgi Plant

Inlet Streams

(1)   Coal, Navajo Sub bituminous; 3600 tph (not used 24 hours per day).

(2)   Influence of Weather on Coal Stockpiles and Open Coal Operations.

Outlet Streams

(3)   Precipitation Run off to Holding Ponds. May include wet scrubber aqueous effluents.

*(4)   Dust and Fumes. Atmosphere in enclosed working areas to be analyzed per Table 18 for particulates.
Discrete stack emissions to atmosphere from enclosed spaces and from dust collection
equipment to be analyzed per Table 18 for particulates. Atmosphere in vicinity of
coal stockpiles, open conveying and handling equipment, and coal fines product
collection system to be analyzed per Table 18 for particulates.

*(5)   Sized Coal to Gasifiers; 1180 tph and to Fuel Gas Production, 208 tph. To be analyzed as feed coal per Table 18.

**(6)   Product Coal Fines, 176 tph. 106 net tph cleaned coal fines to sales. 70 tph refuse
directed to mine for burial with gasifier ash.

* Analytical samples, see Table 18.
** Not included in Table 18; however, potential pollution at the mine will
have to be addressed.

3.3 Oxygen Production (Figure 3 and Table 3)

       The oxygen plant is designed to produce 5650 tons per day of 98% minimum purity vapor phase oxygen.

       Atmospheric air will be filtered and compressed to 90 psia in parallel low-Btu gas turbine/steam turbine-driven centrifugal compressors.

       Intercooling between the first and second cases and aftercooling after the second case will be utilized and will remove approximately 130 gpm of water which will be recovered for use elsewhere. The relatively dry air (0.5% moisture content) will be delivered to parallel cold boxes.

       Air entering the cold box will be cooled to liquefaction temperature by a combination of heat exchange and expansion in a conventional air separation cycle. Once in the liquid state, oxygen and nitrogen will be separated by fractionation. The nitrogen (plus a small quantity of moisture, CO_2, and oxygen) will be regasified in the heat exchange process and its energy utilized before rejection to atmosphere. The liquid oxygen will be gasified to feed the steam turbine-driven oxygen compressors. These centrifugal units will raise the pressure level to 500 psig and deliver 5620 tons per day of oxygen to the Lurgi coal gasifiers. The expansion process in the cold boxes will generate a total of about 500 kW each at full capacity.

N$_2$

(8)

(9)

98% O$_2$

Atmospheric
Air

OXYGEN
PRODUCTION

(7)

(10)

Condensate
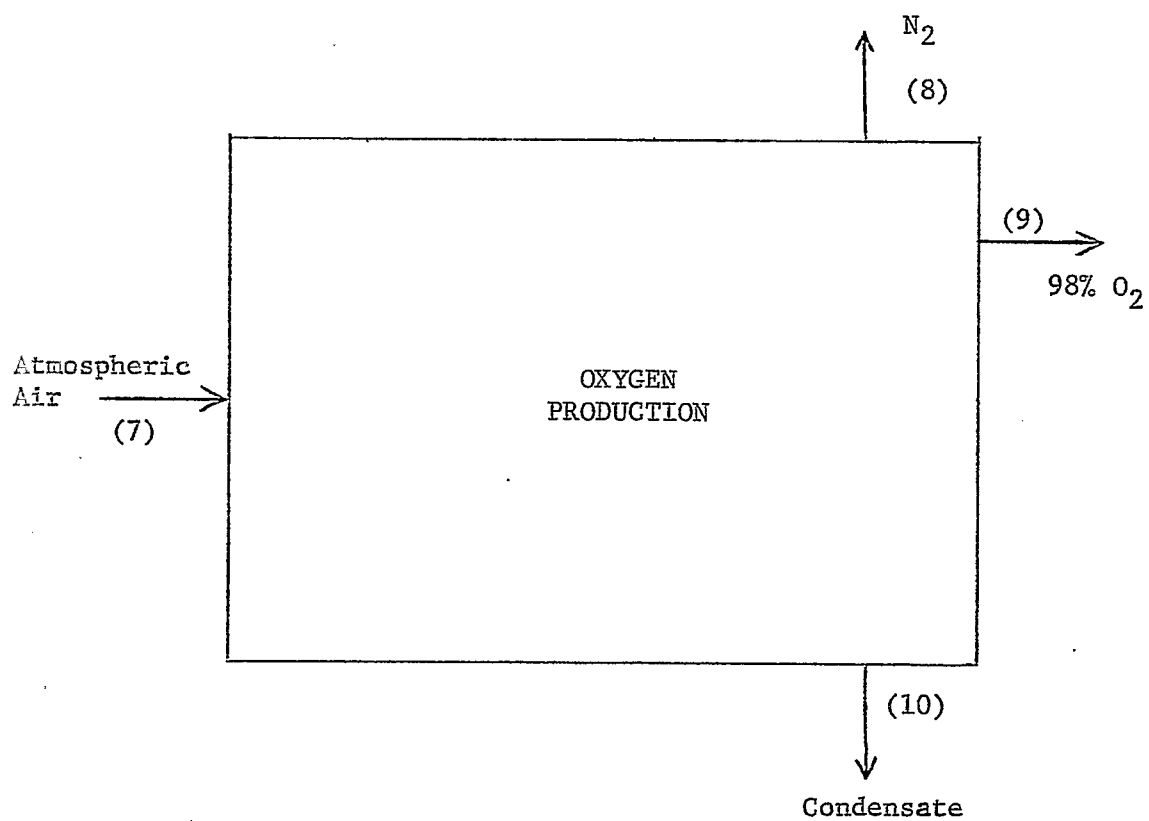
Figure 3

Oxygen Production

Table 3

Oxygen Production

Inlet Streams

(7) Atmospheric air; 500,000 acfm.

Outlet Streams

(8) Nitrogen and other components of air; 794 tph discharged to atmosphere.

(9) 98 percent minimum purity vapor-phase oxygen to gasifiers; 235 tph.

(10) Water condensate from entering air; 125 gpm, to BFW treating.

3.4 Coal Gasification and Gas Liquor Separation
(Figure 4 and Table 4)

Navajo coal will be gasified with oxygen and superheated steam at high pressure. This process will produce a raw gas of the following composition:

Component	Volume %
CO_2	28.03
H_2S	0.37
C_2H_4	0.40
CO	20.20
H_2	38.95
CH_4	11.13
C_2H_6	0.61
N_2+AR	0.31
	100.00

Coal will be conveyed from the coal preparation area to coal bunkers located above the coal gasifiers. The coal will be fed to the gasifiers through coal locks,which will be pressurized by a slip stream from the gas cooling area. (Disposition of this gas is discussed later.)

The Lurgi gasifiers are water-jacketed vessels. Oxygen and process steam will be mixed and introduced into the bottom of the gasifiers. The gasifiers will be operated at about 445 psig. Raw gas leaving the gasifiers will be cooled rapidly by quenching with a gas liquor spray in wash coolers. Ash will be removed from the bottom of the gasifier through ash locks and conveyed via water to the ash disposal area.

Raw gas leaving the wash coolers will be cooled to about 370°F in the waste heat boilers which produce 112 psia steam. Some of the liquid condensed in the waste heat boilers will be recycled to the wash coolers, and the excess will be drawn off to the gas liquor separation unit.

In addition to this excess liquor from gasifiers, the gas liquor separation unit will receive gas liquor from the gas cooling area. The gas liquor at high pressure will be flashed to atmospheric pressure in an expansion vessel to remove dissolved gases. The heavy tar will be settled out in a subsequent settling vessel and sent to product storage. The gas liquor, free of heavy tars, will be sent to the gas liquor treatment area to remove dissolved phenol and ammonia.

Raw gas leaving the gasifier section will be divided into two streams; one will be sent to shift conversion and the other will bypass the shift conversion area and will go directly to gas cooling. Crude gas vented from the cyclic operation of the coal locks, the expansion gas, and small quantities of recycle gas from other areas will be compressed and injected into the main stream in the gas cooling area. The recycled vent gas stream from downstream sections and the lock gas stream from the gas cooling area are not shown in Figure 4.
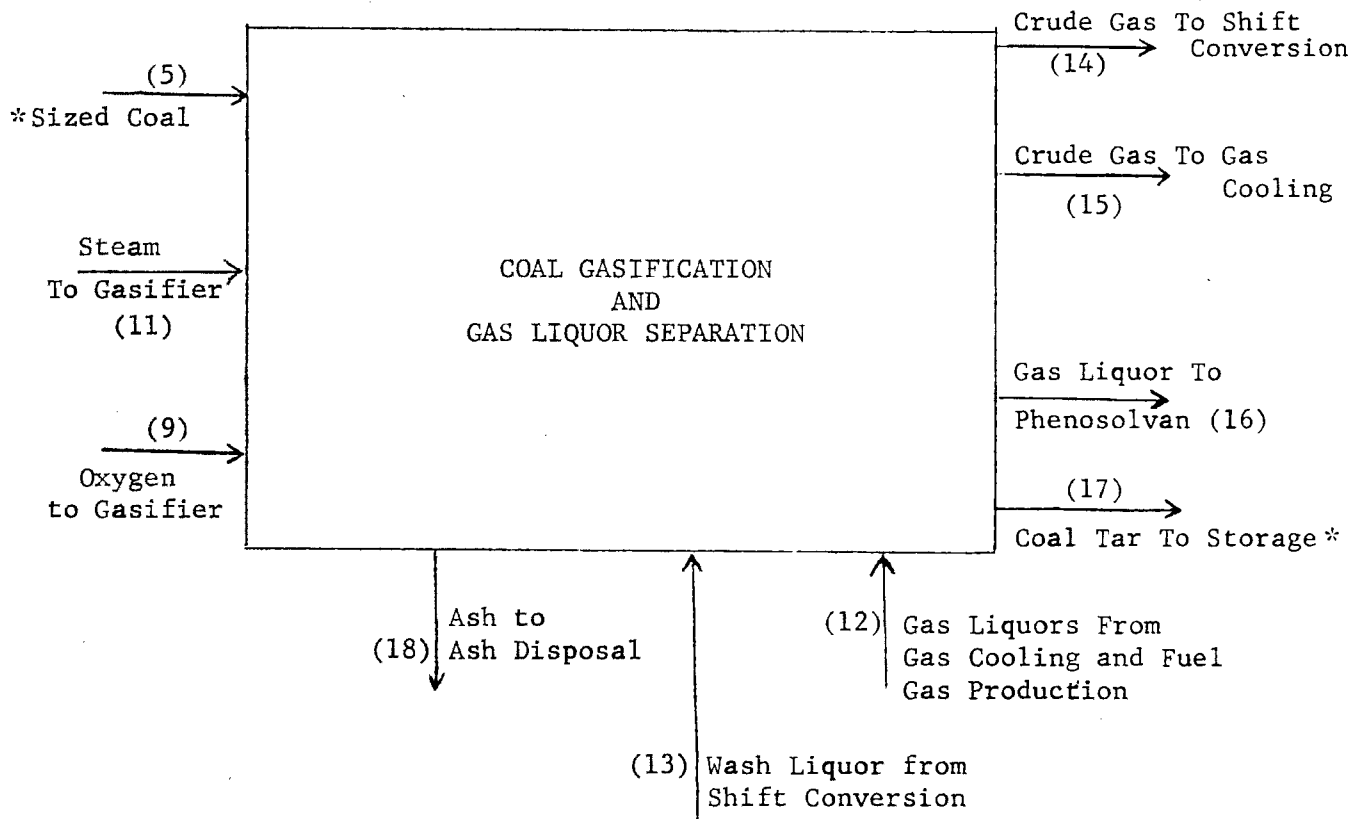
Figure 4

Coal Gasification

Table 4

Coal Gasification

Inlet Streams:

*(5)   Sized coal from Coal Preparation; 1180 tph.

 (9)   Oxygen from Oxygen Plant; 235 tph.

(11)   Steam; 1,784,000 pounds per hour.

(12)   Gas Liquors from Gas Cooling and Fuel Gas Production recycled to gas liquor separator.

(13)   Wash Liquor from Shift Conversion recycled to gas liquor separator.

Outlet Streams:

(14)   Crude Gas to Shift Conversion; 623 tph dry basis.

(15)   Crude Gas to Gas Cooling; 516 tph dry basis.

(16)   Gas Liquor to Phenolsolvan.

*(17)   Coal Tar to Tar Product Storage, analyzed for trace elements per Table 18.

(18)   Ash to Ash Disposal; 186 tph dry basis.

*   Analytical Sample, See Table 18.

3.5 Shift Conversion (Figure 5 and Table 5)

The shift conversion area is designed to produce hydrogen by the "water gas shift" reaction:

$$CO + H_2O = CO_2 + H_2 + 16,538 \text{ Btu per pound mole}$$
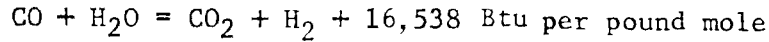
Production of this additional hydrogen will be required to adjust the H_2:CO ratio for proper feed to the methanation plant.

Approximately one-half of the total crude gas will be subjected to shift conversion. The balance will be bypassed directly to the gas cooling area. The ratio of the two gas streams will be adjusted to achieve the desired H_2:CO ratio.

Crude gas feed to the shift conversion area will first be cooled in a waste heat boiler. The cooled gas will then be heated in a series of heat exchangers before passing through a prereactor to retain carbon-containing residues. The heated gas will enter the first shift reactor where the bulk of the carbon monoxide will be catalytically converted. Condensed gas liquor will be recycled to the wash cooler in the gasification area.

The first stage hot gas effluent will be cooled in countercurrent exchange with the feed gas before entering the second shift reactor where further conversion of carbon monoxide will take place. The effluent gas from the second shift reactor will be cooled by exchange with feed gas before leaving the shift conversion unit.

A shift startup heater will be located in a bypass between the pre-reactor and first shift reactor. The heater is indicated to be fired with washed crude gas taken from the main stream ahead of the prereactor.

* (22) Stack Gas From
Startup Heater

Crude Gas From
Gasification
(14)

Converted Gas
to Gas Cooling
(21)

SHIFT
CONVERSION

(19)

Boiler Feed
Water

Gas Liquor to Gasification
Wash Coolers
(20)
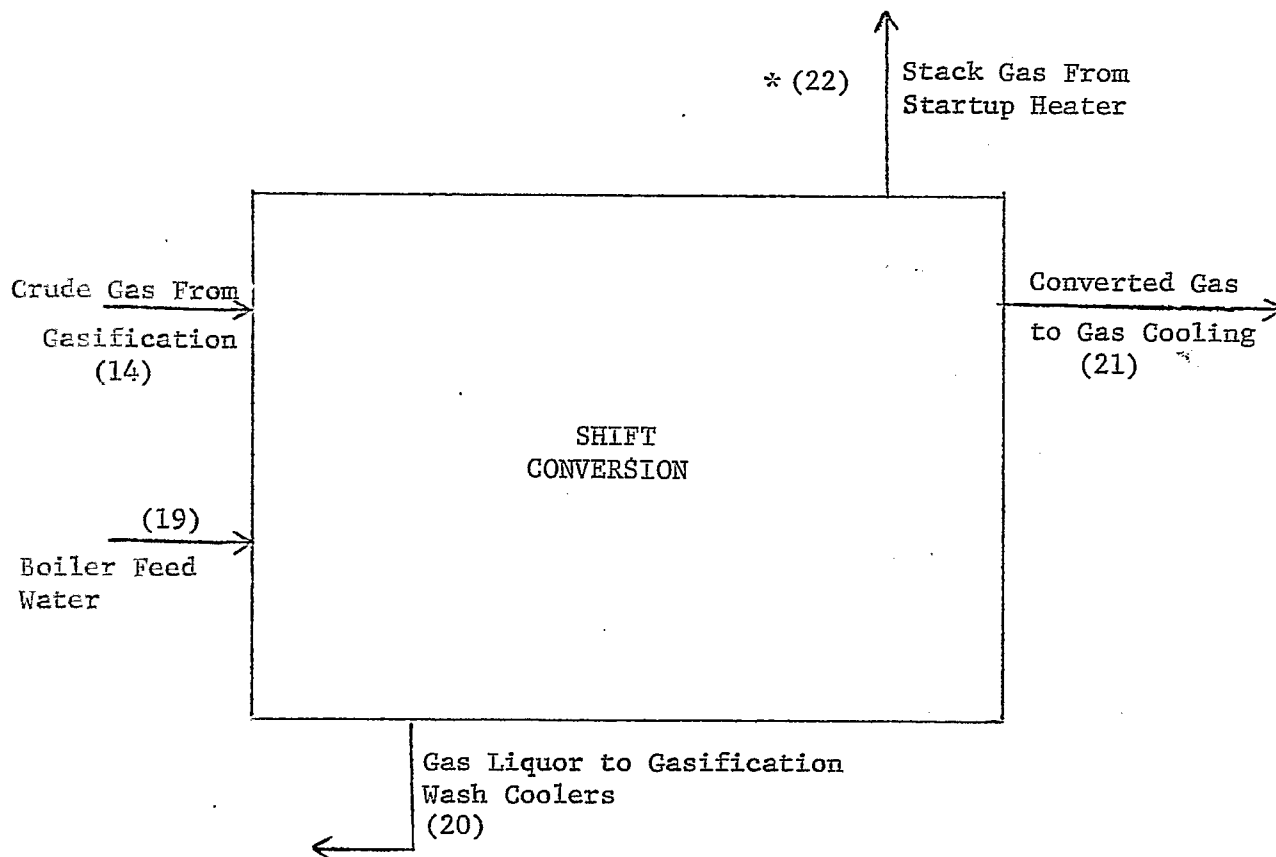
Figure 5

Shift Conversion

Table 5

Shift Conversion

Inlet Streams:

(14) Crude Gas from Gasification; 623 tph dry basis.

(19) Boiler Feed Water.

Outlet Streams:

(20) Gas Liquor recycled to Gasification area.

(21) Converted Gas to Gas Cooling; 696 tph.

*(22) Stack gas from Shift Startup Heater, to be analyzed as combustion stack gas
per Table 18. Note: This stream exists only during shift plant startup periods.

* Analytical Sample, see Table 18.

3.6 Gas Cooling (Figure 6 and Table 6)

The gas cooling area will cool the hot gases from gasification and shift conversion before they are fed to the low-temperature purification area. The cooling scheme will be arranged to recover and utilize as much of the process heat as is practical. The gas cooling will be accomplished in parallel trains. Each train will be further subdivided into two lines of exchangers, one for cooling the crude gas bypassing the shift conversion area, and the other for cooling the converted gas, to provide improved heat recovery efficiency.

Crude gas will first be cooled in a waste heat boiler generating steam at about 76 psia. Further cooling will be accomplished in a low-pressure steam generator. The gas will then be cooled in a precooler by an air cooler. The gas will finally be cooled by cooling water.

The hot gas liquor and tar which will be condensed during cooling in the waste heat boiler and the low-pressure steam generator will be recycled to the primary gas liquor separator in the gasification area. The remaining condensate streams, which will be comprised of gas liquor and a tar oil naphtha mixture, will be gathered and separated in a second gas liquor separation unit.

Converted gas from the shift conversion will first be cooled by exchange with high-pressure boiler feedwater; then in series by generating low-pressure steam. The gas will then be cooled by an air cooler. Final cooling will be by cooling water.

Gas liquor and tar condensate from the converted gas in the first three steps will be cooled with demineralized makeup feedwater and then combined with the remaining condensate streams from subsequent air and water cooling systems. The total stream will then be sent to the gas liquor separator where separation of the tar-oil-naphtha mixture from gas liquor will occur. Gas liquor will be pumped to the gas liquor treatment area and tar oil naphtha mixture will be transported to storage. Vent gas (not shown on Figure 6) is recycled to the gasification area where it is recompressed into the main gas stream.

```
                    ┌──────────────────────────────┐
     (15)           │                              │          (23)
  ────────────────▶ │                              │ ──────────────────▶
  Crude Gas From    │                              │         Mixed Gas to
  Gasification      │        GAS COOLING           │         Purification
                    │                              │
                    │                              │
     (21)           │                              │          (24)
  ────────────────▶ │                              │ ──────────────────▶
  Crude Gas From    │                              │        *Tar Oil Naphtha
  Shift Conversion  │                              │         Product to Storage
                    └───────┬─────────────┬────────┘
                            │             │
                   Gas Liquor to    Gas Liquor to
                   Gas/Liquor Separator   Phenosolvan Treating
                   (12)             (25)
            ◀───────               ──────────▶
```
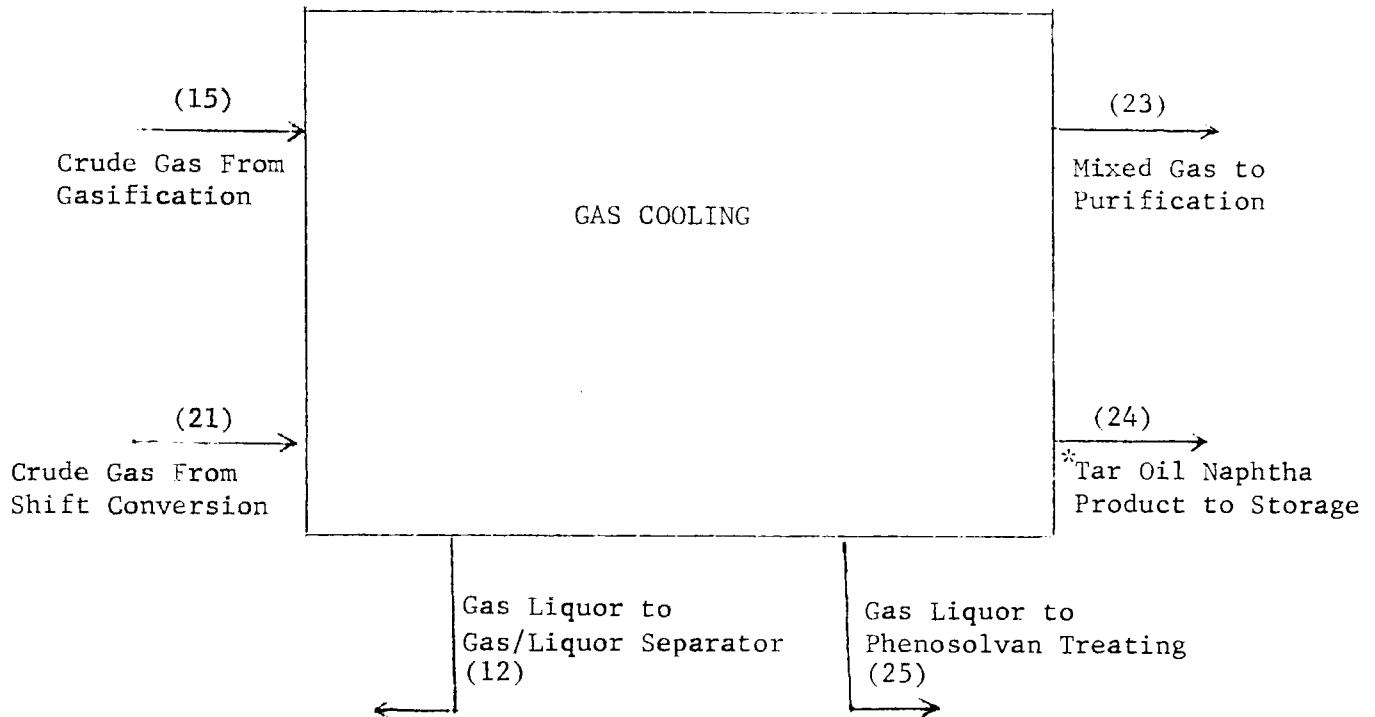
Figure 6

Gas Cooling

Table 6

Gas Cooling

Inlet Streams:

(15)   Crude Gas from Gasification; 516 tph dry basis.

(21)   Crude Gas from Shift Conversion; 696 tph dry basis.

Outlet Streams:

(12)   Gas Liquor to Gas/Liquor Separation.

(23)   Mixed cooled gas to Purification; 1225 tph dry basis.

*(24)   Tar-Oil-Naphtha Product to Storage; 110 gpm, to be analyzed for trace constituents
        per Table 18.

(25)   Gas Liquor to Phenosolvan Treating.

* Analytical Sample, see Table 18.

3.7 Gas Purification (Figure 7 and Table 7)

The gas purification plant is designed to remove H_2S and COS to a total sulfur concentration of 0.1 vppm (parts per million by volume) before the methane synthesis step. After methanation and first-stage compression, the gas will be washed further to reduce the CO_2 content.

The Lurgi Rectisol Process will be used for gas purification. It is a low-temperature, methanol-wash process.

The mixed gas from the gas cooling area will be chilled before entering the prewash tower, where water and naphtha will be removed by cold methanol wash. Naphtha will be recovered from methanol and water by means of the naphtha extractor. Naphtha recovery will be maximized by recycling the naphtha-methanol mixture through the azeotrope column. The methanol will be recovered by distillation in the methanol-water column. A small water stream (not shown on Figure 7) will be recycled to gas/liquor separation.

The naphtha-free gas will enter the H_2S absorber, where H_2S and COS will be removed down to 0.1 vppm total sulfur by cold methanol wash. Heat of absorption will be removed by refrigeration. Some of the absorbed acid gases will be removed from methanol by multiflash in the flash regenerator. The remaining acid gases will be stripped in the hot regenerator. All the acid gas streams will be combined and delivered to the sulfur recovery plant. Vent gas from the flash regenerator will be recycled to the gasification area for recompression into the main gas stream (not shown on Figure 7).

Upon the recovery of refrigeration, by exchange with inlet gas, the sulfur-free gas will exit the Rectisol Unit for methanation. Following methanation and first-stage compression, the methanation product gas will be returned to the Rectisol Unit where it will again be chilled and will enter the CO_2 absorber. The CO_2 content of the gas will be reduced by the cold methanol wash. The heat of absorption will again be carried away by refrigerant. The high-Btu purified dry gas will be warmed and sent to the second-stage compression unit.

The mechanical compression refrigeration unit will provide refrigeration at two temperature levels. The high-level refrigeration (32 F) will be used to condense most of the water out of the mixed gas and the methanation product gas. The remaining water vapor in the gases will be prevented from freezing by methanol injection. The low-level refrigeration (about -50 F) will be used to achieve the low temperature required for effective methanol wash. The makeup methanol stream for this system is not shown on Figure 7.

Acid Gas to
Sulfur Recovery

(27)

(23)

Mixed Gas From
Gas Cooling

(28)

Methanation Feed Gas

GAS PURIFICATION

(26)

Boiler Feed
Water

Process Condensate
(29) to Gas Liquor
Separation

Naphtha Product
To Storage *
(30)
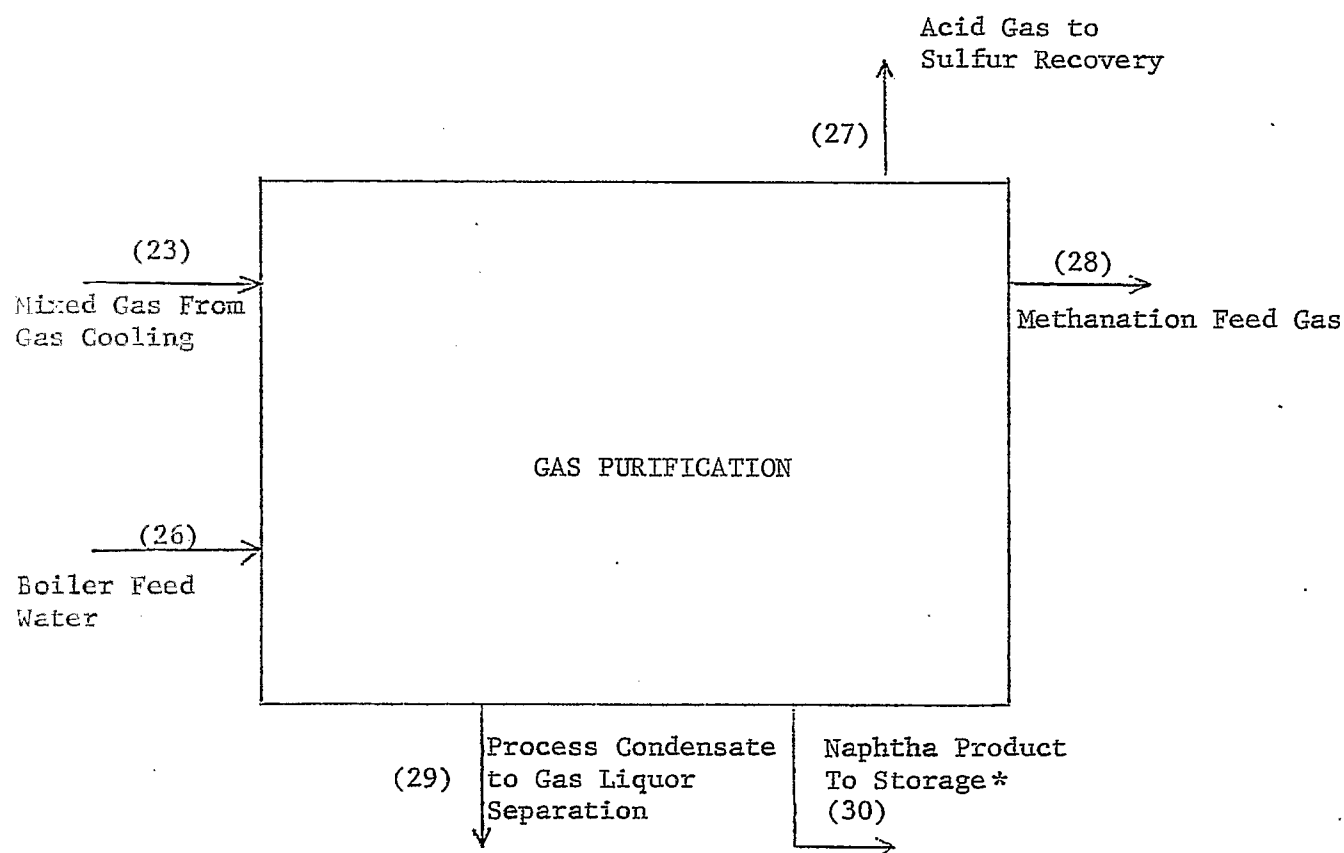
Figure 7

Gas Purification for Lurgi Plant

(Rectisol Plant)

Table 7

Gas Purification for Lurgi Plant

Inlet Streams:

(23)   Mixed Gas from Gas Cooling: 1225 tph dry basis.

(26)   L.P. Boiler Feed Water; 100,000 pound per hour.

Outlet Streams:

(27)   Lean and rich Acid Gases to Sulfur Recovery; 794 tph.

(28)   Methanation Feed Gas; 415 tph.

(29)   Process Condensate to Gas Liquor Separation.

*(30)   Naphtha Product to Storage; 10 tph, to be analyzed per Table 18 for trace constituents.

*   Analytical Sample, see Table 18.

3.8 Methane Synthesis (Figure 8 and Table 8)

The methane synthesis area will convert low-Btu synthesis gas to methane-rich, high-Btu gas by the following chemical reactions:

$$CO + 3H_2 = CH_4 + H_2O + 94,252 \qquad \text{per pound mole of } CH_4 \text{ @ } 700°F$$

$$CO_2 + 4H_2 = CH_4 + 2H_2O + 77,714 \qquad \text{per pound mole of } CH_4 \text{ @ } 700°F$$

Both reactions are very exothermic, as indicated by the heats of reaction listed above. Other minor reactions which will take place are the hydrogenation of ethylene to ethane and hydrocracking of ethane to methane.

Fresh feed will be treated for removal of trace sulfur compounds prior to methanation. Fixed-bed downflow reactors employing pelleted reduced nickel catalysts will be used. A synthesis loop, in which process gases are circulated to dilute the concentration of reactants in the feed, will be used to establish operating conditions conducive to equilibrium reactor operations. Reaction heat generated in the synthesis loop will be removed by generating process steam in waste heat boilers. This steam will ultimately be injected into the gasifiers.

A second-stage, one-pass reactor will be used for final cleanup of the gas from the recycle methanation reactor. Methanation product gas from this reactor will be cooled, compressed, and dehydrated before being sent to the gas transmission line.

Feed gas, entering the unit from gas purification, will be heated by exchange with the product gas stream leaving the recycle loop. The hot feed gas will then enter the synthesis loop.

The synthesis loop will be composed of a recycle methanation reactor, waste heat recovery facilities, and a recycle compressor. The feed gas composition to the recycle methanation reactor will be set by combining the fresh feed gas stream with the gas stream circulated by the recycle compressor. Since the reactor has excess catalyst, the reaction will proceed to near equilibrium. Thus, the temperature rise across the reactor can be controlled by setting the concentration of the reactants.

Reaction heat from the recycle methanation reactor will be removed in the waste heat boiler. Preheated boiler feed water will be supplied from gas cooling, with further preheat supplied by cross exchange with the product gas from the cleanup methanation reactor.
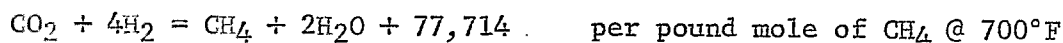
Recycle product from the synthesis loop will enter the cleanup methanator where the heating value of the gas will be increased to 954 Btu/scf. Gas leaving the methanator will be cooled by heat exchange with boiler feed water, cross exchange with fresh feed, then with softened water and cooling water. Condensed water will be separated and reused in raw water treatment.

(28)

Methanation Feed
Gas from
Purification

METHANE SYNTHESIS

(31)

Methane Product
to Compression

(32)

Gas Condensate
to Raw Water
Treatment
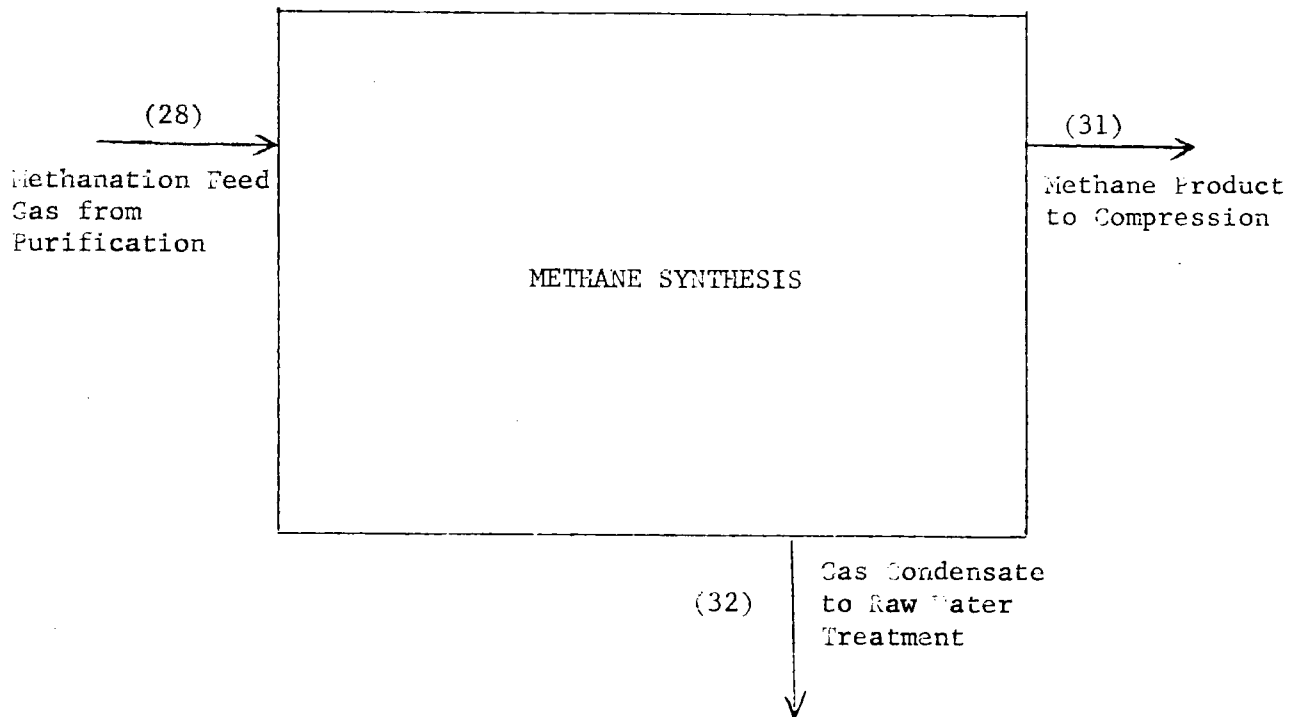
Figure 8

Methane Synthesis

Table 8

Methane Synthesis

Inlet Stream:

(28) Methanation Feed Gas from Purification; 415 tph.

Outlet Streams:

(31) Methane Product to Gas Compression; 257.5 tph.

(32) Gas Condensate to Raw Water Treatment; 157 tph.

3.9 Product Gas Compression and Dehydration
(Figure 9 and Table 9)

The product gas compression and dehydration system will consist of two trains of steam turbine-driven compressors, followed by a conventional glycol system for drying the gas. Product gas will be compressed and dried to meet pipeline specifications.

Product gas from methane synthesis will be compressed by means of a multistage centrifugal compressor. Hot gas discharged from the compressor will be cooled with air and cooling water to 90° F. Water condensed in the final aftercooler will be removed before the gas enters the dehydrator. Lean glycol, pumped to the top of the dehydrator, contacts and dries the gas.

Rich glycol from the bottom of the dehydrator will be fed to the glycol regenerator. Heat added to the bottom of the regenerator and reflux added to the top will effect a separation of glycol and water. Lean glycol is pumped back to the dehydrator and the water transferred to the cooling water system for reuse. Glycol makeup to this system is not shown in Figure 9.

Synthetic pipeline gas from the area will flow through a 2.3-mile, 30" pipeline to join El Paso Natural Gas Company's San Juan main line.

```
                  ┌─────────────────────────────────────────┐
     (31)         │                                         │      (33)
  ──────────────▶ │                                         │  ──────────────▶
Methane Product   │                                         │  Synthetic Gas
from Synthesis    │                                         │  Product to
                  │                                         │  Pipeline*
                  │    GAS COMPRESSION AND DEHYDRATION       │
                  │                                         │
                  │                                         │
                  │                                         │
                  │                                         │
                  └──────────────────┬──────────────────────┘
                                     │        Process Condensate
                            (34)     │        to Cooling Water
                                     ▼        System
```

Figure 9

Gas Compression and Dehydration

Table 9

Gas Compression and Dehydration

Inlet Streams:

(31) Methane Product from Synthesis; 257.5 tph.

Outlet Streams:

*(33) Synthetic Gas Product to Pipeline; 256.9 tph. To be analyzed for
       trace constituents per Table 18.
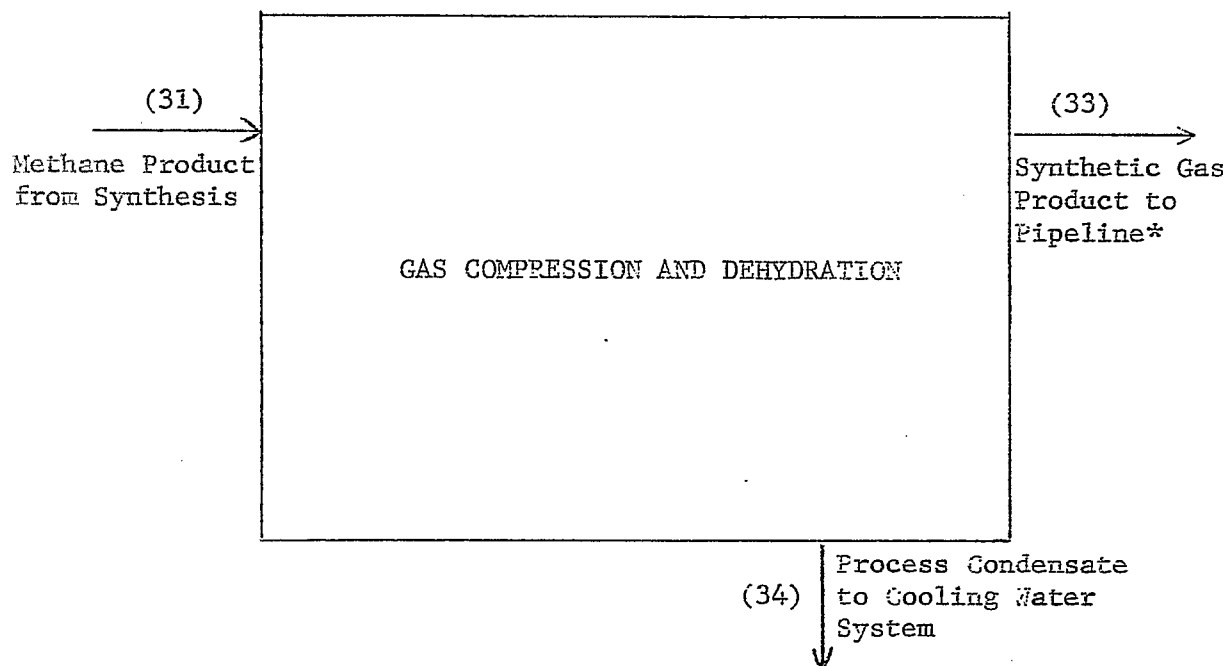
(34) Process Condensate to Cooling Water System; 715 pounds per hour.

* Analytical Sample.

3.10 Sulfur Recovery (Figure 10 and Table 10)

The Stretford process will be used to recover elemental sulfur from hydrogen sulfide present in the acid gas streams. This Stretford unit will operate at about 10 psig. A pressure Stretford absorber operating at about 250 psig will similarly remove hydrogen sulfide from low-Btu fuel gas in the fuel-gas treatment area.

Hydrogen sulfide will be removed by the Stretford solution. The solution will then be regenerated by contact with air.

The overall reaction can be summarized as follows:

$$2H_2S + O_2 = 2H_2O + 2S$$
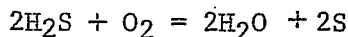
Hydrogen sulfide content in the gases from the Stretford unit will be 10 ppm or less by volume. The carbonyl sulfide (COS) content will not be significantly reduced by contact with Stretford solution.

The absorption section of the plant will consist of two trains for treating the lean H_2S acid gases and a single train for the rich H_2S acid gas. A single oxidizer section will serve to regenerate the Stretford solution from the absorbers in both the low- and high-pressure units.

Feed to the lean H_2S absorbers will be a combined stream consisting of acid gas streams and expansion gas. Feed to the rich H_2S adsorber will be the rich H_2S acid gas stream from gas purification and the coal lock gas stream. Gases fed to the bottom of the absorber towers will be contacted countercurrently by the Stretford solution fed to the top. The lower part of the absorbers will act as a hold tank for the completion of chemical reactions between hydrogen sulfide and the Stretford solution.

Off-gas from the top of the lean H_2S absorbers will be primarily CO_2, but will contain about 10 ppm by volume of hydrogen sulfide and any residual sulfur compounds (such as COS) not converted in the process. The stream, combined with the oxidizer off-gas, will be vented to the atmosphere. Off-gas from the rich H_2S absorber will be incinerated.

Rich solution from the absorbers will be combined with solution from the fuel-gas treating area and flow to the oxidizer. Air will be blown in at the bottom, and sulfur froth will be floated to the surface. The sulfur froth will be pumped to the sulfur separator. Sulfur will be removed from the separator as a liquid and accumulated in a storage pit.

The regenerated Stretford solution will flow from the oxidizer to the pumping tank. Lean solution will be pumped back to the top of the absorbers and to the fuel-gas treating area.

Absorber and Oxidizer
(37) Off-Gases to Atmosphere *

Acid Gases From
Gas Purification
→
(27)

(38)
Absorber Off-Gas
To Incineration *

(35)
- - →

Acid Gases
From Gas
Liquor
Stripping

LOW-PRESSURE STRETFORD UNIT

Rich Stretford
Solution From
Fuel Gas Treating

(36)   (40)   (39)

Liquid Sulfur
Product To
Rail Loading *

Lean Stretford
Solution to
Fuel Gas Treating
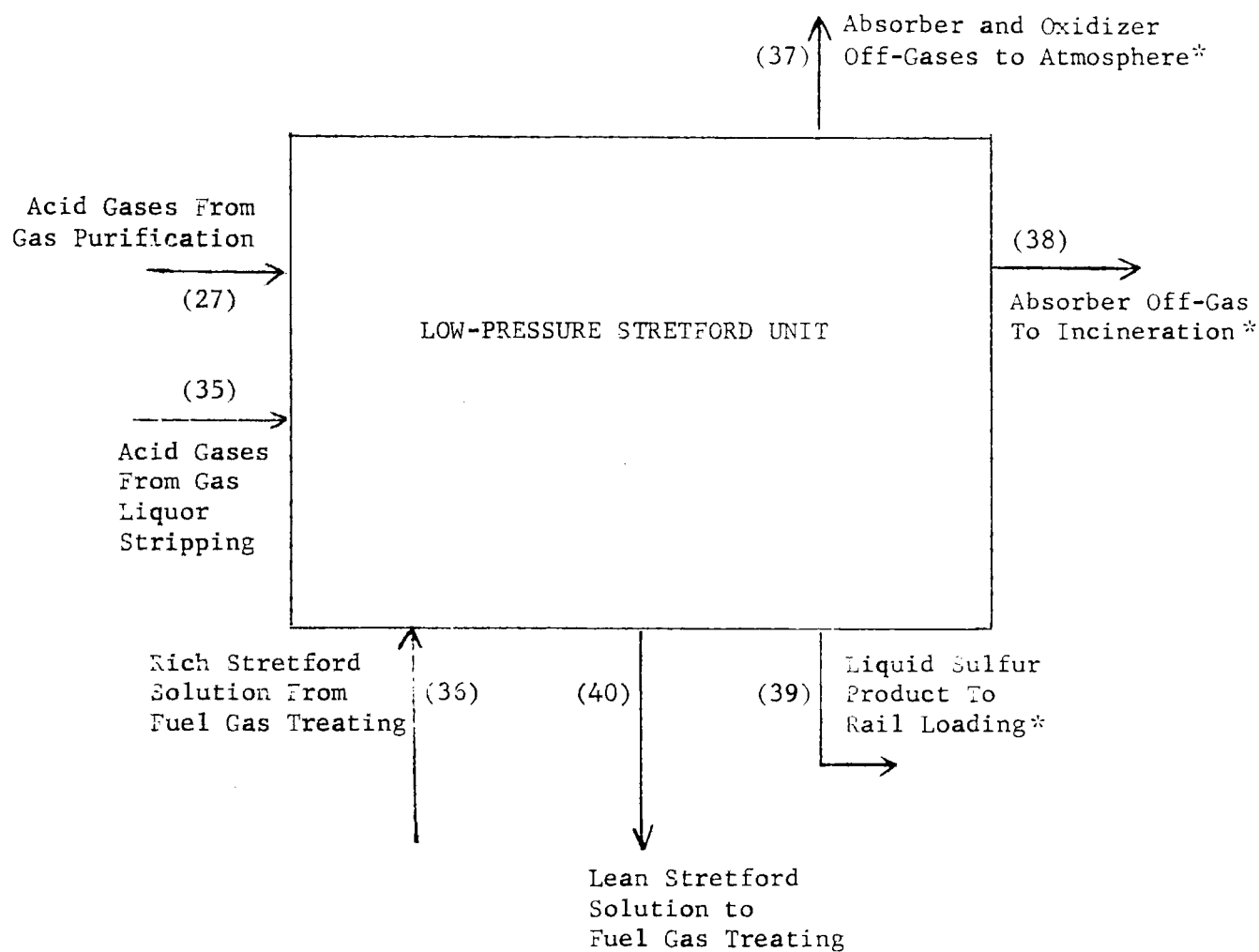
Figure 10

Sulfur Recovery for Lurgi Plant

Table 10

Sulfur Recovery

Inlet Streams:

(27) Acid Gas from Gas Purification; 794 tph.

(35) Acid Gas from Gas Liquor Stripping; 9 tph.

(36) Rich Stretford solution from Fuel Gas Treating.

Outlet Streams:

*(37) Absorber and Oxidizer Off-Gas to Atmosphere; 900 tph. To be analyzed for sulfur compounds and trace constituents per Table 18.

*(38) Absorber Off-Gas to Incineration; 23.8 tph. Incinerator stack to be analyzed per Table 18.

*(39) Liquid Sulfur Product to Rail Loading; 7.8 tph. To be analyzed for trace constituents per Table 18.

 (40) Lean Stretford solution to Fuel Gas Treating.

* Analytical Samples.

3.11 Gas Liquor Treatment (Figure 11 and Table 11)

The gas liquor treatment area is designed to remove ammonia and phenol from contaminated water effluents. The phenol will be recovered as a byproduct, and the ammonia will be recovered in aqueous solution.

In the latest design, the gas liquor treatment area has been broken down into sub-sections which are phenol extraction and gas liquor stripping sub-sections.

The phenol extraction area is designed to remove phenols from the clarified gas liquors. Two parallel systems are provided for gas liquor filtration and extraction, one each for contaminated and clean gas liquors. Common solvent recovery and crude phenol-solvent separation equipment is provided.

The Lurgi Phenosolvan process will be used to remove and recover phenols from the clarified gas liquor.

The following paragraph applies to both the contaminated and clean gas liquor systems. Gas liquor will contain phenols, ammonia, carbon dioxide and hydrogen sulfide. Incoming gas liquor will first pass through gravel filters for removal of suspended matter, and then through the extractors where an organic solvent will extract the phenols (forming the extract phase). The dephenolized gas liquor (raffinate) will then be pumped to gas liquor stripping, where traces of solvent will be removed by nitrogen stripping. The nitrogen stream, which comes from the oxygen production area, is not shown on Figure 11.

The phenol-rich extracts will flow to the solvent distillation column. Heat applied to the column will drive most of the solvent overhead. Vapors from the tower will be condensed and the solvent recycled to the extractors. Fresh solvent makeup will be added to the recycle solvent stream. A water-phenol solution will be recovered from the bottom of the solvent distillation column. This material will be combined with phenol from the bottom of the solvent recovery scrubber and fed to the solvent recovery stripper. There, heat will be applied to strip the solvent and water overhead for recycle to the solvent distillation column. A crude phenol product will be recovered from the bottom of the stripper and transferred to storage and loading.

Solvent-rich nitrogen from stripping dephenolized gas liquor will be returned and contacted with crude phenols to remove the solvent. Scrubbed nitrogen from the solvent recovery scrubber will be returned to gas liquor stripping, where the stream will be contacted with filtered gas liquor to remove traces of phenols. A phenol-rich gas liquor stream will be returned upstream of the extractors.

The gas liquor stripping area is designed to remove solvent, ammonia, carbon dioxide, and hydrogen sulfide from the dephenolized gas liquors. A separate solvent stripper will be provided for the dephenolized contaminated gas liquor. A single train, except for two ammonia strippers, will be used for the dephenolized clean gas liquor.

The incoming gas liquors will be separately introduced to solvent strippers where nitrogen will be used to strip out traces of solvent picked up in the extraction steps. The solvent-rich nitrogen streams will be combined for solvent recovery and returned. Makeup nitrogen will be added to the returned gas and the combined stream will then be compressed, washed with gas liquor to remove traces of phenol, and recycled through the solvent stripper.

Solvent-free, contaminated liquor from the solvent stripper will be sent to ash disposal. Solvent-free, clean gas liquor leaving the solvent stripper will be heated in the deacidifier to remove dissolved carbon dioxide and hydrogen sulfide. Acid gases driven off overhead will be sent to sulfur recovery.

Ammonia removed from the clean gas liquor by steam stripping in the ammonia stripper will be collected overhead as an ammonia solution of about 20 weight percent. Waste liquor from the ammonia stripper will be used directly for cooling tower makeup.

(16)
Gas Liquors
From Gasification

(25)
Gas Liquors From
Gas Cooling

PHENOSOLVAN
——
STRIPPING

(35)
Acid Gases to
Sulfur Recovery

(70)
Contaminated Water
to Ash Disposal

(41)
Crude Phenol
to Storage*

Ammonia Solution
to Storage*   (43)

(42)   Clean Water to
       Main Cooling
       Tower
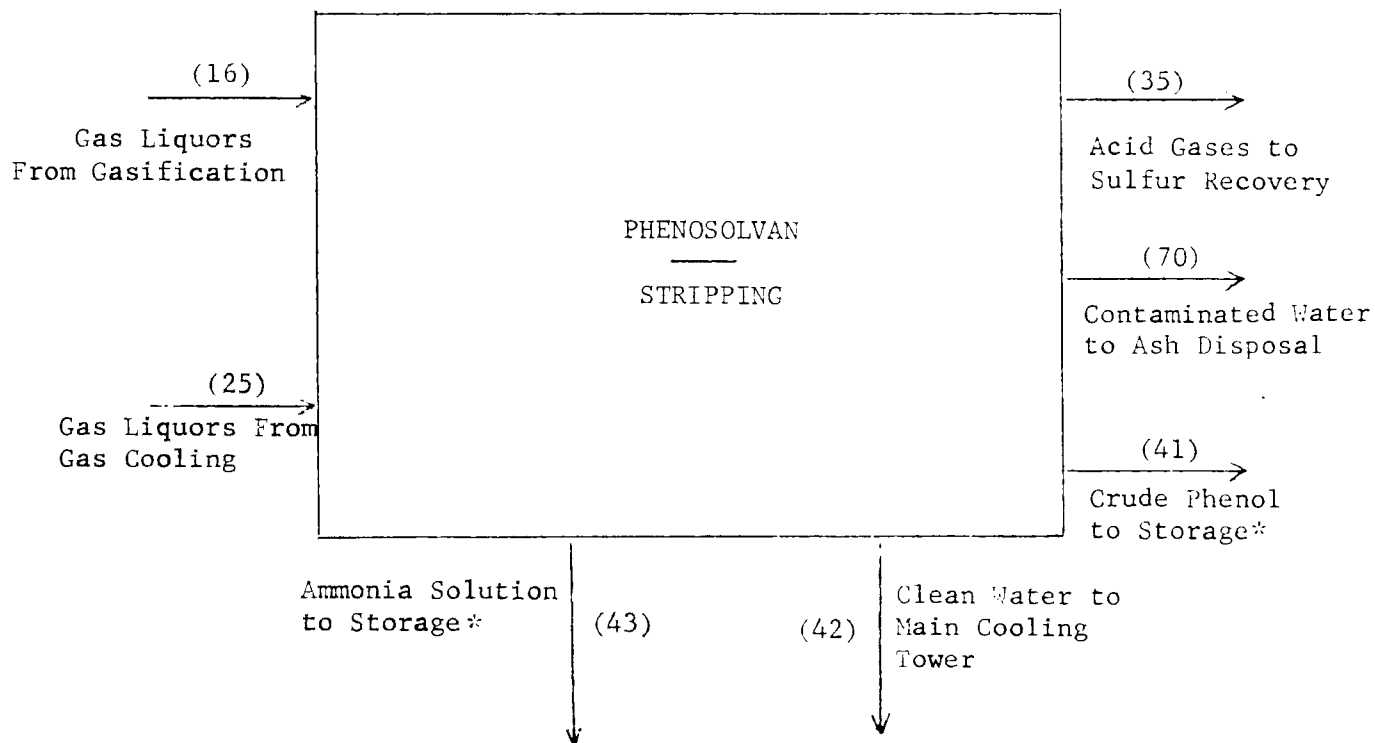
Figure 11

Gas Liquor Treatment

Table 11

Gas Liquor Treatment

Inlet Streams:

(16)   Gas Liquors from Gasification/Separation.

(25)   Gas Liquors from Gas Cooling.

Outlet Streams:

(35)   Acid Gases to Sulfur Recovery; 9 tph.

(70)   Contaminated Water to Ash Disposal; 82 tph.

*(41)   Crude Phenol to Storage; 5.6 tph.   To be analyzed for trace constituents per Table 18.

(42)   Clean Water to Main Cooling Tower; 600 tph.

*(43)   Ammonia Solution to Storage; 53.6 tph.   To be analyzed for trace constituents per Table 18.

* Analytical Samples.

3.12 Fuel Gas Production and Cooling
      (Figure 12 and Table 12)

Basic design for the fuel-gas production area is provided by Lurgi. Navajo coal will be gasified in airblown Lurgi gasifiers operating at about 385 psig.

Sized coal will be conveyed from coal preparation to coal bunkers located above the gasifiers. The coal will be fed to the gasifiers through coal locks which will be pressurized by a slip stream of lock-filling gas. The Lurgi gasifiers are water-jacketed vessels. Hot compressed air and process steam will be mixed and introduced into the gasifiers. Ash will be removed from the bottom of the gasifiers through ash locks and transported to ash disposal.

Hot crude gas leaving the gasifiers will be cooled rapidly by quenching with a gas liquor spray in wash coolers. Crude gas from the wash coolers will be further cooled in waste heat boilers to produce 15 psig steam. A purge stream of tarry gas liquor will be drawn off to gas liquor separation. Recycle gas liquor will be injected into the wash cooler as makeup. Boiler feed water and recycle gas liquor streams are not shown on Figure 12.

Crude fuel gas from this area flows to fuel gas cooling. The fuel gas cooling area is designed to cool the hot crude fuel gases to near ambient temperature.

Crude fuel gas will first be cooled by aerial coolers. Final cooling of the crude fuel gas will be by cooling water. Oily gas liquor condensed in both cooling steps will be combined and sent to gas liquor separation.

Cooled fuel gas will be sent to fuel gas treating.
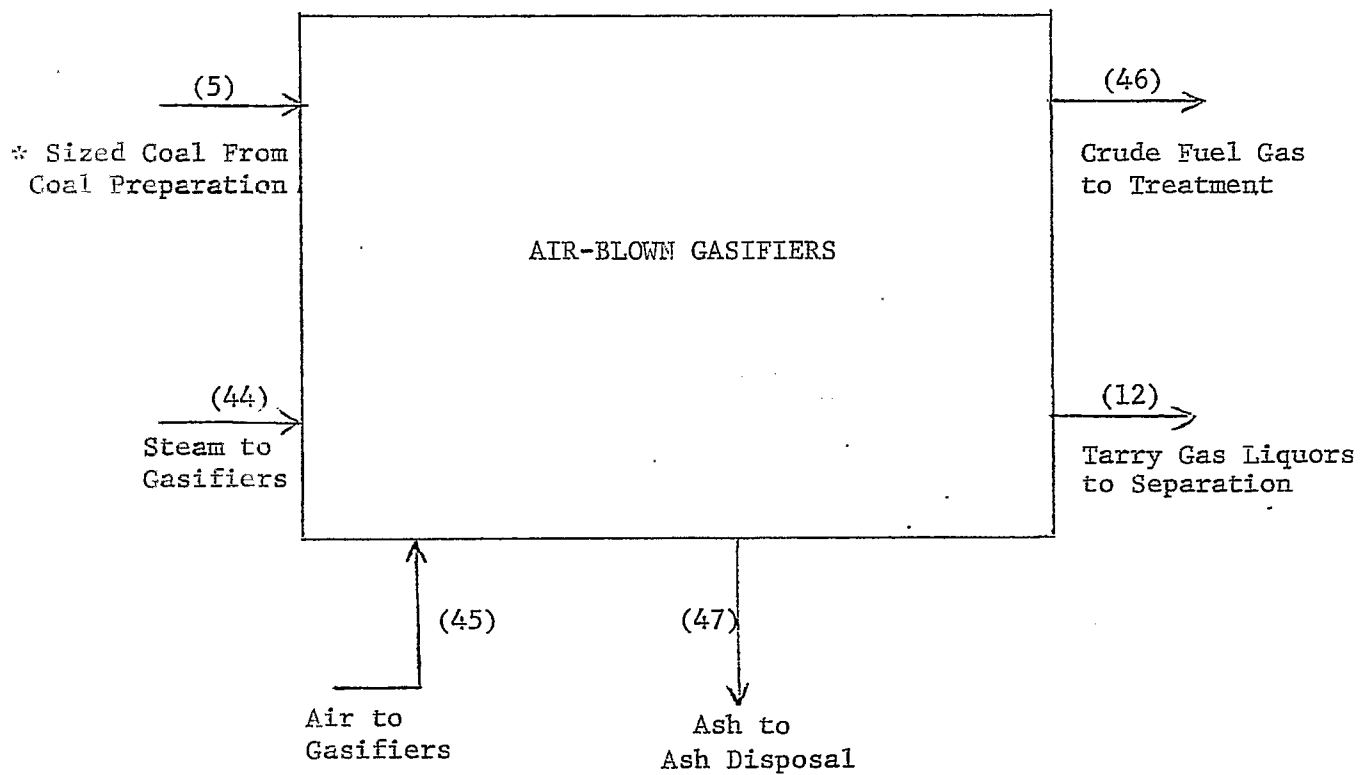
Figure 12

Fuel Gas Production

Table 12

Fuel Gas Production

Inlet Streams:

*(5)   Sized coal from Coal Preparation; 208 tph.

(44)   Steam to Gasifiers; 130 tph.

(45)   Air to Gasifiers; 266 tph.

Outlet Streams:

(12)   Tarry Gas Liquors to Gas Liquor Separation.

(46)   Crude Fuel Gas to Fuel Gas Treatment; 444 tph.

(47)   Ash to Ash Disposal; 42 tph.

* Analytical Sample.

3.13   Fuel Gas Treating (Figure 13 and Table 13)

The fuel gas treating area is designed to clean fuel gas by treating with the Stretford process. This Stretford process will operate at about 250 psig in contrast to the 10 psig operating pressure for the main Stretford unit. Hydrogen sulfide will be removed by the Stretford solution. The solution will then be regenerated by contact with air. Overall, the reaction can be summarized as follows:

$$2H_2S + O_2 = 2H_2O + 2S$$
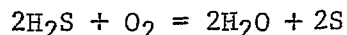
Hydrogen sulfide content in the gases will be less than 10 vppm. Carbonyl sulfide (COS) content of the fuel gas will not be significantly reduced by contact with the Stretford solution.

A single oxidizer section located in the sulfur recovery area will serve to regenerate the rich Stretford solution from the absorbers in this section.

Crude fuel gas is fed to the bottom of a contactor tower and washed countercurrently with lean Stretford solution fed into the top. The lower part of the absorber and the digester vessel downstream will act as a hold tank for the completion of chemical reactions between hydrogen sulfide and the Stretford solution.

Lean solution from the sulfur recovery area will be pumped to the contactor. Energy will be extracted from the rich solution leaving the digester by depressurizing the solution through a power recovery turbine coupled to the booster pump. Rich solution will be transferred to the sulfur recovery area for regeneration.

A portion of the treated fuel gas at near ambient temperature and about 250 psig will be used to fire gas turbines in steam and power generation. The balance of the stream will flow to gas compression where the fuel gas will be heated and expanded to recover power, and then be used to fire heaters and boilers.

Figure 13
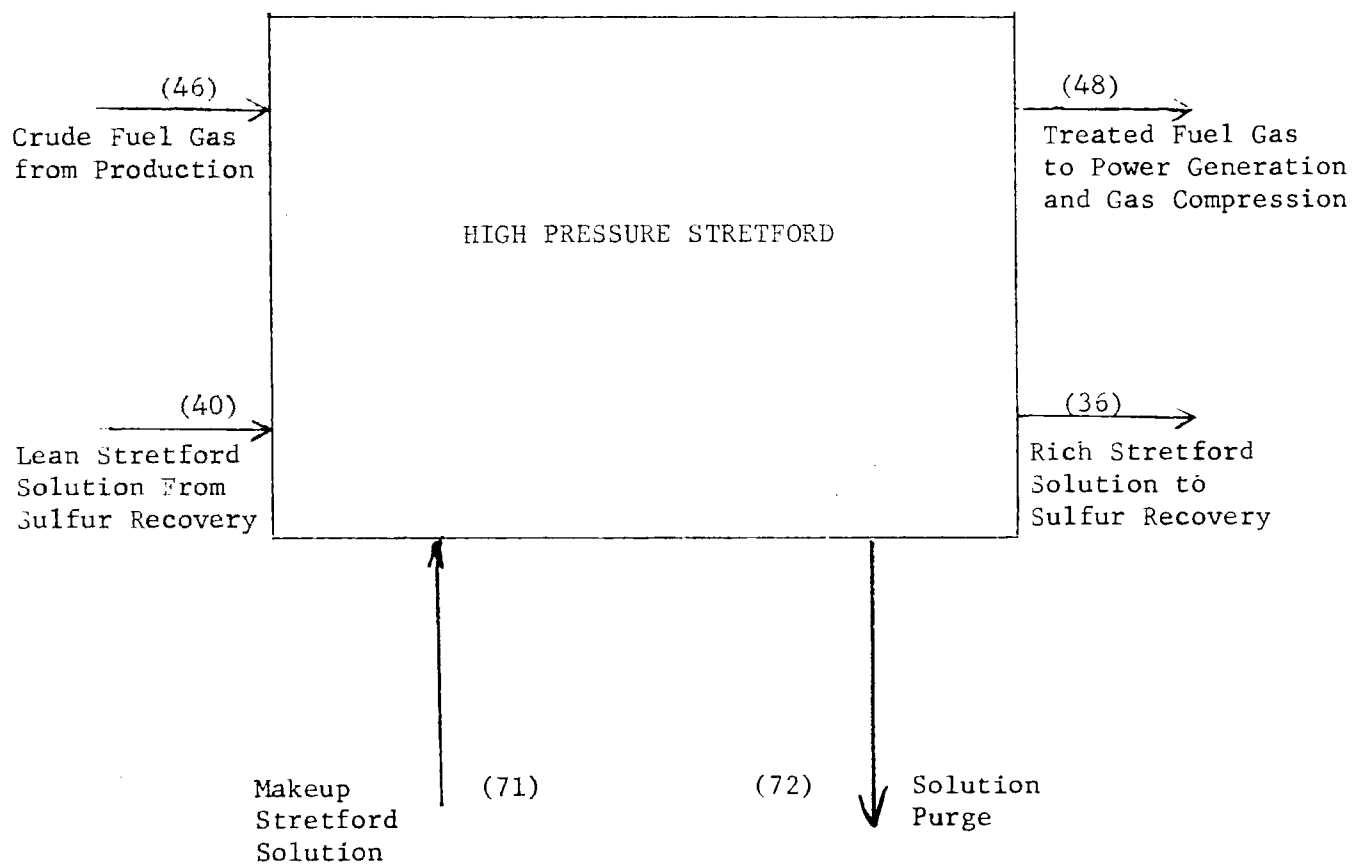
Fuel Gas Treating

Table 13

Fuel Gas Treating

Inlet Streams:

(40) Lean Stretford Solution from Sulfur Recovery.

(46) Crude Fuel Gas from Production; 444 tph.

(71) Makeup Stretford Solution (Quantity not specified).

Outlet Streams:

(36) Rich Stretford Solution to Sulfur Recovery.

(48) Treated Fuel Gas to Power Generation; 443 tph.

(72) Solution Purge (Quantity not defined).

3.14 Steam and Power Generation
      (Figure 14 and Table 14)

Power generation will be from four gas turbine driven generator sets. The capacity of each generator is 33% of normal plant requirements. Excess capacity is to assure continuous, full-load operation with one unit removed from service for inspection or repair.

Steam generation will consist of a combination of process waste heat boilers and heat recovery boilers on gas turbine exhaust. Generally, low pressure steam from the process waste heat boilers will supply process heat requirements, and high-pressure steam will provide process reaction steam and motive power steam.

Eight gas-turbine, heat-recovery boilers will be provided: four on power generation turbines and four on air compression turbines. Excess capacity in the form of one spare electrical generator train plus a free standing boiler will provide flexibility in meeting peak demands and will assure continuous full-load operation whenever one unit is shutdown for inspection or repair.

Steam generated at 612 psia in the methane synthesis area will be superheated to provide motive power steam and process reaction steam to the coal gasifiers.

Hot exhaust gases from the gas turbines will be utilized in heat recovery boilers to generate 1150 psig superheated steam. The boilers will be supplemental fire as required to maintain proper steam conditions. The standing boiler will be fuel gas-fired to generate 1150 psig superheated steam in emergency situations, for startups, and for flexibility.

Deaerator
(51) Vent*

(52) Stack Gases*

(48)

Treated Fuel
Gas From
Treating

(11,44)

Superheated Steam
to Process

STEAM AND POWER GENERATION

(49)

Boiler Feed
Water
∿ 4200 GPM

Electrical
Requirement to
Plant
56,700 KWH

(50)

Blowdown Streams
to Cooling Water System
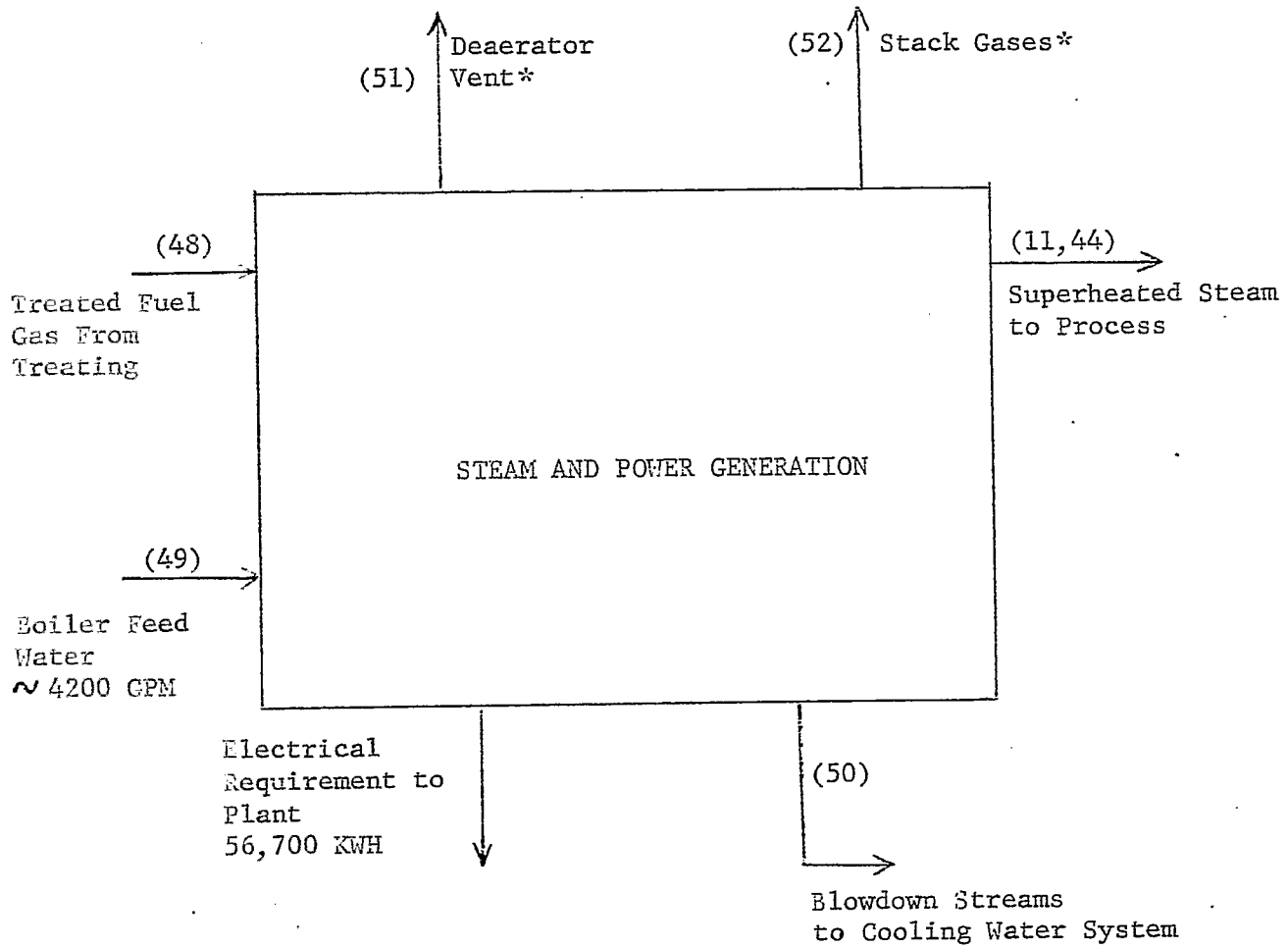
Figure 14

Steam and Power Generation

Table 14

Steam and Power Generation for Lurgi Plant

Inlet Streams:

(48)   Treated Fuel Gas; 443 tph.

(49)   Boiler Feed Water; ~4200 GPM.

Outlet Streams:

(11)+(44)   Superheated Steam at 1150 and 550 psig and Saturated Steam at 15 psig to process;
~4100 GPM.

(50)   Boiler Blowdown to Cooling Water System; 60 GPM.

*(51)   Deaerator Vent to Atmosphere; ~40 GPM.   To be analyzed for trace constituents per Table 18.

*(52)   Stack Flue Gases to Atmosphere.   To be analyzed per Table 18 as stack gases.

*   Analytical Samples.

3.15 Raw Water Treating (Figure 15 and Table 15)

The raw water treating system will receive approximately 6000 gpm of raw water and 600 gpm of process condensate. About 2300 gpm of zeolite softened water for makeup to the low-pressure steam generation systems and 2200 gpm of demineralized water for boiler feedwater and gasifier jacket water will be produced. In addition, an average of 20 gpm of potable water for the plant's domestic water users, 129 gpm for general plant utility water system, and about 440 gpm of treated water for cooling tower makeup will also be produced. Condensate returns from the plant will be collected and treated to remove trace hydrocarbon contaminants before being utilized as makeup to the high-pressure steam generation systems. The hydrocarbon removal system has not been detailed, nor has the disposition of separated hydrocarbon been indicated.

Raw water will be pumped from the raw water reservoir to a lime softener-clarifier for chemical treatment. Pebbled quicklime will be unloaded pneumatically and conveyed to a storage silo. Lime slaking systems will provide a lime feed to the clarifier. Alum feeder and polymer feeder systems will provide other necessary water treating chemicals to the clarifier. Treated water from the clarifier will drain to a clearwell which gives a brief storage time. From the clearwell the water will be pumped through anthracite-filled gravity filters. The filtered water will then flow through either demineralizer sets or zeolite softener sets and then on to the steam generation areas.

Process condensate will be airblown to strip dissolved light hydrocarbon gases and carbon dioxide before being combined with the zeolite softener effluent.

A small stream of treated water will be chlorinated and piped to an elevated potable water tank. The plant potable water system will then be supplied from this tank by gravity.

Tankage for the water systems will be as follows:

a.	Treated Water	(2)	2,500,000 Gallon Tanks
b.	Demineralized Water	(2)	200,000 Gallon Tanks
c.	Softened Water	(2)	750,000 Gallon Tanks
d.	Condensate	(2)	1,100,000 Gallon Tanks
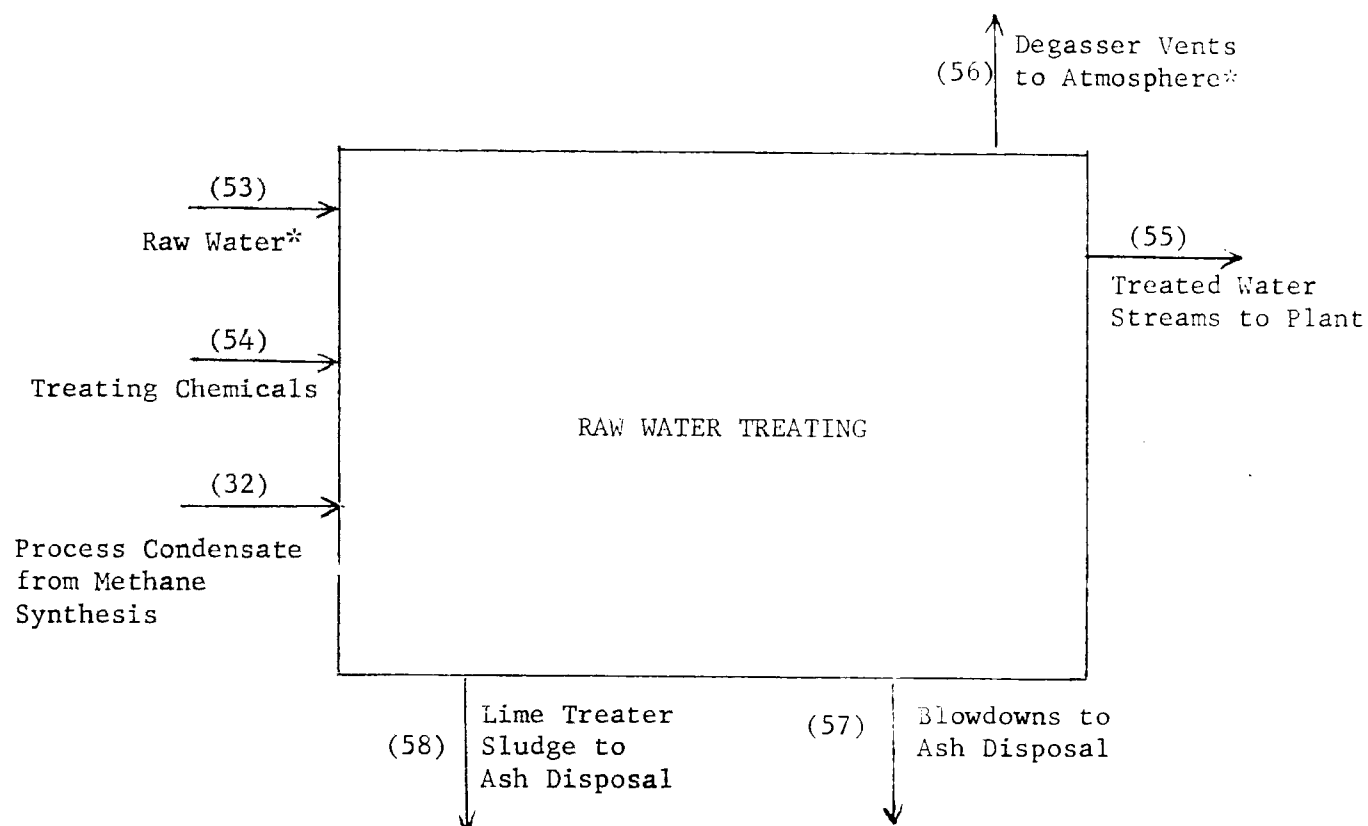
Figure 15

Raw Water Treating

Table 15

Raw Water Treating

Inlet Streams:

(32) Process Condensate From Methane Synthesis; 157 tph.

*(53) Raw Water; 6000 gpm. To be analyzed as water sample per Table 18.

(54) Water Treatment chemicals, including pebbled quicklime, sodium hydroxide solution, sulfuric acid, alum, polymer solution, chlorine, hypochlorite, demineralizer and zeolite polymers, salt, anthracite filter media.

Outlet Streams:

(55) Treated Water to Plant.

*(56) Vent from condensate degasser to atmosphere; 35 gpm. To be analyzed for trace constituents per Table 18.

(57) Blowdowns to Ash Disposal; 270 gpm.

(58) Lime Treater Sludge to Ash Disposal; 220 gpm.

* Analytical Samples.

3.16 Cooling Water System (Figure 16 and Table 16)

Two separate cooling water systems will be provided for the complex: (1) a clean water system which will be dedicated exclusively to the cooling of pure oxygen streams, and (2) the main system which will be for the remaining cooling loads within the complex. Both systems will be designed to produce 75°F cooling water.

The clean water system will consist of one two-cell, cross-flow tower designed to reject 62 million Btu per hour at a circulation rate of 8200 gpm. The main cooling water system will consist of three five-cell cross-flow towers designed to reject 1144 million BTU per hour at a circulation rate of about 153,000 gpm.

The clean cooling water system will be supplied from one two-cell cooling tower. Each cell will be rated at 31 million Btu per hour. The tower will be equipped with three vertical turbine pumps mounted in the pump pit, with one pump acting as a spare. Makeup water to the clean water system will be blowdowns from the process waste heat and power boilers. Total flow available for makeup will be about 460 gpm. Cold water will leave the tower at 75°F and return at 90°F. Blowdown from the clean cooling tower will be used as part of the makeup for the main cooling tower.

The main cooling water system will be supplied from three five-cell cooling towers. Each cell will be rated at 76 million BTU per hour. The cooling towers will be erected over a concrete basin with a pump pit to the side. Each tower will be equipped with four vertical turbine pumps mounted in the pump pit, with one pump acting as a spare. The main source of makeup water, approximately 2400 gpm, will be supplied from gas liquor stripping. Other makeup streams include about 440 gpm of treated water, about 250 gpm of blowdown from the clean cooling water system, and 20 gpm of treated sewage. Cold water will leave the tower at 75°F and return at 90°F.

Water treating chemicals will be added to both water systems as required to control corrosion, scale formation, plant growth, and pH. Sidestream filtration will be used to control the suspended solids.

Water Treatment
Chemicals
(59)

Evaporation
and Drift*
(65)

(42)

Clean Water From
Gas Liquor Treatment

(62)

Main Plant Return

(60)

Miscellaneous Additions

(61)

Oxygen Plant
Return

COOLING WATER SYSTEM

(63)

Main Plant
Cooling Water

(64)

Oxygen Plant
Cooling Water

Cooling Tower
(66) Blowdown to
Ash Disposal
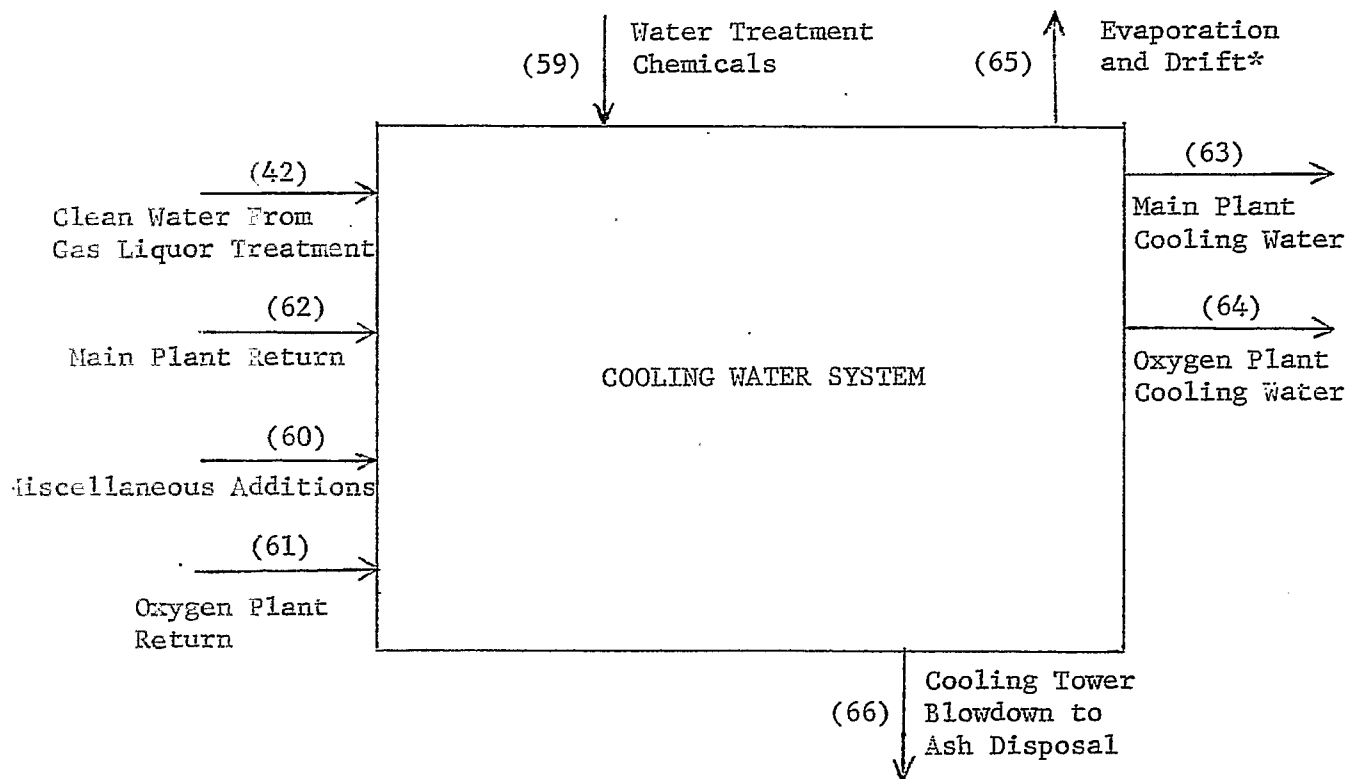
Figure 16

Cooling Water System

Table 16

Cooling Water System

Inlet Streams:

(42)   Clean Water from Gas Liquor Treatment; 2400 gpm.

(59)   Water Treatment Chemicals including anti-foam package, biological (growth control) package, inhibitor feed package, pH (sulfuric acid) package.

(50)+(60)   Miscellaneous Blowdowns and Treated Water Additions; 920 gpm.

(61)   Oxygen Plant Return; 8200 gpm.

(62)   Main Plant Return; 153,000 gpm.

Outlet Streams:

(63)   Main Plant Cooling Water Requirement; 153,000 gpm.

(64)   Oxygen Plant Cooling Water Requirement; 8200 gpm.

*(65)   Evaporation from Towers; 2800 gpm and Drift from Towers; 160 gpm. Atmosphere downwind of towers to be analyzed for trace constituents per Table 18.

(66)   Blowdown from Cooling Water System to Ash Disposal; 330 gpm.

Analytical Sample.

3.17 Ash Disposal (Figure 17 and Table 17)

Wet ash facilities will be designed to handle all of the ash discharged from the airblown and oxygen-blown gasifiers. The equipment will be adequately designed to allow for maximum anticipated variations in ash rate. Coarse ash will be trucked to the mine and fine ash will be stored in a pond.

The ash facilities at the mine and gasification area are interconnected by a continuous belt conveyor.

Ash will be discharged dry and hot from the individual gasifier ash locks into a sluiceway. Water flowing in the launder will quench and transfer the ash to classification and dewatering equipment. The coarse dewatered ash will be transferred on a belt conveyor to the mine ash handling area for disposal in the mine.

The fine ash from the classification step will be dewatered in a thickener and pumped to a fine ash pond for disposal. Water from the thickener will be reclaimed and recycled to the sluiceway. Excess water in the system will be bled to evaporation ponds for disposal.

Dry Ash From
(18) Main Gasifiers

Dry Ash From
(47) Fuel Gas Production

Lime Treating Sludge
From Raw Water Treating

(58)

(57)

Blowdown From
Raw Water Treating
(66)

Cooling Tower Blowdown

(39)

Contaminated
Gas Liquor

ASH DISPOSAL

(69)

Wet Fine Ash Slurry
to Fine Ash Pond*

(68)

Separated Water to
Evaporation Ponds*

(67)

Wet Ash to Mine*
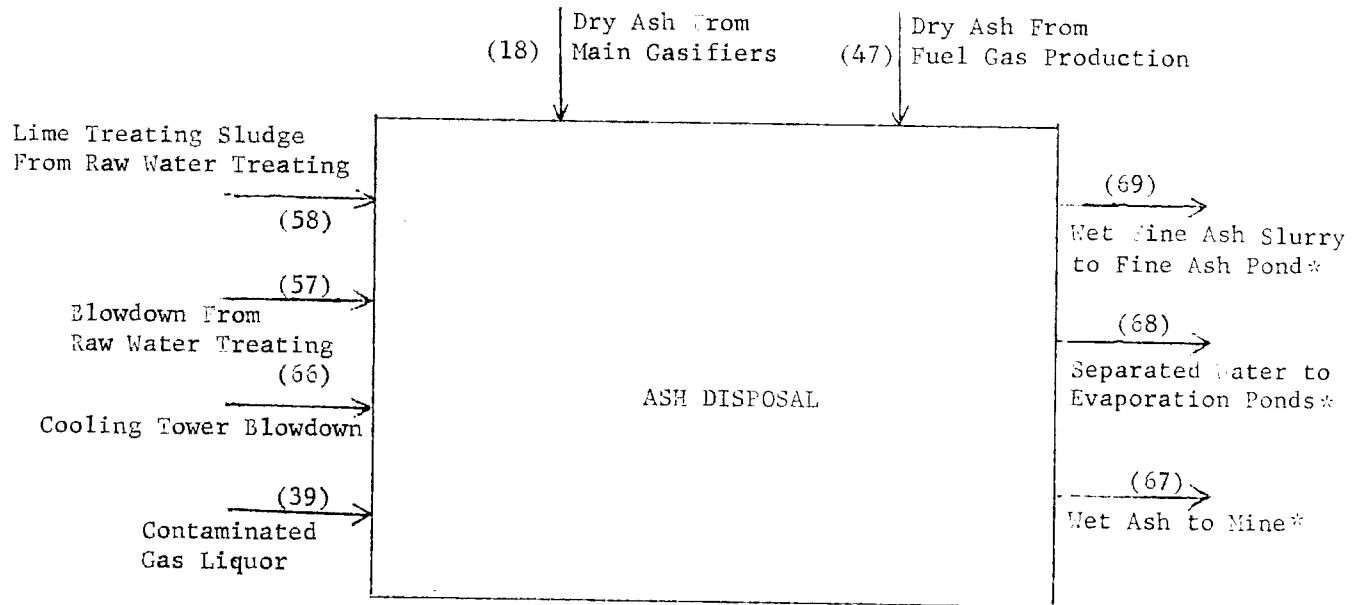
Figure 17

Ash Disposal

Table 17

Ash Disposal

Inlet Streams:

(18)   Dry Ash from Main Gasifiers; 196 tph.

(39)   Contaminated Gas Liquor; 330 gpm.

(47)   Dry Ash from Fuel Gas Production; 42 tph.

(57)   Blowdown from Raw Water Treating; 270 gpm.

(58)   Lime Treated Sludge from Raw Water Treating; 220 gpm.

(66)   Cooling Tower Blowdown; 330 gpm.

Outlet Streams:

*(67)   Wet Ash to Mine; 286 tph.   To be analyzed for trace constituents per Table 18.

*(68)   Separated Water to Evaporation Ponds; 900 gpm.   To be analyzed for trace constituents per Table 18.
Atmosphere over evaporation ponds to be analyzed per Table 18.

*(69)   Wet Fine Ash Slurry to Fine Ash Pond; 150 gpm.   To be analyzed for trace constituents per Table 18.
Atmosphere over evaporation ponds to be analyzed per Table 18.

* Analytical Samples.

3.18 Process Analytical Summary

The streams indicated for analysis around the Lurgi Process model are summarized in Table 18, along with specific references to suggested sampling and analytical procedures described in the Analytical Sections 5-9. Table 19 shows constituents present in coal feeds to gasification for SNG and fuel gas production.

The gasification system as described herein will almost certainly be modified appreciably before commercialization. The analyst is urged to adapt the logic of this analytical scheme to his specific requirements.

It is almost certain that existing legal sanctions will have increased by the time coal gasification systems are commercialized in this country. The analyst may be required to extend the list of analyses, although we have attempted to anticipate some future requirements. For example, polynuclear aromatic (PNA) materials, which may exhibit carcino-genic properties (31,32), may be present in almost any of the effluent streams from this system, and may also constitute significant fractions of the coal liquid byproducts. We have not indicated that all streams be analzyed for PNA, although this may be a future requirement. Similarly, we have not indicated that the coal liquid products be so analyzed, even though they will certainly contain harmful PNA, since the potential hazards of such materials are recognized within the industrial sector which now manufactures and utilizes coal-derived byproducts.

We have not always indicated that particulates recovered from gas or atmospheric samples be completely analyzed. The composition of coal dust, for example, should approximate the feed coal composition. However, procedures for determining the ultimate composition of particulate samples is included in the Analytical Sections. Future restrictions may require such definition. Moreover, it will be possible to analyze any stream in a given sample class for any of the components for which analytical procedures are indicated, so that the analyst may readily expand the analytical system to meet anticipated requirements.

We have attempted to indicate that all heater, incinerator, and boiler stack effluents shall be analyzed, even though such heaters may not have been specifically designated in the process scheme. Table 20 shows constituents expected in flue gases from boiler and heater stacks. Similarly, we intend that the atmosphere in the vicinity of all storage tankage or open storage areas, water cooling towers, and over all holding and evaporation ponds be analyzed for free hydrocarbons. The particular location and plant layout, prevailing winds, and climate will be taken into consideration in the sampling scheme.

This plant will generate additional long-term residuals not detailed in the processing sequence, including spent catalysts (from shift conversion and methanation) and spent filter media. Although such materials may be expected to be sulfated in general, and to contain other polluting materials when discharged, the quantities involved should not significantly affect overall long-term plant balances, unless the expected turnover period is shortened due to malfunction or emergency. Analysis of such discharged streams is indicated, however, to ascertain downstream pollution potential, since such materials will probably be buried with ash in this case unless metal values justify reclamation or unless future sanctions forbid such disposition. Very little attention has so far been given to the "neutralization" of such materials from other industrial processing.

We note also that it is necessary to chemically clean the boilers and associated piping in the power plant before these facilities are placed in operation, and at intervals of 2-3 years thereafter (40). Other plant facilities may require similar treatment. Both acidic and alkaline solutions are used in chemical cleaning. The acidic wastes would typically consist of solutions of hydroxyacetic and formic acids, or hydrochloric acid, at concentrations of less than 5%. The alkaline wastes would typically consist of dilute sodium phosphate solutions (less than 1%). A large amount of water would have to be used for flushing the system.

For a boiler of the size indicated, the total amount of waste produced could amount to several hundred thousand gallons of acidic and alkaline solutions, and up to a million gallons of flushing water. In this case, these wastes may be routed to settling ponds or to the ash basins, where they may be diluted or neutralized.

Finally, although not included in the process scheme herein presented, potential pollution from mining areas and from associated ash disposal operations are additional aspects that will concern any process developer and the immediate population, including plant operators, which may be affected. Environmental guidelines for water discharges from mining facilities already exist (33), and it is probable that future relevant solid waste restrictions will be promulgated.

Table 18

Summary of Effluent Streams to be Analyzed for Lurgi Plant

COAL GASIFICATION

LURGI PROCESS MODEL

Stream No.	Stream Name	Analysis For	Analytical Section Reference
4	Dust and Fumes in Coal Preparation Area	Atmosphere in enclosed spaces, discrete stack emissions from enclosed spaces and from dust collection equipment, and atmosphere in vicinity of coal piles, open conveying and handling equipment, and coal fines collection system to be analyzed for particulates.	Total particulates to be determined in enclosed spaces using a high volume sampler, Section 9; in stacks using EPA Method No. 5, Section 9; and the ASTM D 1739 dust fall test will be performed at various site locations.
5	Sized Coal to Gasifiers and to Fuel Production (See Tables 1 and 19)	Complete coal analysis including trace elements.	Coal will be analyzed for the elements listed in Section 7, Table VI and will be analyzed to determine its gross composition as indicated in Section 7, Table VII.
17	Coal Tar Product*	Trace Sulfur Compounds Trace Elements	Tar will be analyzed for total sulfur (Section 8, Table X); and the trace elements listed in Section 8, Table VIII will be measured.
22	Shift Startup Heater Stack Gas	Stack Gas Analysis Trace Sulfur Compounds Particulates	The stack gas will be analyzed for SO_2/SO_3, NO_x, CO, CO_2, COS, H_2S, and CH_3SH and for particulates. Refer to Section 9.
24	Tar-Oil-Naphtha Product*	Sulfur Trace Elements	This stream will be analyzed for the metals listed in Section 8, Table VIII and for total sulfur as indicated in Section 8, Table X.
30	Naphtha Product*	Sulfur Trace Elements	This stream will be analyzed for the metals listed in Section 8, Table VIII and for total sulfur as indicated in Section 8, Table X.

Table 18 (Cont'd)

Summary of Effluent Streams to be Analyzed for Lurgi Plant

COAL GASIFICATION

LURGI PROCESS MODEL

Stream No.	Stream Name	Analysis For	Analytical Section Reference
33	Synthetic Gas Product	Trace Sulfur Compounds Metal Carbonyls	The gas will be analyzed for particulates, COS, H_2S, CH_3SH and SO_2/SO_3; and for iron, nickel, and cobalt carbonyls. Refer to Section 9.
37 38	Absorber and Oxidizer Off-Gases and Incinerator Stack Gases	Trace Sulfur Compounds Particulates (V, Na)	Off-gases to be analyzed for particulates and for COS, H_2S, CH_3SH and SO_2/SO_3, see Section 9. In addition Na and V will be determined on particulates, see Section 7.
39	Liquid Sulfur Product*	Trace Elements	Sulfur will be analyzed for the metals listed in Section 8, Table VIII, by adaptation of methods which were designed for oil analysis.
41	Crude Phenol Product*	Total Sulfur Trace Elements	The trace elements in Section 8, Table VIII will be determined, and the sulfur content will be determined.
43	Aqueous Ammonia Solution Product*	Trace Sulfur Compounds Trace Elements	Sulfide, thiocyanate, and sulfite will be measured, Section 6, Table IV. The metals which are listed in Section 6, Table IV will be determined.
51	Deaerator Vent Gases	Particulates	Particulates will be determined.

Table 18 (Cont'd)

Summary of Effluent Streams to be Analyzed for Lurgi Plant

COAL GASIFICATION

LURGI PROCESS MODEL

Stream No.	Stream Name	Analysis For	Analytical Section Reference
52	Boiler Stacks and Heaters (multiple stacks are involved, including heaters in shift conversion and gas compression areas, see Table 20).	Stack Gas Analysis Trace Sulfur Compounds Particulates	The stack gases will be analyzed for SO_2/SO_3, NO_x, CO, CO_2, COS, H_2S and CH_3SH and for particulates. Refer to Section 9.
53	Raw Water to Process	Complete Water Analysis	Raw water will be analyzed for all components listed in Section 6, Table IV.
56	Degasser Vent Gases	Trace Sulfur Compounds Hydrocarbons	Vent gases will be analyzed for Thiophene, CS_2, SO_2/SO_3, COS, H_2S and CH_3SH and for benzene, toluene, and other volatile organics. See Section 9.
65	Evaporation and Drift from Cooling Towers	Atmosphere in vicinity of cooling towers to be sampled for: Trace Sulfur Compounds Trace Elements Hydrocarbons and PNA	A high volume sample will be collected and the particulates will be analyzed for the metals listed in Section 7, Table VI. In addition the atmosphere will be sampled for benzene, toluene, and other volatile organics; polynuclear aromatics; and for thiophene, CS_2, SO_2/SO_3, COS, H_2S, and CH_3SH (Section 9).
67	Wet Ash to Mine	Complete coal solids analysis and complete water analysis.	The solid material will be analyzed for the components listed in Section 7, Tables VI and VII. The aqueous phase will be analyzed for the components listed in Section 6, Table IV.

Table 18 (Cont'd)

Summary of Effluent Streams to be Analyzed for Lurgi Plant

COAL GASIFICATION

LURGI PROCESS MODEL

Stream No.	Stream Name	Analysis For	Analytical Section Reference
68	Ash Water Effluent to Evaporation Ponds*	As for Stream 67	The solid material with be analyzed for the components listed in Section 7, Tables VI and VII. The aqueous phase will be analyzed for the components listed in Section 6, Table IV.
69	Wet Fine Ash Slurry to Evaporation Ponds*	As for Stream 67	The solid material will be analyzed for the components listed in Section 7, Tables VI and VII. The aqueous phase will be analyzed for the components listed in Section 6, Table IV.

*   Atmosphere over all evaporation and holding ponds and vicinity of all storage tankage to be sampled and analyzed for hydrocarbons and trace sulfur compounds.

Table 19

Coal Input to Lurgi Coal Gasification (2)

Constituent	To Gas Production (Lbs/Hr)	To Fuel Gas Production (Lbs/Hr)
Carbon + HC	1,237,000	265,200
Sulfur	13,400	2,900
Ash	373,200	80,000
Moisture	315,000	67,500
	1,938,600	415,600
MMBTU/HR (H.H.V.)	16.795	3.601

Table 20

Flue-Gas Streams from Boiler
and Heater Stacks (2)

El Paso Complex

| Component | Lbs/Hr | | |
	Gas Turbines and Boilers	Steam Superheater	Heaters
Water Vapor	234,600	29,100	6,400
Nitrogen	4,798,700	243,300	53,300
Oxygen	1,006,400	11,800	2,600
Carbon Dixide	552,100	76,500	16,800
Sulfur Dioxide	290	40	10
Nitrogen Oxides (NO_2)	480	70	15
Particulates	NIL	NIL	NIL
	6,592,600	360,800	79,100

3.19 Unit Material Balances

As indicated in Section 1, the object of a material balance around
a coal gasification plant, from an environmental viewpoint, is to determine
all effluents to the environment and to furnish accountability for all
potential pollutants entering the plant or produced in the plant. The
analytical summary in Section 3.18 represents the simplest approach to
this balance. However, as indicated in Section 1, either a balance may
not be made or questions may arise as to the accuracy of some measure-
ments. In this case, analyses may have to be made around certain key
units. This would increase the cost considerably. If a balance could
not be established after this effort, then it would be necessary to trace
each component of interest through every unit. The cost would then be
extremely high.

In paragraphs 3.19.1 through 3.19.7 that follow, additional
streams from key units are designated as those that may have to be analyzed
to complete a balance or find a source of error. The analyses of the
streams indicated in these paragraphs require 28 to 29 more samples than
the 20 indicated in Table 18. If satisfactory results were not obtained,
then it may be necessary to analyze all 72 streams of figure 1.

3.19.1 Coal Preparation

It would be appropriate to determine the concentration of organic
and inorganic materials in the run-off from the coal area (streams 2 and
3) as a function of the quantity of rainfall.

3.19.2 Gas Cooling

Streams 15, 21, into gas cooling and streams 12, 23 and 25 from
gas cooling would have to be analyzed to check the analysis of stream 24.

3.19.3 Gas Purification

Streams 23 and 26 into gas purification and streams 27, 28 and 29
from the purification must be analyzed to check stream 30.

3.19.4 Sulfur Recovery

In order to check streams 37, 38 and 39 it will be necessary to
analyze streams 27, 35 and 36 into the Low-Pressure Stretford Unit and
stream 40 out of the unit.

3.19.5 Fuel Gas Treating

It would be wise to analyze stream 72 (solution purge) from the
high pressure Stretford unit. How this is done is difficult to predict
as this purge may be continuous, intermittent or, in some cases, none at
all.

3.19.6 Cooling Water System

This is one of the most critical units for over-all material balance. Good sampling of evaporation and drift losses are difficult and other factors may make the cooling towers research projects in themselves. To get a material balance, it may be necessary to analyze streams 42, 59, 60, 61, and 62 into the system and streams 63, 64 and 66 out of the system. Even this may not be sufficient as trace pollutants can be trapped in slime in the towers. This also may have to be analyzed and its quantity estimated. Whether or not these analyses will check the analysis of stream 65 is uncertain due to the sampling problems mentioned above.

3.19.7 Ash Disposal

The streams into ash disposal should probably be analyzed and compared with effluent streams 67, 68 and 69 to be sure no air pollutants are escaping. This would entail analyses of streams 18, 39, 47, 57, 58 and 66.

3.19.8 Special Unit Material Balances

In some cases, as indicated in Section 1, it may be desirable to determine a material balance around a particular unit. This could arise, for example, when it is necessary to know the contribution of a particular unit to the total effluent/heat load of a plant. Sampling would then be carried out on all the streams in and out of the unit and the samples would be analyzed according to the methods outlined later in Sections 7 through 12. An example of this might be Gas Purification (Section 3.7). All streams in figure 7, together with any others in the particular unit under consideration (e.g., vents, liquid purges, solution makeup, etc.), would then be sampled and analyzed. These analyses, along with heat, steam, hot water, electrical and cooling water requirements, would allow the pollutant/heat load of this unit to be compared with similar units in other plants. It is anticipated that no special revisions of this analytical test plan will be necessary to accommodate such requirements.

4. COAL LIQUEFACTION

Liquefaction, as a term applied to coal processing, is not so definitive as in gasification. The term has been applied generally to processes which produce liquid products from coal, but is also used in connection with solvent or chemical refining processes which desulfurize or de-ash coal (34,35) and to processes such as combined gasification and catalytic recombination, as in the Fischer-Tropsch synthesis, to produce organic liquids (36). The primary de-ashed product from current solvent-refined coal processes, for example, is not liquid at ambient temperatures (37). And the major products from some "liquefaction" processes are not liquids, but rather solid chars containing most of the ash in the original feed coal.

The COED process chosen for the coal liquefaction model falls into this category. Some 50-60 weight percent of the starting coal feed issues as product char, containing about the same amount of sulfur and having about the same heating value as the feed coal. Economic considerations would probably require that a commercial COED facility include a char gasification facility, and the FMC Corporation, the process developer, is currently engaged in char gasification studies (38).

4.1 System Basis

The COED process has been under development by FMC Corporation as Project COED (Char-Oil-Energy Development) since 1962 under the sponsorship of the Office of Coal Research of the U.S. Department of the Interior (6-16). Bench-scale experiments led the way to design and construction in 1965 of a process development unit (PDU) employing multistage, fluidized-bed pyrolysis to process 50-100 pounds of coal per hour (6). Work with the PDU was extended to other coals in 1966, and hydrotreating of COED oil from the PDU was studied by Atlantic Richfield Company (7). Correlated studies included an investigation of char-oil and char-water slurry pipelining economics, high-temperature hydrogenation for char desulfurization, and an economic appraisal of the value of synthetic crude oil produced from COED oil.

A COED pilot plant able to process 36 TPD of coal and able to hydro-treat 30 BPD of oil was designed and constructed at Princeton, New Jersey in 1970 (10). The pilot plant was operated successfully on a number of coals in 1971-72 (11). Development of the process is continuing, with major funding provided by OCR.

The process basis for our process model is the design study developed by FMC Corporation in 1973 for a "25,000 TPD COED plant" (39). Process flowsheets were developed for the pyrolysis plant, raw oil filtration section, and for the hydrotreating facility. This design feeds 25,512 TPD of an Illinois No. 6-seam coal containing 5.9% moisture, 10.6% ash, and 3.8% sulfur. 12,512 TPD of product char is recovered, along with 3945 TPD of hydrotreated oil (24,925 bpd of indicated 25° API gravity). Flowsheets were not developed for coal preparation, gas treatment, hydrogen manufacture, oxygen manufacture, sulfur production, water and waste treatment, or utilities generation. We have estimated some of the auxiliary requirements (16).

4.2 Process Basis

Figure 18 is a schematic representation of the overall processing scheme. The COED process is a continuous, staged, fluidized-bed coal pyrolysis operating at low pressure and is designed to recover liquid, gaseous, and solid fuel components from the pyrolysis train. Heat for the pyrolysis is generated by the reaction of oxygen with a portion of the char in the last pyrolysis stage and is carried countercurrently through the train by the circulation of hot gases and char. Heat is also introduced by the air combustion of the gas used to dry feed coal and to heat fluidizing gas for the first stage. The number of stages in the pyrolysis and the operating temperatures in each may be varied to accomodate feed coals with widely ranging caking or agglomerating tendencies.

Oil that is condensed from the released volatiles is filtered on a rotary precoat pressure filter and catalytically hydrotreated at high pressure to produce a synthetic crude oil. Medium-Btu gas produced after the removal of acid gases is suitable as clean fuel, or may be converted to hydrogen or to high-Btu gas in auxiliary facilities. Residual char (50-60% of feed coal) that is produced has heating value and sulfur content about the same as feed coal.

A large sample of Illinois coals has been analyzed by Ruch and coworkers (41). As an approximate number, Table 21 lists the mean analytical values of trace elements found for Illinois coals, which represent feed for this study.

This system will produce about 500 TPD of sulfur, in addition to char and syncrude.

The streams indicated for analysis around the COED Process model are summarized in Table 35.

The qualifications and considerations outlined in Section 3.18 for coal gasification are also applicable here. It is intended that all heater and boiler stack effluents shall be analyzed. Similarly, this plant will generate residuals, including hydrotreating and reforming catalysts, sulfated lime sludges from flue-gas treating, and chemical sludges and blowdowns from water treating, gas purification, and tail-gas treating that will probably require special treatment before disposition by the time a facility of this type is constructed. Currently, such materials are commonly trucked to landfill or allowed to accumulate in evaporation ponds.
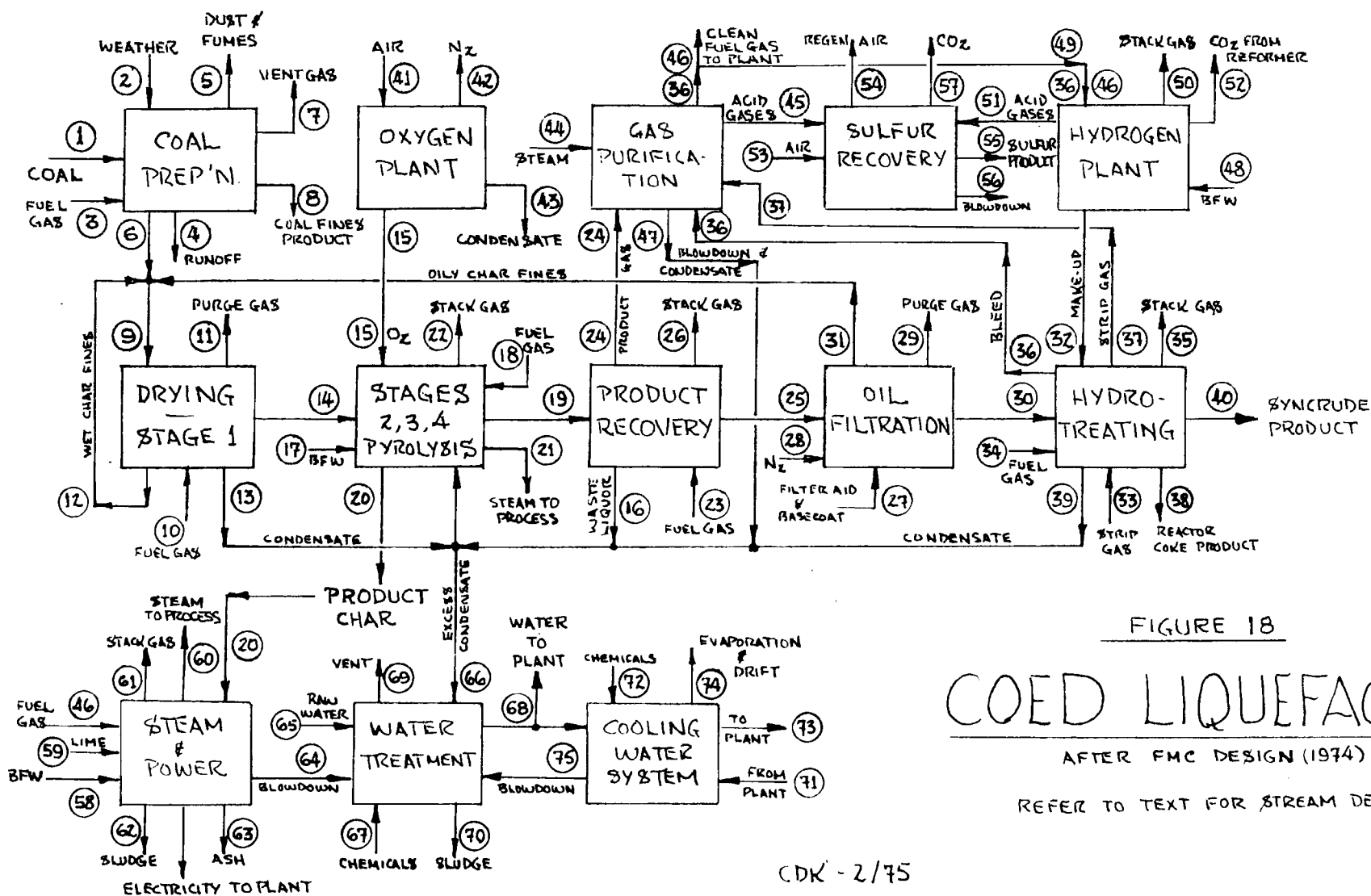
FIGURE 18

COED LIQUEFACTION

AFTER FMC DESIGN (1974)

REFER TO TEXT FOR STREAM DETAILS

CDK - 2/75

Table 21

Mean Analytical Values for 82 Coals from the Illinois Basin (4)

CONSTITUENT	MEAN		STD	MIN	MAX
AS	14,91	PPM	18,94	1,70	93,00
B	113,79	PPM	51,72	12,00	224,00
BE	1,72	PPM	0,83	0,50	4,00
BR	15,27	PPM	5,60	6,00	52,00
CD	2,89	PPM	8,32	0,10	65,00
CO	9,15	PPM	5,76	2,00	34,00
CR	14,10	PPM	7,48	4,00	54,00
CU	14,09	PPM	6,78	5,00	44,00
F	59,30	PPM	19,79	30,00	143,00
GA	3,04	PPM	1,03	1,60	7,30
GE	7,51	PPM	7,08	1,00	43,00
HG	0,21	PPM	0,22	0,03	1,60
HN	53,16	PPM	40,98	6,00	181,00
H8	7,96	PPM	5,68	1,00	29,00
NI	22,35	PPM	10,81	8,00	68,00
P	62,77	PPM	65,66	5,00	339,00
PB	39,83	PPM	45,94	4,00	218,00
SB	1,35	PPM	1,42	0,20	8,90
SE	1,99	PPM	0,93	0,83	7,70
SN	4,56	PPM	6,64	1,00	51,00
V	33,13	PPM	11,63	16,00	78,00
ZN	313,04	PPM	749,92	10,00	5330,00
ZR	72,10	PPM	58,01	12,00	133,00
AL	1,22	%	0,37	0,43	3,04
CA	0,74	%	0,49	0,05	2,67
CL	0,15	%	0,15	0,01	0,54
FE	2,06	%	0,71	0,48	4,32
K	0,16	%	0,04	0,04	0,30
MG	0,05	%	0,02	0,01	0,17
NA	0,03	%	0,04	0,00	0,19
SI	2,39	%	0,62	0,58	4,53
TI	0,06	%	0,02	0,02	0,15
ORS	1,54	%	0,62	0,37	3,09
PYS	1,88	%	0,73	0,29	3,73
SUS	0,09	%	0,18	0,01	1,05
TOS	3,51	%	1,12	0,65	5,59
SXRF	3,19	%	1,05	0,79	5,40
ADL	7,70	%	3,47	1,40	16,70
MOIS	10,02	%	4,23	1,50	18,20
VOL	39,80	%	3,17	31,90	46,40
FIXC	48,98	%	3,92	41,30	61,00
ASH	11,28	%	1,98	4,60	16,00
BTU/LB	12748,91		464,90	11562,00	14352,00
C	70,69	%	3,11	62,43	79,94
H	4,98	%	0,26	4,19	5,76
N	1,35	%	0,30	0,93	1,84
O	8,19	%	1,84	4,13	14,36
HTA	11,18	%	2,17	5,28	15,04
LTA	13,22	%	3,22	3,82	23,53

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

4.3 Coal Preparation (Figure 19 and Table 22)

Onsite coal storage will be required to provide backup for continuous operations. For 30 days storage, there might be eight piles, each about 200 feet wide, 20 feet high, and 1000 feet long. Containment of airborne dusts is generally the only air pollution control required for transport and storage operations, although odor may be a problem in some instances. Covered or enclosed conveyances with dust removal equipment may be necessary, but precautions must be taken against fire or explosion. Circulating gas streams which may be used to inert or blanket a particular operation or which may issue from drying operations will generally require treatment to limit particulate content before discharge to the atmosphere. Careful management and planning will minimize dusting, wind loss, and the hazard of combustion in storage facilities.

The as-received feed coal employed in this design is indicated to have 10-14 weight percent moisture content. The FMC process basis feeds coal of about 5.9 weight percent moisture to the coal dryer ahead of the first pyrolyzer. Hence the free or surface moisture is assumed to be removed in the upstream coal preparation plant.

Free moisture would be removed from feed coal by milling in a stream of hot combustion gases. The mechanical size reduction of an Illinois coal is expected to generate a considerable quantity of minus 200 mesh fines, especially if appreciable drying accompanies the milling operation. The quantity of such fines has been estimated to be 5 to 8 percent of the feed, depending on the type of equipment that may be used. The ultimate consideration is that the total fines fed to the dryer or to the first pyrolyzer shall not overload the cyclone systems that are provided to effect their separation from the respective effluent streams. Therefore fines generated in coal preparation, amounting to 5 percent of feed coal, will not be charged to pyrolysis but will issue as a fuel product. Coal fines would probably be charged to the char gasification system, if this facility is included.

Clean product gas is fired in the mill heater. About 110 tph of water must be removed if coal is received with 14 percent moisture. This may require the firing of 15-20 tph of product gas with 180-200 tph of combustion air in the milling circuit. Assuming a dry particulate separation system is adequate, bag filters might be used to recover fines from the vented gas following primary classification in cyclones.
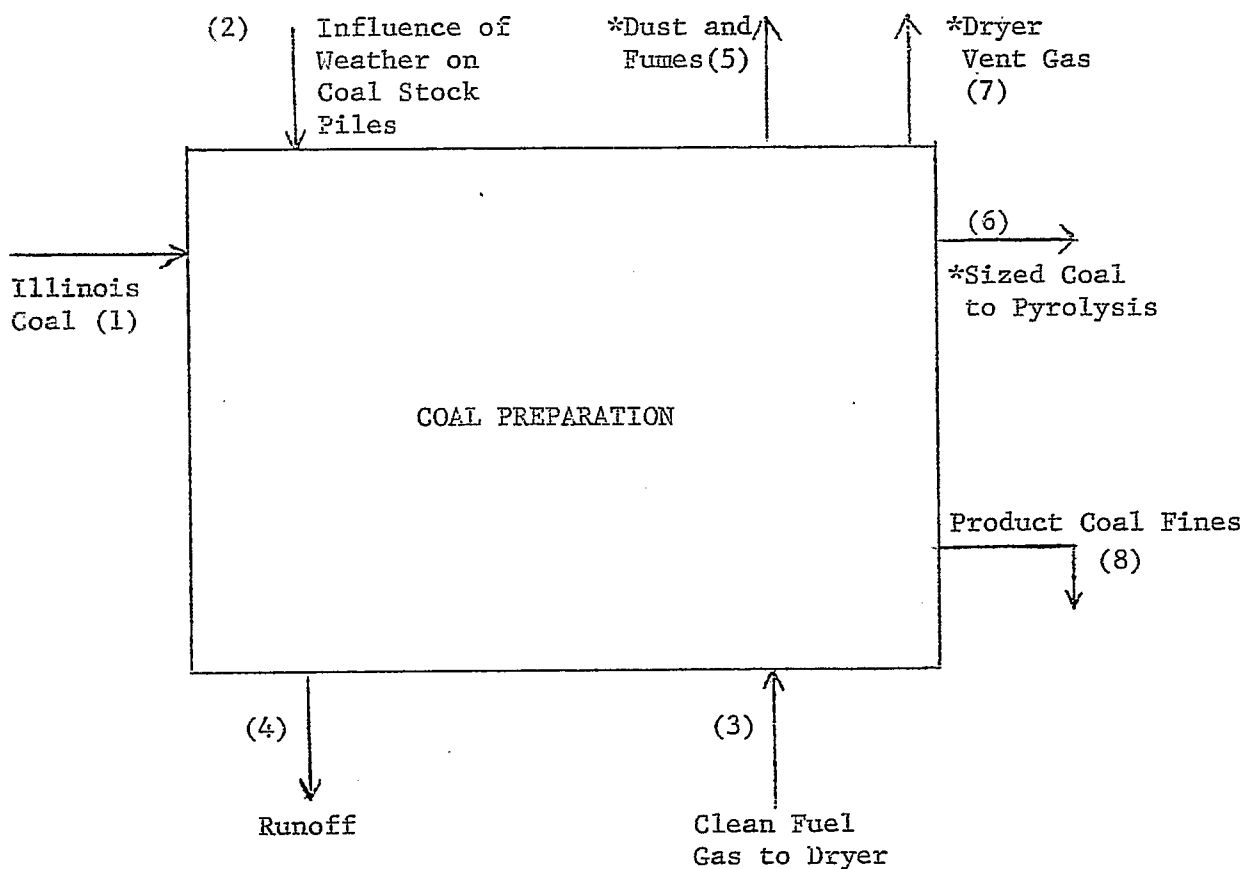
Figure 19

Coal Preparation for COED Plant