Section 4.1

Integrated Gasification Combined Cycle (IGCC)

4. INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

4.1 FIRST-OF-A-KIND IGCC, OXYGEN-BLOWN ENTRAINED-BED GASIFIER

4.1.1 Introduction

This first-of-a-kind IGCC concept is based on the utilization of the Destec oxygen-blown coal gasification process supplying medium-Btu gas to a gas turbine/combined cycle power generating plant. The plant configuration is based on the technology demonstrated at the Wabash River Coal Gasification Repowering Project, but with the design configured for a greenfield site incorporating a new steam turbine. The specific design approach presented herein is based on DOE/Federal Energy Technology Center (FETC) and Parsons concepts, and does not necessarily reflect the approach that Destec Energy would take if they were to commercially offer a facility of this size (MWe) in this time frame.

This example of the IGCC technology is based on selection of a gas turbine derived from the General Electric MS 7001FA machine. Two of these machines are coupled with a single steam turbine to produce a nominal 540 MWe net output. The IGCC portion of the plant is configured with two gasifiers, each of which includes processes to progressively cool and clean the gas, making it suitable for combustion in the gas turbines. The resulting plant produces a net output of 543 MWe at a net efficiency of 40.1 percent on an HHV basis. Performance is based on the use of Illinois No. 6 coal.

4.1.2 Heat and Mass Balance

The pressurized Destec gasifier utilizes a combination of oxygen, water, and coal along with recycled fuel gas to gasify the coal and produce a medium-Btu hot fuel gas. The fuel gas produced in each entrained bed gasifier leaves at 1950°F and enters a hot gas cooler. A significant fraction of the sensible heat in the gas is retained by cooling the gas to 650°F. High-pressure saturated steam is generated in the hot gas cooler and is joined with the main steam supply.

The gas goes through a series of gas cleanup processes including a ceramic candle filter, chloride guard, COS hydrolysis reactor, and an amine-based acid gas removal (AGR) plant. A fraction of the clean hot gas is cooled and recycled to each gasifier to aid in second-stage gasification. Particulates captured by the filter are recycled, resulting in complete carbon conversion. Regeneration gas from the AGR plant is fed to an H_2S-burning H_2SO_4 plant.

The air separation unit (ASU) is partially decoupled from the gas turbines, in that gas turbine compressor discharge air is not used as input to the air separation process. However, some of the nitrogen produced in the ASU is brought back to the gas turbine, where it is mixed with the syngas supplied by the gasifier. This N_2 addition to the syngas aids in minimizing formation of NOx during combustion in the gas turbine burner section.

This plant utilizes a combined cycle for combustion of the medium-Btu gas from the gasifier to generate electric power. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process (gas cooling and sulfation modules).

Each gas turbine operates in an open cycle mode, as described below. The inlet air is compressed in a single spool compressor to the design basis discharge pressure. The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the medium-Btu gas supplied by the gasifier island. The firing of medium-Btu gas in the combustion turbine is expected to require modifications to the burner and turbine sections of the machine. These modifications are discussed in later sections.

The hot combustion gases are conveyed to the inlet of the turbine section on each machine, where they enter and expand through each turbine to produce power to drive the compressor and electric generator. The turbine exhaust gases are conveyed through a HRSG (one for each turbine) to recover the large quantities of thermal energy that remain. Each HRSG exhausts to a separate stack.

Overall performance for the entire plant, including Brayton and Rankine cycles, is summarized in Table 4.1-1, which includes auxiliary power requirements. The Rankine steam power cycle is also shown schematically in the 100 percent load Heat and Mass Balance diagram (Figure 4.1-1).

The steam cycle is based on maximizing heat recovery from the gas turbine exhaust gases, as well as utilizing steam generation opportunities in the gasifier process. As the turbine exhaust gases pass through each HRSG, they progressively transfer heat for reheating steam (cold reheat to hot reheat), superheating main steam, generating main steam in an HP drum, generating and superheating steam from an IP drum (as reheat, and for use in the integral deaerator), and heating feedwater.

The gasifier train provides heat for condensate heating, feedwater heating (partial), and main steam generating. The HRSG and gasifier trains provide all the required condensate and feedwater heating. Therefore, conventional feedwater heaters using turbine extraction steam are not required.

The steam turbine selected to match this cycle is a two-casing, reheat, double-flow (exhaust) machine, exhausting downward to the condenser. The HP and IP turbine sections are contained in one casing, with the LP section in a second casing. Other turbine design arrangements are possible; the configuration represented herein is typical of reheat machines in this size class.

The steam turbine drives a 3600 rpm hydrogen-cooled generator. The turbine exhausts to a single-pressure condenser operating at a nominal 2.0 inches Hga at the 100 percent load design point. Two 50 percent capacity, motor-driven pumps are provided for feedwater and condensate.

Table 4.1-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

(Loads are presented for two IGCC islands, two gas turbines, and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine (two)	394,000
Steam Turbine (one)	254,530
Total	648,530
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	330
Coal Slurry Pumps	370
Condensate Pumps	320
LP/IP Feed Pumps	40
HP Feed Pumps	3,700
Miscellaneous Balance of Plant (Note 1)	1,500
Boost Air Cpmpressor	270
Air Separation Plant	55,880
Oxygen Boost Compressor	10,730
Gasifier Recycle Blower	970
N_2 Compressor	22,950
H_2S Air Blower	1,350
Amine Plant	330
Sulfuric Acid Plant Air Blower	400
Gas Turbine Auxiliaries	800
Steam Turbine Auxiliaries	300
Circulating Water Pumps	2,160
Cooling Tower Fans	1,320
Slag Handling	840
Transformer Loss	1,440
TOTAL AUXILIARIES, kWe	105,340
Net Power, kWe	543,190
Net Efficiency, % HHV	40.1%
Net Heat Rate, Btu/kWh (HHV)	8,522
CONDENSER COOLING DUTY, 10^6 Btu/h	1,465
CONSUMABLES	
As-Received Coal Feed, lb/h	396,790
Oxygen (95% pure), lb/h	329,903
Water (for slurry), lb/h	163,000

Note 1 - Includes plant control systems, lighting, HVAC, etc.

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018° F AND 0.08865 PSIA.
2. DESTEC GASIFIER HAS 90/10 COAL SLURRY FEED SPLIT.
3. THIS CASE IS BASED ON TWO GASIFIER TRAINS, TWO GE FRAME 7FA GAS TURBINES, AND ONE GE TC4F STEAM TURBINE.
4. IP PROCESS STEAM TO ASU AND SLURRY HEATER.
5. LP PROCESS STEAM TO ACID GAS UNIT AND WASTE WATER TREATMENT.
6. PORTION OF L/P STEAM GENERATION PRODUCED BY GASIFIER ISLAND.

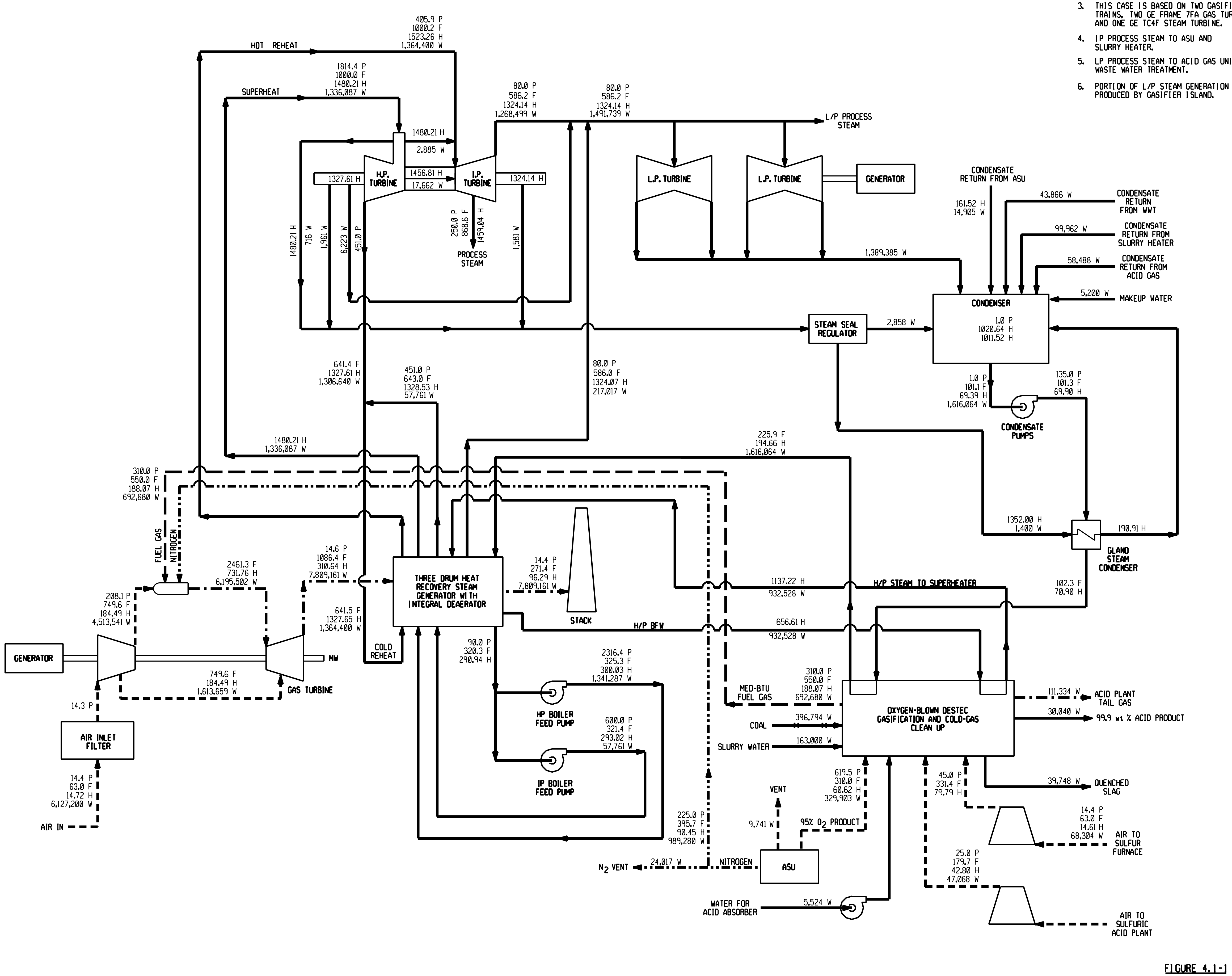

FIGURE 4.1-1

LEGEND

- · · - · · -	NITROGEN
- - - - -	AIR/OXIDANT
— — —	FUEL GAS
— · — · —	COMBUSTION PRODUCTS
—+—+—	SOLIDS
———	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY
(TWO GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	400.000 MWe
STEAM T-G POWER :	258.406 MWe
GENERATOR LOSS (TOTAL):	9.876 MWe
AUXILIARY POWER (TOTAL):	105.340 MWe
NET PLANT POWER :	543.190 MWe
NET PLANT EFFICIENCY :	40.0 %
NET PLANT HEAT RATE :	8,522 Btu/kwh

DEIA-BTM/DSTC-EIA J.S.WHITE 4/23/1998

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | ENGINEER | LEAD DISCP ENGINEER | PROJ ENGR MANAGER | PROJECT MANAGER

STATUS OF DRAWING: PRELIMINARY — DEFINITION: REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUPTIONS. REVIEWED NOT CHECKED.

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PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
600MW INTERGRATED GASIFICATION COMB CYCLE
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
OXYGEN BLOWN ENTRAINED BED GASIFIER
MARKET BASED / FIRST OF A KIND

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-004 REV A

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4.1.3 Emissions Performance

The operation of the combined cycle unit in conjunction with oxygen-blown Destec IGCC technology is projected to result in very low levels of emissions of NOx, SO_2, and particulates (fly ash). A salable byproduct is produced in the form of sulfuric acid at 95 to 98 percent concentration (66.2 °Bé). A summary of the plant emissions is presented in Table 4.1-2.

Table 4.1-2
AIRBORNE EMISSIONS - IGCC, OXYGEN-BLOWN DESTEC

	Values at Design Condition (65% and 85% Capacity Factor)			
	$lb/10^6$ Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.056	737	964	0.48
NOx	0.024	316	414	0.21
Particulates	< 0.002	< 26	< 34	< 0.018
CO_2	200.4	2,640,580	3,453,100	1,708

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the amine-based AGR process. The AGR process removes approximately 99.9 percent of the sulfur compounds in the fuel gas. The H_2S-rich regeneration gas from the AGR system is fed to a 99 percent efficient H_2S-burning H_2SO_4 plant. The actual overall sulfur removal capability is therefore about 98.9 percent.

NOx emissions are limited to approximately 30 ppm by the use of nitrogen injection from the ASU. The ammonia is removed with process condensate prior to the low-temperature AGR process. This helps lower NOx levels as well. The techniques of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can reduce emissions further, but are not applied to the subject plant.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the candle type particulate filter and the gas washing effect of the AGR absorber.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/10^6 Btu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

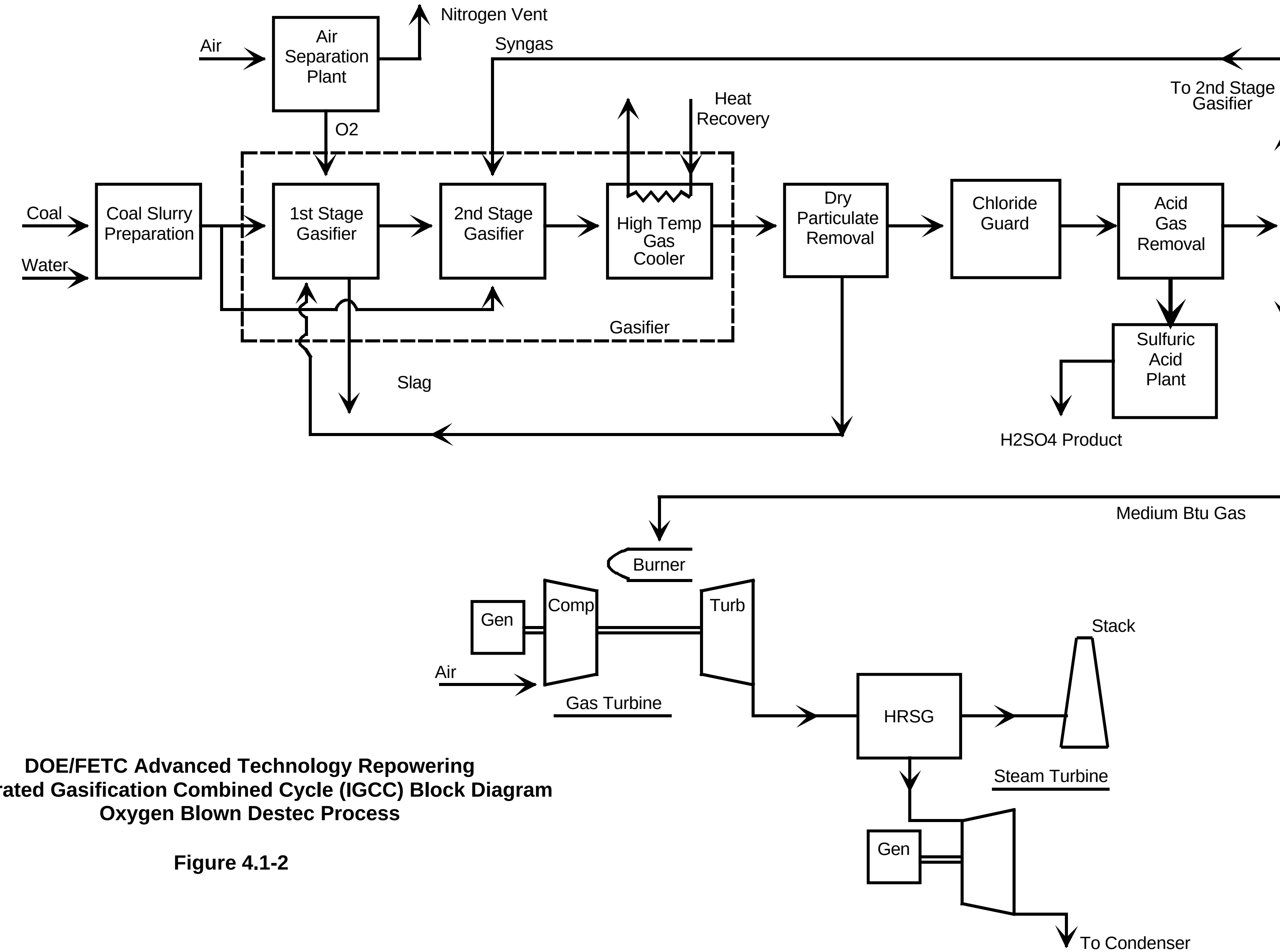
4.1.4 Description of Oxygen-Blown Destec Gasification Island

This design is based on the utilization of two oxygen-blown Destec entrained-bed gasifiers. The medium-Btu gas produced in the gasifiers is cooled and further cleaned downstream of the gasifiers. The final product gas is used to fire two combustion turbine generators, which are each coupled to an HRSG, producing steam for one steam turbine generator.

The following is a summary description of the overall gasification process and its integration with the power generation cycles used in this case. (Refer to Figure 4.1-2.)

Illinois No. 6 coal is ground to 200 mesh and mixed with water to be fed to each pressurized Destec gasifier as a slurry. The slurry is fired with oxygen to produce medium-Btu gas, which is largely composed of CO, H_2, and CO_2, and is discharged from the gasifier at 1950°F and cooled in a gas cooler to 650°F. The oxygen fed to each gasifier is produced in two 50 percent capacity ASU trains, one for each gasifier.

The gas is then cleaned in the dry particulate removal system containing a candle-type barrier filter, resulting in very low levels of particulates. Fly ash from the filter is recycled to the gasifier to ensure complete carbon conversion. The particulate-free gas passes through the chloride guard containing a fixed-bed reactor, exposing the gas to nahcolite, thereby reducing the chloride level to less than 1 ppm to protect downstream equipment. The low-chloride gas passes to the AGR system, which contains a COS hydrolysis reactor and monoethanolamine (MEA) desulfurizer. From the AGR system sufficient sulfur is removed to result in a final sulfur level of about 30 ppm. The regeneration gas from the AGR system is a mixture of H_2S and CO_2, which is a suitable feedstock for a sulfuric acid plant.



DOE/FETC Advanced Technology Repowering
Integrated Gasification Combined Cycle (IGCC) Block Diagram
Oxygen Blown Destec Process

Figure 4.1-2

The clean gas exiting the AGR system is conveyed to the combustion turbines where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The exhaust gas from each combustion turbine and HRSG is released to the atmosphere via a conventional stack.

Based on the selection of the General Electric MS 7001FA combustion turbine, a fuel gas pressure at the gasifier island battery limits of 300 psig was established to provide a margin above the compressor discharge pressure (220 psig at this site), allowing for necessary system and valve pressure drop.

Based on the above, a nominal gasifier pressure of 400 psig is required. At this pressure, two gasifiers are required that are similar in size to the commercial sized unit utilized in the Wabash River Coal Gasification Repowering Project.

4.1.4.1 Coal Grinding and Slurry Preparation

Coal is fed onto conveyor No. 1 by vibratory feeders located below each coal silo. Conveyor No. 1 feeds the coal to an inclined conveyor (No. 2) that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. A vibrating feeder on each hopper outlet supplies the weigh feeder, which in turn feeds a rod mill. The rod mill grinds the coal and wets it with treated slurry water from a slurry water tank. The slurry is then pumped from the rod mill product tank to the slurry storage and slurry blending tanks.

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required will depend on local environmental regulations.

4.1.4.2 Gasifier

Note: The following description is taken from the Coal Gasification Guidebook: Status, Applications, and Technologies, prepared by SEA Pacific, Inc. for the Electric Power Research Institute.

The Destec coal gasifier is a slurry feed, pressurized, upflow, entrained slagging gasifier with two-stage operation. Wet crushers produce slurries with the raw feed coal. Dry coal slurry concentrations range from 50 to 70 wt%, depending on the inherent moisture and quality of the feed coal. In the gasifier model considered herein, about 90 percent of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 2400 to 2600°F. The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed in a novel continuous-pressure letdown/dewatering system.

The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 10 percent of coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1950°F.

Char is produced in the second stage. However, the yield of this char is relatively small because only about 10 percent of the coal is fed to the second stage. Char yield is dependent on the reactivity of the feed coal and decreases with increasing reactivity. The char is recycled to the hotter first stage, where it is easily gasified. The gasifier is refractory-lined and uncooled. The hotter first-stage section of the gasifier also includes a special slag-resistant refractory.

The 1950°F hot gas leaving the gasifier is cooled in the fire-tube product gas cooler to 650°F, generating saturated steam for the steam power cycle in the process.

4.1.4.3 Particulate Removal

The particulate removal stage in this gasification process is dependent upon a high-efficiency ceramic candle barrier filter. The filter is comprised of an array of ceramic candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with gas to remove the fines, which are collected and conveyed to the gasifier. This filter provides a high degree of capture efficiency, resulting in very low levels of particulates in the hot gas supplied to the fixed-bed chloride guard bed, preventing guard bed clogging.

4.1.4.4 Chloride Guard

The chloride guard functions to remove HCl from the hot gas, prior to sulfur removal in the AGR system. This protects the AGR system vessels as well as the gas turbine downstream.

The chloride guard is comprised of two 100 percent capacity pressure vessels packed with a pebble bed of nahcolite, a natural form of sodium bicarbonate. One vessel is normally in service, with a nominal service period of two months. The second vessel is purged, cooled, drained of spent bed material, and recharged while the other vessel is in service. The chloride guard vessels are approximately 13 feet in diameter, 25 feet high, and are fabricated of carbon steel, with an inner lining of a stabilized grade of stainless steel.

4.1.4.5 Acid Gas Removal (AGR)

Following the chloride guard bed, the gas is cooled to 365°F for feed to the COS hydrolysis reactor. The COS is hydrolized with steam in the gas, over a catalyst bed to H_2S, which is more easily removed by the AGR solvent. Before the raw fuel gas can be treated in the sulfur removal process, it must be cooled to 105°F. During this cooling, part of the water vapor condenses. This water, which contains some NH_3, is sent to the wastewater treatment section. No separate HCN removal unit is needed due to the very low HCN concentration in the fuel gas. Following the hydrolysis reactor, the gas is further cooled to 105°F for feed to the AGR absorber.

The monoethanolamine (MEA) process was chosen because of its high selectivity towards H_2S and because of the low partial pressure of H_2S in the fuel gas, necessitating a chemical absorption process rather than a physical absorption process such as the Selexol. The AGR process utilizes a MEA sorbent and several design features to effectively remove and recover H_2S from the fuel gas stream. The MEA solution is relatively expensive, and measures are taken to conserve the solution during operations. As the presence of CO causes amine degradation in the form of heat stable salts, an amine reclaimer is included in the process. Also, additional water wash trays are included in the absorber tower to prevent excessive solvent loss due to vaporization.

Fuel gas enters the absorber tower at 105°F and 330 psia. Approximately 99 percent of the H_2S is removed from the fuel gas stream. The resulting clean fuel gas stream exits the absorber and is heated in a series of regenerative heaters to 505°F.

The rich MEA solution is pumped to a regeneration stripping tower in which the H_2S and CO_2 are stripped from the MEA by counter-current contact with CO_2 vapors generated in a steam-heated reboiler. The regenerated H_2S stream is cooled and separated from the condensed water, and flows to the H_2S recovery compressor for feed to the H_2S-burning sulfuric acid plant.

The only contaminants in the cleaned fuel gas leaving the acid gas removal unit are H_2S and HCN, both in very low concentrations. A small fraction of the cleaned fuel gas is compressed and recycled to the gasifier outlet for back-purging the ceramic candle filter.

4.1.4.6 Sulfuric Acid Plant

The AGR process produces an offgas from the regeneration process, which contains an H_2S concentration of about 50 percent. This is adequate for feed to an H_2S-burning contact process sulfuric acid plant that burns the H_2S acid gas with air, yielding SO_2, water vapor, and heat, which are fed to a conventional contact acid plant. The reaction from SO_2 to SO_3 is an exothermic reversible reaction. Key to the process is the four-pass converter developed by Monsanto. Equilibrium conversion data show that conversion of SO_2 decreases with an increase in temperature. Using a vanadium catalyst, a contact plant takes advantage of both rate and equilibrium considerations by first allowing the gases to enter over a part of the catalyst at about 800 to 825°F, and then allowing the temperature to increase adiabatically as the reaction proceeds. The reaction essentially stops when 60 to 70 percent of the SO_2 has been converted, at a temperature in the vicinity of 1100°F. The gas is cooled in a waste heat boiler and passed through subsequent stages, until the temperature of the gases passing over the last portion of catalyst does not exceed 805°F.

The gases leaving the converter, having passed through two or three layers of catalyst, are cooled and passed through an intermediate absorber tower where some of the SO_3 is removed with 98 percent H_2SO_4. The gases leaving this tower are then reheated, and they flow through the remaining layers of catalyst in the converter. The gases are then cooled and pass through the final absorber tower before discharge to the atmosphere. In this manner, more than 99.7 percent of the SO_2 is converted into SO_3 and subsequently into product sulfuric acid.

4.1.4.7 Gas Turbine Generator

The gas turbine generator selected for this application is based on the General Electric MS 7001FA model. This machine is an axial flow, single spool, constant speed unit, with variable inlet guide vanes. The standard production version of this machine, fired with natural gas, will develop a compressor pressure ratio of 15.2:1 and a rotor inlet temperature of almost 2350°F. In this service, with medium-Btu gas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the medium-Btu gas and expand the combustion products in the turbine section of the machine. A reduction in rotor inlet temperature of about 50°F is expected, relative to a production model W501G machine firing natural gas. This temperature reduction is necessary in order to not exceed design basis gas path temperatures throughout the expander. If the first-stage rotor inlet temperature were maintained at the design value, gas path temperatures downstream of the inlet to the first (HP) turbine stage may increase, relative to natural gas-fired temperatures, due to gas property changes.

The modifications to the machine may include some redesign of the original can-annular combustors. A second potential modification involves increasing the nozzle areas of the turbine to accommodate the mass and volume flow of medium-Btu fuel gas combustion products, which is increased relative to those produced when firing natural gas. Other modifications include rearranging the various auxiliary skids that support the machine to accommodate the spatial requirements of the plant general arrangement.

The generator is a standard hydrogen-cooled machine with static exciter.

4.1.4.8 Steam Generation

Heat Recovery Steam Generator (HRSG)

The HRSG is a drum-type, multi-pressure design that is matched to the characteristics of the gas turbine exhaust gas when firing medium-Btu gas. The HP drum produces steam at main steam pressure, while the IP drum produces steam for export to the cold reheat. The HRSG drum pressures are nominally 2000 psig/600 psig for the HP/IP, respectively. In addition to generating and superheating steam, the HRSG performs reheat duty for the cold/hot reheat steam for the steam turbine, provides condensate and feedwater heating, and also provides deaeration of the condensate.

Gas Cooler

The gas cooler is a fire tube design, which produces steam at main steam pressure, saturated conditions. This steam is conveyed to the HRSG where it is superheated.

4.1.4.9 Air Separation Plant

The air separation plant is designed to produce a nominal output of 3,850 tons/day of 95 percent pure O_2. The plant is designed with two 50 percent capacity production trains. Liquefaction and liquid oxygen storage provide an 8-hour backup supply of oxygen. The inventory of liquid O_2 would be used to enable the plant to produce additional power during peaking periods by shutting down the ASU. The air compressor in each train is powered by an electric motor.

In this air separation process, air is compressed to 70 psig and then cooled in a water scrubbing spray tower. The cooled air enters a reversing heat exchanger, where it is cooled to the liquefaction point prior to entering a double column (high/low pressure) separator. Refrigeration for cooling is provided by expansion of high-pressure gas from the lower part of the high-pressure column.

Onsite storage of liquid O_2 is provided to maintain continuous supply for the gasifier for an 8-hour time period, enhancing plant output during peak power demand periods.

4.1.4.10 Flare Stack

A self-supporting, refractory-lined, carbon steel flare stack is provided to combust and dispose of product gas during startup, shutdown, and upset conditions. The flare stack is provided with multiple pilot burners, fueled by natural gas or propane, with pilot home monitoring instrumentation.

4.1.5 IGCC Support Systems (Balance of Plant)

4.1.5.1 Coal Handling System

The function of the coal handling system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

The bituminous coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor (No. 1). The coal is then transferred to a conveyor (No. 2) that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 by the first of two crushers. The coal then enters the second crusher, which reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the three silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 396,800 lb/h = 198 tph plus 10% margin = 218 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 330,000 lb/h = 165 tph (based on MCR rate multiplied by 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Three and one-half unit trains per week at maximum burn rate. Three unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 9 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 900 tph (maximum, both conveyors in operation)
  - Reclaim rate = 600 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 15,300 tons (72 hours at maximum burn rate)
  - Dead storage = 119,000 tons (30 days at average burn rate)

4.1.5.2 Slag Handling

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. Slag exits through the slag tap into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids flows out of the bottom of the gasifier through a proprietary pressure letdown device into an array of dewatering bins. The components listed above, up to the pressure letdown device, are within the gasifier pressure boundary and at high pressure. Three dewatering bins are provided; these are used in cyclical fashion, one bin receiving, one in a separation phase, and one in an overflow phase for separation of liquids/solids. A flocculation agent is added to assist in separating out the fines during the settling or separation phase. The clear liquid is recycled to the slag quench water bath.

The cooled, dewatered slag is removed by drag chain conveyors and is stored in a storage bin. The bin is sized for a nominal holdup capacity of approximately 72 hours of full-load operation. At periodic intervals, a convoy of slag hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. Approximately 19 truck loads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power.

4.1.6 Steam Cycle Balance of Plant

The following section provides a description of the steam turbines and their auxiliaries.

4.1.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last-stage bucket length of 33.5 inches.

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at 1800 psig/1000°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 400 psig/1000°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled, pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

The steam turbine generator is controlled by a triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

4.1.6.2 Condensate and Feedwater Systems

<u>Condensate</u>

The condensate system pumps condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG.

The system consists of one main condenser; two 50 percent capacity, motor-driven, vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG. Condensate is delivered to a common discharge header through separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Feedwater

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity boiler feed pumps of each type are provided. Each pump is provided with inlet and outlet isolation valves, outlet check valve, and minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

4.1.6.3 Main and Reheat Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the HRSG superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 1900 psig/1000°F exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 450 psig/640°F exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 405 psig/1000°F exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

4.1.6.4 Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

4.1.6.5 Major Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the steam cycle. A summary of the required piping is presented in Table 4.1-3.

4.1.7 Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

Table 4.1-3
INTEGRATED GASIFICATION COMBINED CYCLE

Major Steam Cycle Piping Required

Pipeline	Flow, lb/h	Press., psia	Temp., °F	Material	OD, in.	Twall, in.
Condensate	1,600,000	135	100	A106 Gr. B	10	Sch. 40
HP Feedwater, Pump to HRSG (Total)	1,340,000	2316	325	A106 Gr. B	10	Sch. 160
IP Feedwater, Pump to HRSG (Total)	57,800	600	321	A106 Gr. B	6	Sch. 40
HP Feedwater to Gasifier	932,500	2290	630	A106 Gr. B	10	Sch. 160
HP Steam to HRSG Turbine (Total)	932,500	2260	670	A335 Gr. P22	6	1.50
Main Steam to Steam Turbine (Total)	1,336,100	1814	1000	A335 Gr. P22	8	1.50
Cold Reheat/ST to HRSG	1,300,000	450	640	A106 Gr. B	18	0.50
Hot Reheat/HRSG to ST	1,364,000	405	1000	A335 Gr. P22	20	0.875
Fuel Gas/Gasifier Islands to Gas Turbines (Total)	693,000	310	550	A106 Gr. B	18	Sch. 40
O_2 Piping to Gasifiers (Total)	329,000	620	310	A106 Gr. B	8	Sch. 40

4.1.8 Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

4.1.9 Site, Structures, and System Integration

4.1.9.1 Plant and Ambient Design Conditions

Refer to Section 2 for a description of the plant site and ambient design conditions.

4.1.9.2 New Structures and Systems Integration

The development of the reference plant site to incorporate structures required for this technology is based on the assumption of a flat site. The IGCC gasifiers and related structures are arranged in a cluster, with the coal and slurry preparation facilities adjacent to the south, as shown in the conceptual general arrangement in Figure 4.1-3.

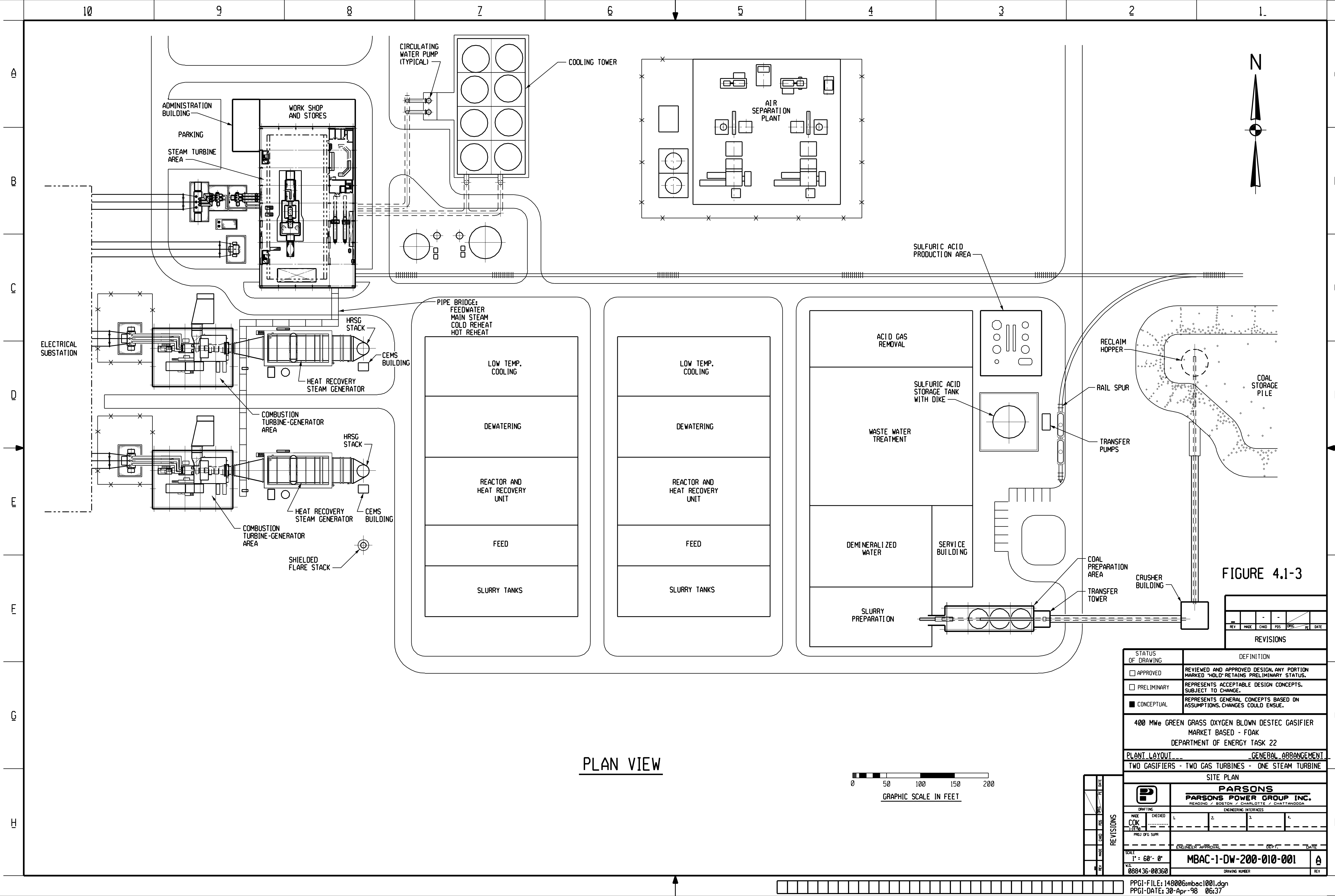
The gasifiers and their associated process blocks are located west of the coal storage pile. The gas turbines and their ancillary equipment are sited west of the gasifier island, in a turbine building. The HRSGs and stacks are east of the gas turbines, with the steam turbine and its generator in a separate building continuing the development to the north. Service and administration buildings are located at the west side of the steam turbine building.

The cooling tower heat sink for the steam turbine is located to the east of the steam turbine building. The air separation plant is further to the east, with storage tanks for liquid O_2 and N_2 located near the gasifier and its related process blocks. Sulfur recovery and wastewater treatment areas are located east and south of the air separation plant.

The arrangement described above provides good alignment and positioning for major interfaces; relatively short steam, feedwater, and fuel gas pipelines; and allows good access for vehicular traffic. Transmission line access from the gas turbine and steam turbine step-up transformer to the switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located north of the gas turbine. The clean, hot, medium-Btu gas is conveyed to the turbine combustors for mixing with the air that remained on-board the machine. Turbine exhaust is ducted directly through the HRSGs and then the 213-foot stacks. The height of the stack is established by application of a good engineering practice rule from 40 CFR 51.00.

Access and construction laydown space are freely available on the periphery of the plant, with several roads, 26 feet wide plus shoulders, running from north to south between the various portions of the plant.


CIRCULATING WATER PUMP (TYPICAL)
COOLING TOWER
ADMINISTRATION BUILDING
WORK SHOP AND STORES
PARKING
STEAM TURBINE AREA
AIR SEPARATION PLANT
N
SULFURIC ACID PRODUCTION AREA
ELECTRICAL SUBSTATION
PIPE BRIDGE: FEEDWATER MAIN STEAM COLD REHEAT HOT REHEAT
HRSG STACK
CEMS BUILDING
HEAT RECOVERY STEAM GENERATOR
COMBUSTION TURBINE-GENERATOR AREA
LOW TEMP. COOLING
DEWATERING
REACTOR AND HEAT RECOVERY UNIT
FEED
SLURRY TANKS
ACID GAS REMOVAL
WASTE WATER TREATMENT
SULFURIC ACID STORAGE TANK WITH DIKE
RECLAIM HOPPER
RAIL SPUR
COAL STORAGE PILE
TRANSFER PUMPS
DEMINERALIZED WATER
SERVICE BUILDING
SLURRY PREPARATION
COAL PREPARATION AREA
TRANSFER TOWER
CRUSHER BUILDING
SHIELDED FLARE STACK
FIGURE 4.1-3
PLAN VIEW
0 50 100 150 200
GRAPHIC SCALE IN FEET
REVISIONS
STATUS OF DRAWING
DEFINITION
APPROVED
REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
PRELIMINARY
REPRESENTS ACCEPTABLE DESIGN CONCEPTS. SUBJECT TO CHANGE.
CONCEPTUAL
REPRESENTS GENERAL CONCEPTS BASED ON ASSUMPTIONS. CHANGES COULD ENSUE.
400 MWe GREEN GRASS OXYGEN BLOWN DESTEC GASIFIER
MARKET BASED - FOAK
DEPARTMENT OF ENERGY TASK 22
PLANT LAYOUT
GENERAL ARRANGEMENT
TWO GASIFIERS - TWO GAS TURBINES - ONE STEAM TURBINE
SITE PLAN
PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA
COK
SCALE 1" = 60'- 0"
W.O. 088436-00360
MBAC-1-DW-200-010-001
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PPGI-DATE: 30-Apr-98 06:37

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4.1.10 Equipment List - Major

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	300 tph	2
8	Conveyor No. 3	48" belt	600 tph	1
9	Crusher Tower	N/A	600 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	600 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer		2
14	Conveyor No. 4	48" belt	600 tph	1
15	Transfer Tower	N/A	600 tph	1
16	Tripper	N/A	600 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	1,600 ton	3

ACCOUNT 1B LIMESTONE HANDLING AND PREPARATION SYSTEM

Not Applicable

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL SLURRY PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Vibratory Feeder		140 tph	3
2	Conveyor No. 1	Belt	280 tph	1
3	Conveyor No. 2	Belt	280 tph	1
4	Rod Mill Feed Hopper	Vertical, double hopper	300 tons	1
5	Vibratory Feeder		140 tph	2
6	Weight Feeder	Belt	140 tph	2
7	Rod Mill	Rotary	140 tph	2
8	Slurry Water Storage Tank	Field erected	100,000 gal	1
9	Slurry Water Pumps	Horizontal, centrifugal	1,200 gpm	2
10	Rod Mill Product Tank	Field erected	200,000 gal	1
11	Rod Mill Product Pumps	Horizontal, centrifugal	2,000 gpm	2
12	Slurry Storage Tank	Field erected	365,000 gal	1
13	Centrifugal Slurry Pumps	Horizontal centrifugal	3,000 gpm	2
14	PD Slurry Pumps	Progressing cavity	500 gpm	4
15	Slurry Blending Tank	Field erected	100,000 gal	1
16	Slurry Blending Tank Pumps	Horizontal centrifugal	450 gpm	2

ACCOUNT 2B SORBENT PREPARATION AND FEED

Not Applicable

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cylindrical, outdoor	50,000 gal	1
2	Condensate Pumps	Vert. canned	1,650 gpm @ 400 ft	2
3	Deaerator (integral with HRSG)	Horiz. spray type	795,000 lb/h 205°F to 240°F	2
4	IP Feed Pump	Horiz. centrifugal single stage	60 gpm/1,200 ft	2
5	HP Feed Pump	Barrel type, multi-staged, centr.	1,400 gpm @ 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	Recip., single stage, double acting, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exchangers	Plate and frame	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
10	Fire Service Booster Pump	Two-stage horiz. centrifugal	250 ft, 700 gpm	1
11	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
12	Raw Water Pumps	SS, single suction	60 ft, 300 gpm	2
13	Filtered Water Pumps	SS, single suction	160 ft, 120 gpm	2
14	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
15	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
16	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

ACCOUNT 4A GASIFICATION (Total for plant)

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Pressurized entrained bed	2400 ton/day/400 psig	2
2	Gas Cooler	Firetube	275 x 10^6 Btu/h	2
3	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	675,000 lb/h, medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT (Total for plant)

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	150,000 scfm, 70 psig discharge pressure	2
2	Cold Box		1,900 ton/day O_2	2
3	Oxygen Compressor	Centrifugal, multi-stage	25,000 scfm, 650 psig discharge pressure	2

ACCOUNT 5 FLUE GAS CLEANUP

(Per each of two gasifiers)

Equipment No.	Description	Type	Design Condition	Qty
1	MEA Absorber	Column	306,000 scfm (35,000 acfm) 385 psia, 1100°F	1
2	MEA Regenerator	Column	30 psia, 1450°F	1
3	Recycle Gas Compressor		36,000 acfm, P/P = 1.8 inlet 22 psia, 300°F	1
4	Recycle Gas Heat Exchanger	Fin tube	3 x 10^6 Btu/h	1
5	Recycle Gas Cooler	Shell & tube	50 x 10^6 Btu/h	1
6	Ceramic Candle Filter		20,000 acfm at 385 psig/650°F	1
7	Sulfuric Acid Plant		225 ton/day @ 98%	1
8	Chloride Guard	Pebble bed, vertical cylindrical pressure vessel	20,000 acfm at 385 psig/625°F	2

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	185 MWe Gas Turbine Generator	Axial flow single spool based on W501G	920 lb/sec airflow 2350°F rotor inlet temp. 15.2:1 pressure ratio	2
2	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	2
3	Air Inlet Filter/Silencer	Two stage	920 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	2
4	Starting Package	Electric motor, torque converter drive, turning gear	2,000 hp, time from turning gear to full load ~30 minutes	2
5	Air to Air Cooler			2
6	Mechanical Package	CS oil reservoir & pumps dual vertical cartridge filters air compressor		2
7	Oil Cooler	Air-cooled, fin fan		2
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	2
9	Generator Glycol Cooler	Air-cooled, fin fan		2
10	Compressor Wash Skid			2
11	Fire Protection Package	Halon		2

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK (Total for plant)

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, multi-pressure, with economizer section and integral deaerator	HP-2300 psig/1000°F 1,336,400 lb/h IP-90 psig/450°F 57,800 lb/h	2
2	Raw Gas Cooler Steam Generator	Fire tube boiler	2300 psig/850°F (drum) 932,528 lb/h	2
3	Stack	Carbon steel plate, type 409 stainless steel liner	213 ft high x 28 ft dia.	2

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	260 MW Steam Turbine Generator	TC2F40	1800 psig 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	1,353,000 lb/h steam @ 2.0 in. Hga with 74°F water, 20°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	2

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. Water Pumps	Vert. wet pit	75,000 gpm @ 60 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	52°F WB/74°F CWT/ 94° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A SLAG DEWATERING & REMOVAL

(Quantities in this account are per gasifier)

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Quench Tank	Water bath	12 tph	1
2	Slag Crusher	Roll	12 tph	1
3	Slag Depressurizer	Proprietary	12 tph	1
4	Slag Dewatering Bin	Horizontal, weir	4 tph	3
5	Slag Conveyor	Drag chain	4 tph	3
6	Slag Conveyor	Drag chain	8 tph	*1
7	Storage Bin	Vertical	1,400 tons	*1
8	Unloading Equipment	Telescoping chute	25 tph	*1

*Total for plant.

4.1.11 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the IGCC plant is shown in Table 4.1-4. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 4.1-4

Client: DEPARTMENT OF ENERGY	**Report Date:** 14-Aug-98 10:59 AM
Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Destec (2000-90/10)
Plant Size: 543.2 MW,net	**Estimate Type:** Conceptual	**Cost Base (Jan)** 1998	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	7,603	1,526	6,640	465		**$16,233**	1,299		3,506	**$21,038**	39
2	COAL & SORBENT PREP & FEED	11,480	2,641	12,398	868		**$27,387**	2,191	919	4,022	**$34,519**	64
3	FEEDWATER & MISC. BOP SYSTEMS	8,097	4,016	6,386	447		**$18,946**	1,516		4,893	**$25,354**	47
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries(Destec)	15,536		15,824	1,108		**$32,468**	2,597	1,623	3,669	**$40,358**	74
4.2	High Temperature Cooling	24,846		25,317	1,772		**$51,935**	4,155	2,597	5,869	**$64,555**	119
4.3	ASU/Oxidant Compression	69,266		w/equip.			**$69,266**	5,541		7,481	**$82,288**	151
4.4-4.9	Other Gasification Equipment	12,543	4,800	11,788	825		**$29,956**	2,396	1,113	4,744	**$38,210**	70
	SUBTOTAL 4	*122,191*	*4,800*	*52,930*	*3,705*		***$183,625***	*14,690*	*5,334*	*21,762*	***$225,411***	*415*
5	HOT GAS CLEANUP & PIPING	37,832	2,554	9,016	631		**$50,033**	4,003	4,093	11,819	**$69,948**	129
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	61,888		3,868	271		**$66,026**	5,282	3,301	7,461	**$82,071**	151
6.2-6.9	Combustion Turbine Accessories		222	256	18		**$496**	40		161	**$696**	1
	SUBTOTAL 6	*61,888*	*222*	*4,124*	*289*		***$66,522***	*5,322*	*3,301*	*7,622*	***$82,767***	*152*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	21,702		3,119	218		**$25,040**	2,003		2,704	**$29,748**	55
7.2-7.9	HRSG Accessories, Ductwork and Stack	3,281	2,209	3,165	222		**$8,877**	710		1,455	**$11,042**	20
	SUBTOTAL 7	*24,983*	*2,209*	*6,284*	*440*		***$33,917***	*2,713*		*4,159*	***$40,790***	*75*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	19,353		3,189	223		**$22,765**	1,821		2,459	**$27,045**	50
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	8,114	247	4,450	311		**$13,122**	1,050		2,440	**$16,612**	31
	SUBTOTAL 8	*27,467*	*247*	*7,638*	*535*		***$35,887***	*2,871*		*4,899*	***$43,657***	*80*
9	COOLING WATER SYSTEM	5,766	3,281	5,428	380		**$14,855**	1,188		2,892	**$18,935**	35
10	ASH/SPENT SORBENT HANDLING SYS	5,750	883	5,042	353		**$12,027**	962	442	1,526	**$14,958**	28
11	ACCESSORY ELECTRIC PLANT	18,990	5,447	14,090	986		**$39,514**	3,161		6,985	**$49,660**	91
12	INSTRUMENTATION & CONTROL	5,902	1,654	6,143	430		**$14,129**	1,130		2,371	**$17,630**	32
13	IMPROVEMENTS TO SITE	2,294	1,319	4,595	322		**$8,530**	682		2,764	**$11,976**	22
14	BUILDINGS & STRUCTURES		5,432	7,129	499		**$13,060**	1,045		3,526	**$17,631**	32
	TOTAL COST	**$340,244**	**$36,230**	**$147,844**	**$10,349**		**$534,667**	**$42,773**	**$14,090**	**$82,746**	**$674,276**	**1241**

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Section 4.2

Market-Based Intermediate Oxygen-Blown Destec – 400 MWe

4.2 MARKET-BASED INTERMEDIATE OXYGEN-BLOWN DESTEC 400 MWe

4.2.1 Introduction

This IGCC concept is based on the utilization of the Destec oxygen-blown coal gasification process supplying medium-Btu gas to a gas turbine/combined cycle power generating plant. The plant configuration is based on a projection of state-of-the-art design for an in-service date of 2005. The availability of a combustion turbine comparable to the Westinghouse 501G is assumed, along with steam turbines incorporating state-of-the-art design features. The specific design approach presented herein is based on DOE/FETC and Parsons concepts, and does not necessarily reflect the approach that Destec Energy would take if they were to commercially offer a facility of this size (MWe) in this time frame.

This case illustrating IGCC technology is based on selection of a gas turbine derived from the Westinghouse "G" machine. This particular machine, coupled with an appropriate steam cycle, will produce a nominal 350 MWe net output. The IGCC portion of the plant is configured with one gasifier island, which includes a transport reactor type hot gas desulfurizer. The resulting plant produces a net output of 349 MWe at a net efficiency of 45.4 percent on an HHV basis. This performance is based on the use of Illinois No. 6 coal. Performance will vary with other fuels.

4.2.2 Heat and Mass Balance

The pressurized Destec gasifier utilizes a combination of oxygen, water, and coal along with recycled fuel gas to gasify the coal and produce a medium-Btu hot fuel gas. The fuel gas produced in the entrained bed gasifier leaves at 1900°F and enters a hot gas cooler. A significant fraction of the sensible heat in the gas is retained by cooling the gas to 1100°F. High-pressure saturated steam is generated in the hot gas cooler and is joined with the main steam supply.

The gas goes through a series of hot gas cleanup processes including transport reactor type hot desulfurization process, barrier filter, and chloride guard. A fraction of the clean hot gas is cooled and recycled to the gasifier to aid in second-stage gasification. Char particulates are recycled to the gasifier, resulting in nearly complete carbon conversion. Regeneration gas from the desulfurizer is fed to an H_2SO_4 plant.

This plant utilizes a combined cycle for combustion of the medium-Btu gas from the gasifier to generate electric power. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process (gas cooling and sulfation modules).

The gas turbine operates in an open cycle mode, as described below.

The inlet air is compressed in a single spool compressor to the design basis discharge pressure. Most of the compressor discharge air passes to the burner section of the machine to support combustion of the medium-Btu gas supplied by the gasifier island, and to cool the burner and turbine expander sections of the machine. The firing of medium-Btu gas in the combustion turbine is expected to require modifications to the burner and turbine sections of the machine. These modifications are discussed in Section 4.2.4.7.

The hot combustion gases are conveyed to the inlet of the turbine section of the machine, where they enter and expand through the turbine to produce power to drive the compressor and electric generator. The combustion turbine utilizes steam cooling for the transitions from the burners to the expander; the steam is returned to the steam cycle for performance augmentation. The turbine exhaust gases are conveyed through a HRSG to recover the large quantities of thermal energy that remain. The HRSG exhausts to the plant stack.

The Rankine steam power cycle is also shown schematically in the 100 percent load Heat and Mass Balance Diagram (Figure 4.2-1). Overall performance for the entire plant, including Brayton and Rankine cycles, is summarized in Table 4.2-1, which includes auxiliary power requirements.

The steam cycle is based on maximizing heat recovery from the gas turbine exhaust gases, as well as utilizing steam generation opportunities in the gasifier process. For this facility, a double-pressure HRSG configuration has been selected. In addition to the high-pressure (HP) drum, an intermediate-pressure (IP) drum is provided in the HRSG to raise steam that is joined with the reheat. Steam conditions at the HP turbine admission valves are set at 1800 psig/1000°F.

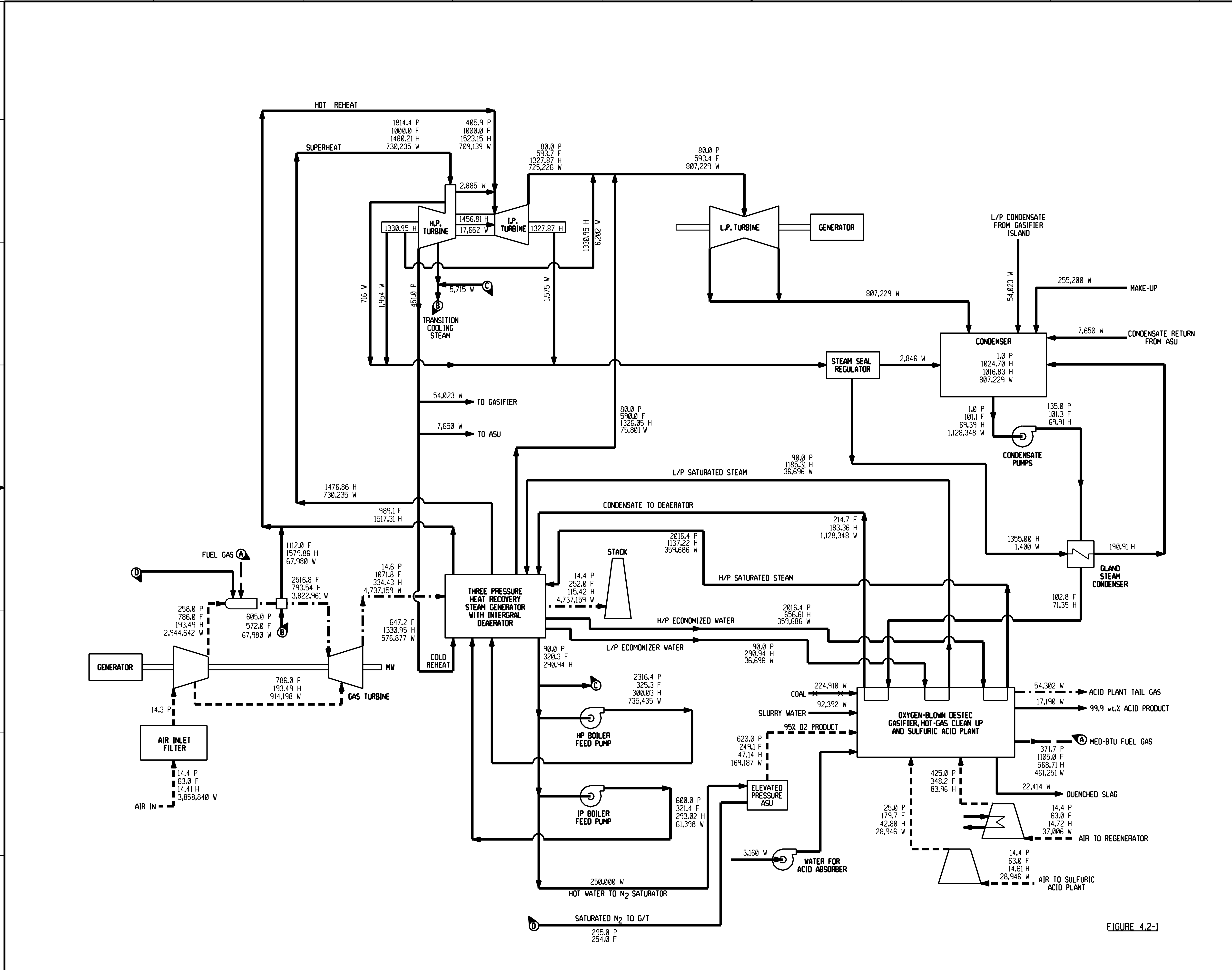

FIGURE 4.2-1

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018°F AND 0.08865 PSIA
2. IP BOILER IN HRSG GENERATES ADDITIONAL COLD REHEAT STEAM.

LEGEND

– – – –	AIR / OXIDANT
— — —	FUEL GAS
—·—·—	COMBUSTION PRODUCTS
—×—×—	SOLIDS
———	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

(ONE GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	267.899 MWe
STEAM T-G POWER :	143.530 MWe
GENERATOR LOSS (TOTAL):	8.133 MWe
AUXILIARY POWER (TOTAL):	54.08 MWe
NET PLANT POWER :	349.211 MWe
NET PLANT EFFICIENCY :	45.4 %
NET PLANT HEAT RATE :	7,513 Btu/kwh

J.S.WHITE DESTECWG/DWG-BOTM 6/18/1998

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	LEAD ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER

STATUS OF DRAWING	DEFINITION	CONSTRUCTION STATUS
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUPTIONS. REVIEWED NOT CHECKED.	

DRAWN BY CLB DATE 7/7/97

CHECKED BY DATE

LEAD DESIGNER DATE

ENGINEER DATE

LEAD DISCIPLINE ENGR. DATE

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE: STATE: LIC. NO.: DATE:

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE

CLEAN COAL TECHNOLOGY PROGRAM
400 MW INTEGRATED GASIFICATION COMB CYCL
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
OXYGEN BLOWN ENTRAINED BED GASIFIER

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-005 REV A

DD

416006:61098.GRA
416006:61098.DGN

PPGI-FILE:
PPGI-DATE:

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Table 4.2-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

(Loads are presented for one IGCC island, one gas turbine, and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY (Net Electric Power at Generator Terminals, kWe)	
Gas Turbine	262,603
Steam Turbine	140,693
Total	403,296
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	190
Coal Slurry Pumps	170
Condensate Pumps	180
IP/IP Feed Pumps	50
HP Feed Pumps	2,030
Miscellaneous Balance of Plant (Note 1)	900
Air Separation Plant	28,505
Boost Air Compressor	370
Oxygen Boost Compressor	5,530
Clasifier Recycle Blower	180
Regenerator Recycle Blower	2,180
Sulfuric Acid Plant Air Blower	250
N2 Compressor	9110
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	300
Saturated Water Pumps	80
Circulating Water Pumps	1,380
Cooling Tower Fans	840
Slag Handling	480
Transformer Loss	960
TOTAL AUXILIARIES, kWe	54,085
Net Power, kWe	349,211
Net Efficiency, % HHV	45.4
Net Heat Rate, Btu/kWh (HHV)	7,513
CONDENSER COOLING DUTY, 10^6 Btu/h	773
CONSUMABLES	
As-Received Coal Feed, lb/h	224,910
Oxygen (95% pure), lb/h	169,187
Water (for slurry), lb/h	92,392

Note 1 - Includes plant control systems, lighting, HVAC, etc.

The HRSG also contains an integral deaerating heater and several economizer sections. The economizer provides essentially all of the necessary feedwater heating (except for that provided by the deaerating heater) by heat recovery from the gas path. Therefore, conventional feedwater heaters using turbine extraction steam are not required.

The steam turbine selected to match this cycle is a two-casing, reheat, double-flow (exhaust) machine, exhausting downward to the condenser. The HP and IP turbine sections are contained in one section, with the LP section in a second casing. Other turbine design arrangements are possible; the configuration represented herein is typical of reheat machines in this size class.

The steam turbine drives a 3600 rpm hydrogen-cooled generator. The turbine exhausts to a single-pressure condenser operating at a nominal 2.0 inches Hga at the 100 percent load design point. For the low-pressure turbine, the last-stage bucket length is 30 inches. Two 50 percent capacity, motor-driven pumps are provided for feedwater and condensate.

4.2.3 Emissions Performance

The operation of the combined cycle unit in conjunction with oxygen-blown Destec IGCC technology is projected to result in very low levels of emissions of NOx, SO_2, and particulates (fly ash). A salable byproduct in the form of sulfuric acid at 99 percent concentration is produced. A summary of the plant emissions is presented in Table 4.2-2.

Table 4.2-2
AIRBORNE EMISSIONS - IGCC, OXYGEN-BLOWN DESTEC

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.017	129	168	0.13
NOx	0.024	179	234	0.182
Particulates	< 0.002	< 15	< 20	0.015
CO_2	200	1,496,745	1,957,282	1,506

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the transport hot gas desulfurizer (THGD) subsystem. The THGD process removes approximately 99.5 percent of the sulfur compounds in the fuel gas.

The reduction in NOx to below 10 ppm is achieved for a fuel gas containing fuel-bound nitrogen (NH_3) by the use of rich-quench lean (staged) combustion technology coupled with syngas dilution by nitrogen available from the ASU. Syngas dilution and staged combustion, sub-stoichiometric combustion followed by excess air dilution, promote the conversion of fuel bound nitrogen to N_2 rather than NOx. The techniques of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can reduce NOx emissions further, but are not applied to the subject plant.

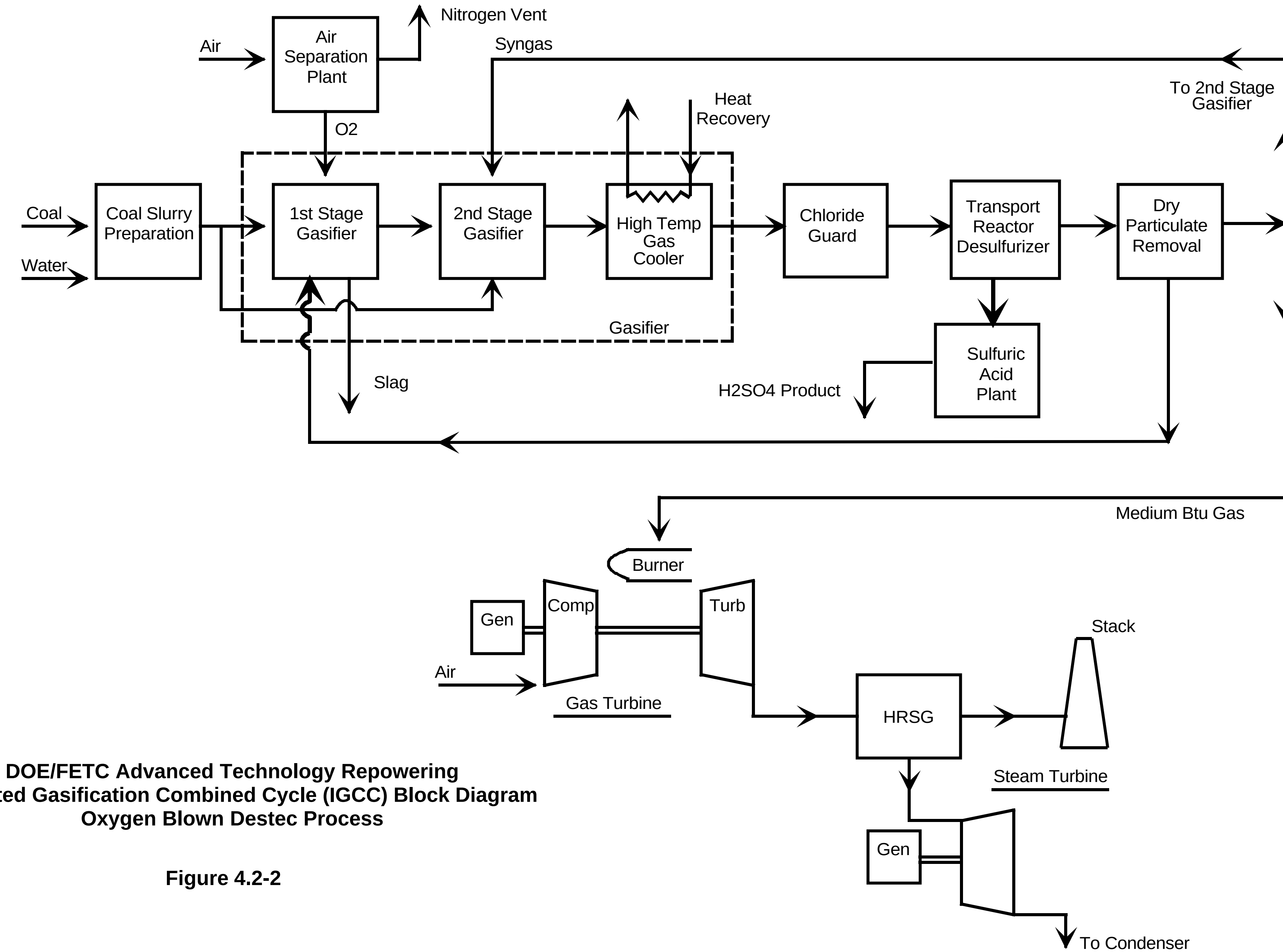
Particulate discharge to the atmosphere is limited by the use of a ceramic candle type barrier filter, which provides a particulate removal rate of greater than 99.99 percent.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/MMBtu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

4.2.4 Description of Oxygen-Blown IGCC

This reference design is based on the utilization of one oxygen-blown Destec entrained bed, slagging gasifier employing in-bed desulfurization. The medium-Btu gas produced in the gasifier is further cleaned in transport reactor type hot gas desulfurization and filtration processes downstream of the gasifier. The final product gas is used to fire a combustion turbine generator, which is coupled to a HRSG for driving one steam turbine generator.

The following is a summary description of the overall gasification process and its integration with the power generation cycles used in this reference design. (Refer to Figure 4.2-2.)



DOE/FETC Advanced Technology Repowering
Integrated Gasification Combined Cycle (IGCC) Block Diagram
Oxygen Blown Destec Process

Figure 4.2-2

Illinois No. 6 coal is ground to 200 mesh and mixed with water to be fed to the pressurized Destec gasifier as a slurry. The slurry is fired with oxygen to produce medium-Btu gas, which is largely comprised of CO, H_2, and CO_2, and is discharged from the gasifier at 1900°F and cooled in a gas cooler to 1100°F.

The cooled gas passes through the chloride guard containing a fixed bed reactor, exposing the gas to nahcolite to reduce the chloride level to less than 1 ppm, thus protecting the sorbent and the combustion turbine downstream. The gas then enters the THGD, where sufficient sulfur is removed to result in a final sulfur level of approximately 30 ppm. The gas is then cleaned in the dry particulate removal system containing a final ceramic candle type barrier filter, resulting in very low levels of particulates. Fly ash from the filter is transferred to the fines combustor where it is oxidized. The regeneration gas from the THGD is a mixture of air and SO_2, which is a suitable feedstock for the sulfuric acid plant.

The gas exiting the THGD is conveyed to the combustion turbine where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The exhaust gas from the turbine and HRSG is released to the atmosphere via a conventional stack.

Based on the selection of a machine derived from Westinghouse “G” class combustion turbine, a fuel gas pressure of 400 psig was established to provide a margin above the compressor discharge pressure (275 psig for this reference case), allowing for necessary system and valve pressure drop.

Based on the above, a nominal gasifier pressure of 500 psig is required. At this pressure, a single gasifier is required. The gasifier is similar in size to the commercial-sized island utilized in the Wabash River Coal Gasification Repowering Project, which operates at a nominal pressure of 450 psig. The wall thickness of the gasifiers and other vessels and piping comprising the gasifier islands is increased by approximately 11 percent to compensate for the higher pressure (500 psig vs. 450 psig).

4.2.4.1 Coal Grinding and Slurry Preparation

Coal is fed onto conveyor No. 1 by vibratory feeders located below each coal silo. Conveyor No. 1 feeds the coal to an inclined conveyor (No. 2) that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. A vibrating feeder on each hopper outlet supplies the weigh feeder, which in turn feeds a rod mill. The rod mill grinds the coal and wets it with treated slurry water from a slurry water tank. The slurry is then pumped from the rod mill product tank to the slurry storage and slurry blending tanks.

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required will depend on local environmental regulations.

4.2.4.2 Gasifier

Note: The following description is taken from the Coal Gasification Guidebook: Status, Applications, and Technologies, prepared by SFA Pacific, Inc. for the Electric Power Research Institute.

The Destec coal gasifier is a slurry feed, pressurized, upflow, entrained slagging gasifier whose two-stage operation makes it unique. Wet crushers produce slurries with the raw feed coal. Dry coal slurry concentrations range from 50 to 70 wt%, depending on the inherent moisture and quality of the feed coal. The slurry water consists of recycle water from the raw gas cooling together with makeup water. About 80 percent of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 2400 to 2600°F. The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed in a novel continuous-pressure letdown/dewatering system.

The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 20 percent of coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1900°F.

Char is produced in the second stage. However, the yield of this char is relatively small because only about 20 percent of the coal is fed to the second stage. Char yield is dependent on the reactivity of the feed coal and decreases with increasing reactivity. The char is recycled to the hotter first stage, where it is easily gasified. The gasifier is refractory lined and uncooled. The hotter first-stage section of the gasifier also includes a special slag-resistant refractory. The 1900°F hot gas leaving the gasifier is cooled in the fire-tube product gas cooler to 1100°F, generating saturated steam for the steam power cycle in the process.

4.2.4.3 Acid Gas Removal (AGR)

The THGD section of the IGCC island serves to remove most of the sulfur from the gas produced by the gasifier. The gas delivered from the gasifier to the THGD system is at 1100°F and 425 psig. The sulfur compounds in the gas (predominantly H_2S) react with the sorbent to form zinc sulfides, yielding a clean gas containing less than 30 ppmv of sulfur compounds. The sorbent for this process is Z-sorb, a zinc-based material also containing nickel oxide.

The uncleaned gas enters the bottom of an absorber column, where it mixes with powdered sorbent, and then rises in the column. The gas/powder mixture exiting the column passes through a cyclone where the sorbent is stripped out for recycle. The clean gas discharged from the absorber flows to a high-efficiency barrier-type filter to remove any remaining particulates.

A regeneration column is used to regenerate the sorbent material from sulfide form to oxide form. Regeneration gas, laden with SO_2, is conveyed to the sulfator for capture of the sulfur and conversion to a disposable form.

4.2.4.4 Particulate Removal

The particulate removal stage in this gasification process is dependent upon a high-efficiency barrier filter comprised of an array of ceramic candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with gas to remove the fines, which are collected and conveyed to the gasifier.

4.2.4.5 Chloride Guard

The chloride guard functions to remove HCl from the hot gas, prior to delivery to the combustion turbine.

The chloride guard is comprised of two 100 percent capacity pressure vessels packed with a pebble bed of nahcolite, a natural form of sodium bicarbonate. One vessel is normally in service, with a nominal service period of two months. The second vessel is purged, cooled, drained of spent bed material, and recharged, while the other vessel is in service. The chloride guard vessels are approximately 13 feet in diameter, 25 feet high, and are fabricated of carbon steel.

4.2.4.6 Sulfuric Acid Plant

The regeneration of the sorbent in the THGD subsystem produces an offgas from the regeneration process, which contains an SO_2 concentration of 13 percent. This is adequate for feed to a contact process sulfuric acid plant. Key to the process is the four-pass converter developed by Monsanto. The reaction from SO_2 to SO_3 is an exothermic reversible reaction. Equilibrium conversion data show that conversion of SO_2 decreases with an increase in temperature. Using a vanadium catalyst, a contact plant takes advantage of both rate and equilibrium considerations by first allowing the gases to enter over a part of the catalyst at about 800 to 825°F, and then allowing the temperature to increase adiabatically as the reaction proceeds. The reaction essentially stops when about 60 to 70 percent of the SO_2 has been converted, at a temperature in the vicinity of 1100°F. The gas is cooled in a waste heat boiler and passed through subsequent stages, until the temperature of the gases passing over the last portion of catalyst does not exceed 805°F.

The gases leaving the converter, having passed through two or three layers of catalyst, are cooled and passed through an intermediate absorber tower where some of the SO_3 is removed with 98 percent H_2SO_4. The gases leaving this tower are then reheated, and they flow through the remaining layers of catalyst in the converter. The gases are then cooled and pass through the final absorber tower before discharge to the atmosphere. In this manner, more than 99.7 percent of the SO_2 is converted into SO_3 and subsequently into product sulfuric acid.

4.2.4.7 Gas Turbine Generator

The gas turbine generator selected for this application is based on a derivative of the Westinghouse “G” class machine. This machine is an axial flow, single spool, constant speed unit, with variable inlet guide vanes. The standard production version of this machine, fired with natural gas, will develop a compressor pressure ratio of 19.2:1 and a rotor inlet temperature of almost 2600°F. In this service, with medium-Btu gas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the fuel gas and expand the combustion products in the turbine section of the machine.

The modifications to the machine include some redesign of the original can-annular combustors to allow firing of a medium-Btu gas derived from an IGCC plant. A second modification involves increasing the nozzle area of the first-stage turbine to accommodate the mass and volume flow of medium-Btu fuel gas combustion products, which is increased relative to those produced when firing natural gas. An increase in turbine nozzle areas of between 7 and 10 percent may be required. Other modifications include rearranging the various auxiliary skids that support the machine to accommodate the spatial requirements of the plant general arrangement. The generator is a standard hydrogen-cooled machine with static exciter.

4.2.4.8 Steam Generation

Heat Recovery Steam Generator (HRSG)

The HRSG is a drum-type, triple-pressure design that is matched to the characteristics of the Westinghouse “G” turbine exhaust gas when firing medium-Btu gas. The HP drum produces steam at main steam pressure while the IP drum produces steam that is combined with the reheat.

Gas Cooler

The gas cooler contains a steam drum and heating surface for the production of saturated steam. This steam is conveyed to the HRSG where it is superheated.

4.2.4.9 Air Separation Plant

The air separation plant is designed to produce a nominal output of 2,050 tons/day of 95 percent pure O_2. The plant is designed with one 100 percent capacity production train. Liquefaction and liquid oxygen storage provide an 8-hour backup supply of oxygen.

In this air separation process, air is compressed to 70 psig and then cooled in a water scrubbing spray tower. The cooled air enters a reversing heat exchanger, where it is cooled to the liquefaction point prior to entering a double column (high/low pressure) separator. Refrigeration for cooling is provided by expansion of high-pressure gas from the lower part of the high-pressure column.

4.2.5 <u>IGCC Support Systems (Balance of Plant)</u>

4.2.5.1 Coal Handling System

The function of the balance-of-plant coal handling system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper unloader and coal receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

<u>Operation Description</u>

The bituminous coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor (No. 1). The coal is then transferred to a conveyor (No. 2) that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 by the first of two crushers. The coal then enters the second crusher, which reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the stationary tripper, which loads the coal into one of the two silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 225,000 lb/h = 113 tph plus 10% margin = 124 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 192,000 lb/h = 96 tph (based on MCR rate multiplied by an assumed 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Two unit trains per week at maximum burn rate
  - One and one-half unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 9 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 900 tph (maximum, both conveyors in operation)
  - Reclaim rate = 400 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 9,000 tons (72 hours at maximum burn rate)
  - Dead storage = 70,000 tons (30 days at average burn rate)

4.2.5.2 Slag Ash Handling

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. The ash is removed from the process as slag. Spent material drains from the gasifier bed into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids leaves the gasifier pressure boundary, through a proprietary pressure letdown device, to a series of dewatering bins. The separated liquid is recycled to the slag quench water bath.

The cooled, solidified slag is stored in a storage vessel. The hopper is sized for a nominal holdup capacity of approximately 72 hours of full-load operation. At periodic intervals, a convoy of slag hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. Approximately 12 truck loads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power.

4.2.6 Steam Cycle Balance of Plant

The following section provides a description of the steam turbines and their auxiliaries.

4.2.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last-stage bucket length of 30 inches.

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at 1800 psig/1000°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the HP turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 485 psig/1000°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Extraction steam from the HP section is used for the burner transition cooling in the G machine. The steam from the transition cooling is then routed to the hot reheat.

Turbine bearings are lubricated by a closed-loop water-cooled pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure-regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

The steam turbine generator is controlled by triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

4.2.6.2 Condensate and Feedwater Systems

<u>Condensate</u>

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG. The system consists of one main condenser; two 50 percent capacity, motor-driven variable speed vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG. Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Feedwater

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two motor-driven, HP and IP, 50 percent capacity boiler feed pumps are provided. Each pump is provided with a variable speed drive to support startup, shutdown, and part-load operation. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

4.2.6.3 Main and Reheat Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the HRSG superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 1800 psig/1000°F exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 450 psig/650°F exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 400 psig/1000°F exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

4.2.6.4 Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

4.2.6.5 Major Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the steam cycle. A summary of the required piping is presented in Table 4.2-3.

4.2.7 Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

4.2.8 Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designedfor automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

Table 4.2-3
INTEGRATED GASIFICATION COMBINED CYCLE

Major Steam Cycle Piping Required

Pipeline	**Flow, lb/h**	**Press., psia**	**Temp., °F**	**Material**	**OD, in.**	**Twall, in.**
Condensate	1,128,400	135	100	A106 Gr. B	8	Sch. 40
HP Feedwater, Pump to HRSG	735,400	2316	325	A106 Gr. C	8	Sch. 160
IP Feedwater, Pump to HRSG	61,000	600	321	A106 Gr. B	3	Sch. 40
HP Feedwater to Gasifier	359,700	2016	420	A106 Gr. C	6	Sch. 160
HP steam from Gasifier`	359,700	2016	640	A106 Gr. C	6	Sch. 160
Main Steam/HRSG to Steam Turbine	730,200	1814	1000	A335 Gr. P91	8	1.375
Cold Reheat/ST to HRSG	577,000	451	647	A106 Gr. B	14	Sch. 40
Hot Reheat/HRSG to ST	709,000	406	1000	A335 Gr. P91	16	Sch. 40
Cold Reheat/GT for Cooling	68,000	451	647	A106 Gr. B	6	Sch. 40
Fuel Gas/Gasifier Island to Gas Turbine	461,300	372	1105	A335 Gr. P91	16	Sch. 40
O_2 Piping to Gasifier	170,000	620	250	A106 Gr B	6	Sch. 40

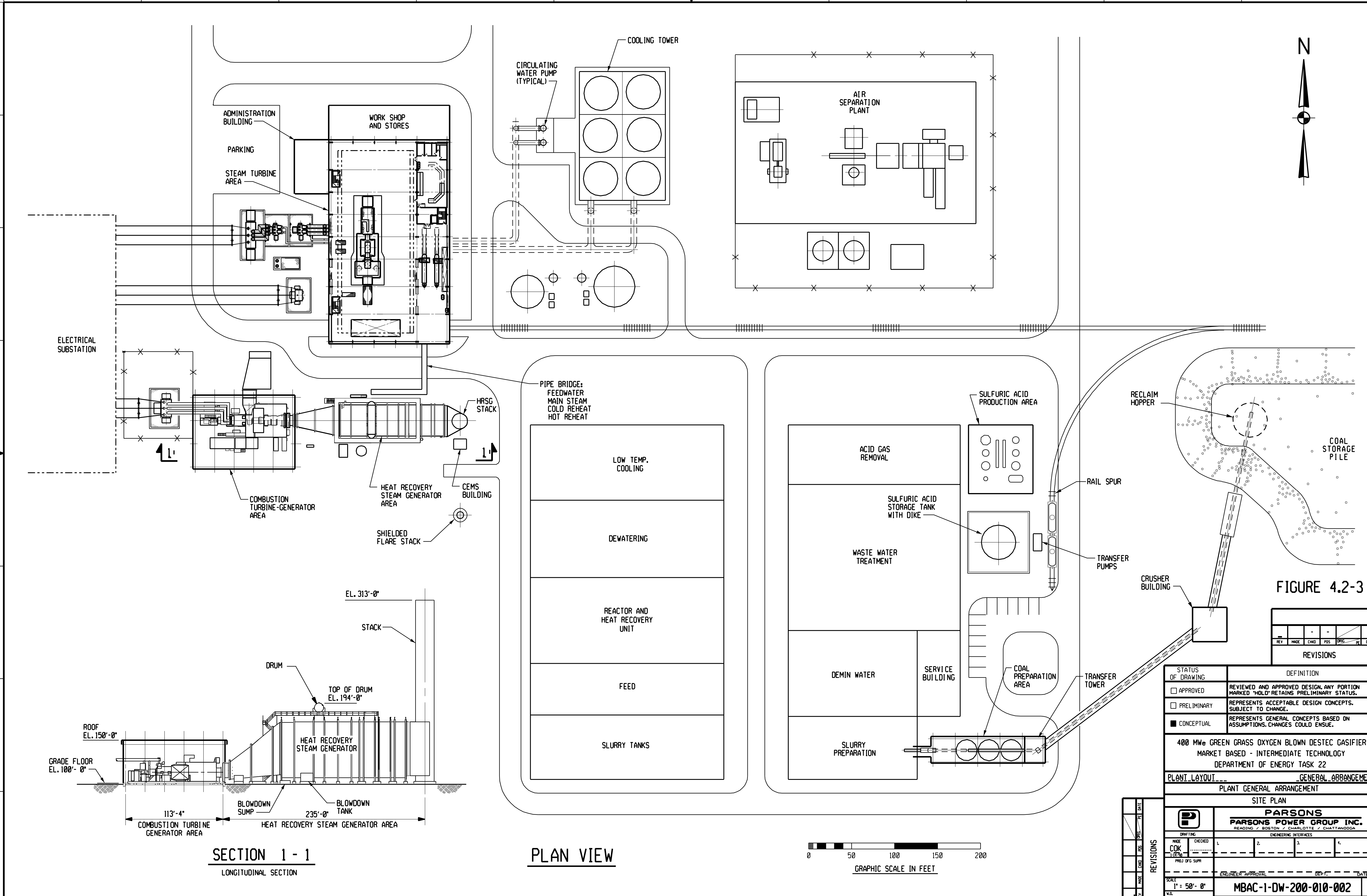
4.2.9 Site, Structures, and Systems Integration

4.2.9.1 Plant Site and Ambient Design Conditions

Refer to Section 2 for a description of the plant site and ambient design conditions.

4.2.9.2 New Structures and Systems Integration

The development of the reference plant site to incorporate structures required for this technology is based on the assumption of a flat site. The IGCC gasifier and related structures are arranged in a cluster, with the coal and slurry preparation facilities adjacent to the south, as shown in the conceptual arrangement in Figure 4.2-3.



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The gasifier and its associated process blocks are located west of the coal storage pile. The gas turbine and its ancillary equipment are sited west of the gasifier island, in a turbine building designed expressly for this purpose. A HRSG and stack are east of the gas turbine, with the steam turbine and its generator in a separate building continuing the development to the north. Service and administration buildings are located at the west side of the steam turbine building.

The cooling tower heat sink for the steam turbine is located to the east of the steam turbine building. The air separation plant is further to the east, with storage tanks for liquid O_2 located near the gasifier and its related process blocks. Sulfur recovery and wastewater treatment areas are located east and south of the air separation plant.

The arrangement described above provides good alignment and positioning for major interfaces; relatively short steam, feedwater, and fuel gas pipelines; and allows good access for vehicular traffic. Transmission line access from the gas turbine and steam turbine step-up transformer to the switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located north of the gas turbine. The clean, hot, medium-Btu gas is conveyed to the turbine combustors for mixing with the air that remained on-board the machine. Turbine exhaust is ducted directly through a triple-pressure HRSG and then to a new 213-foot stack. The height of the stack is established by application of a good engineering practice rule from 40 CFR 51.00.

Access and construction laydown space are freely available on the periphery of the plant, with several roads, 26 feet wide plus shoulders, running from north to south between the various portions of the plant.

4.2.10 Equipment List - Major

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	200 tph	2
8	Conveyor No. 3	48" belt	400 tph	1
9	Crusher Tower	N/A	400 tph	1
10	Coal Surge Bin w/Vent Filter	Compartment	400 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer		1
14	Conveyor No. 4	48" belt	400 tph	1
15	Transfer Tower	N/A	400 tph	1
16	Tripper	N/A	400 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	1,500 ton	2

ACCOUNT 1B LIMESTONE HANDLING AND PREPARATION SYSTEM

Not Applicable

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL SLURRY PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Vibratory Feeder		80 tph	2
2	Conveyor No. 1	Belt	160 tph	1
3	Conveyor No. 2	Belt	160 tph	1
4	Rod Mill Feed Hopper	Vertical, double hopper	200 ton	1
5	Vibratory Feeder		80 tph	2
6	Weight Feeder	Belt	80 tph	2
7	Rod Mill	Rotary	80 tph	2
8	Slurry Water Storage Tank	Field-erected	80,000 gal	1
9	Slurry Water Pumps	Horizontal, centrifugal	600 gpm	2
10	Rod Mill Product Tank	Field-erected	150,000	1
11	Rod Mill Product Pumps	Horizontal, centrifugal	800 gpm	2
12	Slurry Storage Tank	Field-erected	280,000	1
13	Centrifugal Slurry Pumps	Horizontal, centrifugal	1,600 gpm	2
14	PD Slurry Pumps	Progressing cavity	270 gpm	2
15	Slurry Blending Tank	Field-erected	80,000 gal	1
16	Slurry Blending Tank Pumps	Horizontal, centrifugal	300 gpm	2

ACCOUNT 2B SORBENT PREPARATION AND FEED

Not Applicable

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cyl., outdoor	50,000 gal	1
2	Condensate Pumps	Vert. canned	1,100 gpm @ 310 ft	2
3	Deaerator and Storage Tank	Horiz. spray type	1,130,000 lb/h 215°F	1
4	IP Feed Pumps	Interstage bleed from HP feed pump	60 gpm/1,100 ft	2
5	HP Feed Pumps	Barrel type, multi-staged, centr.	735 gpm / 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	20,000 gal No. 2 oil	2
3	Fuel Oil Unloading Pump	Gear	50 psig, 100 gpm	1
4	Fuel Oil Supply Pump	Gear	150 psig, 5 gpm	2
5	Service Air Compressors	Recip., single-stage, double acting, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exch	Plate and frame	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
11	Fire Service Booster Pump	Two-stage horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water	SS, single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	SS, single suction	160 ft, 120 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

ACCOUNT 4A GASIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Pressurized entrained bed	2860 tpd/500 psig	1
2	Gas Cooler	Firetube	167 x 10^6 Btu/h	1
3	Flare Stack	Shielded	465,000 lb/h medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	80,000 acfm, 70 psig discharge pressure	1
2	Cold Box		2,100 ton/day O_2	1
3	Oxygen Compressor	Centrifugal, multi-stage	33,200 scfm, 650 psig discharge pressure	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Qty
1	Sorbent Storage Hopper	*		1
2	Sorbent Feed Hopper	*		1
3	Transport Desulfurizer	*		1
4	Desulfurizer Cyclone	*		1
5	Transport Regenerator	*		1
6	Regenerator Cyclone	*		1
7	Sorbent Regeneration Air Heater	*		1
8	Regenerator Effluent Gas Cooler	*		1

* This information is proprietary and is not presented.

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	250 MWe Gas Turbine Generator	Axial flow single spool based on Westinghouse G-class	1,100 lb/sec airflow 2600°F rotor inlet temp. 19.2:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1,100 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2,500 hp, time from turning gear to full load ~30 minutes	1
5	Air-to-Air Cooler			1
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
7	Oil Cooler	Air-cooled, fin fan		1
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
9	Generator Glycol Cooler	Air-cooled, fin fan		1
10	Compressor Wash Skid			1
11	Fire Protection Package	Halon		1

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, triple pressure, with economizer sections and integral deaerator	HP-2300 psig/325°F 730,000 lb/h superheat to 1000°F IP-600 psig/320°F 63,000 lb/h	1
2	Raw Gas Cooler Steam Generator	Drum and superheater	2000 psig/sat. steam 360,000 lb/h Superheat to 1000°F	1
3	Stack	Carbon steel plate lined with type 409 stainless steel	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	140 MW Turbine Generator	TC2F30	1800 psig 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	716,000 lb/h steam @ 2.0 in. Hga with 78°F water, 19°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	40,000 gpm @ 60 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell counter-flow, film type fill	56°F WB/78°F CWT/ 97° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A SLAG DEWATERING & REMOVAL

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Quench Tank	Water bath		1
2	Slag Precrusher		12 tph solids	1
3	Slag Crusher	Roll	12 tph solids	1
4	Slag Depressurizing Unit	Proprietary	12 tph solids	1
5	Slag Dewatering Unit	Horizontal, weir	4 tph solids	3
5	Slag Conveyor	Drag chain	4 tph	3
6	Slag Conveyor	Drag chain	8 tph	*1
6	Slag Storage Vessel	Reinf. concrete vert. cylindrical	1,200 ton	*1
7	Slide Gate Valve			*1
8	Telescoping Unloader		25 tph	*1

*Total for plant.

4.2.11 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the market-based intermediate O_2-blown Destec 400 MW plant is shown in Table 4.2-4. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 4.2-4

Client: DEPARTMENT OF ENERGY | **Report Date:** 14-Aug-98 11:00 AM

Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Destec (2005-80/20)

Plant Size: 349.2 MW,net | **Estimate Type:** Conceptual | **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	5,347	1,073	4,670	327		**$11,417**	913		2,466	**$14,796**	42
2	COAL & SORBENT PREP & FEED	6,455	1,485	6,972	488		**$15,400**	1,232	517	2,261	**$19,410**	56
3	FEEDWATER & MISC. BOP SYSTEMS	5,483	2,655	4,284	300		**$12,722**	1,018		3,309	**$17,049**	49
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries(Destec)	8,575		8,734	611		**$17,921**	1,434	1,792	2,115	**$23,261**	67
4.2	High Temperature Cooling	14,603		14,880	1,042		**$30,525**	2,442	3,052	3,602	**$39,621**	113
4.3	ASU/Oxidant Compression	45,518		w/equip.			**$45,518**	3,641		4,916	**$54,075**	155
4.4-4.9	Other Gasification Equipment		3,760	2,093	147		**$5,999**	480		1,700	**$8,179**	23
	SUBTOTAL 4	*68,696*	*3,760*	*25,707*	*1,800*		***$99,963***	*7,997*	*4,845*	*12,333*	***$125,137***	*358*
5	HOT GAS CLEANUP & PIPING	24,722	2,048	8,700	609		**$36,079**	2,886	4,305	8,814	**$52,084**	149
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	42,367		2,820	197		**$45,384**	3,631	3,404	5,242	**$57,660**	165
6.2-6.9	Combustion Turbine Accessories		136	157	11		**$305**	24		99	**$428**	1
	SUBTOTAL 6	*42,367*	*136*	*2,977*	*208*		***$45,689***	*3,655*	*3,404*	*5,341*	***$58,088***	*166*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	13,056		1,877	131		**$15,065**	1,205		1,627	**$17,897**	51
7.2-7.9	HRSG Accessories, Ductwork and Stack	1,898	706	1,341	94		**$4,039**	323		605	**$4,967**	14
	SUBTOTAL 7	*14,955*	*706*	*3,217*	*225*		***$19,103***	*1,528*		*2,232*	***$22,864***	*65*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	12,044		1,984	139		**$14,168**	1,133		1,530	**$16,831**	48
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	5,263	160	2,887	202		**$8,513**	681		1,583	**$10,777**	31
	SUBTOTAL 8	*17,308*	*160*	*4,871*	*341*		***$22,680***	*1,814*		*3,113*	***$27,608***	*79*
9	COOLING WATER SYSTEM	3,714	2,055	3,501	245		**$9,514**	761		1,846	**$12,121**	35
10	ASH/SPENT SORBENT HANDLING SYS	3,463	642	2,949	206		**$7,261**	581	494	967	**$9,303**	27
11	ACCESSORY ELECTRIC PLANT	11,636	3,829	9,563	669		**$25,696**	2,056		4,571	**$32,323**	93
12	INSTRUMENTATION & CONTROL	5,117	1,434	5,327	373		**$12,251**	980		2,056	**$15,287**	44
13	IMPROVEMENTS TO SITE	1,831	1,053	3,667	257		**$6,807**	545		2,205	**$9,557**	27
14	BUILDINGS & STRUCTURES		4,241	5,471	383		**$10,096**	808		2,726	**$13,629**	39
	TOTAL COST	**$211,093**	**$25,277**	**$91,876**	**$6,431**		**$334,677**	**$26,774**	**$13,564**	**$54,240**	**$429,256**	**1229**

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Section 4.3

Advanced Air-Blown Transport Reactor IGCC

4.3 ADVANCED AIR-BLOWN TRANSPORT REACTOR IGCC

4.3.1 Introduction

This IGCC concept is based on the utilization of the MW Kellogg air-blown transport reactor coal gasification process supplying low-Btu gas to a gas turbine/combined cycle power plant. The plant configuration is based on current information and design preferences, a "market-based" design, the availability of newer combustion and steam turbines, and a greenfield site.

This version of IGCC technology is based on selection of a gas turbine derived from the General Electric "H" machine. This machine provides values of power output, airflow, and compressor pressure ratio that provide a good match with the gasifier and the steam plant cycle. For this study, one gas turbine is combined with a steam turbine on a single shaft, driving one electric generator. The IGCC portion of the plant is configured with two gasifier islands, including in-situ desulfurization with a hot gas polisher. The resulting performance for the market-based plant is significantly enhanced over the intermediate phase Destec oxygen-blown IGCC system described earlier in this document.

4.3.2 Heat and Mass Balance

This plant utilizes a combined cycle for combustion of the low-Btu gas from the gasifier to generate electric power. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process (gas cooler and sulfator).

The pressurized transport reactor gasifier utilizes a combination of air and steam to gasify the coal and produce a low-Btu hot fuel gas. The fuel gas produced in the transport gasifier leaves at 1690°F and enters a hot gas cooler. A significant fraction of the sensible heat in the gas is retained by cooling the gas to only 1100°F. High-pressure saturated steam is generated in the hot gas cooler and is superheated in the HRSG, which also performs reheating duty, steam generation (IP and LP pressure levels), and economizer duty (heats feedwater and condensate).

The gas flows through a series of hot gas cleanup processes including a chloride guard, transport reactor desulfurization polisher, and final particulate filter. A fraction of the clean hot gas is cooled and recycled to back purge the particulate filter. A separate fines combustor provides complete carbon conversion, handling the particulates captured by the barrier filter.

The gas turbine operates in an open cycle mode. The inlet air is compressed in a single spool compressor; a small portion of the compressed air is conveyed off-board the machine, after-cooled, boosted to a higher pressure in a separate compressor, and supplied to the gasification process. Most of the compressor discharge air remains on-board the machine; a small portion is used for cooling of certain hot section components. The major portion of the airflow passes to the burner section to support combustion of the low-Btu gas supplied by the gasifier islands.

The hot combustion gases are conveyed to the inlet of the turbine section of the machine, where they expand through the turbine to produce power to drive the compressor and electric generator. The turbine exhaust gases are conveyed through a HRSG to recover thermal energy, and then exhaust to the plant stack.

One aspect in which this application differs from the original “H” gas turbine design configuration concerns the increase in mass and volumetric flow rates of fuel gas. This results from the low-Btu gasification process used, which requires significant increases in fuel flow rates in order to deliver the required combustion heat input. The gas turbine is fitted with new combustors designed to fire the low-Btu gas. The increase in mass and volume flow rates also requires that the turbine nozzle areas increase by approximately 4 percent to pass the higher flow. The increase in nozzle area is considered to be within the capabilities of the basic design of the machine. The gas turbine used in this application thus requires modifications in several respects, and is considered a derivative of the GE “H” machine, and not an actual production model.

Overall performance for the entire plant, including Brayton and Rankine cycles, is summarized in Table 4.3-1, which includes auxiliary power requirements. The Rankine steam power cycle is also shown schematically in the 100 percent load Heat and Mass Balance diagram (Figure 4.3-1).

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018° F AND 0.08865 PSIA
2. IP BOILER IN HRSG GENERATES ADDITIONAL COLD REHEAT STEAM.

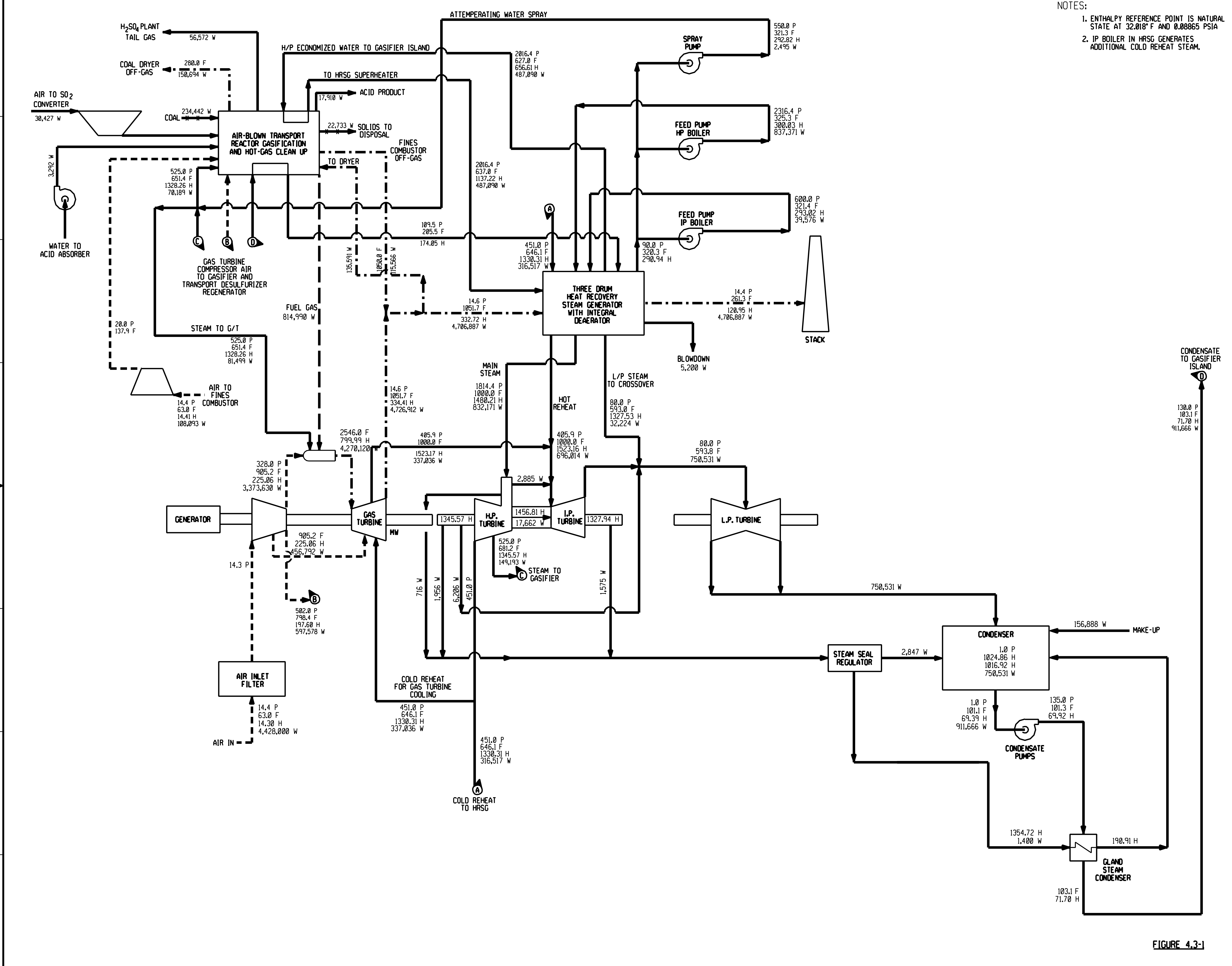

FIGURE 4.3-1

LEGEND

- - - -	AIR / OXIDANT
— — —	FUEL GAS
—·—·—	COMBUSTION PRODUCTS
—×—×—	SOLIDS
———	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY
(ONE GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	275.443 MWe
STEAM T-G POWER :	142.230 MWe
GENERATOR LOSS (TOTAL):	6.265 MWe
AUXILIARY POWER (TOTAL):	13.28 MWe
NET PLANT POWER :	398.128 MWe
NET PLANT EFFICIENCY :	49.7 %
NET PLANT HEAT RATE :	6,870 Btu/kwh

BTMTRAN4/TRANATS4 J.S.WHITE 6/12/1998

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | ENGINEER | LEAD DISCP ENGINEER | PROJ ENGR MANAGER | PROJECT MANAGER

STATUS OF DRAWING: PRELIMINARY — DEFINITION: REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS: CONCEPTUAL DESIGN STUDY NOT FOR CONSTRUCTION

DRAWN BY: CLR DATE: 3/22/98

CHECKED BY DATE

LEAD DESIGNER DATE

ENGINEER DATE

LEAD DISCIPLINE ENGR. DATE

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF
PE: STATE:
LIC. NO.: DATE:

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
AIR BLOWN TRANSPORT REACTOR
GASIFICATION COMBINED CYCLE
DEPARTMENT OF ENERGY TASK 22
PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER
GENERAL ELECTRIC "H" ATS

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-008 REV A

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Table 4.3-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

(Loads are presented for two transport gasifiers, one gas turbine, and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine	271,311
Steam Turbine	140,097
Total	411,408
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	200
Condensate Pumps	150
IP Feed Pump	30
HP Feed Pump	2,310
Acid Pumps	50
Miscellaneous Balance of Plant (Note 1)	900
Screw Feeders	100
Boost Air Compressor	4,530
Recycle Gas Compressor	290
Sulfuric Acid Plant Blower	260
Fines Combustor Blower	590
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	300
Circulating Water Pumps	1,190
Cooling Tower Fans	820
Ash Handling	180
Transformer Loss	980
TOTAL AUXILIARIES, kWe	13,280
Net Power, kWe	398,128
Net Efficiency, % HHV	49.7
Net Heat Rate, Btu/kWh (HHV)	6,870
CONDENSER COOLING DUTY, 10^6 Btu/h	714
CONSUMABLES	
As-Received Coal Feed, lb/h	234,442

Note 1 - Includes plant control systems, lighting, HVAC, etc.

The Rankine cycle used herein is based on 1800 psig/1000°F/1000°F single reheat configuration. The high-pressure turbine is supplied with 832,171 lb/h steam at 1815 psia and 1000°F. Main steam is generated in a HRSG drum and in drums associated with the gasifier hot gas cooler and the sulfator. Superheat is provided by superheaters in the HRSG.

The cold reheat flow from the HP turbine is split into two streams. One stream is routed to the reheater in the HRSG (316,517 lb/h of steam at 451 psia and 687°F). The second stream (337,036) lb/h at the same pressure and temperature as the first stream) is conveyed to the gas turbine, where it provides closed-loop cooling of selected gas path components. The steam is reheated to 1000°F in the process, and rejoins the hot reheat steam from the HRSG en route to the IP turbine section.

In the unit, a single machine comprised of tandem HP, IP, and LP sections on the same shaft as the gas turbine, both driving one 3600 rpm hydrogen-cooled generator. The steam turbine exhausts to a single-pressure condenser operating at 2.0 inches Hga at the nominal 100 percent load design point.

The condensate and feedwater heating is accomplished by heat recovery from the gas turbine exhaust, in the HRSG, with some heat recovery also available in the gasifier island. Condensate is defined as fluid pumped from the condenser hotwell to the deaerator inlet. Feedwater is defined as fluid pumped from the deaerator storage tank to the various steam drums.

The net plant output power, after plant auxiliary power requirements are deducted, is nominally 398 MWe. The overall net plant efficiency is 49.7 percent HHV. An estimate of the auxiliary loads, including the gasifier island and existing balance of plant, is presented in Table 4.3-1.

In summary, the major features of the steam turbine cycle for this IGCC plant include the following:

- Subcritical steam conditions and single reheat (1800 psig/1000°F/1000°F).
- Boiler feed pumps are motor-driven.

- Turbine configuration is based on one 3600 rpm tandem compound, two-flow exhaust machines.
- A single open feedwater heater is used in the turbine cycle.
- Condensate and feedwater heating are principally accomplished in the HRSG, and by several heat recovery opportunities in the gasifier island.

4.3.3 Emissions Performance

The reference fossil unit with air-blown transport IGCC technology is projected to result in low emissions of NOx. The emission of SO_2 and particulates (fly ash) is expected to be at extremely low levels. CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/MMBtu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency. The emissions levels are presented in Table 4.3-2.

Table 4.3-2
AIRBORNE EMISSIONS - IGCC - TRANSPORT REACTOR

	Values at Design Condition (65% and 85% Capacity Factor)			
	lb/10^6 Btu	Tons/year 65%	Tons/year 85%	lb/MWh
SO_2	0.017	134	175	0.12
NOx	0.024	187	244	0.16
Particulates	0.002	15	20	0.014
CO_2	200.4	1,560,180	2,040,200	1,376

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the transport hot gas desulfurizer (THGD) subsystem. The THGD process removes approximately 99.5 percent of the sulfur compounds in the fuel gas.

The reduction in NOx is achieved for a fuel gas containing fuel-bound nitrogen (NH_3) by the use of rich-quench lean (staged) combustion technology coupled with syngas dilution by steam from the steam cycle. Syngas dilution and staged combustion, sub-stoichiometric combustion followed by excess air dilution, promote the conversion of fuel bound nitrogen to N_2 rather than NOx. The techniques of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can reduce NOx emissions further, but are not applied to the subject plant in accordance with the ground rules stated in Section 3.

Particulate discharge to the atmosphere is reduced by the use of the ceramic candle barrier filters, which provide an efficiency of 99.9 percent.

CO_2 emissions are unchanged on an intensive basis (1b/MMBtu), since the same fuel is used (Illinois No. 6 coal). Total CO_2 emissions decrease slightly due to the large increase in net efficiency, even though output is increased significantly.

4.3.4 Description of Air-Blown Transport Integrated Gasification Combined Cycle Gasification Island

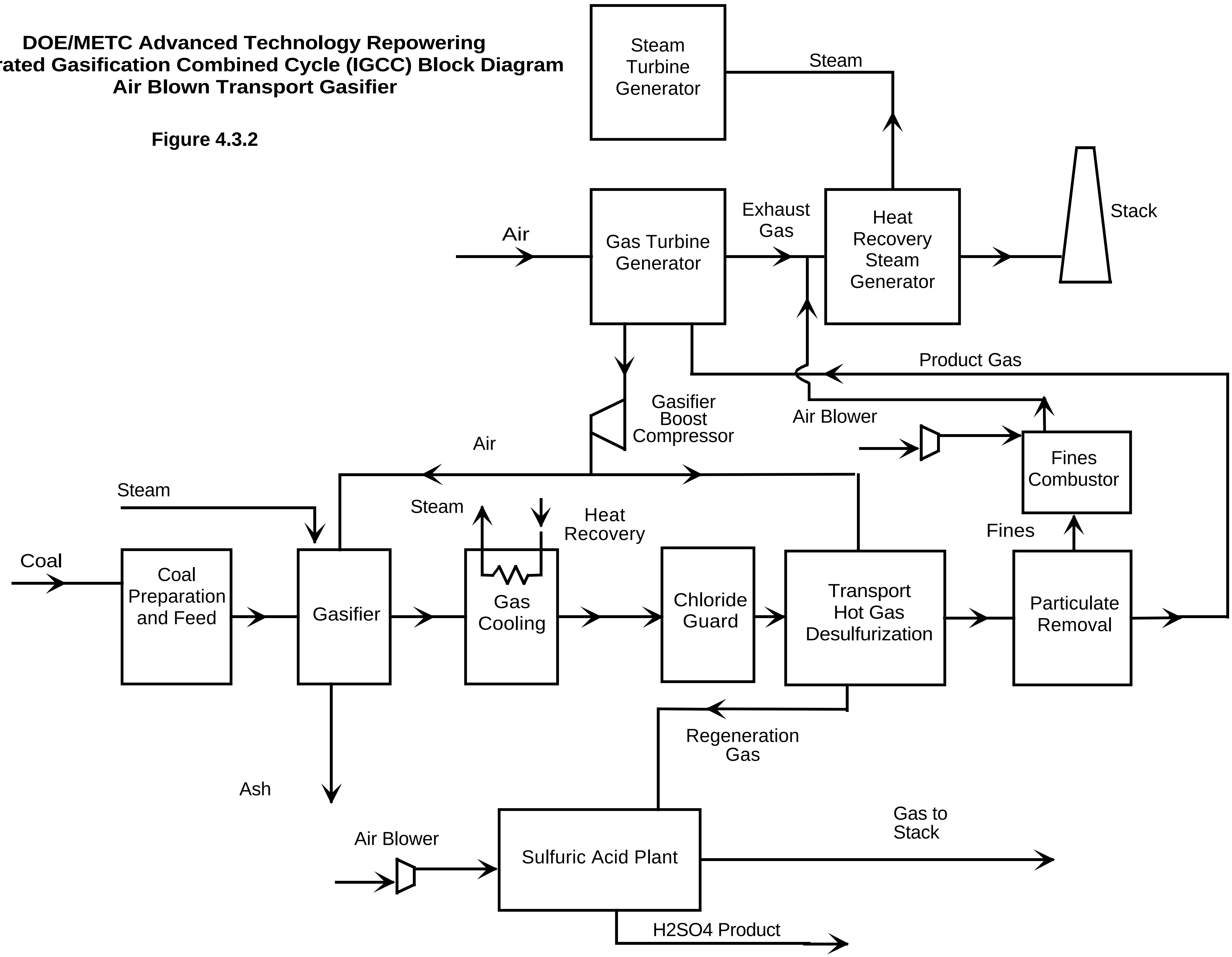
This case is based on the utilization of the air-blown M.W. Kellogg transport reactor gasifier employing in-bed desulfurization. The low-Btu gas produced in the gasifier is further cleaned in hot gas desulfurization and filtration processes downstream of the gasifier. The final product gas is used to fire a combustion turbine generator, which is coupled to a HRSG, which generates steam to drive a steam turbine generator.

The following is a summary description of the overall gasification process and its integration with the power generation cycles used in this case (refer to Figure 4.3-2).

A portion of the air discharged from the gas turbine compressor is after-cooled and then further compressed in a boost compressor to the gasifier operating pressure. Crushed coal is fed to the gasifier where it reacts with the air and steam fed to the gasifier to produce low-Btu gas. The gas, which is largely comprised of CO, H_2, CH_4, and inerts, is discharged from the gasifier and cooled in a gas cooler to 1100°F.

DOE/METC Advanced Technology Repowering
Integrated Gasification Combined Cycle (IGCC) Block Diagram
Air Blown Transport Gasifier

Figure 4.3.2



The cooled gas passes to the chloride guard containing a fixed bed reactor exposing the gas to a nahcolite sorbent to reduce the chloride level to less than 1 ppm to protect the combustion turbine downstream.. The gas is then routed to the hot gas desulfurizer, where sufficient sulfur is removed to result in a final sulfur level of about 30 ppm. The gas is then cleaned in a particulate removal system containing a barrier filter containing a large number of ceramic candles arranged in a cylindrical vessel, resulting in very low levels of particulates.

The gas exiting the particulate removal system represents the final product gas and is conveyed to the combustion turbine where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The exhaust gas from the combustion turbine and HRSG is released to the atmosphere via a conventional stack.

Final “closure” of the process cycle is achieved in the fines combustor. The fines combustor is used to oxidize fines from the candle filter; no heat recovery is attempted from this very small stream.

Based on the GE “H” turbine selection, a fuel gas pressure of 450 psig was established to provide a margin above the compressor discharge pressure, allowing for necessary system and valve pressure drop. Based on the above, a gasifier pressure of 475 psig, nominal, is required.

4.3.4.1 Gasifier

The transport gasifier is comprised of a mixing zone, a riser, cyclones, a standpipe, and a non-mechanical valve. Air and steam are introduced at the bottom of the gasifier in the mixing zone. Coal is introduced in the upper section of the mixing zone. The top section of the gasifier discharges into the disengager or primary cyclone. The cyclone is connected to the standpipe, which discharges the solids at the bottom through a non-mechanical valve into the transport gasifier mixing zone at the bottom of the riser.

The gasifier system operates by circulating the entrained solids up through the gasifier riser, through the cyclone, and down through the standpipe. The solids re-enter the gasifier mixing zone through the non-mechanical valve. The steam and air jets provide the motive force to maintain the bed in circulation and oxidize the char as it enters the gasifier mixing zone. The hot gases react with coal/char in the mixing zone and riser to produce gasification products.

The gas and entrained solids leaving the primary cyclone are passed through the secondary cyclone to provide final de-entrainment of the solids from the gas. The solids separated in the secondary cyclone fall through the dipleg into the standpipe. A solids purge stream is withdrawn from the standpipe for solids inventory maintenance.

The gas leaving the secondary cyclone passes through a gas cooler, which reduces the gas temperature from about 1900°F to 1100°F. The cooled gas then passes in succession through a fixed bed chloride guard, transport gas desulfurizer, and a final-stage particulate removal in a candle type filter.

4.3.4.2 Gas Cooling

The hot gas leaving the gasifier is cooled in the product gas cooler to 1100°F, superheating and/or reheating steam from the steam power cycle in the process.

4.3.4.3 Chloride Guard

The chloride guard functions to remove HCl from the gas, prior to discharge to the combustion turbine. The chloride guard is comprised of two 100 percent capacity pressure vessels packed with a pebble bed of nahcolite, a form of sodium bicarbonate. One vessel is normally in service, with a nominal service period of two months. The second vessel is purged, cooled, drained of spent bed material, and recharged while the other vessel is in service. The chloride guard vessels are approximately 13 feet in diameter, 25 feet high, and are fabricated of carbon steel.

4.3.4.4 Transport Hot Gas Desulfurization

The transport reactor desulfurizer consists of a riser tube, disengager, and standpipe for both the absorber section and regeneration section. Two desulfurizer trains are provided, one for each gasifier. Each absorber contains a circulating inventory of Z-sorb sorbent.

The regenerator is a transport reactor, through which sorbent from each absorber passes through the regenerator riser, disengagers, and then back to the absorber through the standpipe. Assuming similar sorbent velocities and densities, as in the desulfurizer column, each regenerator is somewhat smaller in diameter compared to the desulfurizer, but is approximately the same in height. Regeneration is performed at 1200°F. The regeneration off-gas, containing predominantly SO_2, is sent to the sulfuric acid plant.

The particles are disengaged from gas passing through the high-efficiency cyclones at the top of the absorber. Some Z-sorb is also retained by the regeneration outlet gas. The total of 2750 lb/h fines elutriated from the transport desulfurization absorber, which are predominantly 20 micron particles from the gasifier and the balance being Z-sorb, are recovered in the ceramic gas filter.

4.3.4.5 Particulate Removal

The particulate removal stage in this gasification process consists of a ceramic candle filter. The individual filter elements, or candles, are distributed in an array inside a refractory-lined carbon steel pressure vessel. The filter is cleaned by periodically back pulsing it with gas to remove the fines, which are collected and oxidized in the fines combustor.

4.3.4.6 Fines Combustor

The fines combustor is an atmospheric fluid bed combustor, which receives spent sorbent from the gasifier cyclone and regeneration gas from the THGD process.

4.3.4.7 Sulfuric Acid Plant

The AGR process produces an offgas from the regeneration process, which contains an H_2S concentration of about 50 percent. This is adequate for feed to an H_2S-burning contact process sulfuric acid plant that burns the H_2S acid gas with air, yielding SO_2, water vapor, and heat, which are fed to a conventional contact acid plant. The reaction from SO_2 to SO_3 is an exothermic reversible reaction. Key to the process is the four-pass converter developed by Monsanto. Equilibrium conversion data show that conversion of SO_2 decreases with an increase in temperature. Using a vanadium catalyst, a contact plant takes advantage of both rate and equilibrium considerations by first allowing the gases to enter over a part of the catalyst at about 800 to 825°F, and then allowing the temperature to increase adiabatically as the reaction proceeds. The reaction essentially stops when 60 to 70 percent of the SO_2 has been converted, at a temperature in the vicinity of 1100°F. The gas is cooled in a waste heat boiler and passed through subsequent stages, until the temperature of the gases passing over the last portion of catalyst does not exceed 805°F.

The gases leaving the converter, having passed through two or three layers of catalyst, are cooled and passed through an intermediate absorber tower where some of the SO_3 is removed with 98 percent H_2SO_4. The gases leaving this tower are then reheated, and they flow through the remaining layers of catalyst in the converter. The gases are then cooled and pass through the final absorber tower before discharge to the atmosphere. In this manner, more than 99.7 percent of the SO_2 is converted into SO_3 and subsequently into product sulfuric acid.

4.3.4.8 Gas Turbine Generator

The gas turbine generator selected for this application is based on the GE "H" machine. This machine is an axial flow, single spool, constant speed unit, with variable inlet guide vanes and four stages of variable stator vanes. The standard production version of this machine, fired with natural gas, will develop a compressor pressure ratio of 23:1 and a rotor inlet temperature of almost 2600°F. In this service, with low-Btu gas from an IGCC plant, the machine must be modified in order to properly combust the low-Btu gas and expand the combustion products in the turbine section of the machine.

The modifications to the machine include the replacement or modification of the original can-annular combustor with new combustors designed for efficient, low-NOx combustion of the low-Btu gas. A second modification involves increasing the nozzle area of the first-stage turbine to accommodate the mass and volume flow of low-Btu fuel gas combustion products which are increased relative to those produced when firing natural gas. An increase in turbine nozzle areas of approximately 4 percent is required. Other modifications include rearranging the various auxiliary skids that support the machine, to accommodate the spatial requirements of the design. The generator is a standard hydrogen-cooled machine with static exciter.

4.3.4.9 Steam Generation

Heat Recovery Steam Generator (HRSG)

The HRSG is a drum type, triple-pressure design that is matched to the characteristics of the gas turbine exhaust gas when firing low-Btu gas, and to the steam conditions of the steam turbine; namely, 1800 psig/1000°F/1000°F. The HP drum produces steam at main steam pressure, which is then superheated in the HRSG to 1000°F. A mid-pressure drum produces steam at the pressure required for steam cooling of portions of the “H” turbine. This steam is heated and returned to the steam cycle to mix with hot reheat steam. Some of the steam produced by the mid-pressure drum is conveyed to the gasifier for injection into the gasifier vessel. A low-pressure drum produces steam for the integral deaerator of the HRSG, and for admission to the LP section of the steam turbine.

Gas Cooler

The gas cooler contains a steam drum for the production of main steam at turbine throttle conditions (1800 psig). This steam is conveyed to the HRSG enroute to the steam turbine, where it is superheated and combined with the main steam produced by the HRSG for routing to the steam turbines.

4.3.4.10 Fuel Preparation and Injection System

The fuel preparation and injection system receives crushed coal, sized at 1" x 0, from the coal handling system. The system interface is at the slide gate valves at the discharge of the silos. The silos supply coal through slide gate valves to two vibratory feeders, which feed coal to two bowl mills. The ground coal (average particle size is less than 250 microns) exiting the mills is transported pneumatically to each of two storage (surge) hoppers, one for each gasifier train. The coal passes from the storage hopper to a weight feeder and then to a mixing screw conveyor, which conveys the coal to a dense phase pneumatic conveyor and on to the gasifier pressurization lock hoppers.

Each lock hopper train is comprised of a storage injector and a primary injector; these lock hoppers are pressurized by compressed air from the transport boost compressor. The storage injectors discharge into the primary injectors, which discharge the coal into the gasifier.

4.3.4.11 Flare Stack

A self-supporting, refractory-lined, carbon steel flare stack is provided to combust and dispose of product gas during startup, shutdown, and upset conditions. The flare stack is provided with multiple pilot burners, fueled by natural gas or propane, with pilot flame monitoring instrumentation.

4.3.5 IGCC Support Systems (Balance of Plant)

4.3.5.1 Coal Handling System

The function of the coal handling system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the bottom trestle car dumper and coal receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

The bituminous coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor (No. 1). The coal is then transferred to a conveyor (No. 2) that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0. The coal then enters a second crusher that reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the stationary tripper that loads the coal into one of the two silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 234,400 lb/h = 117.2 tph plus 10% margin = 129 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 203,000 lb/h = 102 tph (based on MCR rate multiplied by an 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Two unit trains per week at maximum burn rate
  - One and one-half unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 9 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 900 tph (maximum, both conveyors in operation)
  - Reclaim rate = 400 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 9,500 tons (72 hours at maximum burn rate)
  - Dead storage = 69,000 tons (30 days at average burn rate)

4.3.5.2 Ash Handling

The ash handling system conveys, stores, and disposes of ash removed from the gasification process.

Spent material drains from the gasifier into a receiver vessel, which provides several hours holdup capacity. The receiving hopper operate at atmospheric pressure. A slide gate valve at the bottom outlet of the hopper regulates the flow of material from the hopper to a screw cooler, which cools and transports the ash out and onto a system of drag chain conveyors. The conveyors transport the ash to a pair of storage silos for temporary holdup. The silos are sized for a nominal holdup capacity of 36 hours of full-load operation each. At periodic intervals, a convoy of ash hauling trucks will transit the unloading station underneath the silos and remove a quantity of ash for disposal. Approximately 32 truck loads per day are required to remove the total quantity of ash produced by the plant operating at nominal rated power.

4.3.6 Steam Cycle Balance of Plant

The following section provides a description of the steam turbines and their auxiliaries.

4.3.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last-stage bucket length of 33.5 inches.

Main steam from the HRSG passes through the stop valves and control valves and enters the turbine at 1800 psig/1000°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns as cold reheat to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 400 psig/1000°F. A portion of the cold reheat is routed to the gas turbine and used for cooling. This steam is reheated to 1000°F performing the cooling duty, is combined with the hot reheat coming from the HRSG, and enters the IP section. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled, pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft.

The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

The steam turbine generator is controlled by a triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant DCS, and incorporates on-line repair capability.

4.3.6.2 Condensate and Feedwater Systems

Condensate

The condensate system pumps condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG. The system consists of one main condenser; two 50 percent capacity, motor-driven, vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG. Condensate is delivered to a common discharge header through separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Feedwater

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity boiler feed pumps of each type are provided. Each pump is provided with inlet and outlet isolation valves, outlet check valve, and minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

4.3.6.3 Main and Reheat Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the HRSG superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 1800 psig/1000°F exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 437 psig/685°F exits the HP turbine and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam at approximately 391 psig/1000°F exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

A portion of the reheat is conveyed to the gas turbine, where it is provided closed-loop cooling of selected gas path components. The steam is reheated to 1000°F in the process, and rejoins the hot reheat steam from the HRSG en route to the IP turbine section.

4.3.6.4 Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps; a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

4.3.6.5 Major Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the steam cycle. A summary of the required piping is presented in Table 4.3-3.

4.3.7 Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

4.3.8 Site, Structures, and Systems Integration

4.3.8.1 Plant Site and Ambient Design Conditions

Refer to Section 2 for a description of the plant site and ambient design conditions.

Table 4.3-3
INTEGRATED GASIFICATION COMBINED CYCLE

New Steam Cycle Piping Required

Pipeline	Flow, lb/h	Press., psia	Temp., °F	Material	OD, in.	Twall, in.
Condensate	911,670	135	100	A106 Gr. B	8	Sch. 40
IP Feedwater, Pump to HRSG	39,580	600	321	A106 Gr. B	3	Sch. 40
HP Feedwater/Pump to HRSG	837,400	2316	325	A106 Gr. C	8	Sch. 160
HP Feedwater/HRSG to Gasifier Island	487,100	2016	627	A106 Gr. C	6	Sch. 160
Main Steam/Gasifier Island to HRSG	487,100	2016	637	A106 Gr. C	6	Sch. 160
Main Steam/HRSG to Steam Turbine	832,200	1815	1000	A335 Gr. P91	10	1.125
Cold Reheat/ST to GT	337,000	451	646	A106 Gr. C	12	Sch. 40
Cold Reheat/ST to HRSG	316,500	451	646	A106 Gr. C	12	Sch. 40
Hot Reheat/From GT	337,000	406	1000	A335 Gr. 91	10	Sch. 40
Hot Reheat/HRSG to ST	696,000	406	1000	A335 Gr. 91	18	Sch. 40
Fuel Gas/Gasifier Island to Gas Turbine	814,990	450	1070	A335 Gr. P91	20	0.50

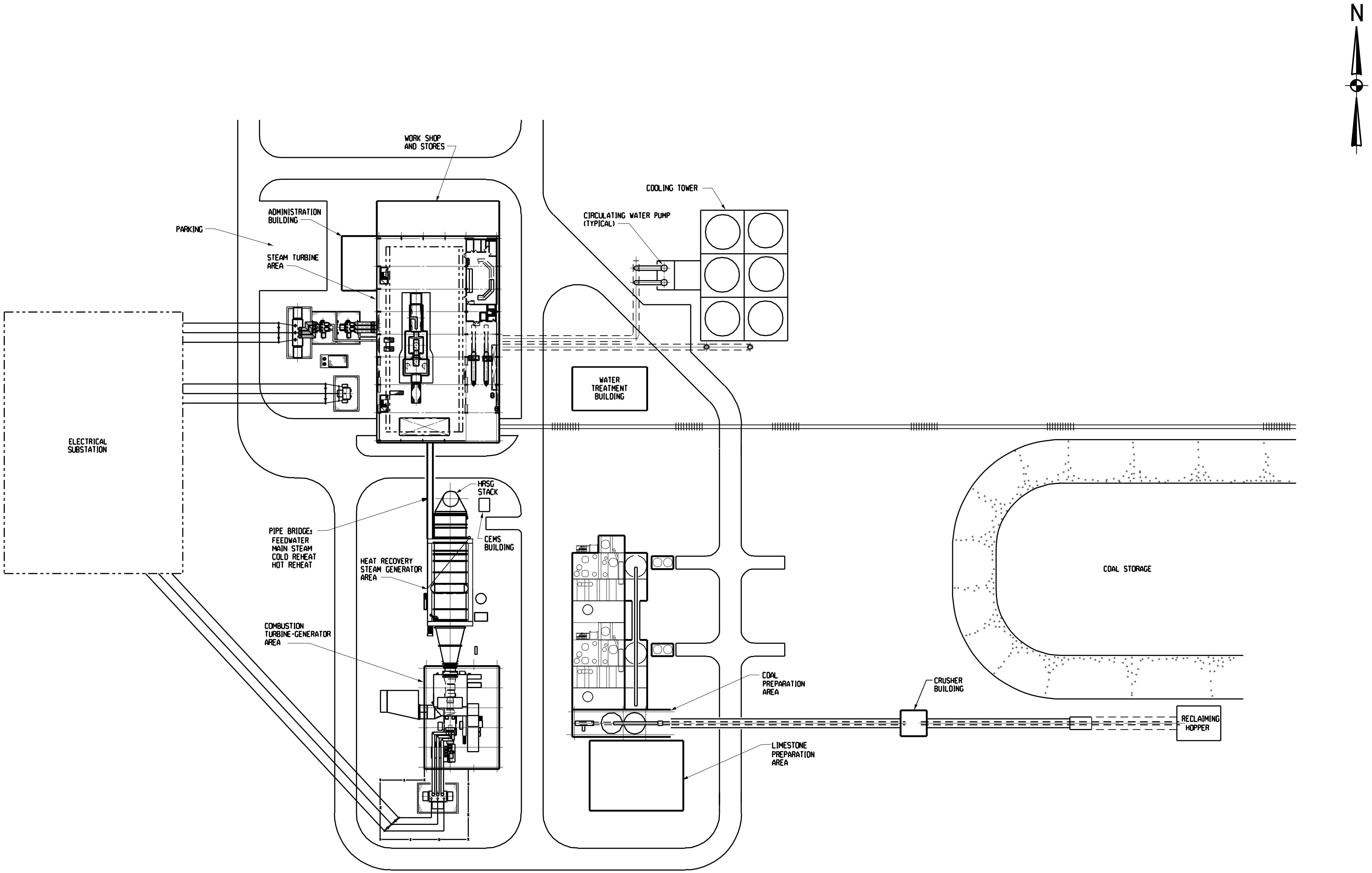
4.3.8.2 New Structures and Systems Integration

The development of the reference plant site to incorporate new structures required for this technology is based on the assumption of a flat site.

The two gasifier islands and the associated building enclosing it are located west of the coal preparation equipment. Ash silos are positioned due east of each gasifier island. The gas turbine and its ancillary equipment are sited west of the gasifier island, in a new turbine building designed expressly for this purpose. A HRSG and stack complete the development to the north of the gas turbine. The flare stack is located north of the gasifier island, at a sufficient distance to satisfy exclusion radius requirements. Figure 4.3-3 is included to show the layout of the plant.

The arrangement described above provides good alignment and positioning for major interfaces, relatively short steam, feedwater, and fuel gas pipelines, and allows good access for heavy trucks for ash removal. Transmission line access from the gas turbine step-up transformer to the existing switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located west of the gas turbine. Air taken from the compressor discharge flows to the two gasifier islands. The clean, hot, low-Btu gas is conveyed to the turbine topping combustors for mixing with the air that remains on board the machine.



PLAN

FIGURE 4.3-3

0 50 100 150 200
GRAPHIC SCALE IN FEET

NOTES:

DD

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER	LEAD DSCP ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER

STATUS OF DRAWING	DEFINITION
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS

DRAWN BY CLR DATE 12/21/98
CHECKED BY DATE
LEAD DESIGNER DATE
ENGINEER DATE
LEAD DISCIPLINE ENGR. DATE

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF
PE: STATE:
LIC. NO.: DATE:
PROJECT ENGINEERING MANAGER
PROJECT MANAGER

PARSONS
PARSONS ENERGY & CHEMICALS GROUP INC.
READING OFFICE

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
ADVANCED AIR-BLOWN TRANSPORT REACTOR
DEPARTMENT OF ENERGY TASK 22

PLANT GENERAL ARRANGEMENT
PLAN VIEW

SCALE 1"=50'
PARSON'S DWG. NO. 8436-1-200-010-001
REV

ARCH HVAC I & C ELECT MECH CIVIL STRUC

PPGI-FILE:148006:8436001.dgn
PPGI-DATE:

Reserved for reverse side of Figure 4.3-3 (11x17)

4.3.9 Equipment List - Major

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	200 tph	2
8	Conveyor No. 3	48" belt	400 tph	1
9	Crusher Tower	N/A	400 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	400 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer		1
14	Conveyor No. 4	48" belt	400 tph	1
15	Transfer Tower	N/A	400 tph	1
16	Tripper	N/A	400 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	1,500 ton	2

ACCOUNT 2 COAL PREPARATION AND FEED

ACCOUNT 2A FUEL PREPARATION AND INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Vibratory Feeder		175 tph	2
2	Pulverizer	Bowl	175 tph	2
3	Surge Hopper with Vent Filter and Slide Gate	Vertical, cylindrical	1,060 ton	2
4	Feeder	Gravimetric	70 tph	2
5	Screw Feeder	Mixing	75 tph	2
6	Dense Phase Transporter		75 tph	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cyl., outdoor	50,000 gal	1
2	Condensate Pumps	Vert. canned	900 gpm @ 300 ft	2
3	Deaerator and Storage Tank	Horiz. spray type	911,666 lb/h 205°F to 240°F	1
4	IP Feed Pumps	Interstage bleed from HP feed pump	40 gpm/1,200 ft	2
5	HP Feed Pumps	Barrel type, multi-staged, centr.	900 gpm/5,200 ft	2

Note: LP feedwater taken from condensate stream prior to deaerator inlet.

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F, 100,000 lb/h	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	100,000 gal No. 2 oil	1
3	Fuel Oil Unloading Pump	Gear	50 psig, 100 gpm	1
4	Fuel Oil Supply Pump	Gear	150 psig, 5 gpm	2
5	Service Air Compressors	Recip., single-stage, double acting, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exch	Plate and frame	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
11	Fire Service Booster Pump	Two-stage horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water	SS, single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	SS, single suction	160 ft, 120 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

ACCOUNT 4A GASIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Riser	Refractory-lined	1,440 tpd/400 psig	2
2	Standpipe	Refractory-lined	167 x 10^6 Btu/h	2
3	Primary Cyclone	Conical bottom		2
4	Secondary Cyclone	Conical bottom		2
5	Non-Metallic Valve	Refractory-lined		2
6	Boost Air Compressor	Centrifugal, single stage, variable speed drive	4250 acfm, housing design: 550 psig, 350°F	2
7	Boost Air Receiver	Carbon steel vessel ASME VIII	2,200 ft^3	2
8	Exit Gas Cooler	Fin-tube	93 x 10^6 Btu/h	2
9	Recycle Gas Compressor	Screw	210 acfm, housing design 550 psig/200°F	2
10	Recycle Gas Cooler	Shell and tube	10 x 10^6 Btu/h	2
11	Filter Purge	Piston, single stage	20 acfm, housing design 800 psig/200°F	2
12	Flare Stack	Self-supporting, lined steel, pilot ignition	810,000 lb/h low-Btu gas	1

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A HIGH TEMPERATURE DESULFURIZATION

(Transport Hot Gas Desulfurizer)

Equipment No.	Description	Type	Design Condition	Qty
1	Sorbent Storage Hopper	*		2
2	Sorbent Feed Hopper	*		
3	Transport Desulfurizer	*		2
4	Desulfurizer Cyclone	*		2
5	Transport Regenerator	*		2
6	Regenerator Cyclone	*		2
7	Sorbent Regeneration Air Heater	*		2
8	Regenerator Effluent Gas Cooler	*		2

* This information is proprietary and is not presented.

ACCOUNT 5B SULFUR RECOVERY

Equipment No.	Description	Type	Design Condition	Qty
7	Sulfuric Acid Plant		225 ton/day @ 98%	1

ACCOUNT 5C CHLORINE GUARD

Equipment No.	Description	Type	Design Condition	Qty
1	Chlorine Guard Reactor	Pebble bed, vertical cyl. pressure vessel	570,000 lb/h, 400 psig, 1100°F	4

ACCOUNT 5D PARTICULATE REMOVAL

Equipment No.	Description	Type	Design Condition	Qty
1	Fines Cyclone	Vertical cyl., conical bottom	570,000 lb/h, 400 psig 1100°F	2
2	Fines Cyclone Lock Hopper	Vertical cyl., conical bottom	90 ft^3, 400 psig	2
3	F. C. Depressurization Lock Hopper	Vertical cyl., conical bottom	90 ft^3, 400 psig	2
4	Burner Filter	Ceramic candle	570,000 lb/h	2
5	B.F. Lock Hopper	Vertical cyl., conical bottom		2
6	B.F. Depressurization Lock Hopper	Vertical cyl., conical bottom		2
7	Solids Conveyor	Drag chain	30 tph	2
8	Fines Combustor	Atmospheric fluid bed		2

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	300 MWe Gas Turbine Generator	Axial flow single spool based on General Electric "H" class	1,230 lb/sec airflow 2600°F rotor inlet temp. 23:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1,230 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	1
5	Air-to-Air Cooler			1
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
7	Oil Cooler	Air-cooled, fin fan		1
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
9	Generator Glycol Cooler	Air-cooled, fin fan		1
10	Compressor Wash Skid			1
11	Fire Protection Package	Halon		1

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, triple pressure, with economizer sections and integral deaerator	HP-2300 psig/629°F 832,171 lb/h superheat to 1000°F IP-585 psig/489°F 39,576 lb/h	1
2	Raw Gas Cooler Steam Generator	Drum and heater	2000 psig/629°F (drum) 487,000 lb/h Sat. Steam	1
3	Stack	Carbon steel plate lined with type 409 stainless steel	213 ft high x 28 ft dia.	1
4	Bypass Stack and Diverter Valve	Carbon steel plate lined with type 409 stainless steel	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

(on same shaft as gas turbine)

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	150 MW Steam Turbine	TC2F30	1800 psig 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Electric Generator	Synchronous with static exciter	440 MWe/23 kV/ 3600 rpm	
6	Generator Coolers	Plate and frame		2
7	Hydrogen Seal Oil System	Closed loop		1
8	Surface Condenser	Single pass, divided waterbox	750,531 lb/h steam @ 2.0 in. Hga with 78°F water, 19°F temp rise	1
9	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	40,000 gpm @ 60 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell counter-flow, film type fill	56°F WB/78°F CWT/ 97° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Ash Lock Hopper	Vertical cyl., conical bottom	200 ft^3, 400 psig	2
2	Ash Receiver	Vertical cyl., conical bottom		2
3	Screw Feeder	Water cooled	30,000 lb/h	2
5	Cyclone	Vertical cyl., conical bottom		2
6	Heat Recovery HEX	Solids cooler	11 x 10^6 Btu/h	2
7	Ash Silo	Vertical cylindrical, reinf. concrete	500 tons	2

4.3.10 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the advanced IGCC plant is shown in Table 4.3-4. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 4.3-4

Client: DEPARTMENT OF ENERGY
Report Date: 14-Aug-98 08:50 AM
Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Transport Reactor (2010)
Plant Size: 398.1 MW,net
Estimate Type: Conceptual
Cost Base (Jan) 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	5,486	1,737	4,365	306		**$11,895**	952		2,569	**$15,416**	39
2	COAL & SORBENT PREP & FEED	5,568	775	3,580	251		**$10,173**	814	343	2,266	**$13,596**	34
3	FEEDWATER & MISC. BOP SYSTEMS	5,332	2,747	4,131	289		**$12,500**	1,000		3,236	**$16,736**	42
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries	14,365		7,725	541		**$22,631**	1,810	5,658	6,020	**$36,118**	91
4.2	High Temperature Cooling	4,394		2,363	165		**$6,923**	554	1,038	1,703	**$10,218**	26
4.3	Recycle Gas System	1,799		1,342	94		**$3,235**	259	485	796	**$4,775**	12
4.4-4.9	Other Gasification Equipment	5,936	3,684	3,555	249		**$13,424**	1,074	1,128	3,662	**$19,288**	48
	SUBTOTAL 4	*26,494*	*3,684*	*14,985*	*1,049*		***$46,212***	*3,697*	*8,310*	*12,181*	***$70,400***	*177*
5	HOT GAS CLEANUP & PIPING	33,305	4,211	12,718	890		**$51,124**	4,090	9,044	12,921	**$77,179**	194
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	43,435		3,306	231		**$46,973**	3,758	3,523	5,425	**$59,680**	150
6.2-6.9	Combustion Turbine Accessories		148	170	12		**$330**	26		107	**$463**	1
	SUBTOTAL 6	*43,435*	*148*	*3,477*	*243*		***$47,303***	*3,784*	*3,523*	*5,532*	***$60,143***	*151*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	12,666		1,821	127		**$14,614**	1,169		1,578	**$17,362**	44
7.2-7.9	HRSG Accessories, Ductwork and Stack	1,876	698	1,325	93		**$3,993**	319		598	**$4,910**	12
	SUBTOTAL 7	*14,543*	*698*	*3,146*	*220*		***$18,607***	*1,489*		*2,176*	***$22,272***	*56*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	10,806		1,978	138		**$12,922**	1,034		1,396	**$15,351**	39
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	5,256	160	2,882	202		**$8,500**	680		1,581	**$10,761**	27
	SUBTOTAL 8	*16,061*	*160*	*4,860*	*340*		***$21,422***	*1,714*		*2,976*	***$26,112***	*66*
9	COOLING WATER SYSTEM	3,713	2,057	3,500	245		**$9,515**	761		1,846	**$12,123**	30
10	ASH/SPENT SORBENT HANDLING SYS	3,630	798	1,472	103		**$6,003**	480	252	1,019	**$7,754**	19
11	ACCESSORY ELECTRIC PLANT	8,939	2,252	5,834	408		**$17,434**	1,395		3,063	**$21,892**	55
12	INSTRUMENTATION & CONTROL	5,222	1,463	5,436	380		**$12,501**	1,000		2,098	**$15,599**	39
13	IMPROVEMENTS TO SITE	1,848	1,063	3,701	259		**$6,872**	550		2,226	**$9,648**	24
14	BUILDINGS & STRUCTURES		4,264	5,493	384		**$10,141**	811		2,738	**$13,691**	34
	TOTAL COST	**$173,578**	**$26,057**	**$76,699**	**$5,369**		**$281,703**	**$22,536**	**$21,471**	**$56,850**	**$382,559**	**961**

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Section 4.4

Market-Based Advanced Oxygen-Blown Destec 500 MWe

4.4 MARKET-BASED ADVANCED OXYGEN-BLOWN DESTEC 500 MWe

4.4.1 Introduction

This IGCC concept is based on the utilization of the Destec oxygen-blown coal gasification process supplying medium-Btu gas to a gas turbine/combined cycle power generating plant. The plant configuration is based on a projection of state-of-the-art design for an in-service date of 2010. The availability of a combustion turbine comparable to the General Electric "H" is assumed, along with steam turbines incorporating state-of-the-art design features. The specific design approach presented herein is based on DOE/FETC and Parsons concepts, and does not necessarily reflect the approach that Destec Energy would take if they were to commercially offer a facility of this size (MWe) in this time frame.

This case illustrating IGCC technology is based on selection of a gas turbine derived from the General Electric "H" machine. This particular machine, coupled with an appropriate steam cycle, will produce a nominal 500 MWe net output. The IGCC portion of the plant is configured with one gasifier island, which includes a transport reactor type hot gas desulfurizer. The resulting plant produces a net output of 427 MWe at a net efficiency of 49 percent on an HHV basis. This performance is based on the use of Illinois No. 6 coal. Performance will vary with other fuels.

4.4.2 Heat and Mass Balance

The pressurized Destec gasifier utilizes a combination of oxygen and water along with recycled fuel gas to gasify coal and produce a medium-Btu hot fuel gas. The fuel gas produced in the entrained bed gasifier leaves at 1900°F and enters a hot gas cooler. A significant fraction of the sensible heat in the gas is retained by cooling the gas to 1110°F. High-pressure steam is generated in the hot gas cooler and routed to the appropriate location in the HRSG.

The fuel gas goes through a series of hot gas cleanup processes including chloride guard, transport reactor type hot-gas desulfurization process and barrier filter. A fraction of the clean hot gas is cooled and recycled to the gasifier to aid in second-stage gasification. Char particulates are recycled to the gasifier, resulting in nearly complete carbon conversion. Regeneration gas from the desulfurizer is fed to an H_2SO_4 plant.

This plant utilizes a combined cycle for combustion of the medium-Btu gas from the gasifier to generate electric power. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the HRSG, by feedwater heating in the HRSG, and by heat recovery from the IGCC process (gas cooling and sulfation modules).

The gas turbine operates in an open cycle mode, as described below.

The inlet air is compressed in a single spool compressor to the design basis discharge pressure. Most of the compressor discharge air passes to the burner section of the machine to support combustion of the medium-Btu gas supplied by the gasifier island, and to cool the burner and turbine expander sections of the machine. The firing of medium-Btu gas in the combustion turbine is expected to require modifications to the burner and turbine sections of the machine. These modifications are discussed in Section 4.4.4.7.

The hot combustion gases are conveyed to the inlet of the turbine section of the machine, where they enter and expand through the turbine to produce power to drive the compressor and electric generator. The combustion turbine utilizes cold reheat from the steam turbine for cooling the stationary and rotating parts of the turbine, mainly the first- and second-stage stationary nozzle and buckets plus the stage one shroud. The steam is returned to the steam cycle for performance augmentation. The turbine exhaust gases are conveyed through a HRSG to recover the large quantities of thermal energy that remain. The HRSG exhausts to the plant stack.

The Rankine steam power cycle is also shown schematically in the 100 percent load Heat and Mass Balance Diagram (Figure 4.4-1). Overall performance for the entire plant, including Brayton and Rankine cycles, is summarized in Table 4.4-1, which includes auxiliary power requirements.

The steam cycle is based on maximizing heat recovery from the gas turbine exhaust gases, as well as utilizing steam generation opportunities in the gasifier process. For this facility, a triple-pressure HRSG configuration has been selected. In addition to the high-pressure (HP) drum, an intermediate-pressure (IP) drum is provided in the HRSG to raise steam that is joined with the reheat.

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018° F AND 0.08865 PSIA
2. IP BOILER IN HRSG GENERATES ADDITIONAL COLD REHEAT STEAM.
3. DESTEC GASIFIER USED 78/22 COAL SLURRY FEED SPLIT.

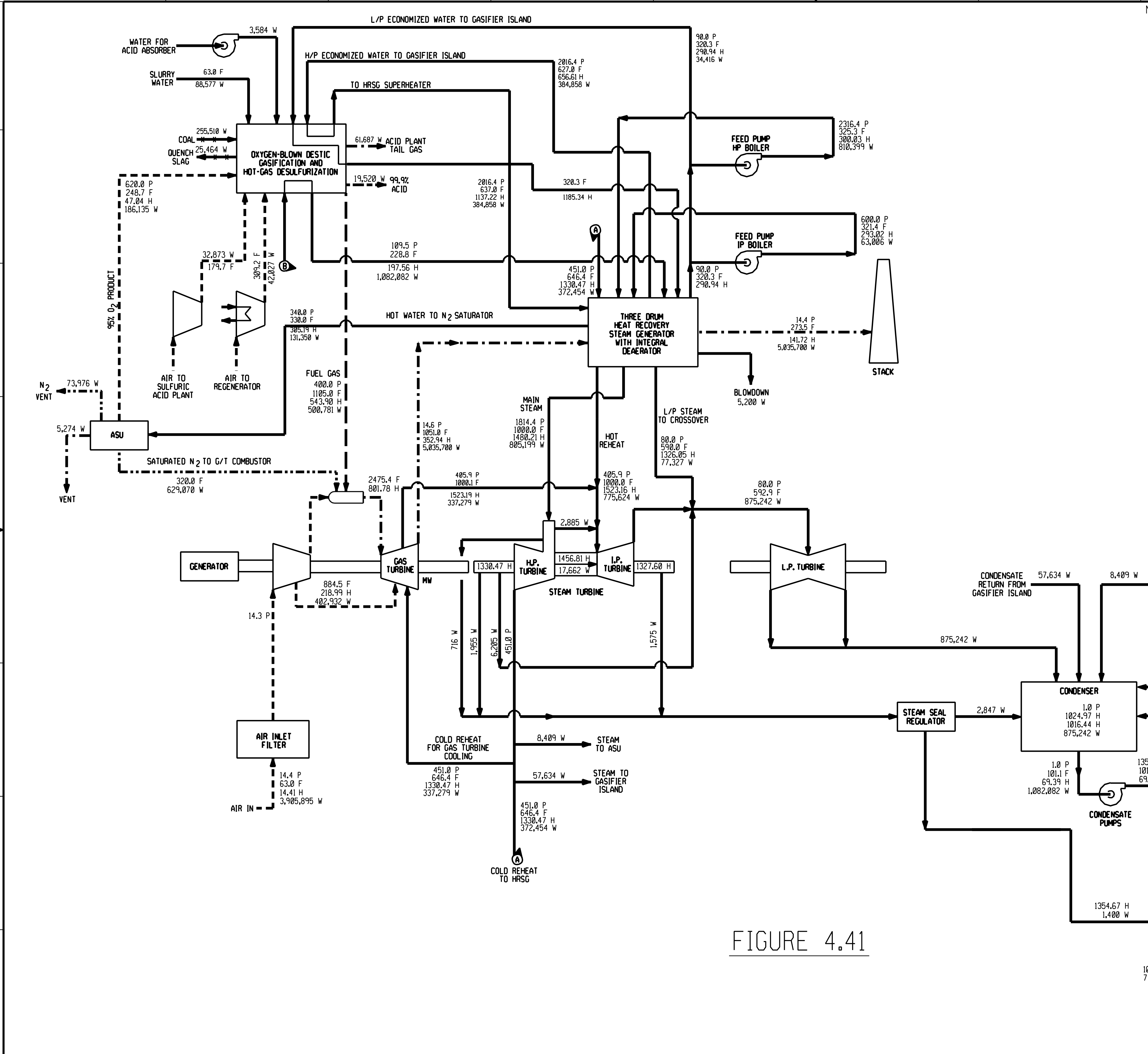

FIGURE 4.41

LEGEND

— · — ·	SULFURIC ACID
— · · · —	NITROGEN
— — —	AIR / OXIDANT
—— ——	FUEL GAS
—— · ——	COMBUSTION PRODUCTS
—×—×—	SOLIDS
———	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY
(ONE GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	340.314 MWe
STEAM T-G POWER :	157.244 MWe
GENERATOR LOSS (TOTAL):	7.463 MWe
TRANSFORMER LOSS (TOTAL):	1.180 MWe
AUXILIARY POWER (TOTAL):	61.180 MWe
NET PLANT POWER :	427.735 MWe
NET PLANT EFFICIENCY :	49.0 %
NET PLANT HEAT RATE :	6,968 Btu/kwh

DSTCATS3/DSTCHBT3 J.S.WHITE 4/22/1998

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | LEAD DISCP ENGINEER | PROJ ENGR MANAGER | PROJECT MANAGER

STATUS OF DRAWING: PRELIMINARY — DEFINITION: REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS: CONCEPTUAL DESIGN STUDY NOT FOR CONSTRUCTION

DRAWN BY CLR DATE 3/22/98
CHECKED BY DATE
LEAD DESIGNER DATE
ENGINEER DATE
LEAD DISCIPLINE ENGR. DATE
ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE: STATE: LIC. NO.: DATE:
PROJECT ENGINEERING MANAGER
PROJECT MANAGER

PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
OXYGEN BLOWN DESTEC GASIFIER
GASIFICATION COMBINED CYCLE

DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER
GENERAL ELECTIRC "H" ATS

SCALE NONE
PARSON'S DWG. NO. MBAC-1-400-314-010 REV A

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Table 4.4-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

(Loads are presented for one IGCC island, one gas turbine, and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY (Net Electric Power at Generator Terminals, kWe)	
Gas Turbine	335,210
Steam Turbine	154,885
Total	490,095
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	210
Coal Slurry Pumps	180
Condensate Pumps	170
IP/IP Feed Pumps	5,030
HP Feed Pumps	2,240
Miscellaneous Balance of Plant (Note 1)	900
Air Separation Plant	31,340
Oxygen Boost Compressor	6,060
Nitrogen Compressor	13,640
Regenerator Compressor	2,370
Recycle Blower	60
Acid Pump	10
Acid Plant Air Blower	290
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	300
Saturated Water Pumps	50
Circulating Water Pumps	1,420
Cooling Tower Fans	980
Slag Handling	530
Transformer Loss	1,180
TOTAL AUXILIARIES, kWe	62,360
Net Power, kWe	427,735
Net Efficiency, % HHV	49.0
Net Heat Rate, Btu/kWh (HHV)	6,969
CONDENSER COOLING DUTY, 10^6 Btu/h	900
CONSUMABLES	
As-Received Coal Feed, lb/h	255,510
Oxygen (95% pure), lb/h	186,135
Water (for slurry), lb/h	88,577

Note 1 - Includes plant control systems, lighting, HVAC, etc.

The low-pressure (LP) drum, not shown, supplies steam for feedwater deaeration. Steam conditions at the HP turbine admission valves are set at 1800 psig/1000°F.

The HRSG also contains an integral deaerating heater and several economizer sections. The economizer preheats the feedwater before it is sent to the gasifier for final heating by heat recovery from the gas path. Therefore, conventional feedwater heaters using turbine extraction steam are not required.

The steam turbine selected to match this cycle is a two-casing, reheat, double-flow (exhaust) machine, exhausting downward to the condenser. The HP and IP turbine sections are contained in one section, with the LP section in a second casing. Other turbine design arrangements are possible; the configuration represented herein is typical of reheat machines in this size class.

The steam turbine drives a 3600 rpm hydrogen-cooled generator. The turbine exhausts to a single-pressure condenser operating at a nominal 2.0 inches Hga at the 100 percent load design point. For the LP turbine, the last-stage bucket length is 30 inches. Two 50 percent capacity, motor-driven pumps are provided for feedwater and condensate.

4.4.3 <u>Emissions Performance</u>

The operation of the combined cycle unit in conjunction with oxygen-blown Destec IGCC technology is projected to result in very low levels of emissions of NOx, SO_2, and particulates (fly ash). A salable byproduct in the form of sulfuric acid at 99 percent concentration is produced. A summary of the plant emissions is presented in Table 4.4-2.

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the transport hot gas desulfurizer (THGD) subsystem. The THGD process removes approximately 99.5 percent of the sulfur compounds in the fuel gas.

Table 4.4-2
AIRBORNE EMISSIONS - IGCC, OXYGEN-BLOWN DESTEC

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	Tons/year 65%	Tons/year 85%	lb/MWh
SO_2	0.017	146	191	0.12
NOx	0.024	204	266	0.167
Particulates	< 0.002	< 17	< 22	0.014
CO_2	200	1,700,400	2,2223,600	1,396

The reduction in NOx to below 10 ppm is achieved for a fuel gas containing fuel-bound nitrogen (NH_3) by the use of rich-quench lean (staged) combustion technology coupled with syngas dilution by saturated nitrogen available from the ASU. Syngas dilution, staged combustion, and sub-stoichiometric combustion followed by excess air dilution promote the conversion of fuel bound nitrogen to N_2 rather than NOx. The techniques of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can reduce NOx emissions further, but are not applied to the subject plant.

Particulate discharge to the atmosphere is limited by the use of a ceramic candle type barrier filter, which provides a particulate removal rate of greater than 99.99 percent.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/MMBtu) since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

4.4.4 <u>Description of Oxygen-Blown IGCC</u>

This reference design is based on the utilization of one oxygen-blown Destec entrained-bed, slagging gasifier. The medium-Btu gas produced in the gasifier is desulfurized in a transport reactor type hot gas desulfurization and filtration process downstream of the gasifier. The final product gas is used to fire a combustion turbine generator, which is coupled to a HRSG for driving one steam turbine generator.

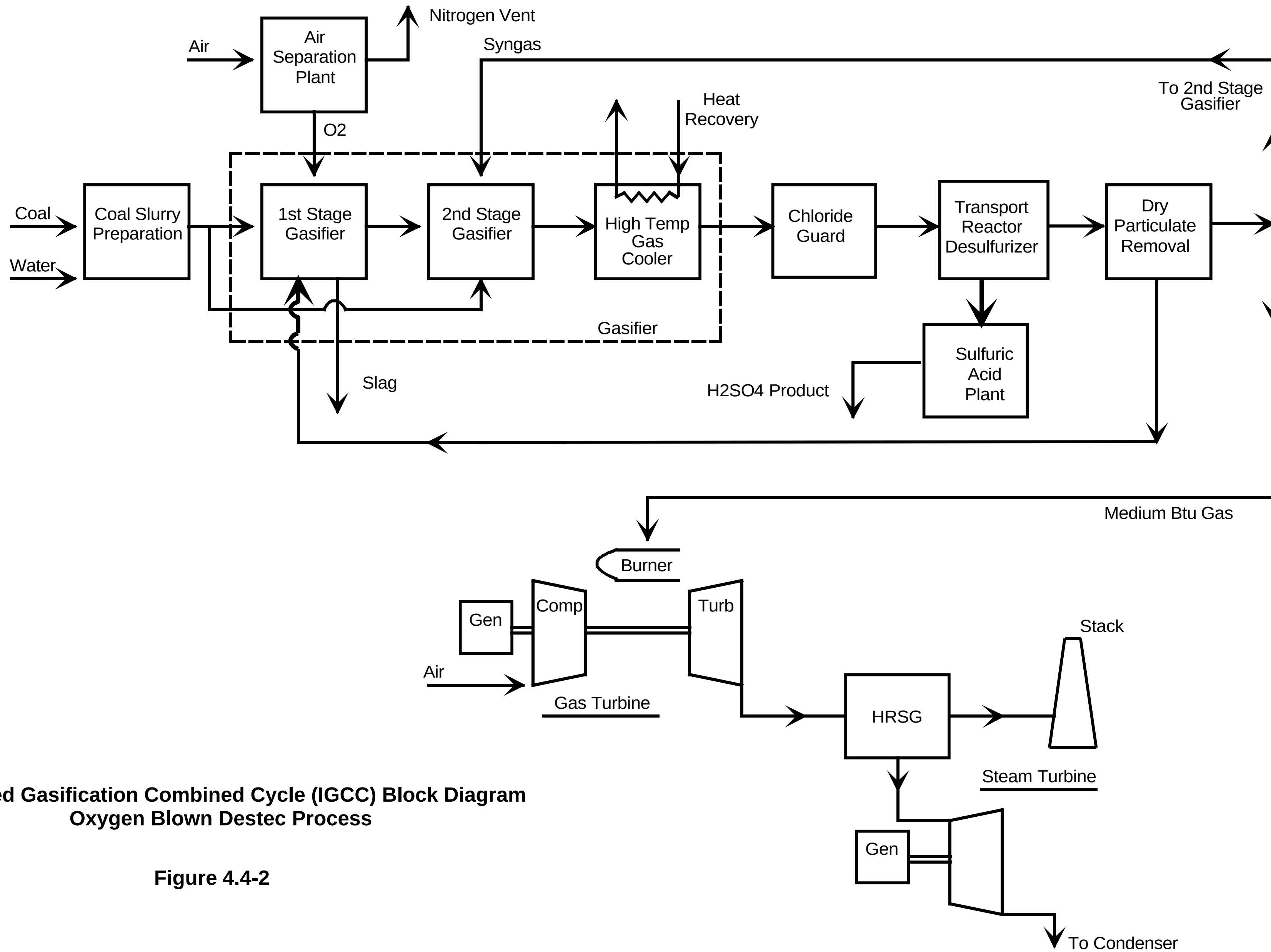
The following is a summary description of the overall gasification process and its integration with the power generation cycles used in this reference design. (Refer to Figure 4.4-2.)

Illinois No. 6 coal is ground to 200 mesh and mixed with water to be fed to the pressurized Destec gasifier as a slurry. The slurry is fired with oxygen to produce medium-Btu gas, which is largely comprised of CO, H_2, and CO_2, and is discharged from the gasifier at 1900°F and cooled in a gas cooler to 1110°F.

The cooled gas passes through the chloride guard containing a fixed-bed reactor, exposing the gas to nahcolite to reduce the chloride level to less than 1 ppm, thus protecting the sorbent and the combustion turbine downstream. The gas then enters the THGD, where sufficient sulfur is removed to result in a final sulfur level of less than 10 ppm. The gas is then cleaned in the dry particulate removal system containing a final ceramic candle type barrier filter, resulting in very low levels of particulates. Fly ash from the filter is transferred to the fines combustor where it is oxidized. The regeneration gas from the THGD is a mixture of air and SO_2, which is a suitable feedstock for the sulfuric acid plant.

The gas exiting the THGD is conveyed to the combustion turbine where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The exhaust gas from the turbine and HRSG is released to the atmosphere via a conventional stack.

Based on the selection of a machine derived from General Electric “H” class combustion turbine, a fuel gas pressure of 400 psig was established to provide a margin above the compressor discharge pressure (275 psig for this reference case), allowing for necessary system and valve pressure drop.



Integrated Gasification Combined Cycle (IGCC) Block Diagram
Oxygen Blown Destec Process

Figure 4.4-2

Based on the above, a nominal gasifier pressure of 500 psig is required. At this pressure, a single gasifier is required. The gasifier is similar in size to the commercial-sized island utilized in the Wabash River Coal Gasification Repowering Project, which operates at a nominal pressure of 450 psig. The wall thickness of the gasifiers and other vessels and piping comprising the gasifier islands is increased by approximately 11 percent to compensate for the higher pressure (500 psig vs. 450 psig).

4.4.4.1 Coal Grinding and Slurry Preparation

Coal is fed onto conveyor No. 1 by vibratory feeders located below each coal silo. Conveyor No. 1 feeds the coal to an inclined conveyor (No. 2) that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. A vibrating feeder on each hopper outlet supplies the weigh feeder, which in turn feeds a rod mill. The rod mill grinds the coal and wets it with treated slurry water from a slurry water tank. The slurry is then pumped from the rod mill product tank to the slurry storage and slurry blending tanks.

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required will depend on local environmental regulations.

4.4.4.2 Gasifier

Note: The following description is taken from the Coal Gasification Guidebook: Status, Applications, and Technologies, prepared by SFA Pacific, Inc. for the Electric Power Research Institute.

The Destec coal gasifier is a slurry feed, pressurized, upflow, entrained slagging gasifier whose two-stage operation makes it unique. Wet crushers produce slurries with the raw feed coal. Dry coal slurry concentrations range from 50 to 70 wt%, depending on the inherent moisture and quality of the feed coal. The slurry water consists of recycle water from the raw gas cooling together with makeup water. About 80 percent of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 2400 to 2600°F. The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed in a novel continuous-pressure letdown/dewatering system.

The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 20 percent of coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1900°F.

Char is produced in the second stage. However, the yield of this char is relatively small because only about 20 percent of the coal is fed to the second stage. Char yield is dependent on the reactivity of the feed coal and decreases with increasing reactivity. The char is recycled to the hotter first stage, where it is easily gasified. The gasifier is refractory lined and uncooled. The hotter first-stage section of the gasifier also includes a special slag-resistant refractory. The 1900°F hot gas leaving the gasifier is cooled in the fire-tube product gas cooler to 1100°F, generating saturated steam for the steam power cycle in the process.

4.4.4.3 Gas Desulfurization

The THGD section of the IGCC island serves to remove most of the sulfur from the gas produced by the gasifier. The gas delivered from the gasifier to the THGD system is at 1100°F and 425 psig. The sulfur compounds in the gas (predominantly H_2S) react with the sorbent to form zinc sulfides, yielding a clean gas containing less than 10 ppmv of sulfur compounds. The sorbent for this process is Z-sorb, a zinc-based material also containing nickel oxide.

The uncleaned gas enters the bottom of an absorber column, where it mixes with powdered sorbent, and then rises in the column. The gas/powder mixture exiting the column passes through a cyclone where the sorbent is stripped out for recycle. The clean gas discharged from the absorber flows to a high-efficiency barrier-type filter to remove any remaining particulates.

A regeneration column is used to regenerate the sorbent material from sulfide form to oxide form. Regeneration gas, laden with SO_2, is conveyed to the sulfator for capture of the sulfur and conversion to a disposable form.

4.4.4.4 Particulate Removal

The particulate removal stage in this gasification process is dependent upon a high-efficiency barrier filter comprised of an array of ceramic candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with gas to remove the fines, which are collected and conveyed to the gasifier.

4.4.4.5 Chloride Guard

The chloride guard functions to remove HCl from the hot gas, prior to delivery to the combustion turbine.

The chloride guard is comprised of two 100 percent capacity pressure vessels packed with a pebble bed of nahcolite, a natural form of sodium bicarbonate. One vessel is normally in service, with a nominal service period of two months. The second vessel is purged, cooled, drained of spent bed material, and recharged while the other vessel is in service. The chloride guard vessels are approximately 13 feet in diameter, 25 feet high, and fabricated of carbon steel.

4.4.4.6 Sulfuric Acid Plant

The regeneration of the sorbent in the THGD subsystem produces an offgas from the regeneration process, which contains an SO_2 concentration of 13 percent. This is adequate for feed to a contact process sulfuric acid plant. Key to the process is the four-pass converter developed by Monsanto. The reaction from SO_2 to SO_3 is an exothermic reversible reaction. Equilibrium conversion data show that conversion of SO_2 decreases with an increase in temperature. Using a vanadium catalyst, a contact plant takes advantage of both rate and equilibrium considerations by first allowing the gases to enter over a part of the catalyst at about 800 to 825°F, and then allowing the temperature to increase adiabatically as the reaction proceeds. The reaction essentially stops when about 60 to 70 percent of the SO_2 has been converted, at a temperature in the vicinity of 1100°F. The gas is cooled in a waste heat boiler and passed through subsequent stages, until the temperature of the gases passing over the last portion of catalyst does not exceed 805°F.

The gases leaving the converter, having passed through two or three layers of catalyst, are cooled and passed through an intermediate absorber tower where some of the SO_3 is removed with 98 percent H_2SO_4. The gases leaving this tower are then reheated, and they flow through the remaining layers of catalyst in the converter. The gases are then cooled and pass through the final absorber tower before discharge to the atmosphere. In this manner, more than 99.7 percent of the SO_2 is converted into SO_3 and subsequently into product sulfuric acid.

4.4.4.7 Gas Turbine Generator

The combustion turbine used for the second case is a General Electric Model "H." This machine is an axial flow, single spool, constant speed unit with variable inlet guide vanes and four stages of variable stator vans. A summary of the features of the machine is presented below:

- Inlet and Filter — Two-stage, renewable pad filters, preceded by a rain louver and screen
- Compressor — Axial flow, 18-stage, 23:1 pressure ratio
- Combustors — Can-annular, 12 cans, dry low-NOx type
- Turbine — Steam cooling - two stages, air cooling - one stage, no cooling - one stage
- Generator — Hydrogen-cooled, 20 kV, 60 Hz static exciter

4.4.4.8 Steam Generation

Heat Recovery Steam Generator

The HRSG is a drum-type, triple-pressure design with an integral deaerator. The HRSG is matched to the characteristics of the General Electric "H" turbine exhaust gas when firing medium-Btu gas. The HP drum produces steam at main steam pressure while the IP drum produces steam that is combined with the reheat. The LP drum produces steam that is used for feedwater deaeration. The LP drum also serves as storage for feedwater, and suction of the boiler feed pump is taken from this drum.

Gas Cooler

The gas cooler contains a steam drum and heating surface for the production of saturated steam. This steam is conveyed to the HRSG where it is superheated.

4.4.4.9 Air Separation Plant

The elevated pressure air separation plant is designed to produce a nominal output of 2,200 tons/day of 95 percent pure O_2. The plant is designed with one 100 percent capacity production train. Liquefaction and liquid oxygen storage provide an 8-hour backup supply of oxygen. Nitrogen for fuel gas dilution is also produced.

In this air separation process, air is compressed to 196 psig and then cooled. The cooled air enters a reversing heat exchanger, where it is cooled to the liquefaction point prior to entering a double column (high/low pressure) separator. Refrigeration for cooling is provided by expansion of high-pressure gas from the lower part of the high-pressure column.

4.4.5 IGCC Support Systems (Balance of Plant)

4.4.5.1 Coal Handling System

The function of the balance-of-plant coal handling system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper unloader and coal receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

The bituminous coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor (No. 1). The coal is then transferred to a conveyor (No. 2) that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 by the first of two crushers. The coal then enters the second crusher, which reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the stationary tripper, which loads the coal into one of the two silos.

<u>Technical Requirements and Design Basis</u>

- Coal burn rate:
  - Maximum coal burn rate = 255,500 lb/h = 128 tph plus 10% margin = 140 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 217,000 lb/h = 108 tph (based on MCR rate multiplied by an assumed 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Two and one quarter unit trains per week at maximum burn rate
  - One and three-quarters unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 9 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 900 tph (maximum, both conveyors in operation)
  - Reclaim rate = 400 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 10,000 tons (72 hours at maximum burn rate)

– Dead storage = 85,000 tons (30 days at average burn rate)

4.4.5.2 Slag Ash Handling

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. The ash is removed from the process as slag. Spent material drains from the gasifier bed into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids leaves the gasifier pressure boundary, through a proprietary pressure letdown device, to a series of dewatering bins. The separated liquid is recycled to the slag quench water bath.

The cooled, solidified slag is stored in a storage vessel. The hopper is sized for a nominal holdup capacity of approximately 72 hours of full-load operation. At periodic intervals, a convoy of slag hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. Approximately 12 truck loads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power.

4.4.6 Steam Cycle Balance of Plant

The following section provides a description of the steam turbines and their auxiliaries.

4.4.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last-stage bucket length of 30 inches.

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at 1800 psig/1000°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the HP turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 395 psig/1000°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Extraction steam from the cold reheat is used for the "H" machine to provide cooling the stationary and rotating parts of the turbine, mainly the first- and second-stage stationary nozzle and buckets plus the stage one shroud. The steam is returned to the hot reheat for performance augmentation.

Turbine bearings are lubricated by a closed-loop water-cooled pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure-regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

The steam turbine generator is controlled by a triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

4.4.6.2 Condensate and Feedwater Systems

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG. The system consists of one main condenser; two 50 percent capacity, motor-driven variable speed vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG. Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Feedwater

The function of the feedwater system is to pump the various feedwater streams from the LP drum with deaerator storage capabilities located in the HRSG to the respective steam drums. Two motor-driven, HP and IP, 50 percent capacity boiler feed pumps are provided. Each pump is provided with a variable speed drive to support startup, shutdown, and part-load operation. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the LP drum. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

4.4.6.3 Main and Reheat Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the HRSG superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 1800 psig/1000°F exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 440 psig/650°F exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 395 psig/1000°F exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

4.4.6.4 Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

4.4.6.5 Major Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the steam cycle. A summary of the required piping is presented in Table 4.4-3.

Table 4.4-3
INTEGRATED GASIFICATION COMBINED CYCLE

Major Steam Cycle Piping Required

Pipeline	Flow, lb/h	Press., psia	Temp., °F	Material	OD, in.	Twall, in.
Condensate	1,100,000	135	100	A106 Gr. B	8	Sch. 40
HP Feedwater, Pump to HRSG	810,000	2316	325	A106 Gr. C	8	Sch. 160
IP Feedwater, Pump to HRSG	63,000	600	320	A106 Gr. B	3	Sch. 40
LP Econ. Water to Gasifier	34,400	90	320	A106 Gr. C	3	Sch. 40
LP Econ. Steam to HRSG	34,400	90	320	A106 Gr. C	6	Sch. 40
HP Econ. Water to Gasifier	385,000	2016	627	A106 Gr. C	8	Sch. 160
HP Econ. Steam to HRSG	385,000	2016	637	A335 Gr. P91	6	Sch. 160
Main Steam/HRSG to Steam Turbine	805,000	1815	1000	A335 Gr. P91	10	1.375
Cold Reheat/ST to HRSG	372,500	450	650	A106 Gr. B	14	Sch. 40
Hot Reheat/HRSG to ST	776,000	405	1000	A335 Gr. P91	18	Sch. 40
Cold Reheat to GT	337,300	450	650	A106 Gr. B	12	Sch. 40
Hot Reheat from GT	337,300	405	1000	A335 Gr. P91	14	Sch. 40
Fuel Gas/Gasifier Island to Gas Turbine	500,800	400	1105	A335 Gr. P91	16	Sch. 40
O_2 Piping to Gasifier	186,000	620	250	A106 Gr B	6	Sch. 40

4.4.7 Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

4.4.8 Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

4.4.9 Site, Structures, and Systems Integration

4.4.9.1 Plant Site and Ambient Design Conditions

Refer to Section 2 for a description of the plant site and ambient design conditions.

4.4.9.2 New Structures and Systems Integration

The development of the reference plant site to incorporate structures required for this technology is based on the assumption of a flat site. The IGCC gasifier and related structures are arranged in a cluster, with the coal and slurry preparation facilities adjacent to the south, as shown in the conceptual arrangement presented in Section 4.2. Figure 4.2-3 presents the basic plant arrangement.

The gasifier and its associated process blocks are located west of the coal storage pile. The gas turbine and its ancillary equipment are sited west of the gasifier island, in a turbine building designed expressly for this purpose. A HRSG and stack are east of the gas turbine, with the steam turbine and its generator in a separate building continuing the development to the north. Service and administration buildings are located at the west side of the steam turbine building.

The cooling tower heat sink for the steam turbine is located to the east of the steam turbine building. The air separation plant is further to the east, with storage tanks for liquid O_2 located near the gasifier and its related process blocks. Sulfur recovery and wastewater treatment areas are located east and south of the air separation plant.

The arrangement described above provides good alignment and positioning for major interfaces; relatively short steam, feedwater, and fuel gas pipelines; and allows good access for vehicular traffic. Transmission line access from the gas turbine and steam turbine step-up transformer to the switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located north of the gas turbine. The clean, hot, medium-Btu gas is conveyed to the turbine combustors for mixing with the air that remained on-board the machine. Turbine exhaust is ducted directly through a triple-pressure HRSG and then to a new 213-foot stack. The height of the stack is established by application of a good engineering practice rule from 40 CFR 51.00.

Access and construction laydown space are freely available on the periphery of the plant, with several roads, 26 feet wide plus shoulders, running from north to south between the various portions of the plant.

4.4.10 Equipment List - Major

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	200 tph	2
8	Conveyor No. 3	48" belt	400 tph	1
9	Crusher Tower	N/A	400 tph	1
10	Coal Surge Bin w/Vent Filter	Compartment	400 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer		1
14	Conveyor No. 4	48" belt	400 tph	1
15	Transfer Tower	N/A	400 tph	1
16	Tripper	N/A	400 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	1,500 ton	2

ACCOUNT 1B LIMESTONE HANDLING AND PREPARATION SYSTEM

Not Applicable

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL SLURRY PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Vibratory Feeder		80 tph	2
2	Conveyor No. 1	Belt	160 tph	1
3	Conveyor No. 2	Belt	160 tph	1
4	Rod Mill Feed Hopper	Vertical, double hopper	200 ton	1
5	Vibratory Feeder		80 tph	2
6	Weight Feeder	Belt	80 tph	2
7	Rod Mill	Rotary	80 tph	2
8	Slurry Water Storage Tank	Field-erected	100,000 gal	1
9	Slurry Water Pumps	Horizontal, centrifugal	625 gpm	2
10	Rod Mill Product Tank	Field-erected	170,000	1
11	Rod Mill Product Pumps	Horizontal, centrifugal	850 gpm	2
12	Slurry Storage Tank	Field-erected	300,000	1
13	Centrifugal Slurry Pumps	Horizontal, centrifugal	1,700 gpm	2
14	PD Slurry Pumps	Progressing cavity	300 gpm	2
15	Slurry Blending Tank	Field-erected	100,000 gal	1
16	Slurry Blending Tank Pumps	Horizontal, centrifugal	325 gpm	2

ACCOUNT 2B SORBENT PREPARATION AND FEED

Not Applicable

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cyl., outdoor	50,000 gal	1
2	Condensate Pumps	Vert. canned	1,100 gpm @ 310 ft	2
3	Deaerator	Horiz. spray type	1,130,000 lb/h 215°F	1
4	IP Feed Pumps	Interstage bleed from HP feed pump	66 gpm/1,200 ft	2
5	HP Feed Pumps	Barrel type, multi-staged, centr.	850 gpm / 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	20,000 gal No. 2 oil	2
3	Fuel Oil Unloading Pump	Gear	50 psig, 100 gpm	1
4	Fuel Oil Supply Pump	Gear	150 psig, 5 gpm	2
5	Service Air Compressors	Recip., single-stage, double acting, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exch	Plate and frame	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
11	Fire Service Booster Pump	Two-stage horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water	SS, single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	SS, single suction	160 ft, 120 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

ACCOUNT 4A GASIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Pressurized entrained bed	2860 tpd/500 psig	1
2	Gas Cooler	Firetube	167×10^6 Btu/h	1
3	Flare Stack	Shielded	465,000 lb/h medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	80,000 acfm, 70 psig discharge pressure	1
2	Cold Box		2,200 ton/day O_2	1
3	Oxygen Compressor	Centrifugal, multi-stage	33,200 scfm, 620 psig discharge pressure	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Qty
1	Sorbent Storage Hopper	*		1
2	Sorbent Feed Hopper	*		1
3	Transport Desulfurizer	*		1
4	Desulfurizer Cyclone	*		1
5	Transport Regenerator	*		1
6	Regenerator Cyclone	*		1
7	Sorbent Regeneration Air Heater	*		1
8	Regenerator Effluent Gas Cooler	*		1

* This information is proprietary and is not presented.

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	340 MWe Gas Turbine Generator	Axial flow single spool based on “H”	1510 lb/sec airflow 2600°F rotor inlet temp. 23:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1510 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	1
5	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
6	Oil Cooler	Air-cooled, fin fan		1
7	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
8	Generator Glycol Cooler	Air-cooled, fin fan		1
9	Compressor Wash Skid			1
10	Fire Protection Package	Halon		1

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, triple pressure, with economizer sections and integral deaerator	HP-2300 psig/325°F 805,000 lb/h superheat to 1000°F IP-600 psig/320°F 63,000 lb/h	1
2	Raw Gas Cooler Steam Generator	Drum and heater	2300 psig/sat. steam 384,000 lb/h	1
3	Stack	Carbon steel plate lined with type 409 stainless steel	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	160 MW Turbine Generator	TC2F30	1800 psig/1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	875,000 lb/h steam @ 2.0 in. Hga with 78°F water, 19°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2700/25 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	40,000 gpm @ 60 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell counter-flow, film type fill	56°F WB/78°F CWT/ 97° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A SLAG DEWATERING & REMOVAL

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Quench Tank	Water bath		1
2	Slag Precrusher		12 tph solids	1
3	Slag Crusher	Roll	12 tph solids	1
4	Slag Depressurizing Unit	Proprietary	12 tph solids	1
5	Slag Dewatering Unit	Horizontal, weir	4 tph solids	3
5	Slag Conveyor	Drag chain	4 tph	3
6	Slag Conveyor	Drag chain	8 tph	*1
6	Slag Storage Vessel	Reinf. concrete vert. cylindrical	1,200 ton	*1
7	Slide Gate Valve			*1
8	Telescoping Unloader		25 tph	*1

*Total for plant.

4.4.11 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the market-based intermediate O_2-blown Destec 400 MW plant is shown in Table 4.4-4. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 4.4-4

Client: DEPARTMENT OF ENERGY
Report Date: 14-Aug-98 11:02 AM
Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Destec (2010-"H")
Plant Size: 427.7 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	5,752	1,154	5,023	352		**$12,281**	982		2,653	**$15,916**	37
2	COAL & SORBENT PREP & FEED	6,977	1,605	7,535	527		**$16,644**	1,332	559	2,444	**$20,978**	49
3	FEEDWATER & MISC. BOP SYSTEMS	5,803	2,825	4,504	315		**$13,447**	1,076		3,505	**$18,028**	42
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries(Destec)	9,257		9,429	660		**$19,346**	1,548	1,935	2,283	**$25,111**	59
4.2	High Temperature Cooling	15,118		15,405	1,078		**$31,602**	2,528	3,160	3,729	**$41,019**	96
4.3	ASU/Oxidant Compression	57,300		w/equip.			**$57,300**	4,584		6,188	**$68,072**	159
4.4-4.9	Other Gasification Equipment		3,924	2,194	154		**$6,271**	502		1,793	**$8,566**	20
	SUBTOTAL 4	*81,675*	*3,924*	*27,027*	*1,892*		***$114,519***	*9,161*	*5,095*	*13,993*	***$142,768***	*334*
5	HOT GAS CLEANUP & PIPING	26,369	2,264	9,371	656		**$38,659**	3,093	4,547	9,438	**$55,737**	130
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	43,435		3,306	231		**$46,973**	3,758	3,523	5,425	**$59,680**	140
6.2-6.9	Combustion Turbine Accessories		148	170	12		**$330**	26		107	**$463**	1
	SUBTOTAL 6	*43,435*	*148*	*3,477*	*243*		***$47,303***	*3,784*	*3,523*	*5,532*	***$60,143***	*141*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	13,255		1,905	133		**$15,294**	1,224		1,652	**$18,169**	42
7.2-7.9	HRSG Accessories, Ductwork and Stack	1,997	743	1,410	99		**$4,249**	340		637	**$5,226**	12
	SUBTOTAL 7	*15,252*	*743*	*3,316*	*232*		***$19,543***	*1,563*		*2,288*	***$23,395***	*55*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	11,689		2,140	150		**$13,978**	1,118		1,510	**$16,606**	39
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	5,646	172	3,097	217		**$9,132**	731		1,698	**$11,561**	27
	SUBTOTAL 8	*17,335*	*172*	*5,236*	*367*		***$23,110***	*1,849*		*3,208*	***$28,167***	*66*
9	COOLING WATER SYSTEM	3,997	2,227	3,766	264		**$10,253**	820		1,991	**$13,064**	31
10	ASH/SPENT SORBENT HANDLING SYS	3,726	686	3,177	222		**$7,811**	625	534	1,039	**$10,009**	23
11	ACCESSORY ELECTRIC PLANT	12,384	4,091	10,067	705		**$27,247**	2,180		4,858	**$34,285**	80
12	INSTRUMENTATION & CONTROL	6,517	1,548	5,752	403		**$14,220**	1,138		2,327	**$17,685**	41
13	IMPROVEMENTS TO SITE	2,006	1,153	4,017	281		**$7,458**	597		2,416	**$10,471**	24
14	BUILDINGS & STRUCTURES		4,505	5,812	407		**$10,724**	858		2,895	**$14,477**	34
	TOTAL COST	**$231,228**	**$27,045**	**$98,081**	**$6,866**		**$363,220**	**$29,058**	**$14,258**	**$58,589**	**$465,125**	**1087**