National Student Design Competition 1993

AMERICAN INSTITUTE OF CHEMICAL ENGINEERS
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If there are any questions about the design problem, student chapter counselors and design course, instructors are asked to contact:

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Please read the rules found on the preceding page carefullybefore submitting a solution to AIChE

AMERICAN INSTITUTE OF CHEMICAL ENGINEERS
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AIChE NATIONAL STUDENT DESIGN COMPETITION 1993

Integrated Coal Gasification Combined Cycle Power Generation Plant Design

DEADLINE FOR MAILING

Solutions must be postmarked not later than **Midnight, June 4, 1993.**

RULES OF THE CONTEST

Solutions will be graded on (a) substantial correctness of results and soundness of conclusions, (b) ingenuity and logic employed, (c) accuracy of computations, and (d) form of presentation. Accuracy of computations is intended to mean primarily freedom from mistakes; extreme precision is not necessary.

It is to be assumed that the statement of the problem contains all the pertinent data except for those readily available in handbooks and similar reference works. The use of textbooks, handbooks, journal articles, and lecture notes is permitted, and use of the supporting data provided by AIChE for this case study is strongly encouraged.

Students may use any available commercial or library computer programs in preparing their solutions. Students are warned, however, that physical property data built into such programs may differ from data given in the problem statement. In such cases, as with data from other literature sources, values given in the problem statement are most applicable. Students using commercial or library computer programs or other solution aids should so state in their reports and include proper references and documentation. Students are further advised that the problem can be solved without the use of sophisticated computer programs. Judging is based on the overall suitability of the solution, not on skills in manipulating computer programs.

The Student Contest Problem is designed to be solved by individual chemical engineering students working entirely alone, and it is judged on that basis. There are, however, other academically sound approaches to using the problem. The following confidentiality rules therefore apply:

1. For students whose solutions may be considered for the contest:
The problem may not be discussed with anyone (students, faculty, or others, in or out of class) before or during the period allowed for solution. Discussion with faculty and students at that school is permitted only after complete final reports have been submitted to the chapter counselor.

2. For students whose solutions are not intended for the contest:
Discussion with faculty and with other students at that school who are not participating in the contest is permitted.

3. For all students:
The problem may not be discussed with students or faculty from other schools, or with individuals in the same school who are still working on the problem for the contest, until after **June 4, 1993**. This is particularly important in cases where neighboring institutions may be using different schedules.

Submission of a solution for the competition implies strict adherence to these conditions.

A period of not more than thirty days is allowed for completion of the solution. This period may be selected at the discretion of the individual counselor, but in order to be eligible for an award a solution must be postmarked not later that midnight, **June 4, 1993**. ONLY SOLUTIONS SUBMITTED BY NATIONAL STUDENT MEMBERS OF AIChE WILL BE CONSIDERED FOR AWARDS.

THE FINISHED REPORT SHOULD BE SUBMITTED TO THE CHAPTER COUNSELOR WITHIN THE 30-DAY PERIOD. There should not be any variation in form of content between the solution submitted to the chapter counselor and that sent to the AIChE office. The body of the report must be suitable for reproduction, that is, typewritten or computer-generated. Tables may be written in ink. Supporting calculations and other appendix material may be in pencil. Each counselor should select the best solution or solutions, not to exceed two, from his or her chapter and send these by registered mail to the Institute.

Two copies of the solution(s) must be accompanied by a letter of transmittal giving only the contestant's name, school address, home address, home telephone number, and student chapter, lightly attached to the report. This letter will be retained for identification by the executive director of the Institute. The solution itself must bear no reference to the student's name or institution by which it might be identified. In this connection, graph paper bearing the name of the institution should be avoided. Original manuscript(s) must remain in the possession of the student chapter counselor, or faculty member, sponsoring the student(s).

As soon as the winners have been notified, original manuscripts for first, second, third and honorable mention categories must be forwarded to the office of the executive director as soon as possible.

Richard E. Emmert
Executive Director
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PROBLEM STATEMENT OUTLINE

"INTEGRATED COAL GASIFICATION COMBINED CYCLE POWER GENERATION PLANT DESIGN"

INTRODUCTION

Energy conservation efforts by electric utilities and their customers are expected to help temper the growth in electricity demand over the next twenty years. Despite this trend, electricity use in all sectors - residential, commercial, and industrial is still expected to show continued growth in the years ahead. The Department of Energy forecasts that electricity consumption in the U.S. will be more than 20% above the 1990 levels by the end of this decade.

To meet this demand, utilities will build additional power plants and extend the lives of existing older power plants. Ready availability, secure domestic supply and low price will make coal the fuel choice for the majority of new baseload generating capacity. Coal fired power plants now supply more than 50% of all electricity generated in the U.S. Increased emphasis on environmental quality will require that new coal-based power plants use the cleanest, most efficient generating technologies available.

Coal **G**asification **C**ombined **C**ycle (CGCC) power generation is the cleanest, most efficient method of producing electricity from coal. It reduces emissions of sulfur dioxide and nitrogen oxide, both associated with acid rain, to levels far below strict Federal standards as well as producing less carbon dioxide, heavy metals, and solid wastes.

The business department of your company wants a new estimate of the cost of electricity from a more optimally designed CGCC. Your engineering department has been asked to redo a previous preliminary design evaluation. In particular, alternate designs of two sections of the coal gasification plant must be evaluated to improve the overall plant energy performance and reduce costs.

STATEMENT OF THE PROBLEM

You are to provide:

1. A block flow diagram similar to Figure 1 of your plant design showing in addition to the major equipment blocks all the interfacial equipment between equipment blocks and all interface streams.

2. Provide material balances as needed to size the specified pieces of equipment and package units.

3. Estimate the installed cost for all pieces of equipment and package units.

4. Provide an economic analysis of the cost of electricity at a specified investment rate of return. Include a table or tables giving the financial details of the return on investment analysis. The table is to include details of the calculation such as operating and maintenance costs, etc.

FINAL REPORT FORMAT

1. INTRODUCTION - Describe in words for the reviewer the task you have been asked to perform.

2. SUMMARY - Summarize the results of your analysis, conclusions, and recommendations. Very briefly, tell what was done to reduce cost and increase net power production. Also discuss what else might be done to improve the plant performance. Include:

    * gross kW production

    * net kW production

    * total capital cost in $ and in $/kW of net production

    * heat rate in BTU/hr (HHV basis) of as-received coal per kW of net power production

3. DISCUSSION - Present the details of your results including assumptions and their impact. Tables and graphs need not be included in the this section, but can be referenced.

4. CONCLUSIONS - List your conclusions in decreasing order of significance. Provide more detail than

given in the summary.

5. RECOMMENDATIONS FOR FURTHER IMPROVEMENTS AND THEIR POTENTIAL FOR REDUCTION IN COST OF ELECTRICITY - A section describing what additional changes could be made if specific constraints contained in this problem statement were lifted, and the potential improvements which might result. Provide more detail than given in the summary.

6. ATTACHMENTS - Include as attachments all figures, tables, and calculations, especially those specified in the Statement of the Problem and Design Data and Bases sections. Include as a separate attachment a table or list of additional assumptions (beyond those provided in this problem statement) that were necessary for your problem solution.

INTEGRATED COAL GASIFICATION COMBINED CYCLE PROCESS DESCRIPTION

CGCC integrates three commercially proven technologies (see Figure 1): the efficient separation of oxygen from air in a modern air separation unit (ASU), the manufacture of a clean burning fuel gas from coal in the coal gasification plant (CGP) and the highly efficient use of that fuel gas to produce electricity in a combined cycle power plant (CCPP). In the coal gasification process, coal reacts with oxygen and steam at high temperature and pressure to produce a fuel gas. Oxygen is provided by a modern cryogenic air separation unit. The raw fuel gas is cleaned and then burned in a CCPP. The CCPP has two basic components: High efficiency gas turbines, now in use in the utility industry, burn the clean fuel gas to produce electricity. Exhaust heat from the gas turbine is recovered as steam and converted to additional power by traditional steam turbines.

Integration of the thermal energy recovery sections of the CCPP with the CGP reduces the overall plant capital costs. Additional integration of the compressed air systems of the combined cycle and ASU can lead to both reduced capital costs and reduced auxiliary power requirements. Finally, available mass and energy can be redirected and more fully integrated to produce more net power. The overall thermal efficiency in converting coal to net electric power can be as high as 43-46% (LHV basis), which is higher than in a pulverized coal boiler steam cycle plant.

COMBINED CYCLE POWER PLANT

The major components of the combined cycle power plant (CCPP) include the gas turbine (GT), the heat recovery steam generator (HRSG), and the steam turbine (see Figure 2). Modern gas turbines compress air, raise the air to high temperature with fuel in a combustor, then expand the heated, pressurized gas in a power turbine to atmospheric pressure. The fuel may be natural gas, clean coal gas, by-product refinery gas, or liquid fuels. The compressor, power turbine and generator may be on one shaft to drive the compressor and net out electricity with the generator.

Depending upon the details of the integration, a portion of the compressed air may be extracted to supply air to the ASU. Steam and/or return nitrogen may be added to the gas turbine combustor to control thermal NOx formation. In addition, these diluents provide more mass for expansion in the power turbine to generate more net electricity.

The thermal energy of the GT flue gas is further recovered by heat transfer to steam in the HRSG. The HRSG produces HP, MP, and LP steam products, which are superheated and sent to the appropriate stage of the steam turbine. High pressure saturated steam from the CGP is integrated into this steam cycle. Condensate is also integrated between the process blocks, and acts as a heat sink to economically recover low level heat for additional steam generation.

Modern high efficiency gas turbines can convert some 37-40% (LHV basis) of the chemical energy in its fuel to net electricity. Most of the GT flue gas thermal energy is recovered for additional power generation in the steam cycle, yielding an overall CCPP energy efficiency of 52-53% (LHV basis).

For this problem, the CCPP will be purchased as a turnkey unit, fully installed.

COAL GASIFICATION PLANT

Coal is one of the most abundant sources of energy in the U.S. Gasification is a process in which this "hydrocarbon" feedstock is converted into a gas consisting mainly of carbon monoxide and hydrogen. The product gas can be used as fuel for power production. Gasification is a unique process as in almost all cases it can be described by assuming equilibrium conditions, particularly for entrained slagging gasifiers as are being studied here.

The reactions which follow are for the oldest of gasification processes - coal gasification. They represent the primary reactions taking place. The heat of reaction assumes that the carbon is present as pure graphite. A negative heat of reaction shows that the reaction is exothermic.

C +	1/2 O_2	-->	CO	-110 MJ/kmole carbon
C +	H_2O	-->	CO + H_2	+ 131 MJ/kmole carbon
C +	2 H_2	-->	CH_4	- 75 MJ/kmole carbon

These reactions describe in fact the three ways in which a hydrocarbon fuel can be gasified:

1) partial oxidation
2) endothermic reaction with steam
3) hydro-gasification

Reactions involved other coal constituents are also occurring. In practice coal will contain heteroatoms such as sulfur and nitrogen, and the oxygen used will always contain some argon. Nitrogen in the coal is mostly converted to molecular nitrogen, but a small part is converted to ammonia and other reduced nitrogen species. Sulfur is 90% converted to hydrogen sulfide and carbonyl sulfide. The remainder of the sulfur in the coal leaves in the ash streams. In an entrained flow gasifier, because of the high temperatures the ash melts in the gasifier and is then solidified and discharged in a glassy form.

There is also increasing environmental pressure for the reduction of sulfur and nitrogen oxides and carbon dioxide emissions. This gives coal gasification additional advantages over conventional coal fired power stations. Sulfur removal is easier, cheaper and accomplished to a greater extent in coal gasification. Nitrogen oxide (NOx) precursors are removed to low levels in the fuel gas before entering the gas turbine combustor. Overall, carbon dioxide emissions for CGCC are lower than for conventional pulverized coal technologies because the process is more efficient.

Figure 3 shows a block diagram of a CGP capable of supplying fuel gas to a CCPP. Please refer to this and the additional referenced figures during the brief descriptions of the various sections provided below.

<u>Coal Preparation (Coal Milling & Drying)</u>

Figure 4 presents a block diagram of the coal preparation area base case. This plant is required to prepare the coal that will be converted to fuel gas in the gasification plant. In this particular process, coal is pulverized with a roller type mill. Hot gas is introduced to the mill, where it "flash" dries the coal. The dried and pulverized coal is then carried from the mill by the circulation gas. The dried coal is next separated from the circulation gas in a conventional baghouse or bag filter system. Nitrogen is the pulse cleaning gas which is injected into the bags to periodically remove the coal from the bags.

Following the baghouse, a portion of the water-laden dust-free circulation gas is vented to the atmosphere to purge the water removed from the coal and also to control the system pressure. Dry make-up gas is added to the circulation gas to maintain a constant mass flow in the circulation loop at the mill inlet.

The circulation gas is recirculated with a blower, and is also reheated indirectly using steam. The heat input to the circulating gas is controlled by the mill exit temperature. Extended surface area heat exchangers are used in the reheat heat exchanger as they have a low pressure drop while providing a ten-fold increase in effective heat transfer surface area.

<u>Coal Pressurization & Feeding, Gasification, and Slag Handling</u>

Figure 3 presents a block flow diagram for the CGP base case, including the coal pressurization and feeding, gasification, and slag handling sections. Following the pulverization and drying of coal in the milling system, the coal is pressurized in the coal pressurization and feeding section of the plant. The technology which is in use in this process is a lock hopper technology, suitable for the dry feeding of pulverized coal into the gasifier.

Following pressurization, dried and milled coal is delivered to a gasifier. The organic components of the coal are converted at high temperature and pressure to a fuel gas containing mainly carbon monoxide and hydrogen, plus small amounts of carbon dioxide, water, and hydrogen sulfide. Nitrogen is also present in the fuel gas since it is used as a conveying gas to pressurize and transport the coal into the gasifier.

Under the conditions in the gasifier, the mineral matter (or ash) in the coal is melted. Part of this molten ash is entrained overhead with the product fuel gas. This entrained material is referred to as fly ash. The remaining molten ash is deposited on the gasifier walls as molten slag. The molten slag flows down the gasifier walls and across the floor to an opening in the center called the slag tap. From the slag tap the molten slag drips into a water bath. The function of the water bath is to freeze the molten slag into a granular glassy material. This material is referred to as slag. The slag from the gasifier is depressurized and stored in a stockpile, as it is a salable by-product material. The glassy granular slag can be used as an ingredient in concrete and asphalt, and has a market value.

Quench and Fuel Gas Cooling

The fly ash that leaves the gasifier with the raw fuel gas must also be frozen to avoid building deposits on downstream cooling equipment. The molten ash is frozen by mixing "quench" gas into the fuel gas leaving the gasifier and allowing the entrained fly ash droplets to freeze.

Following the quench the fuel gas must be further cooled. For this purpose a series of heat exchangers are typically used. In these exchangers boiler feedwater is heated and saturated steam is generated. Approximately 15-18% of the energy in the coal is converted to steam in this portion of the plant. This steam is further converted to salable electricity by the steam turbine in the CCPP.

Gas Cleanup

The remainder of the CGP is referred to as the gas cleanup portion of the plant. In the various processing steps involved in gas cleanup, the trace constituents in the fuel gas (e.g. fly ash, carbonyl sulfide, ammonia, hydrogen sulfide) are removed in individual steps.

Following cooling of the fuel gas, fly ash is removed in a large filter. This fly ash also represents a salable by-product stream.

After this step, the trace amounts of carbonyl sulfide are "removed" by converting it to hydrogen sulfide in a catalyst bed. Both ammonia and hydrogen sulfide are then removed in absorbers. In the ammonia removal step, the fuel gas is cooled in the absorber to 100 °F and excess water vapor in the fuel gas is condensed. Ammonia removed from the syngas is converted to elemental nitrogen. A water treating step is included to recover this process water for reuse in the plant steam system. The hydrogen sulfide removed from the fuel gas is converted to salable elemental sulfur in the sulfur recovery portion of the plant. This unit typically consists of a Claus sulfur recovery unit and some form of off-gas treating unit to limit total sulfur emissions to the environment.

Finally, the clean fuel gas is reheated in a final heat exchanger prior to being sent to the gas turbine. This exchanger is an integral part of the gasification section 1700 psia steam system.

AIR SEPARATION UNIT

A modern air separation unit provides the oxygen and high pressure (HP) and low pressure (LP) nitrogen streams needed by the coal gasification combined cycle (CGCC) process. LP nitrogen may also be returned to the gas turbine for NOx suppression and to provide additional mass for power generation. The ASU consists of a main air compressor, contaminants removal section, a cryogenic fractionation unit, and booster compressors for the oxygen and nitrogen (see figure 5). The cryogenic factionation unit consists of a 2-column distillation operation under cryogenic conditions.

In an integrated CGCC plant, some of the required air may be extracted from the gas turbine at pressure and the balance is then provided by a stand-alone compressor. Heat can be recovered from the extracted air by heat exchange with LP nitrogen and with boiler feed water. The combined compressed air streams are cooled against cooling water and routed to the cryogenic section of the plant for mole sieve drying and fractionation.

Oxygen product at 95% volume is compressed and routed to the gasifier. Nitrogen is compressed to higher pressure and then used in the gasification plant for coal handling. Some LP nitrogen is also routed to the gasification plant for miscellaneous usages, but much of this nitrogen is compressed and returned to the gas turbine combustor for NOx control.

DESIGN APPROACH

The main process feed rates and products must first be established. In this problem, the fuel required by the gas turbine is fixed. This fuel requirement sets the coal gasification product rate, which is then related to the as-fed (AF) or dried coal feed rate by the term "cold gas efficiency" (CGE). CGE is the ratio of the clean fuel gas chemical energy expressed in a higher heating value (HHV) basis divided by the chemical energy of the as-received (AR) coal also on an HHV basis. The oxygen requirements are set by the weight ratio of pure oxygen to the moisture-and-ash-free (MAF) coal entering the gasifier.

High pressure steam production and the return nitrogen flow rate to the gas turbine are variables to be maximized to improve overall energy performance.

TECHNICAL DATA

COAL GASIFICATION PLANT

1. Design Coal data are presented in Table 1.

TABLE 1
Proximate Analysis, % weight

Moisture (AR)	9.07
Ash (MF)	7.59
Volatile Matter (MF)	36.97
Fixed Carbon (MF)	55.44

TABLE 1 - (cont'd)
Ultimate Analysis, % weight (MF)

Carbon	78.03
Hydrogen	5.06
Nitrogen	1.69
Sulfur	1.97
Ash	7.59
Oxygen (by difference)	5.66

Heating Value

HHV (AR) BTU/lb	12775

Abbreviations:
AR - as received in the plant
MF - moisture free
MAF - moisture & ash free
HHV - higher heating value
LHV - lower heating value

2. The fuel gas heat capacity is well represented by the following equation. Neglect the effect of composition other than the effect of nitrogen dilution as provided for in the equation.

$$Cp\ (BTU/lb{\cdot}°F) = A + B * y_{N2} + C * T + D * T^2$$

equation valid for fuel gas from 100-2800 °F

where:
y_{N2} = mole fraction nitrogen in fuel gas
T = temperature, °F
A = 3.49 E-01 B = 1.45 E-01 C = 4.07 E-05 D = 5.15 E-09

3. Fuel gas heating value may be calculated by the following equation:

$$LHV\ (BTU/mol) = 104036 * y_{H2} + 121745 * y_{CO} + 223156 * y_{H2S} + 236092 * y_{COS} + 345165 * y_{CH4}$$

$$HHV\ (BTU/mol) = 122971 * y_{H2} + 121745 * y_{CO} + 242077 * y_{H2S} + 236092 * y_{COS} + 383036 * y_{CH4} + 18920.7 * y_{H2O}$$

where:
y_{H2} = mole fraction hydrogen in fuel gas
y_{CO} = mole fraction carbon monoxide in fuel gas
y_{H2S} = mole fraction hydrogen sulfide in fuel gas
y_{COS} = mole fraction carbonyl sulfide in fuel gas
y_{CH4} = mole fraction methane in fuel gas
y_{H2O} = mole fraction water vapor in fuel gas

AIR SEPARATION UNIT

1. Air Separation Unit gas stream composition data are given in Table 2.

TABLE 2
AIR SEPARATION UNIT COMPOSITION DATA
(mole %)

	AIR	HP N_2	O_2	LP N_2
N_2	77.33	99.8	2.3	98.9
O_2	20.74	0.1	95.0	0.6
Ar	0.92	0.1	2.7	0.5
H_2O	1.01	--	--	--

Abbreviations:
LP - low pressure
HP - high pressure

DESIGN DATA & BASES

GENERAL

1. **Use the data and design constraints and assumptions provided here rather than information from other sources. Note that comments regarding the validity of such assumptions are expected as part of the problem solution.**

2. **Additional assumptions can be made if the information provided is insufficient or unclear. However, such assumptions are to be clearly stated and the need defined. A list of all such assumptions is to be included as a table in the attachments to each problem solution.**

3. Ideal gas properties and calculation methods are applicable.

4. The following saturated steam pressure levels are in general use and thus available in the plant:

   a. 65 psia (low pressure, LP) - generated and used only in package units
   b. 600 psia (medium pressure, MP) - generated and used only in package units
   c. 1700 psia (high pressure, HP)

5. Boiler feed water at the above pressure levels is also available from the combined cycle power plant, but only at a temperature of 92 °F.

6. Cooling water is available at 65 °F. Use a 20 °F rise.

7. Ambient air temperature is 59 °F, with a relative humidity of 60%, and elevation is sea level.

8. All electrical motor driver efficiencies = 98%.

9. General plant consumption of low pressure nitrogen is 3000 lb/hr. This includes all purging requirements.

10. Auxiliary power consumption for the gasification section, including the packaged process units and general facilities is 3500 kW. This <u>does not</u> include the power requirements for the mill, mill circulation blower, and the quench gas compressor.

11. Gasification plant Cold Gas Efficiency = 82.1%. Cold gas efficiency is defined as the ratio: (HHV clean fuel gas to turbine / HHV AR coal fed to gasifier). HHV of the fuel gas is based on the composition leaving the H_2S removal block.

12. Heat exchanger design data are given in Table 3.

TABLE 3
HEAT EXCHANGER DESIGN DATA

(Overall Heat Transfer Coefficient - $BTU/ft^2 \cdot hr \cdot °F$, and Pressure Drop - psi)

	AIR SEPARATION	MILLING & DRYING	FUEL GAS COOLING
Gas-Gas	40		
Gas-Liquid	50		80
Gas-Vapor (1)		10 (2)	100
Vapor-Liquid (1)		100 (2)	
Pressure Drop	4 psi	5 "wc (3)	5 psi

Footnotes:
(1) Vapor can be condensing or evaporating service
(2) Special extended surface area exchanger
(3) Pressure drop is given in inches water column

13. Compressor & Blower design data are given in Table 4.

TABLE 4
COMPRESSOR & BLOWER DESIGN DATA
(# STAGES / COMPRESSOR EFFICIENCY)

	AIR SEPARATION	MILLING & DRYING	FUEL GAS COOLING
HP Nitrogen	4 / 70 (1,2)		
Recycle Nitrogen	1 / 76 (1)		2 / 76 (1)
HP Oxygen	3 / 70 (1,2)		
Air	6 / 85 (1,2)		
Inert Gas		1 / 75 (3)	
Fuel gas			1 / 80 (3)

Footnotes:
(1) Efficiency given is an adiabatic efficiency.
(2) Machine is intercooled between stages to 72 °F - neglect pressure drop of intercooler.
(3) Efficiency given is a polytropic efficiency.

COMBINED CYCLE POWER PLANT

1. Preliminary studies have shown that the clean fuel gas temperature to the gas turbine combustor should be set at 550 °F to achieve the best overall plant efficiency.

2. These studies have also shown that the fuel gas heat input to the gas turbine is 1573 MM BTU/hr (on an LHV Basis).

3. The total gross power production from the CCPP in kW is given by the following formula:

   CCPP Gross kW = 236028 + 0.0553 * N_2 + 0.119 * GPSTM

   where:

   N_2 = total lb/hr of return nitrogen from ASU to CCPP (NOTE: credit can be taken for return nitrogen used in the quench. In other words, nitrogen added to the fuel gas as quench also qualifies.)

   GPSTM = lb/hr of HP steam from gasification plant to CCPP

   BACKGROUND: This formula allows for the interchange between N_2 and steam, which are added to the combustor to control NOx at 25 ppmv @ 15% volume O_2 in the stack gas.

4. The auxiliary load for this plant section is defined by the following equation:

   CCPP AUX LOAD, kW = 0.00449 * GPSTM + 2614.6

   where:

   GPSTM = lb/hr of HP steam from gasification plant to CCPP

COAL GASIFICATION PLANT

Coal Milling & Drying

With an ICGCC system, steam, waste heat, and nitrogen can be used to increase the power generation in the CCPP. Thus the goal of the design engineer is to prepare a design which minimizes the energy consumption in the mill system in order to maximize the electrical generation by the CCPP.

Specifically you have been asked to develop alternatives to the base case for this section (see Figure 4) that result in a net increase in power generation for the ICGCC. Develop a process sketch for your best alternative. Create a table comparing the energy balance for your design with the energy balance for the base case.

The following data apply to the system design:

1. The coal milling and drying system will produce sufficient pulverized and dried coal to feed the gasifier, which in turn will provide sufficient fuel gas to meet the gas turbine fuel requirements.

2. Since it is premised that the 600 psia steam system is in balance, assume that all heat requirements and waste heat recovery result in marginal use or savings of 1700 psia steam.

3. The maximum mill exit temperature will be less than 230 °F.

4. The dew point of the gas stream entering the baghouse must be 40 °F below the stream temperature to prevent condensation of moisture.

5. For the base case design, low pressure return nitrogen is used for the circulation gas, and is supplied to the seal purges and make-up gas systems.

6. The mill baghouse nitrogen requirements are 0.007 lb low pressure N_2 per lb of moisture free coal.

7. The mill manufacturer gave the following information about the mill system:

    a. Recirculation gases required are 2.2 lb gas per lb of as-received coal.

    b. Seal purge gases, which enter the process, are 1% of the inlet gas flow, and are required at 10" water column above the mill inlet pressure.

    c. The maximum safe operating level of oxygen in the circulation gas is 5 % vol.

    d. Table 5 presents mill system parameters to produce the desired dry coal moisture level of 2 % wt:

TABLE 5
MILL DRYING OPERATING CONDITIONS

Mill Exit Temperature °F	Relative Humidity %
190	61.0
210	53.2
230	44.9

    e. Mill work is 12.6 BTU per lb of as-received coal, 90% of the mill driver power requirements.

    f. Environmental heat losses from the mill are 1.5MM BTU/hr at 230 °F.

    g. The coal specific heat is 0.3 BTU/lb·°F, on a moisture free basis.

    h. The heat of desorption of moisture from coal is 30 BTU per lb of moisture removed, in addition to the heat of vaporization of water.

8. The pressure in the circulating loop is controlled to hold the pressure at the inlet to the baghouse at 10 inches water column gage.

9. Pressure drop for various pieces of equipment is given in Table 6.

TABLE 6
MILL AREA EQUIPMENT PRESSURE DROP

Coal Pulverizer	20 inches water column
Bagfilter	8 inches water column
Extended Surface Exchangers	5 inches water column
Piping & Ducting	negligible

10. The combustion turbine/steam turbine vendor supplied the following additional information for evaluation purposes. Low pressure (so-called "return") nitrogen may be used to displace steam injection for NO_X control in the gas turbine, thus freeing this steam for additional power generation in the steam turbine.

    a. Each additional pound of low pressure nitrogen available for use in the combustion turbine frees up steam for use in the steam turbine. The equation provided with the combined cycle design basis provides this relationship.

    b. The steam rate for 600 psia steam to the steam turbine is 9.2 lb/hr·kW. The steam rate for 1700 psia steam to the steam turbine is 8.4 lb/hr·kW.

11. Refer to Tables 3 and 4 for additional heat exchanger and compressor/blower equipment design data.

<u>**Coal Pressurization & Feeding, Gasification, and Slag Handling**</u>

The coal pressurization and feeding, gasification, and slag handling portions of the gasification plant represent proprietary technologies. For the purposes of this problem, they will be purchased directly from the licensor of the technology as fully installed units. The following design and operating data are provided.

1. The raw fuel gas composition exiting the gasifier (as mole fraction) is given in Table 7.

TABLE 7
RAW FUEL GAS COMPOSITION EXITING GASIFIER
(mole fraction)

H_2 =	2.977E-01	CO =	6.098E-01	N_2 =	5.852E-02
Ar =	9.104E-03	CH_4 =	1.559E-04	COS =	3.571E-04
O_2 =	1.600E-06	H_2O =	1.323E-02	NH_3 =	1.824E-04
H_2S =	5.135E-03	CO_2 =	5.796E-03		

2. The gasification slagging efficiency is 90%. Slagging efficiency is defined as the fraction of the total ash entering with the feed coal that leaves the gasifier as slag. The remainder of the ash is fly ash and leaves the gasifier with the raw fuel gas.

3. High pressure nitrogen consumption by the coal pressurization & feeding, gasification, and slag handling portions of plant is 0.07 lb nitrogen per lb of fuel gas produced.

4. Medium pressure steam (600 psia) is generated by the gasifier cooling system. This steam system may be assumed to be in balance between generators and consumers. Consumers of medium pressure steam include the following package units: NH_3 removal, H_2S removal, water treating, and sulfur recovery. No calculations on the medium pressure steam system for these units or for the gasifier are required for this problem.

Quench and Fuel Gas Cooling

Defining the details of the quench and fuel gas cooling heat recovery system are two of the objectives of this problem. The goal is to define the process that results in the lowest cost of electricity from the ICGCC plant.

The design requirements are:

1. Develop a quench process.

Specifically, each solution is to include a process block flow diagram illustrating the quench configuration selected. Include all interface streams and interface equipment (e.g. compressors, heat exchangers, etc).

a) Either residual nitrogen from the ASU and/or recycled solids-free (ash free) fuel gas from the gasification plant are the only two possibilities for the quench gas for this problem.

b) The raw fuel gas exit temperature from the gasifier is 2800 °F.

c) The target quenched gas (mixed gas) temperature is 1800 °F.

d) Quench gas is required to be at least 46 psi above the fuel gas pressure at the quench injection point.

e) The quench injection system may be assumed to consist of a piping "TEE" (assume that the quench costs are included in the gasification package).

2. Develop the gasification plant high pressure (1700 psia) saturated steam system.

For the 1700 psia steam system, each solution is to include a block flow diagram showing all sources of energy in the problem. Also include a figure showing the cooling curve (e.g. a composite plot of total enthalpy versus temperature for both the cooling and heating streams).

a) The steam system should be as close to a balanced steam system as is practical. By balanced it is meant that boiler feedwater should be preheated to the saturation temperature and only then evaporated to make saturated steam. Note that there is no credit for energy present in preheated boiler feed water that is not converted to steam.

b) The closest approach temperature between cold and hot streams in a heat exchanger is 30 °F.

c) The coldest allowable fuel gas temperature is 40 °F above the dewpoint of the fuel gas stream.

d) Consider all available sources of heat for integration into the high pressure steam system, to the extent justified by the overall economics. Boiler feedwater preheat can be obtained from many sources and may be used subject to the above limitations. Compressor intercoolers are not acceptable sources of preheat, as they use cooling water for the intercooling.

High Pressure Filter

The following data is provided to design and size the high pressure filter.

1. Filter Element Data: The filter elements are rigid cylindrical porous ceramic elements, with element dimensions of 6 cm outer diameter by 1.5 meter length.

2. Design filtration velocity = 10 feet/minute (= actual fuel gas volumetric flow rate / total filter surface area).

3. Sizing data: The filter vessel internal diameter is calculated from the required tubesheet area for the number of filter elements plus an added 1 foot of diameter. The required tubesheet area is 0.067 ft^2/element, and can be calculated by assuming a triangular pitch layout of the elements with a pitch (= element centerline-centerline spacing / element outer diameter) of 2.

4. Equipment Pressure Drop = 2 psi.

5. High pressure nitrogen consumption for on-line filter cleaning is 0.14 lb N_2 per lb ash collected by filter. This nitrogen is mixed with the fuel gas flowing through the filter.

6. Certain mechanical components of the filter limit the applicable temperature range to less than 650 °F.

COS Conversion Reactor

The COS conversion reactor should be designed and sized according to the following data.

1. The general reaction is that of COS hydrolysis:

   $$COS + H_2O \dashrightarrow CO_2 + H_2S$$

2. The required COS level in the clean fuel gas is < 8.5 lb per hr of sulfur as COS.

3. The required COS conversion can be achieved at 450 °F with a design space velocity = 6000 hr^{-1}. Space velocity is here defined as = fuel gas flow rate in standard cubic feet per hour / total catalyst bed volume.

4. Catalyst properties: The catalyst particle size is a nominal 1/4 inch, spherical particle, with a catalyst bed porosity of 0.35.

5. Design catalyst bed pressure drop = 5 psi.

Final Gas Cleanup

The NH_3 removal, water treating, H_2S removal, and sulfur recovery units are all commercially available technologies. Assume that a contractor will purchase the technologies from their various vendors and will provide them as a single installed package unit for this ICGCC.

The following design and operating data is provided.

1. Neglect piping related pressure drop losses in the fuel gas path. The equipment related pressure drops are controlling.

2. NH_3 removal requirement, < 1 PPMV NH_3 in clean fuel gas.

3. Fuel gas path pressure drop through the NH_3 removal step is 5 psi.

4. The NH_3 and H_2S removal sections operate at 100 °F for best efficiency. Fuel gas entering the NH3 absorber is cooled by the circulating absorber water to 100 °F. Fuel gas leaves the NH_3 removal unit saturated with water at this temperature. Excess water above the saturation level is condensed in

the absorber and is sent to the water treating process.

5. The water treating plant is to be sized for three times the nominal water rate calculated on the above basis.

6. The required H_2S removal system is designed to leave < 0.9 lb per hr of sulfur as H_2S in the clean fuel gas.

7. 99.9 % of the H2S removed from the fuel gas is recovered for sale as elemental sulfur in the associated sulfur recovery and tail gas treating units. The 0.1 % not recovered as elemental sulfur is emitted from the final tail gas incinerator as SO_2.

8. Co-adsorption of other fuel gas species occurs in both the NH_3 removal and H_2S removal steps. These losses are 0.15 % vol of the H_2, 0.09 % vol of the CO, and 42.4 % vol of the CO_2. The losses are divided between the two absorption processes, but for the purposes of this problem assume they occur only in the H_2S removal step.

9. Fuel gas path pressure drop through the H_2S removal step is 8 psi.

10. The required fuel gas supply pressure at the gas turbine control valve is 320 psia (i.e. required pressure of fuel gas downstream of the final fuel gas reheater in the CGP).

11. The clean fuel gas must be reheated to 550 °F prior to being sent to the CCPP.

AIR SEPARATION UNIT

1. The cryogenic portion of the ASU will be purchased as a packaged unit. The interfacial equipment (compressors and heat exchangers) will however be individually sized and its cost estimated.

2. The following work is required:

   a) Generate a material balance around the major pieces of equipment in the ASU as shown in Figure 5.

   b) Determine the power requirements for all compressors and indicate complete suction and discharge conditions for each.

   c) Size the air/nitrogen and air/condensate exchangers.

   Refer to the information presented in Figure 5 and in Tables 3 and 4. The composition of the air streams and various product streams are presented in Table 2.

3. The oxygen requirements were set by the gasification plant as 0.9629 pounds of 100% O_2 per pound of MAF coal (see definition of MAF in Table 1). The oxygen compressor discharge is uncooled with a pressure set at 150 psia above the gasifier exit pressure.

4. Assume that a fixed amount of air, 321,840 lb/hr, is available from the gas turbine. Assume a compressed air loss of 0.15% of the total ASU air requirements.

5. All excess low pressure nitrogen can be returned to the power plant to increase overall power generation. The water condensed from the air feed streams is added to the returned nitrogen stream just upstream of the air/return nitrogen exchanger.

6. The recycle nitrogen stream (see Figure 5) required by the ASU equals 1/3 of the oxygen mass flow rate to the gasification plant.

7. Additional high and low pressure nitrogen requirements are indicated in the Design Bases for the various CGP sections. The HP nitrogen compressor discharge pressure is set at 100 psia above the oxygen compressor discharge pressure.

8. The auxiliary power load for other than the compression portion of the plant is 100 kW total.

PERFORMANCE AND ECONOMIC DATA

The business department of your company wants an estimate of the cost of electricity to obtain an investment rate of return of 15% on investment capital for your best design. They suggest the use of the following data:

1. Construction of the plant will begin in June, 1994 and the plant is started up in January, 1996.
2. The life of the plant is 15 years.
3. The income tax rate is 38%.
4. Use straight line depreciation.
5. Assume that working capital will be 10% of the total installed cost.
6. Assume coal price escalation of 3.0% per year and an inflation of 5% per year.
7. Assume the plant will operate 24 hours per day 311 days per year.

CAPITAL COST

1. Assume that 40% of the capital is expended in 1994 and 60% in 1995.
2. Add 5% to the installed cost estimate for all packaged units to cover contingencies.
3. Determine the installed cost of the individual pieces of equipment by using a Lang factor of 3.0.
4. Add an additional 13% of the sum of the installed packaged and equipment costs to cover the installed cost of general facilities.
5. Total installed capital cost is the sum of the installed package units, equipment and general facilities costs.

OPERATING AND MAINTENANCE COSTS

Raw Material Costs

1. Coal Cost per Ton, FOB Mine = $25.00
2. Transportation Cost per Ton, Mine to Plant = $25.00

Operating Costs

1. Utility costs for steam and electricity are not given since these are produced in the process.
2. Catalyst, Chemicals, and miscellaneous Utilities = 5% of Raw Material Cost
3. Operating Supplies = 0.5% per year of Capital Investment
4. Operating Staff Cost = 1% per year of Capital Investment
5. Maintenance Staff/Manpower Cost = 2% per year of Capital Investment
6. Maintenance Material Cost = 2% per year of Capital Investment
7. Insurance, Taxes, and Miscellaneous = 1% per year of Capital Investment
8. Home Office, Marketing, & Distribution Cost = 1% per year of Capital Investment

By-product Credits

1. The market value of slag is $7 per ton produced, FOB at the gasification plant.

2. The market value of fly ash is $4 per ton produced, FOB at the gasification plant.

3. The market value for sulfur is $100 per ton produced, FOB at the gasification plant.

INDIVIDUAL & PACKAGE UNIT EQUIPMENT COSTS

1. Combined Cycle Power Plant installed equipment cost

   CCPP Installed Equipment Cost, (in 1991 $) = 129E+06 * (0.949 + 1.336E-06 * GPSTM)$^{0.18}$

   Where GPSTM = lb/hr of HP steam from the gasification plant to CCPP.

2. The ASU installed equipment cost for the cryogenic section (see Figure 5) is without compressors, motors, or indicated heat exchangers.

   ASU Installed Equipment Cost, (in 1991 $) = $23,117,000

3. Heat exchanger cost data are given in Table 8.

TABLE 8
HEAT EXCHANGER COST DATA
(Bare Equipment Costs, in 1991 $)

	AIR SEPARATION	MILLING & DRYING	FUEL GAS COOLING
Gas-Gas	$8.7*(XA)^{1.0}$		
Gas-Liquid	$7.3*(XA)^{1.0}$		$630*(XA)^{0.70}$
Gas-Vapor (1)		$11*(XA)^{1.0}$	$2330*(XA)^{0.70}$
Vapor-Liquid (1)		$11*(XA)^{1.0}$	

Footnotes:
XA = heat exchanger surface area, ft^2
(1) Vapor can be condensing or evaporating service

4. Compressor & blower cost data are given in Table 9.

TABLE 9
COMPRESSOR & BLOWER COST DATA
(Bare Equipment Costs, in 1991 $)

	AIR SEPARATION	MILLING & DRYING	FUEL GAS COOLING
HP Nitrogen	$4430*(kW)^{0.72}$ (1)		
Return Nitrogen	$1570*(kW)^{0.72}$ (1)		$1570*(kW)^{0.72}$ (1)
HP Oxygen	$3270*(kW)^{0.72}$ (1)		
Air	$8070*(kW)^{0.61}$ (1)		
Inert Gas		$600*(hp)^{0.75}$ (2)	
Fuel gas			$4720*(hp)^{0.75}$ (2)

Footnotes:
kW = compressor power requirement in kiloWatts
hp = compressor power requirement in brake horsepower
(1) Bare Equipment Cost does not include motor driver cost.
Motor driver bare equipment cost, (in 1991 $) = $45*(kW)^{0.98}$
(2) Bare Equipment Cost includes motor driver cost

5. Coal Preparation Equipment Costs

   Coal Pulverizer Bare Equipment Cost, (in 1991 $) = 100,000 * (AR Coal Feed Rate, ton/hr) $^{0.70}$

   Fabric Filter Bare Equipment Cost, (in 1991 $) = 50 * (Inlet Gas Flow, ACFM) $^{0.70}$

6. Combined coal pressurization gasification & slag handling installed equipment cost:

   Installed Cost, (in 1991 $) = 316,800 * (As-fed Coal Feed Rate to Gasifier, ton/day) $^{0.70}$

7. High pressure filter equipment cost:

   Bare filter equipment cost, (in 1991 $) = 450,900 * (Vessel ID, ft) $^{0.70}$

8. Remainder of fly ash handling portion of process:

Installed Equipment Cost, (in 1991 \$) = 19,470 * (fly ash production rate, lb/hr)$^{0.75}$

9. The COS reactor bare equipment cost should be calculated in as a simple pressure vessel (see Reference), with the following data:

   a) vertical cylindrical vessel
   b) carbon steel materials
   c) hemispherical heads
   d) 1/8" corrosion allowance
   e) design pressure = operating pressure * 1.25
   f) vessel shell + head weight increased by 35% to account for additional weight of the internals (catalyst support, etc)

   REFERENCE: Peters, M.S., & K. D. Timmerhaus, "Plant Design and Economics for Chemical Engineers," 3'rd Edition, pp. 569-575, McGraw-Hill, 1986

10. Ammonia removal package unit equipment cost:

    Installed Equipment Cost, (in 1991 \$) = 390 * (Inlet Fuel Gas Flow, lb/hr) $^{0.70}$

11. Water treatment system package unit equipment cost:

    Installed Equipment Cost, (in 1991 \$) = 2400 * (Process Water Flow, lb/hr) $^{0.75}$

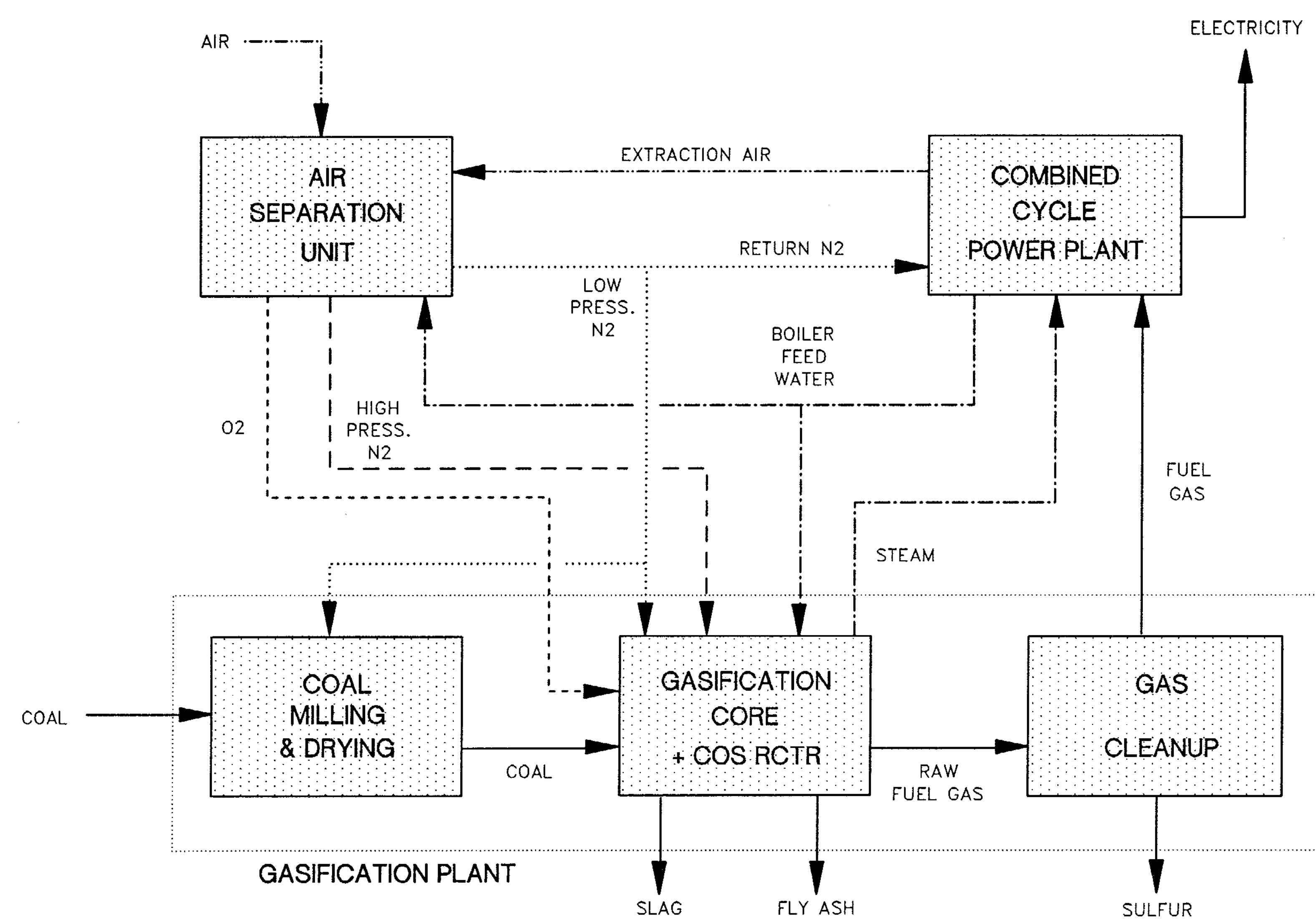
12. H_2S removal package unit equipment cost:

    Installed Equipment Cost, (in 1991 \$) = 960 * (Inlet Fuel Gas Flow, lb/hr) $^{0.70}$

13. Sulfur recovery system package unit equipment cost:

    Installed Equipment Cost, (in 1991 \$) = 34,560 * (Sulfur Production Rate, lb/hr) $^{0.70}$

FIGURE 1
BLOCK DIAGRAM - COAL GASIFICATION COMBINED CYCLE PLANT



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NOTE: Figure does not show required interfacial equipment.

FIGURE 2
BLOCK DIAGRAM - COMBINED CYCLE POWER BLOCK

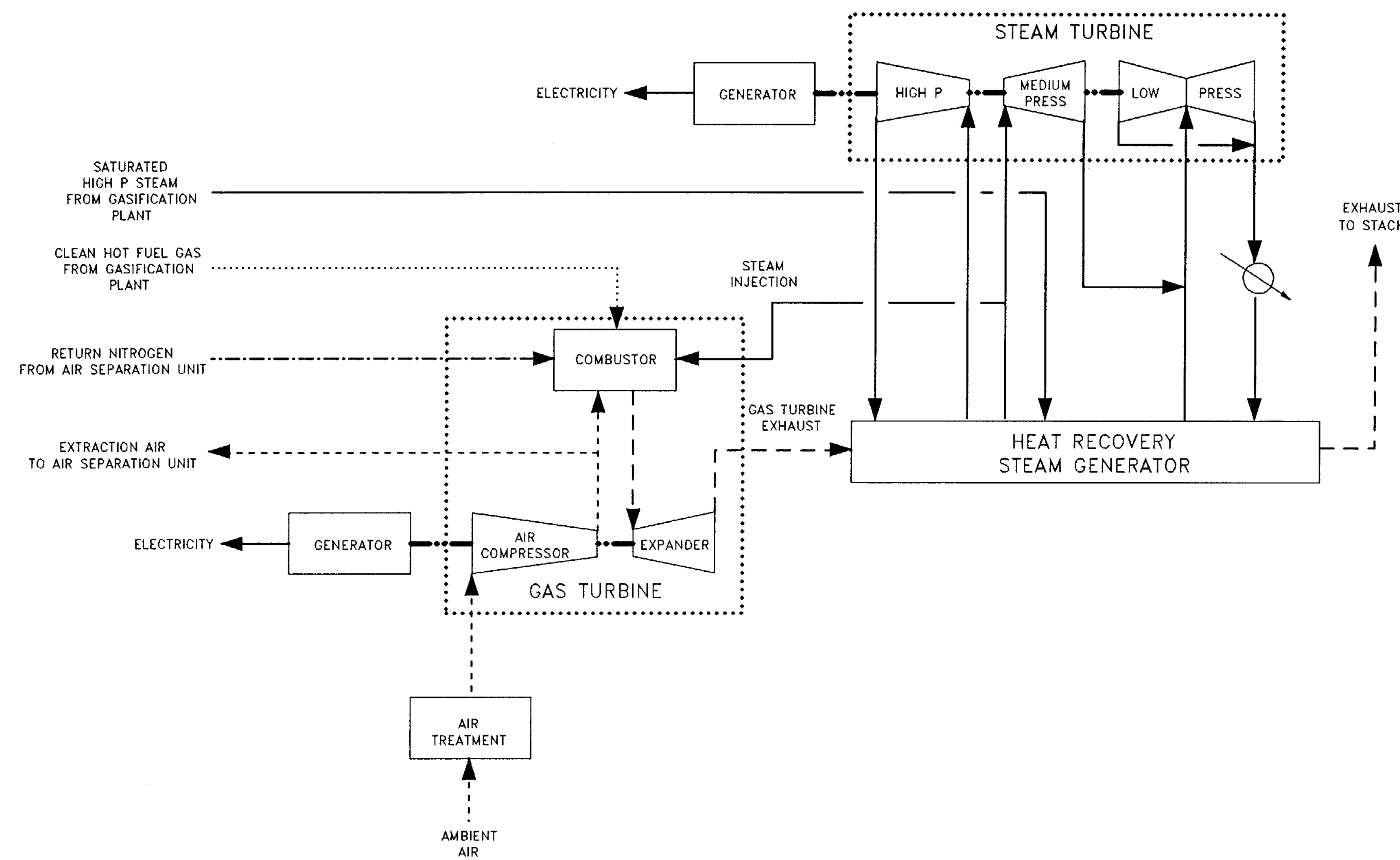

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FIGURE 3

BLOCK DIAGRAM - COAL GASIFICATION PLANT

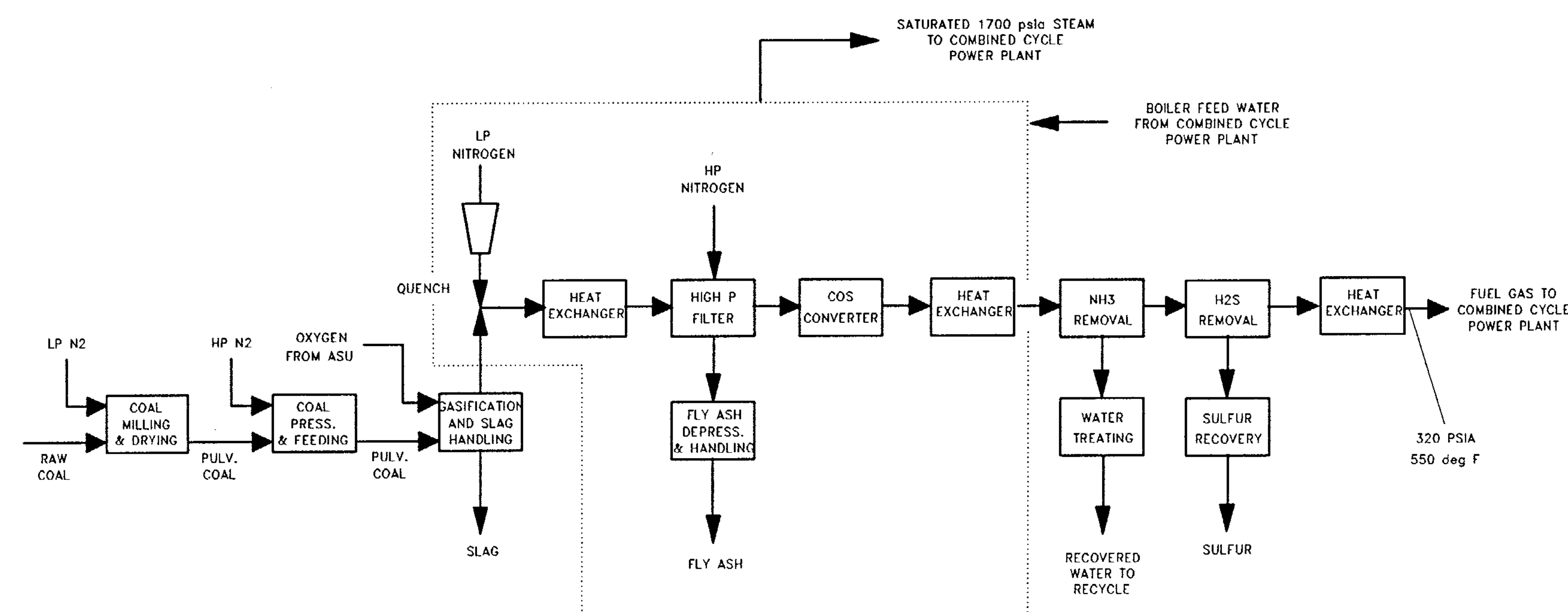

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FIGURE 4

PROCESS FLOW DIAGRAM - COAL MILLING AND DRYING SYSTEM
(BASE CASE REPRESENTATION)

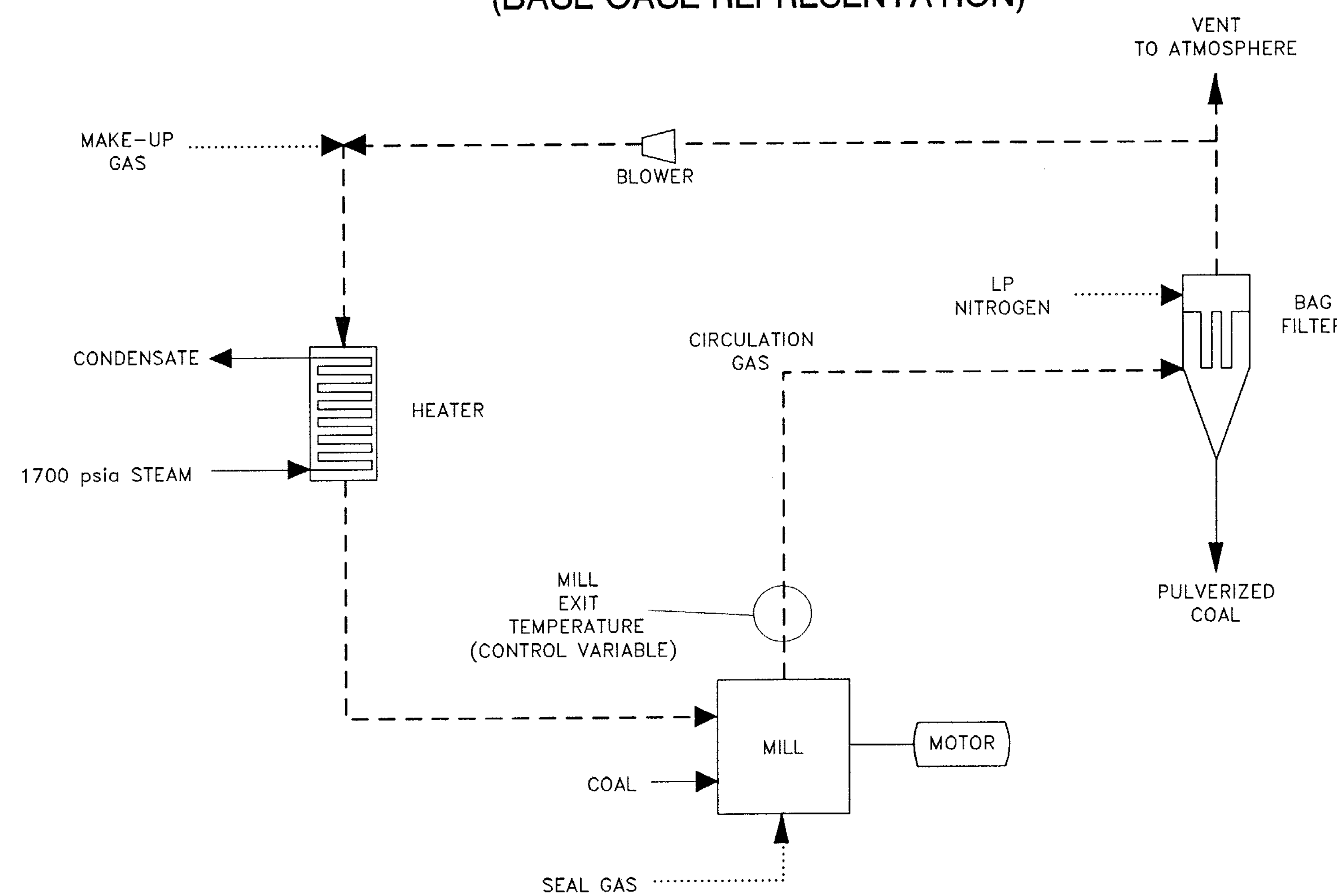

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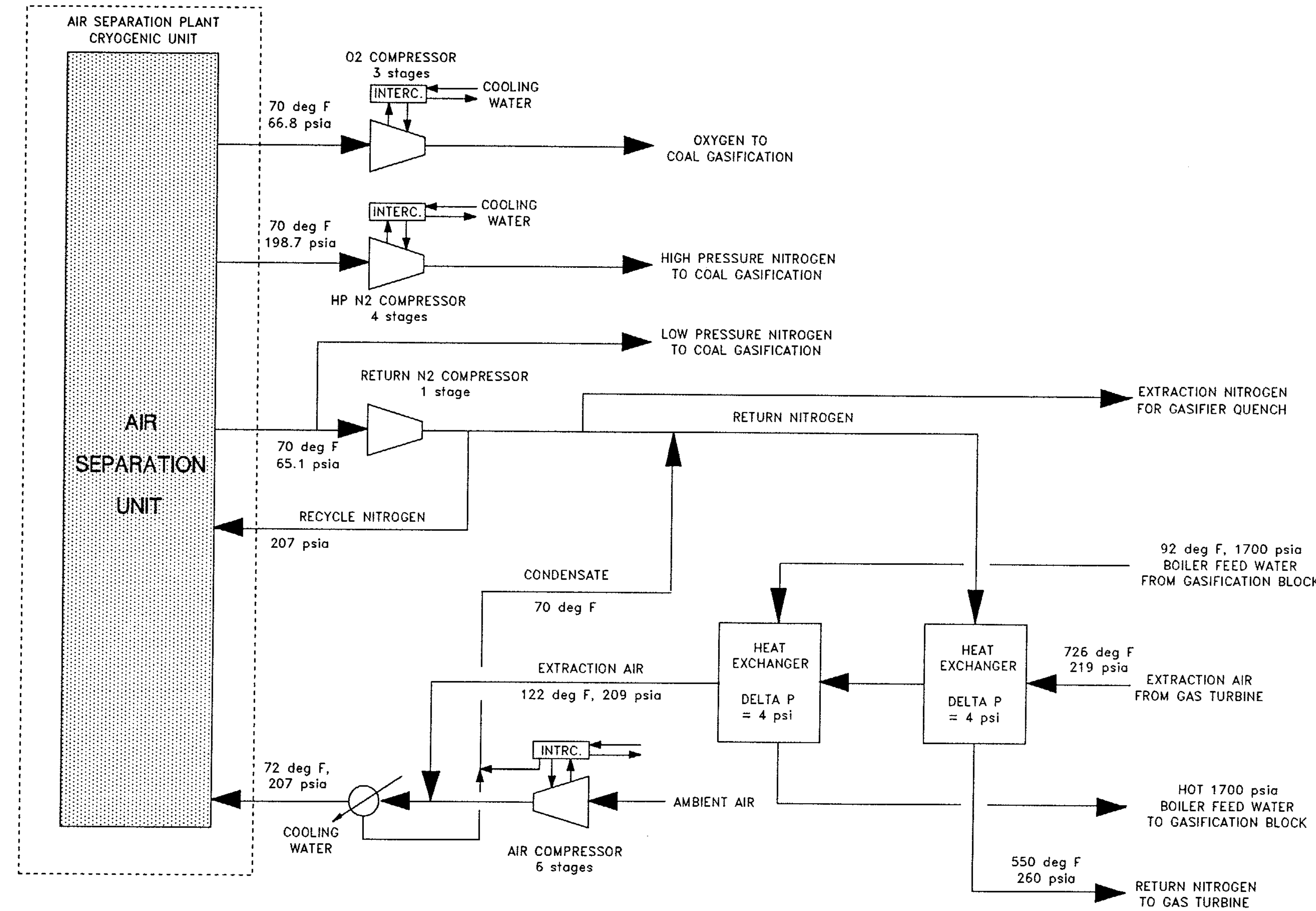
FIGURE 5
BLOCK DIAGRAM - AIR SEPARATION UNIT



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NOTES