DOE/MC/26308-3645
(DE94004063)

CE IGCC Repowering Project
Clean Coal II Project

Annual Report
January 1, 1992 - December 31, 1992

December 1993

Work Performed Under Contract No.: DE-FC21-90MC26308

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Combustion Engineering, Inc.
Windsor, Connecticut

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1000 Prospect Hill
Windsor, Connecticut 06095

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CE IGCC REPOWERING PROJECT
1992 ANNUAL TECHNICAL REPORT

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ABBREVIATIONS

ABB	Asea Brown Bovari
ABB-ES	ABB Environmental Services
AFD	approved for design
BACT	Best Available Control Technology
BCAC	booster compressor air cooler
BP1	Budget Period 1
BP2	Budget Period 2
BP3	Budget Period 3
CE	Combustion Engineering
CWL&P	City, Water, Light, and Power
DOE	Department of Energy
EA	Environmental Assessment
EMP	Environmental Monitoring Plan
EMPO	Environmental Monitoring Plan Outline
FONSI	Finding Of No Significant Impact
GE	General Electric
GEESI	General Electric Environmental Systems Inc.
GT	gas turbine
HAZOP	Hazard and Operability
HGCU	Hot Gas Clean Up
HHV	higher heating value
HRSG	heat recovery steam generator
HTSH	high temperature super heater
ID	inside diameter
IEPA	Illinois Environmental Protection Agency
IGCC	integrated gasification combined cycle
KDL	Kreisinger Development Laboratory
kW	kilowatt
LBG	low BTU gas
LCI	Lummus Crest International
LPFWH	low pressure feed water heater
LTSH	low temperature super heater
MAH	mill air heater
MCR	maximum continuous rating
METC	Morgantown Energy Technology Center
MFD	material flow diagram
MW	megawatts
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Authority
NPDES	National Pollution Discharge Elimination System
NPHR	net plant heat rate
OD	outside diameter
PEP	Project Evaluation Plan
PFD	process flow diagram
PHA	Preliminary Hazard Analysis
PMP	Project Management Plan
PON	Program Opportunity Notice
PSD	Prevention of Significant Deterioration
PSIA	pounds per square inch absolute
P&ID	piping and instrumentation diagram
SGC	syngas cooler
SMSD	Springfield Metro Sanitary District
ST	steam turbine
WBS	Work Breakdown Structure

I EXECUTIVE SUMMARY

CE is participating in a $270 million coal gasification combined cycle repowering project that will provide a nominal 60 MW of electricity to City, Water, light and Power (CWL&P) in Springfield, Illinois. The IGCC system will consist of CE's air-blown entrained flow two-stage gasifier; an advanced hot gas cleanup system; a combustion turbine adapted to use low-BTU gas; and all necessary coal handling equipment.

The project is currently in the second budget period of five. The major activities during this budget period are:

- Establishment of an approved for design (AFD) engineering package.
- Development of a detailed cost estimate.
- Resolution of project business issues.
- CWL&P renewal and replacement activities.
- Application for environmental air permits.

The Project Management Plan was updated. The conceptual design of the plant was completed and a cost and schedule baseline for the project was established previously in Budget Period One. This information was used to establish AFD Process Flow Diagrams, Piping and Instrument Diagrams, Equipment Data Sheets, material take offs, site modification plans and other information necessary to develop a plus or minus 20% cost estimate. Environmental permitting activities are continuing. At the end of 1992 the major activities remaining for Budget Period two is to finish the cost estimate and complete the Continuation Request Documents.

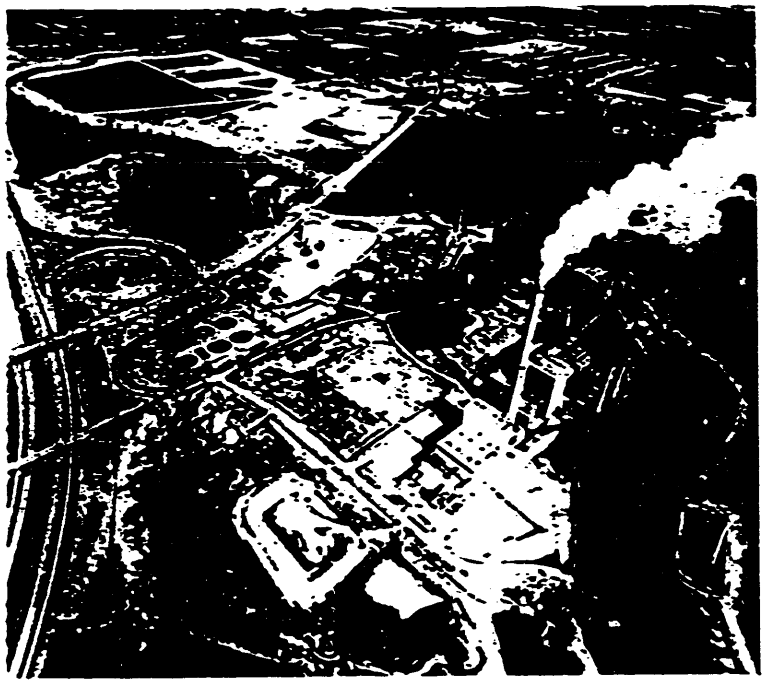
II INTRODUCTION

CE is participating in a $270 million coal gasification combined cycle repowering project that will provide a nominal 60 MW of electricity to City Water, Light & Power (CWL&P) in Springfield, Illinois. The CE project will demonstrate Integrated Gasification Combined Cycle (IGCC) technology in a commercial application by repowering an existing CWL&P Plant in Springfield, Illinois. The project duration will be 126 months, including a 63-month demonstration period.

III PROJECT DESCRIPTION

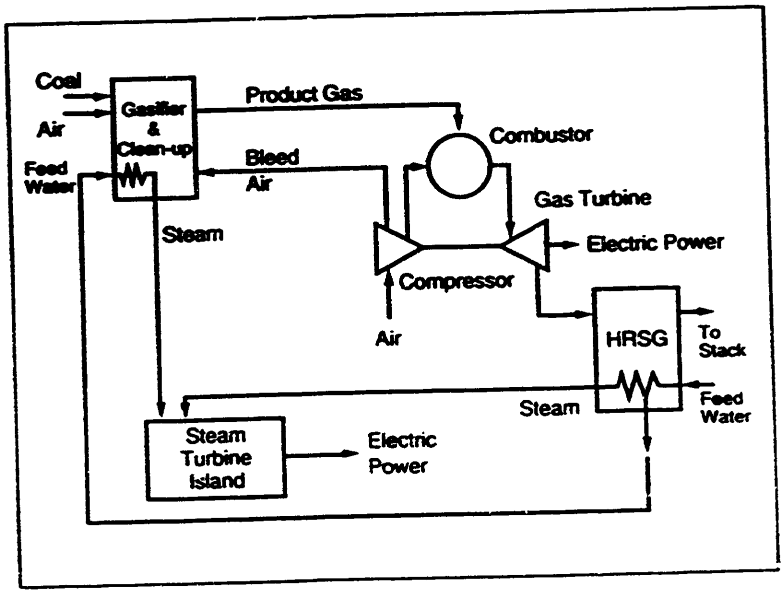
The IGCC system will consist of CE's air-blown, entrained-flow, two-stage, pressurized coal gasifier; an advanced hot gas cleanup process; a combustion turbine adapted to use low-Btu coal gas; and all necessary coal handling equipment. CWL&P's Lakeside Station (Figure 1) will be the site for this project. The result of repowering will be an IGCC power plant with low environmental emissions and high net plant efficiency. The repowering will increase plant output by 40 MWe through addition of the combustion turbine, thus providing a total IGCC capacity of a nominal 60 MWe. Nearly half of the project will be funded by the United States Department of Energy (DOE), under Round II of the Clean Coal Technology Program, while CWL&P, State of Illinois, and CE will fund the rest.

FIGURE 1



Lakeside Photo

FIGURE 2



Simplified IGCC

The IGCC will include CE's slagging, entrained-flow, gasifier operating in a pressurized mode and using air as the oxidant. The hot gas will be cleaned of particulate matter (char) which is recycled back to the gasifier. After particulate removal, the product gas will be cleaned of sulfur prior to burning in a gas turbine.

The proposed project includes design and demonstration of an advanced hot gas cleanup process for removal of sulfur from the product gas of the gasifier. The sulfur removal method features a newly developed moving-bed zinc ferrite system downstream of the gasifier. CE intends to use the General Electric (GE) moving bed, zinc ferrite sulfur removal system currently being piloted by GE Environmental Systems, Inc. The process data from these pilot tests is expected to be sufficient for the design of a full-scale system to be used in the proposed demonstration.

In this plant, the gasifier will be producing a low-Btu gas (LBG). The LBG will be used as fuel in a standard GE gas turbine to produce power. This gas turbine will have the capability to fire LBG and natural gas (for start-up). Since firing LBG uses less air than natural gas, the gas turbine air compressor will have extra capacity. This extra compressed air will be used to pressurize the gasifier and supply the air needed in the gasification process.

The plant is made of three major blocks of equipment as shown in Figure 2. They are the fuel gas island which includes the gasifier and gas cleanup, gas turbine power block, and the steam turbine block which includes the steam turbine and the HRSG.

As major equipment sections are completed, they will be individually started up and brought on-line to produce power. The combined cycle equipment will have the shortest lead time so this equipment will be installed, checked out, and brought into commercial service first. Initially, the gas turbine will be fired on natural gas operating as a combined cycle with a new heat recovery steam generator and a new steam turbine. All of this equipment will be checked out and operated prior to the start-up of the gasification plant.

The last major block of equipment will be the fuel gas island including the gasifier and gas cleanup equipment. When this equipment is put into operation, the plant will be a fully integrated coal gasification combined cycle plant.

IV RESULTS

A) Performance Summary

The DOE/CE Cooperative Agreement requires that CE complete the CE IGCC Repowering Project as spelled out in the Statement of Work with funding controlled by a number of Budget Periods.

This report covers work performed in Budget Period 2. This Budget Period includes the following:

- Establishment of an Approved for Design (AFD) engineering package.
- Development of a plus or minus 20% Cost Estimate.
- Resolution of project Business issues.
- CWL&P renewal and Replacement Activities.
- Application for environmental air permits.

The conceptual design work that was accomplished during Budget Period 1 was used to develop a more detailed series of process flow diagrams for the gasifier island and the balance of plant. These PFD's were expanded from the original conceptual design PFD's to include all major equipment along with the major control loops. Materials of construction were identified for all of the components and process lines and a Material Flow Diagram (MFD) was developed. From these documents, equipment lists and design data sheets were made for all identified equipment. The data sheets were used to obtain cost information.

A series of general arrangement drawings of the gasifier island and the combined cycle were done to estimate construction costs. Engineering specification packages were made for major components of the plant including the gas turbine, steam turbine, sulfur recovery system, hot gas cleanup system, heat recovery steam generator, booster compressor, coal handling, and slag removal systems. The gasifier and syngas cooler were designed and preliminary drawings made to estimate costs and shop schedule.

At the end of 1992, the cost estimate was still being developed. This activity has shown to require more time than was originally estimated and a request has been made to extend Budget Period 2 into the first part of 1993.

Environmental activities were mainly concerned with supplying the information required for the BACT (best available control technology) demonstration as part of the prevention of significant deterioration (PSD) determination of the air emissions permit application. Both the preliminary and final BACT documents were submitted in 1992. Also, approval of the EA and FONSI were received. The air emissions permitting activities will continue into 1993.

B) Work Breakdown Structure (WBS)

The Work Breakdown Structure for the Project is shown in Figure 3.

C) 1992 Accomplishments

The goals for Budget period 2 were to complete basic engineering and produce an approved for design (AFD) engineering package and a plus or minus 20% cost estimate. At the end of 1992, the cost estimate is being developed. The basic engineering activities have produced AFD process flow diagrams, metallurgical flow diagrams, preliminary control philosophy, piping and instrumentation diagrams, arrangement drawings for the gasifier island and balance of plant, equipment data sheets, and requisition packages for all major equipment and subsystems.

WORK BREAKDOWN STRUCTURE

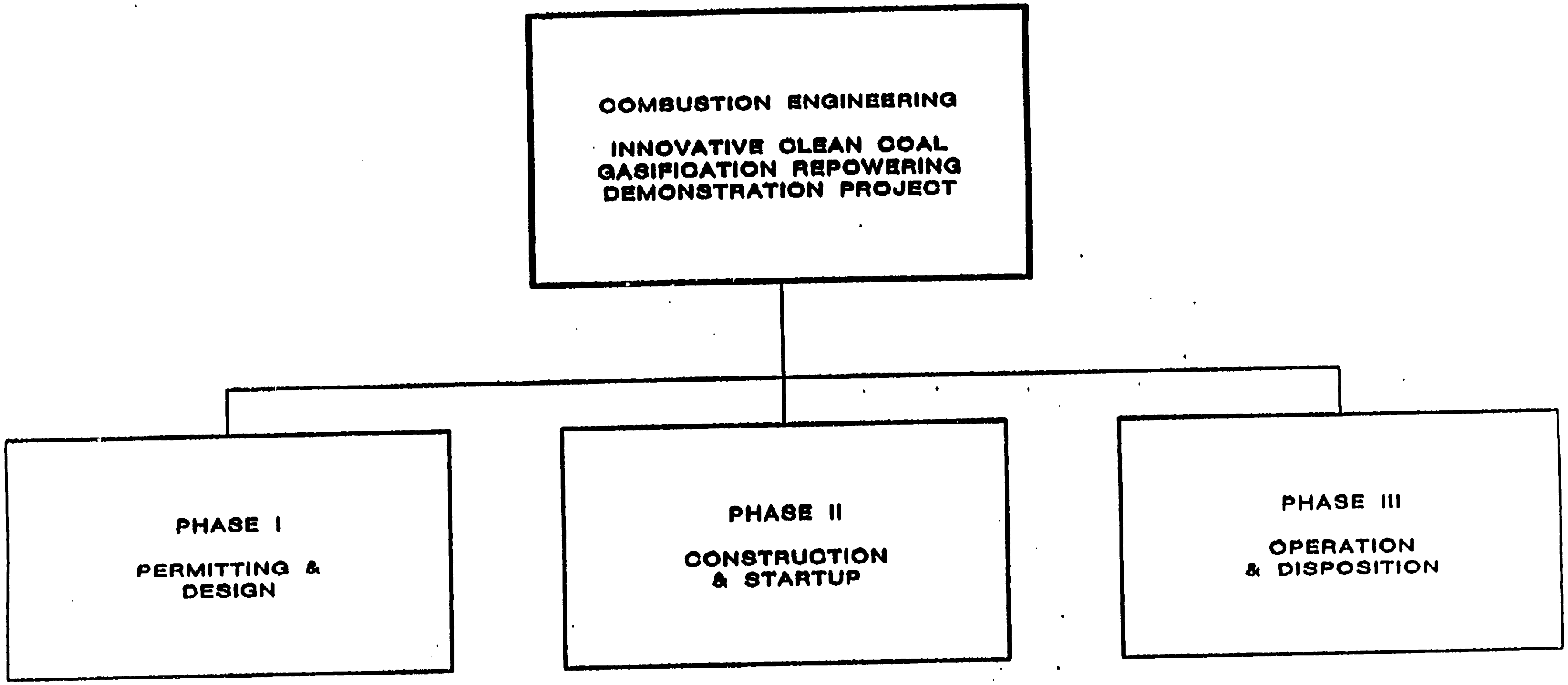


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FIGURE 3

In support of the basic engineering, several IGCC performance studies were made to determine the best heat rate for the plant and to select the equipment configuration. A computer model to calculate plant performance was written. This program was used to evaluate several heat rate sensitive process decisions. These calculations were used to select the plant design basis after consulting with CWL&P. Heat and mass balances were generated for all of the anticipated operating conditions.

The gasifier and heat exchanger initial mechanical design was completed and a series of drawings were made from which the cost and shop schedule could be estimated.

Balance of plant activities were done to design the coal handling yard and the slag handling system. Requisitions packages were completed for the gas turbine, steam turbine, HRSG, booster compressor, and sulfur recovery plant. Arrangement drawings were made for the modifications to the Lakeside building for the combined cycle installation. Arrangement drawings were made for the gasifier island, coal feed yard and other site changes.

The environmental activities centered on the BACT document which was submitted to IEPA in December 1992.

A list of deliverables for budget period 2 is given in Table 1. The first deliverable listed is the EA/FONSI. The Finding of No Significant Impact (FONSI) was issued by the DOE in March of 1992.

The Project Management Plan (PMP) was submitted in February and updated in November. The Project Evaluation Plan (PEP) was submitted in February and issued in April. The 1991 Annual Technical Report was submitted originally in January and after several revisions finally issued in November. A paper was presented at the 1992 Gasification Conference in September. Five other presentations were made at various conferences throughout 1992. The rest of the deliverables on the list are scheduled to be completed in the first part of 1993.

Table 1

Deliverables	**Date**
EA/FONSI	March, 1992
EMP (draft)	March, 1993
PMP BP2	November, 1992
PEP BP2	April, 1992
1991 Annual Report	November, 1992
1992 Gasification Conference	September, 1992
Long Lead Item Report	April, 1993
Design Support Topical Reports	April, 1993
HGCU Topical Report	March, 1993
Gasifier Data Report	December, 1993
BP2 Design Review Package	April, 1993
Project Evaluation Report	April, 1993
Continuation Application	April, 1993
Major Project Evaluation	April, 1993
Public Design Report	June, 1993
1992 Annual Report	February, 1993

D) Work to be Completed During 1993

The work scheduled for 1993 is to complete the deliverables for BP2 as listed in Table 1. This work includes the finishing of the cost estimate and preparing the Continuation Request. If the Continuation Request is granted, work will proceed into BP3. The work items for BP3 in 1993 will be established as part of the Continuation Request documents.

V. ENVIRONMENTAL DISCUSSION

A) NEPA Support

The provisions of the National Environmental Policy Act (NEPA) apply to the IGCC Repowering Project because project sponsorship and funding by the DOE constitutes a "significant federal action" as defined in the Act. NEPA activities for the project on the part of ABB Combustion Engineering and ABB Environmental Services (ABB-ES) were essentially completed prior to the beginning of 1992. NEPA activities prior to 1992 consisted of preparation of and Environmental Information Volume by ABB-ES, preparation of an Environmental Assessment by DOE, and preparation of a draft Finding of No Significant Impact (FONSI) by DOE. The requirements of NEPA were fulfilled in March of 1992 when DOE issued a Final FONSI.

B) Environmental Monitoring Plan

In the Program Opportunity Notice (PON) for funding of Innovative Clean Coal Technology program, DOE identified certain requirements for monitoring completed projects to more thoroughly document their environmental affects. The process identified consists of three steps. The first consists of preparation of an Environmental Monitoring Plan Outline (EMPO). The second step involves preparation of an Environmental Monitoring Plan (EMP). The final step involves the implementation of the EMP.

The EMPO was prepared by ABB-ES and submitted and accepted as adequate by DOE prior to 1992. The EMP will add additional detail to the EMPO, based on the final design details for the project. During 1992, significant design details were being developed and revised to make meaningful refinement of the EMPO infeasible. Preparation of the EMP for submittal to DOE is currently scheduled for the first quarter of 1993.

C) Environmental Permitting

Permitting activities for 1992 focused on preparations for filing an air emission license application (Prevention of Significant Deterioration [PSD]). this focus was due the relatively long time-line required for conducting pre-filing investigations and the relatively long anticipated agency review period. An attempt was made early in 1992 to "freeze" the project design for permitting purposes. This effort was hampered by the ongoing refinement of the project design. Due the nature of some of the design developments, the certainty of being able to modify a permit obtained on the basis of the "frozen" design became questionable. As a result, several delays to air permitting activities occurred and substantial portions of the licensing activities required reworking.

Environmental permitting activities related to other media (water and solid waste) were minimal during 1992, again awaiting further design development. Throughout 1992, staff of the Illinois Environmental Protection Agency (IEPA) with responsibility for wastewater and solid waste licensing participated in several project meetings. IEPA staff input was sought and obtained on the identification of potential licensing issues. IEPA staff also provided guidance on the overall licensing requirements for the project and the timeframes involved in license review.

D) Air Modeling

During 1992 a significant amount of modeling occurred as part of the impact assessment required as part of the PSD permit application. The impact assessment consists of three major components: screening modeling and refined modeling protocol document; refined modeling of the significant impact zone; and compliance modeling. The first two portions of the impact assessment were submitted to IEPA during 1992. During the impact assessment, several potential problems were encountered. The first was obtaining a layout for the plant that was sufficiently accurate as to be representative of the final project configuration. Several months of delay resulted from significant changes to the plant layout as the design was refined, thereby necessitating rework of previously conducted modeling.

Second, screening modeling predicted violations of air quality standards from the existing Lakeside Generating Station as a result of downwash affects induced by the proposed gasifier structure. Because the predicted violations were relatively small, the decision to proceed with refined modeling was made given the overly conservative nature of the screening model. During refined modeling, very small violations of air quality standards were again demonstrated. ABB-ES modeling staff were able to work within the model to determine the optimal height for the gasifier structure and were able to identify a configuration for the gasifier structure where compliance with all applicable air quality standards was possible. This information was shared with design staff as a design requirement.

Compliance modeling to demonstrate compliance with air quality standards including impacts from other sources (existing) within the significant impact zone is now underway and will be completed during the first quarter of 1993. All of the modeling results will be part of the PSD application that will be filed with IEPA.

E) BACT Determination

The PSD permit application also includes a Best Available Control Technology (BACT) determination. The purpose of the BACT determination is to establish that the controls proposed for the project are appropriate and comply with the requirements of the Clean Air Act as Amended. The BACT determination included several meetings with staff from the IEPA to present the project, identify issues, define the review process, and coordinate the review of the submitted documents. Both draft and final BACT documents were been submitted to IEPA during 1992. It is believed that all major issues associated with the BACT determination have been resolved including: control technologies, emission limits, and general license conditions. A major success of the BACT determination was obtaining IEPA agreement to defer the requirement for

Selective Catalytic Reduction for the control of oxides of nitrogen until after the five year determination period to allow a more accurate evaluation of the IGCC technology and to reduce the costs of the determination.

F) Air Permit

The complete air emission (PSD) application which will include application forms, the BACT demonstration and the modeling results will be prepared for filing during the first part of 1993. Processing of the permit application by IEPA is expected to require up to six months and will likely include a public hearing.

G) Plans for Other Environmental Permits

Applications for remaining environmental permits will be prepared during the first quarter of 1993 including:

NPDES Permit modification application for submittal to Illinois Environmental Protection Agency (IEPA) by City, Water, Light & Power (CWL&P), operator of the host facility. This will include meetings with IEPA, CWL&P, and project design staff.

Industrial Pretreatment Works Construction Permit for submittal to IEPA by City, Water, Light & Power (CWL&P). This will include meeting with IEPA, CWL&P, design staff, and the Springfield Metro Sanitary District (SMSD).

Industrial Wastewater Discharge Permit for submittal to SMSD by CWL&P. This will require coordination with CWL&P, project design staff, and SMSD.

Special Waste Classification/Special Waste Stream Authorization permit for submittal by CWL&P to IEPA. This will require coordination with the IEPA Solid Waste Unit, CWL&P, and project design staff. The purpose of this permit will be to define the disposal requirements of IGCC slag and zinc titanate from the hot gas clean-up system.

Large-Scale Development Review permit application for submittal to the City of Springfield by CWL&P. This will require coordination with CWL&P, the City of Springfield, the Springfield-Sangamon County Regional Planning Commission, and project design staff and will include participation at one public hearing before the City Council.

VI TECHNICAL DISCUSSION

A) IGCC Performance Studies

The program STMCYC was used for calculation of steam cycle performance over a wide range of possible operating conditions for the plant. These performance results were then evaluated and compared for the various design changes. The basic study done to evaluate designs was a load and ambient temperature variation study. Table 2 describes the operating condition envelope considered for this study.

TABLE 2
PLANT OPERATING CONDITIONS

	Ambient Temperature (Deg. F.)			
Gas Turbine Load	95	59	0	
Base	Case 1	Case 2	Case 3	
80%	Case 4	Case 5	Case 6	
30%	Case 7	Case 8	Case 9	

Notes:
- Base gas turbine load refers to design turbine inlet temperature and inlet guide vanes fully open.
- 80 percent gas turbine load refers to design turbine inlet temperature and inlet guide vanes fully closed.
- 30 percent gas turbine load refers to reduced turbine inlet temperature and inlet guide vane fully closed.

The primary purpose for this study was to select and evaluate heat exchanger and other steam cycle components design points. The evaluation of the selected design points were based on the performance calculations from this program for the cases shown in Table 2. The primary result of this study was the selection of design points for all the steam cycle components. Another result of this study was a set of curves which illustrate the steam cycle performance over the operating condition envelope. These curves are not included. Table 3 summarizes the overall plant performance for this matrix of operating conditions. Because this study was done before equipment selection, conservative values for auxiliary power were used. These conservative values are shown in the table. This study was done without considering supplemental firing in the HRSG to reduce the number of variables. This does not affect steam cycle sizing since supplemental firing is not used at off design conditions. The effect of supplemental firing is included in the base design condition discussed later.

The performance for the IGCC is fairly typical of normal natural gas fired combined cycles. Net plant heat rate is fairly constant between 80 and 100 percent load. The gas turbine inlet guide vanes control air flow over this range while maintaining turbine inlet temperature constant. Below about 80 percent load net plant heat rate is degraded sharply. This occurs primarily because of reduced gas turbine inlet temperature which sharply degrades gas turbine thermal efficiency.

Reduced gas turbine inlet temperature also causes a reduction in gas turbine exhaust temperature. This causes HRSG superheater outlet temperature to be reduced. Although the superheater outlet temperature from the gasifier syngas cooler is maintained at set point over this wide load range, the mixed steam temperature to the steam turbine is lowered and steam turbine thermal efficiency is also degraded. Reduced gas turbine load also causes stack temperature to increase when gas turbine load is below about 80 percent.

TABLE 3
NET PLANT HEAT RATE CALCULATION

AMBIENT TEMPERATURE	(Deg F)	95			59			0		
GAS TURBINE LOAD		BASE	80%	30%	BASE	80%	30%	BASE	80%	30%
Combustion Turbine Generator Output	(kW)	32550	26540	10390	37890	30290	12290	46460	36110	14780
Steam turbine Generator Output	(kW)	31490	28317	13844	33689	29640	13510	36990	31752	12951
Gross Plant Output	(kW)	64040	54857	24234	71579	59930	25800	83450	67862	27731
Plant Auxilary Power	(kW)	8433	7746	4833	9017	8177	5007	10062	8953	5287
Net Plant Output	(kW)	55607	47111	19401	62562	51753	20793	73388	58908	22444
Coal Heat Input	(MM-Btu/hr HHV)	508.425	441.709	253.650	564.551	478.196	270.936	660.070	540.206	297.072
Natural Gas Heat Input (GT)	(MM-Btu/hr HHV)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Natural Gas Heat Input (HRSG)	(MM-Btu/hr HHV)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Fuel Heat Input	(MM-Btu/hr HHV)	508.425	441.709	253.650	564.551	478.196	270.936	660.070	540.206	297.072
Net Plant Heat Rate	(Btu/kWhr)	9143	9376	13074	9024	9240	13030	8994	9170	13236
Plant Thermal Efficiency	(Percent)	37.33	36.40	26.10	37.82	36.94	26.19	37.95	37.22	25.79

B) Computer Modeling

A computer program was developed to model the steam cycle for the IGCC plant. This program calculates steady state performance for the steam cycle of this IGCC plant. The primary purpose for this model was to provide a tool for analysis of the cycle when operating at off design conditions.

A simplified diagram of the steam cycle is shown in Figure 4. The steam turbine is designed for 1265 psia, 950°F steam conditions. Full load steam turbine output is about 37 MW. There are two main steam generating systems which a.e in parallel in this cycle. The HRSG generates steam by recovering heat from the gas turbine exhaust stream. In parallel with the HRSG the gasifier heat recovery systems also are recovering heat. The primary heat sources for the gasifier heat recovery systems are the gasifier waterwalls, the syngas cooler, and the desulfurization system evaporator bank.

The steam leaving the turbine enters a deaerating condenser system. The condensate leaving the condenser system then enters a low pressure feedwater heater. The feedwater leaves the feedwater heater before entering the HRSG at a temperature high enough to avoid acid dew point problems. About 90 percent of the economizer duty is done in the HRSG with the remaining 10 percent done in the booster compressor air cooler which is in a parallel circuit with the HRSG economizer. The booster compressor air cooler is used to maintain the air temperature leaving the booster air compressor at 600°F. The HRSG economizer circuit also provides the heat source for the coal mill system. Mill air heater #1 uses recirculated water from the economizer outlet to heat the air stream for the coal milling operation. The water leaving mill air heater #1 is returned to the feedwater circuit at the entrance of the low pressure feedwater heater. The majority of the feedwater leaving the economizer is biased between the HRSG steam drum and the gasifier steam drum. The water leaving the booster compressor air cooler also feeds the gasifier steam drum.

The water in the HRSG drum is naturally circulated thru the evaporator banks in the HRSG and back to the drum. The steam water mixture is separated in the drum. The separated water is combined with the entering feedwater and then feeds the evaporator banks as described above. The separated steam feeds the superheater circuit where it is heated to 950°F. HRSG steam outlet temperature is controlled by desuperheating spray water. The HRSG also has provisions for supplemental natural gas firing for additional steam generation when required.

The water which feeds the gasifier steam drum is combined with recirculated water and is pumped thru the gasifier island evaporator circuits. The steam water mixture generated in these circuits is returned to the drum where the steam and water are separated. A small fraction of the steam leaving the drum feeds the coal heater component and the mill air heater #2 (normally not required) where the steam is condensed at high pressure. The condensate is pumped back to the gasifier drum. The majority of the steam leaving the gasifier steam drum feeds the gasifier superheater circuit where it is heated to 950°F. Gasifier steam temperature control is provided by desuperheating spray water.

CONCEPTUAL STEAM CYCLE

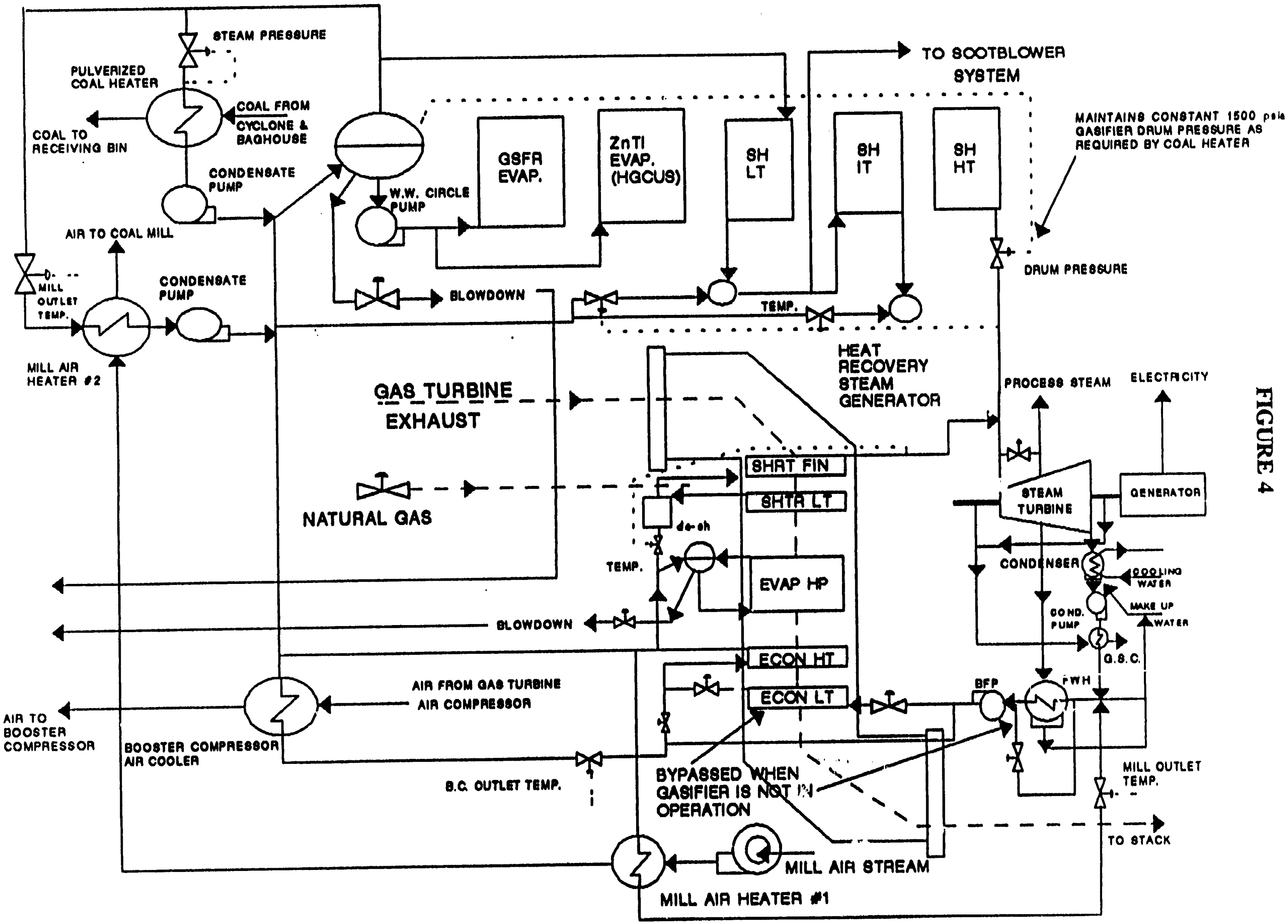


FIGURE 4

Gasifier steam drum pressure is held constant at 1500 psia with a gasifier drum pressure control valve. This is required in order to maintain the heat source for the coal heater at about 600° F. Coal heating is required in order to avoid steam condensation on the pulverized coal. Steam is used for pressurization and fluidization of the coal in the lockhopper system and for transport of the coal to the gasifier in the fuel pipes.

The steam from the gasifier superheat circuit and from the HRSG superheat circuit are combined and flow to the steam turbine. The steam is expanded thru the turbine providing power for the steam turbine generator. Two extractions are taken from the steam turbine. The first extraction, at about 450 psia for the design point, is for process steam uses. The second extraction is for the low pressure feedwater heater.

The basic flow chart and file structure for the main program (STMCYC) is shown in Figure 5. The program STMCYC is a "batch" type program that calls several other programs in a sequential manner until the programs are converged. Convergence is determined by monitoring the property values for the streams which interconnect between the various program modules. Once the changes for all the monitored property values (from one iteration loop to the next) are within the prescribed tolerance values, the program is converged. The main program calls five other programs. Four of these programs (STURBS, HRSG, SGC, CEIGCCHX) were existing design programs used at CE. Some of these existing programs were written in fortran and others in basic programming languages. These programs were used basically as sub-programs called from the main program. Transfer of information between the sub-programs is done with files.

SCINIT is a Fortran initialization program which provides initial guesses for the starting values of all the required input variables for the programs.

STURBS is a Fortran program which calculates steam turbine performance, condenser performance, boiler feed pump performance and the performance for the low pressure feedwater heater components of the steam cycle. The convergence status for the main program is also determined within this program.

CEIGCCHX is a Fortran program which is used to calculate the performance of external heat exchangers. This program is used for analysis of the Booster Compressor Air Cooler and the Mill Air Heater #1 heat exchangers.

HRSG is a Basic program used to calculate the performance for the Heat Recovery Steam Generator component. The HRSG is used to recover heat from the gas turbine exhaust stream.

SGC is also a Basic program which is used to calculate performance for the Syngas Cooler component of the steam cycle. The Syngas Cooler recovers heat from the Low Btu Gas stream leaving the gasifier.

CWL&P STEAM CYCLE PROGRAM FLOW CHART AND FILE STRUCTURE

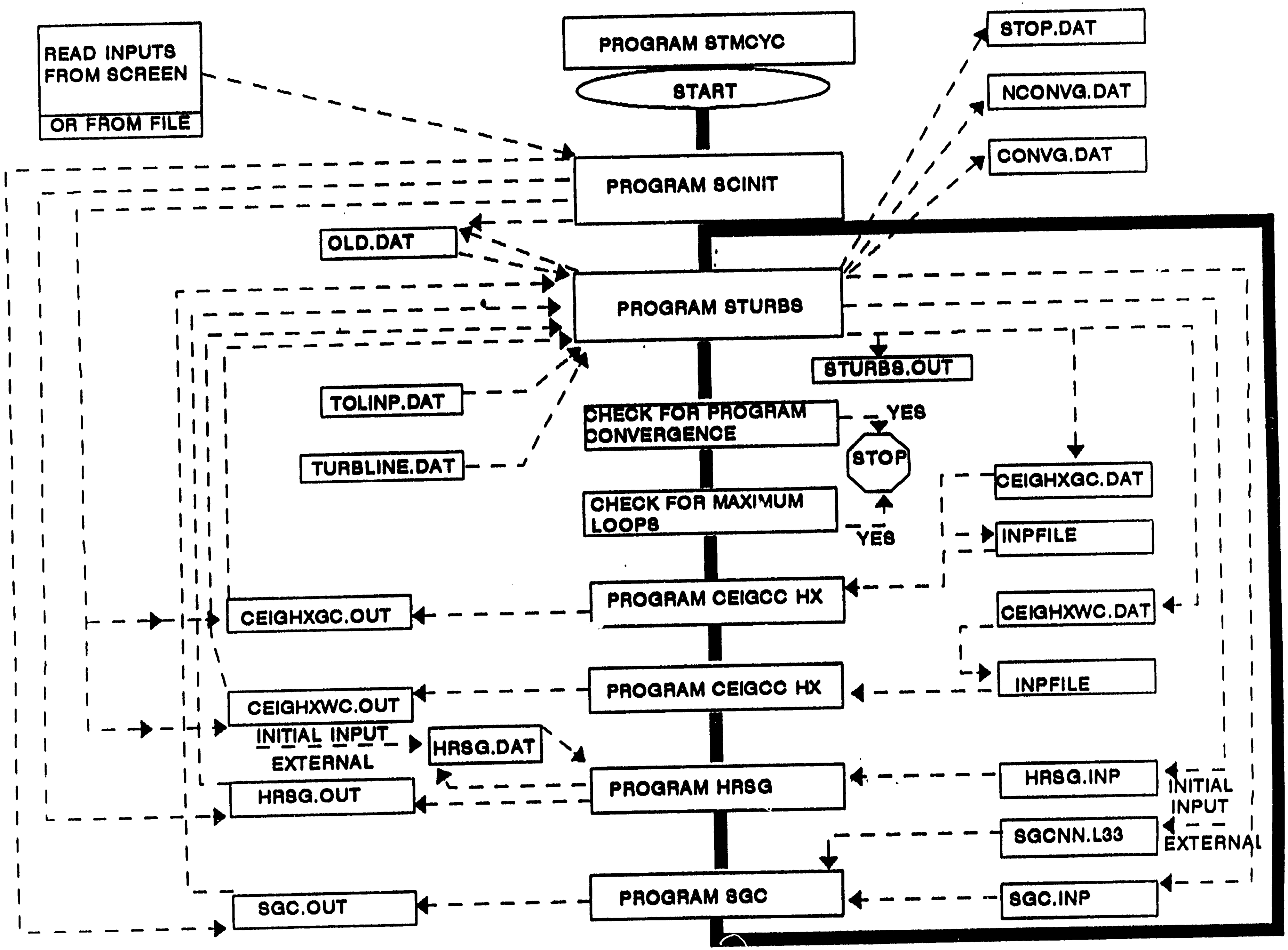


FIGURE 5

C) **Heat Rate Sensitive Process Decisions**

Several studies were completed to quantify the effects of various process options on net plant heat rate (NPHR). The following list shows some of the various process options which were evaluated.

- Gasifier air temperature study
- HRSG stack temperature study
- HRSG feedwater temperature study
- Supplemental HRSG firing study
- Process steam source option study
- Coal and char feed system study

i) **Gasifier Air Temperature Study**

Air for the gasification system is extracted from the gas turbine air compressor discharge at about 155 psia for the base gas turbine load, 95°F ambient temperature operating condition. The air extraction condition (temperature, pressure) and the required LBG fuel pressure for the gas turbine are dependent on the gas turbine load and the ambient temperature. The extracted gasifier air stream must be raised in pressure such that the LBG fuel produced is at a pressure high enough to feed to the gas turbine combustor. The required pressure increase to the gasifier air stream is about 130 psi and it is provided by a booster air compressor.

Several options are available for the gasifier air feed system. The simplest system would be to directly feed this air from the gas turbine (without any cooling) to the booster compressor and then to the gasifier. Optionally the air stream to the booster compressor could be cooled.

Cooling of the gasifier air stream prior to entering the booster air compressor would reduce the power requirements for the booster compressor as compared to the uncooled case. If the heat removed from the air was recovered in the steam cycle an increase in the output of the steam turbine would also occur.

For a given gas turbine operating condition, a reduction in gasifier air temperature causes changes to the gasifier operating requirements. The gas turbine still requires the same amount of energy (sensible + chemical) in the LBG fuel stream to provide the required turbine inlet temperature. But if the air feed stream to the gasifier is at a lower temperature, the amount of coal fired in the gasifier must be increased to provide the additional energy required to satisfy the gasifier energy balance. The gasifier stoichiometry would be leaner which would reduce the product gas heating value slightly as gasifier air feed temperature is reduced.

The effect on net plant heat rate favors higher gasifier air temperatures although this effect is not a strong one. Some of our preliminary studies have shown that reducing gasifier air temperature from 800 to 500°F degrades net plant heat rate by about 0.7 percent.

From a practical standpoint it is difficult to find commercially available booster compressors designed for high compressor outlet temperatures. There are, however, many other types of compressors which do operate at high temperature. Our survey showed that 600°F was about the current practical limit for machines with our design requirements.

ii) HRSG Stack Temperature Study

An important decision in the design of a power plant is the design point stack temperature. In order to quantify the effects of stack temperature on net plant heat rate a small study was done. Three stack temperatures were investigated in this study (200, 250, 300°F). The results indicate that about a 36°F change in stack temperature is equivalent to about a one percent change in net plant heat rate. The sensitivity of net plant heat rate to stack temperature is also shown to be very linear.

Because there are small amounts of sulfur dioxide and trioxide in the fluegas leaving the HRSG acid dew point temperature is also a consideration in selection of the stack temperature. Other considerations are net plant heat rate and capital costs. Another important consideration with respect to acid dew point temperature is how stack temperature changes as a function of plant operating conditions. All of these factors were used in selecting the stack exit temperature.

iii) HRSG Feedwater Temperature Study

The feedwater for the HRSG is provided from the boiler feed pump which takes water from the discharge of the low pressure extraction feedwater heater. The feedwater temperature entering the HRSG can therefore be varied by selecting different steam turbine extraction pressures for the low pressure feedwater heater.

For a given stack temperature, the selected feedwater temperature impacts the size of the HRSG economizer bank and the net plant heat rate. As feedwater temperature is raised closer to the stack temperature the log mean temperature difference for this bank is lowered and the heat transfer surface area requirement is increased. However, with a higher feedwater temperature entering the economizer the HRSG will generate more steam since the pinch point for the cycle is at the economizer cold end. The additional steam generation is partially offset by the additional steam extraction required by the low pressure feedwater heater.

A comparison of feedwater temperatures was done for the 250°F stack temperature case. Two feedwater temperatures were investigated to determine the effect on net plant heat rate (230 and 200°F). The 200°F feedwater temperature, as compared to 230°F, would reduce the amount of main steam generated by about 7,000 lbm/hr causing a reduction in steam turbine output. The low pressure feedwater heater would however require about 10,000 lbm/hr less steam extracted from the steam turbine which actually increases output from the steam turbine stages below the extraction pressure. The net effect to the steam turbine is a reduction in power output of about 0.5 MW for the 200°F case as compared to the 230°F case. The reduction in steam turbine power for the 200°F case (as compared to 230°F) would degrade net plant heat rate by about 0.9 percent. The design point HRSG feedwater temperature selected for this cycle was 230°F.

iv) Supplemental HRSG Firing Study

One of the primary design requirements for this plant is to provide 60 MW net output at a 95°F. ambient temperature. With the 95°F ambient condition and the gas turbine operating at the Base Load firing condition, the net plant output is calculated to be about 55.6 MW. In order to obtain 60 MW a various options were investigated.

One option investigated was to peak fire the gas turbine. This mode of gas turbine operation runs the gas turbine at a higher turbine inlet temperature. With this mode of operation an additional 8% output from the plant is available which would satisfy the 60 MW net output criteria. There are a couple of impacts of operating the gas turbine in this peak firing mode. From a performance standpoint there is an improvement in net plant heat rate of about 1.3 percent as compared to base firing mode. From an operation and maintenance standpoint the inspection intervals and associated maintenance requirements are increased.

Another option available to increase plant output is to fire additional fuel in the HRSG (supplemental HRSG firing) to increase the output of the steam turbine. A study was done to quantify the effects of supplemental HRSG firing on net plant heat rate. This study considered supplemental firing with either LBG or natural gas. The results showed that the incremental thermal efficiency for supplemental firing with LBG was about 21 percent. Similarly, the incremental thermal efficiency for supplemental firing with natural gas is about 29 percent.

The primary reason for the significantly better incremental thermal efficiency with supplemental natural gas firing relates to the throttling process which occurs with supplemental LBG firing. When firing LBG in the HRSG the fraction of the LBG which is fired in the HRSG is throttled from high pressure (about 225 psia) into the HRSG and combusted. The air and coal which was fed to the gasifier to produce this LBG required power to compress. Normally (without supplemental LBG firing) the LBG fuel stream is fed to the gas turbine and combusted. The high temperature and pressure combustion product stream is expanded to about atmospheric pressure in the gas turbine. The expansion process generates significantly more power than was required in the compression step.

Based on this information and associated cost differentials for these options, the customer, CWL&P, decided to specify supplemental natural gas firing in the HRSG as the preferred method to obtain 60MW net output from the plant.

v) Coal and Char Feed System Study

Feeding of coal and char into the gasifier is done with lockhopper type systems. The gas used for lockhopper pressurization and fluidization must be basically inert (very little if any oxygen) and it must be at a pressure high enough to feed the material into the gasifier which is operating at about 270 psia. Ideally the transport gas would also be inert since any oxygen introduced into the reductor zone of the gasifier would consume some of the low btu gas. Some of the options for this fluid are listed below.

- Steam
- Inerted fluegas from the HRSG
- Fluegas from an adjacent boiler
- Nitrogen

Utilization of steam would be convenient but would require the coal to be heated to about 500°F in order to avoid condensing the steam onto the coal particles. The char is collected at about 1000°F and, therefore, steam should work well for this system. The steam could be extracted from the steam turbine or generated in a separate process steam generator.

Fluegas from the HRSG could also be used if it were inerted by burning off the excess oxygen. Typically the oxygen content of the HRSG fluegas ranges between 12 to 16 percent by volume depending on gas turbine load. The oxygen could be burned off with LBG or natural gas. The coal would also have to be heated for this option since this fluegas contains significant quantities of water vapor.

There are several other operating boilers located fairly close to the site and therefore fluegas from one of these boilers could be compressed and used. The coal would also have to be heated for this option since this fluegas also contains significant quantities of water vapor. The advantage of using fluegas from another boiler is that it is much lower in oxygen content than the fluegas leaving the HRSG (typically ranging between 3 and 5 percent by volume) and, therefore, less fuel would have to be consumed to inert this fluegas.

Nitrogen could be purchased and used for this purpose. There will be a small nitrogen use at the plant anyway for other purposes. However the rate of expected usage for the coal and char feed system would be much higher than for the other plant uses. The use of nitrogen does not require the coal to be heated which would reduce capital costs. The compression of the nitrogen was assumed to be provided by simply boiling off the required flow rate utilizing a waste heat source to provide this duty. Therefore, no additional auxiliary power would be required. The amount of nitrogen required for this system adds significantly to the plant operating costs.

The effect on net plant heat rate for these options was investigated in a preliminary study in order to see if any significant efficiency advantages were apparent between the options. Steam was used as the base case for the study and the net plant heat rate ratios are all relative to the steam case. The results shown in table 4 indicate fairly small differences between the cases. Therefore, the selection criteria was based primarily on capital cost and operating cost differentials between the cases.

Table 4
Net Plant Heat Rate Comparison

Pressurizing, Fluidizing and Transport Fluid Type	NPHR Ratio
Steam	1.000
Inerted fluegas from the HRSG	1.013
Fluegas from an adjacent boiler	1.005
Nitrogen	0.982

The selected fluid for pressurizing, fluidizing, and transport of both the coal and char was steam.

vi) Process Steam Source Options

Process steam is used in this plant for several purposes.The total quantity of process steam required for these uses is dependent on the plant operating condition. The quantity is also time dependent due to the batch type of operation required for the coal and char lockhopper systems and the cyclic steam requirements for sootblower system. The time averaged total process steam flow requirement for the MCR plant operating point is about 15000 lbm/hr.

The pressure requirements for these process steam uses are all at about the same value except for the sootblower steam. Since sootblowing requires high kinetic energy steam with relatively high flow for short time periods the best choice is to use high pressure steam extracted from the gasifier superheater circuit for this duty.

Several potential sources are available for the remaining low pressure process steam requirements as shown in the following list.

1.) Separate process steam generator located in the HRSG
2.) Steam turbine extraction
3.) Utilization of main steam

Because of the cyclic nature of the process steam requirements as described previously, option 1 would have to be designed to generate more than the time averaged quantity of process steam in order to accommodate the peak flow requirements. Any additional steam generated from this system could then be admitted into an admission port on the steam turbine as required in order to handle these fluctuations.

The second option (steam turbine extraction) would have a limited load range where the extraction point pressure would remain above the required value. Once the process steam header pressure drops below the set point pressure as steam turbine load is reduced the process steam extraction source could be switched to the main steam line thru a pressure reduction valve.

A study was done to quantify the effects on net plant heat rate of these various process steam options. Using option 1 for the process steam source is the least efficient method. Option 3 shows a slight improvement in net plant heat rate (about 0.3 percent better than option 1). Option 2 is the most efficient method (about 1.4 percent better than option 3 and about 1.7 percent better than option 1). Capital costs also favor option 2.

Based on the results of this study it was decided to use the turbine extraction as the primary source for the process steam. Once this source was not able to maintain the set point pressure in the process steam header, the main steam line would be used.

vii) Cost Reduction Study Heat Rate Effects

A list of several items was developed to reduce the cost of the plant as a part of a plant cost reduction study. Four of the proposed items were identified as items which would cause significant impacts on net plant heat rate. The first item proposed was to eliminate coal mill air heater #1 (which utilizes recirculated water from the economizer as the heat source) and utilize a larger version of coal mill air heater #2 (which uses steam from the gasifier steam drum as the heat source). The second item proposed was to eliminate the high pressure steam generator in the HGCUS and reject this heat to the lake water. The third proposed option was to use lake water for the booster air compressor cooler rather than recovering this heat in the economizer circuit. The fourth proposed option was to eliminate the low pressure feedwater heater in the steam cycle.

Table 5 shows the impacts of the proposed changes to net plant heat rate.

Table 5
Cost Reduction Net Heat Rate Effects

Proposed Cost Reduction Measure	Change to NPHR Btu/Kwhr
Eliminate Coal Mill Air Heater #1	+ 190
Eliminate High Pressure Steam Generator in HGCUS	+ 177
Use Lake Water For Booster Compressor Cooler	+ 245
Eliminate Low Pressure Feedwater Heater	+ 486

It is clear that each of these changes would reduce the capital cost of the plant. However heat rate is also an important part of this demonstration project and, therefore, none of these changes were recommended.

viii) HRSG Performance Design
The Heat Recovery Steam Generator (HRSG) recovers the major fraction of the total heat added to the steam cycle of this plant. It is designed to generate high pressure superheated steam by recovering heat from the gas turbine exhaust stream. This steam is combined with additional steam generated from the gasifier island and expanded thru a steam turbine for power generation. The HRSG is also used to preheat the feedwater which is supplied to the gasifier island. The capability for additional HRSG steam generation is provided thru the use of supplemental natural gas firing.

The performance design of the HRSG component for this plant was an iterative process. This process involved the consideration of various HRSG design points and performance requirements. Because of the highly integrated steam cycle concept defined for this plant, the design of the HRSG was also very sensitive to the various heat recovery options which were investigated for the gasifier island. Performance design is defined as that part of the design process where heat exchanger surfaces are determined in order to satisfy the various plant performance requirements. Some of the plant performance requirements which impacted the performance design of the HRSG are listed below.

- Plant output of 60MW net at 95°F ambient temperature
- 1265 psia, 950°F steam conditions

- Acceptable steam cycle performance for the following envelope of plant operating conditions:
  - gas turbine loads from 30 to 100 percent
  - ambient temperatures from 0 to 95°F.
- Acceptable steam cycle performance with the gasifier in both the normal and high performance modes of operation.
- Acceptable steam cycle performance with the gasifier not in operation and the gas turbine firing natural gas for the operating condition envelope defined above.
- Steam cycle arrangement as shown in Figure 4.

The basic heating surface performance design for the HRSG is governed primarily by three cases. The primary design case (NPBL-95-S60) is with the gasifier in the normal performance mode of operation, the gas turbine at base load firing LBG at 95 °F. ambient temperature, and a small amount of supplemental natural gas fired in the HRSG. The supplemental natural gas firing in the HRSG is provided such that 292,840 lbm/hr superheater outlet flow is obtained which provides 60 net MW output from the plant. The other two cases are natural gas fired gas turbine cases with the gasifier not in operation. One of these cases (NGBL-95-SO) has no supplemental natural gas firing in the HRSG while the other case (NGBL-95-S60) fires enough supplemental natural gas in the HRSG to generate 236,439 lbm/hr superheater outlet flow such that 60 net MW output is obtained from the plant.

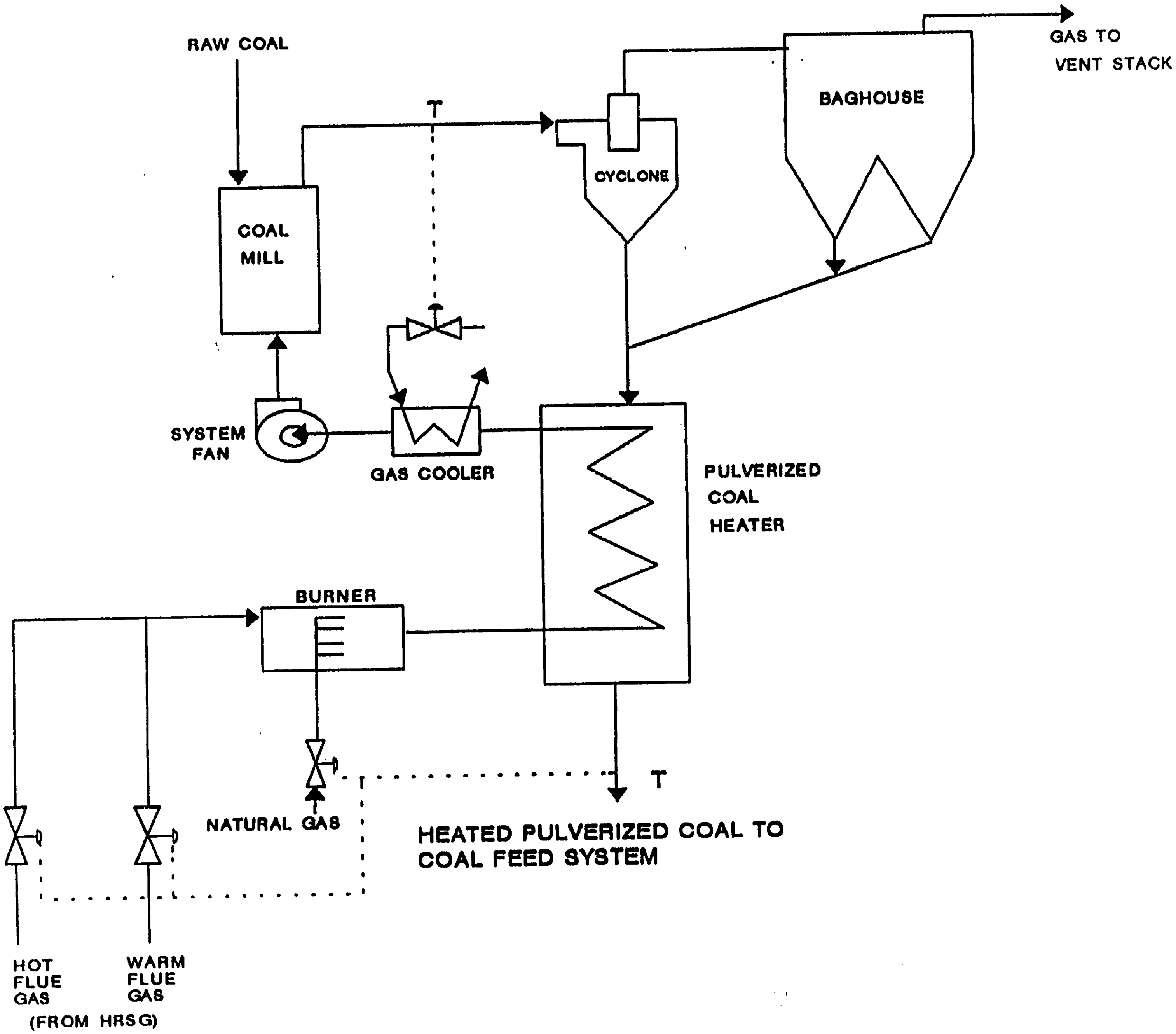
In general, the HRSG is first surfaced as a standard natural gas fired combined cycle HRSG without any supplemental firing (Case NGBL-95-SO). The surface calculations are specified with a 20°F evaporator outlet pinch point temperature difference and 10°F approach for the economizer. The low pressure feedwater heater is bypassed for this case. The booster compressor air cooler and the mill air heater #1 are not used for this case and feedwater is not supplied to the gasifier island. The LT economizer section is also bypassed in this mode of operation. Four percent desuperheater spray is specified as an additional requirement for surfacing of the evaporator and superheater circuits for this case. This case defines the total superheater surface requirement (HTSH + LTSH) although the split between HT and LT is not specified by the requirements of this case. The evaporator bank surface requirement, and the surface requirement for the HT economizer section are also defined by the specifications for this case.

Case NGBL-95-S60 defines the maximum amount of supplemental natural gas firing for the HRSG and therefore provides the information necessary to locate the supplemental firing burners.

Case NPBL-95-S60 is the case which specifies the total economizer section surface requirement (HT + LT). The surface required for the LT economizer is defined by knowing the total economizer surface requirement from this case and the HT section requirement from case NGBL-95-SO. This case also defines the maximum steam and water pressures during normal operation and the draft loss across the HRSG for this case should be less than 10 in.w.g.

FIGURE 6

COAL PREPARATION SYSTEM



ix) Coal Preparation System Alternate
The coal preparation system for this plant consists of a coal milling system and a coal heating system. The coal must be heated to about 500°F in order to avoid condensation problems in the coal feed system. Steam is used in the coal feed system for lockhopper pressurization/ fluidization and as the carrier gas for transport of the pulverized coal to the gasifier.

At the end of budget period 1 the coal preparation system was conceptually arranged as shown in Figure 6. In this system flue gas taken directly from the HRSG is drawn into the pulverized coal heater. The temperature of the flue gas is controlled to maintain the desired pulverized coal temperature leaving the pulverized coal heater. The flow of flue gas is provided by the system fan and is controlled by coal mill load. The gas leaving the pulverized coal heater flows thru the system fan and then to the coal mill. The flue gas temperature entering the mill is controlled to maintain the temperature leaving the mill at the set point value. The stream leaving the mill enters a cyclone and baghouse where the pulverized coal is separated from the flue gas. The flue gas leaving the baghouse is vented to the atmosphere. The pulverized coal streams from the cyclone and baghouse are combined and flow through the pulverized coal heater and then into the coal feed system.

Fluegas dampers, a natural gas burner, and a heat exchanger would be required for control purposes. From a control system viewpoint this system was somewhat cumbersome and possibly quite slow in response for some of the controlled variables. Relatively long and expensive flue gas ducts from the HRSG to the coal preparation system would be required. The heat transfer rates for the pulverized coal heater were also expected to be quite low with the use of flue gas and therefore this component could become quite high in capital cost. For these reasons a study was done to investigate other coal preparation system concepts.

The result of this study is shown in Figure 7. In this system air is used as the gas for the coal mill thus eliminating the fluegas ducts from the HRSG to the coal mill. The air flow is again controlled by the coal mill load and is provided by the fans. The air leaving the forced draft fan flows thru coal mill air heater #1 where it is heated enough to maintain the outlet of the coal mill at the set point temperature. If coal mill air heater #1 can not provide enough heat, coal mill heater #2 is also used. The air then flows thru the coal mill where it dries and conveys the pulverized coal out of the mill. The stream leaving the coal mill enters a cyclone and baghouse for separation of the pulverized coal from the air. The air leaving the baghouse flows through the induced draft fan and is then vented to the atmosphere. The pulverized coal streams from the cyclone and baghouse enter the pulverized coal heater where it is heated to the required temperature.

The heat source for coal mill heater #1 is provided from the feedwater stream to the gasifier. The cooled feedwater stream leaving this heat exchanger is returned to the low pressure feedwater heater inlet. In this way the heat source used for this duty is still primarily the low grade heat in the HRSG low temperature flue gas but the system for providing this heat is less costly.

COAL PREPARATION SYSTEM

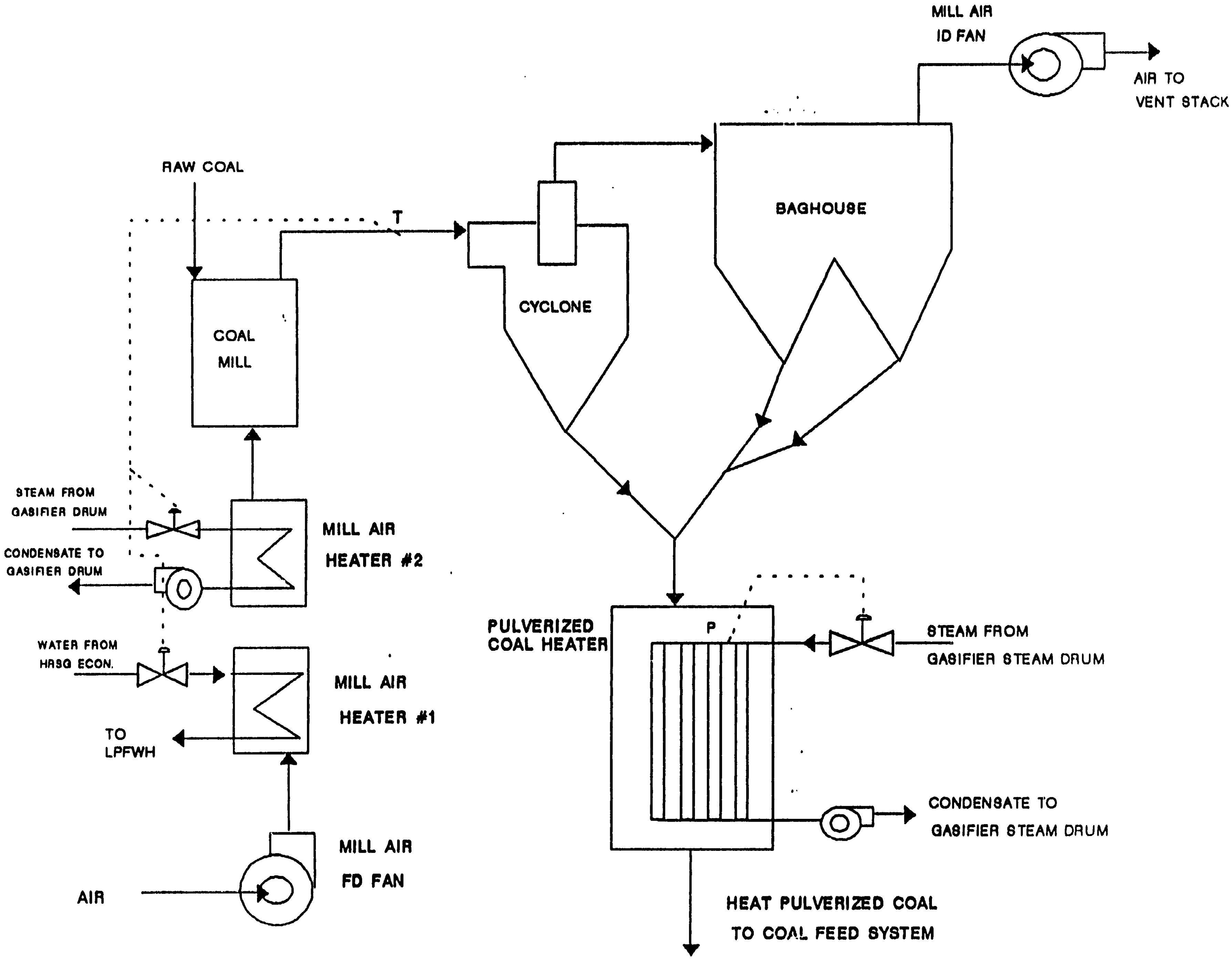


FIGURE 7

Coal mill air heater #2 uses saturated steam from the gasifier steam drum for the heat source. The condensate is returned to the steam drum. This heat exchanger is only used when coal mill heater #1 can not provide enough heat to satisfy the required coal mill outlet temperature. A separate study has shown this heat exchanger will be used only at high load with ambient temperatures below 0°F.

The heat source for the pulverized coal heater is also saturated steam from the gasifier steam drum. The gasifier drum is controlled to a constant pressure of about 1500 psia with a drum pressure control valve located in the gasifier superheater circuit and therefore provides a constant source temperature of about 600°F for the pulverized coal heater. This system therefore inherently provides protection from overheating of the coal.

Two fans are used (forced and induced draft) as a balanced draft system in order to control the pressure of the coal mill to slightly below atmospheric.

A comparison of net plant heat rate was done for the two systems. The net plant heat rate for the system shown in Figure 7 is only about 0.3 percent worse than the system shown in Figure 6. This is caused by a reduction in steam turbine output of about 0.9 percent which is partially offset by a reduction in the fan power requirement for this system.

x) Coal Feed System Alternate

At the end of 1992 a study was done comparing three alternate coal feed system designs to the base case. The study scope was limited to only a comparison of net plant heat rates for the cases. The base case is represented by the Approved for Design (AFD) material and energy balance.

Alternate 1 differs from the base case primarily in that nitrogen is used for transport, pressurization, and fluidization of the coal (steam, extracted from the steam turbine, was used for these purposes in the base case). The coal is transported to the gasifier at 200°F as compared to 500°F for the base case. Alternate 1, therefore, does not require a pulverized coal heater system. Additionally the gasifier circulating water pumps are eliminated for this option and the gasifier and SGC evaporative circuits are designed for natural circulation. Other assumptions related to the HRSG are listed below and are consistent with the base case.

- 250°F stack temperature
- 230°F feedwater temperature to the HRSG
- 1265 psia, 950°F steam conditions
- Natural gas supplemental firing amount same as for the base case
- 550°F feedwater to the gasifier

Alternate 2 is the same as Alternate 1 except the coal mill air stream is heated with a natural gas fired burner. The base case and Alternate 1 used recirculation of economizer water thru the coal mill air heater #1 heat exchanger as the source for this

TABLE 6
NET PLANT HEAT RATE ALTERNATE CALCULATION

		BASE	ALT-1	ALT-2	ALT-3
Coal Transport And LM Pressurization Fluid		STEAM	N2	N2	N2
Combustion Turbine Generator Output	(kW)	32550	32550	32550	32550
Steam turbine Generator Output	(kW)	36691	37164	38315	37147
Gross Plant Output	(kW)	69241	69714	70865	69697
Plant Auxilary Power	(kW)	8617	8501	8489	8451
Net Plant Output	(kW)	60624	61213	62376	61246
Coal Heat Input	(MM–Btu/hr HHV)	508.425	508.425	508.425	508.425
Natural Gas Heat Input (GT)	(MM–Btu/hr HHV)	0.000	0.000	0.000	0.000
Natural Gas Heat Input (HRSG)	(MM–Btu/hr HHV)	62.726	62.726	62.726	53.258
Natural Gas Heat Input (Mill System)	(MM–Btu/hr HHV)	0.000	0.000	12.937	12.937
Total Fuel Heat Input	(MM–Btu/hr HHV)	571.152	571.152	584.088	574.620
Net Plant Heat Rate	(Btu/kWhr)	9421	9331	9364	9382
Plant Thermal Efficiency	(Percent)	36.23	36.58	36.45	36.38

heat duty. Alternates 1 and 2 were both calculated with the same ground rules as the base case. One of the ground rules shown above was a 250 °F stack temperature. With Alternate 2 the log mean temperature differences for the economizer and evaporator banks were significantly reduced which would increase the size and cost of these components.

Alternate 3 was added as another option. This case is the same as Alternate 2 except it uses the same HRSG surfacing as for the base case. Some of the HRSG ground rules were therefore relaxed for this case. The amount of supplemental firing in the HRSG for this case was calculated such that the total steam flow to the steam turbine is the same as for the base case. The stack temperature for this case increases to about 260 °F and the feedwater temperature leaving the economizer is about 573 °F as compared to 550 °F for all the other cases.

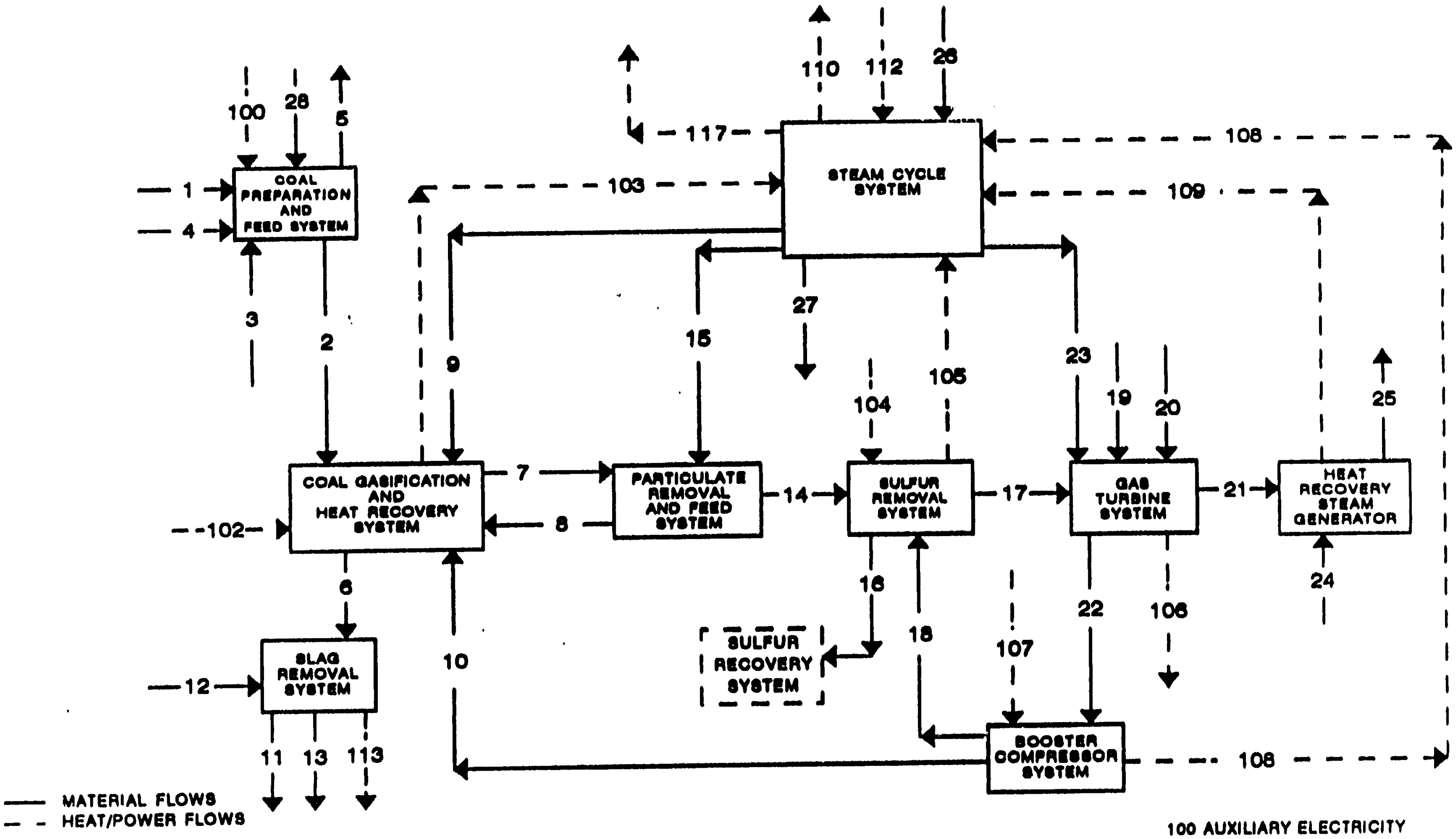
Table 6 shows the comparison of these cases. This comparison shows power outputs from the gas turbine and steam turbine, fuel inputs from coal and natural gas, auxiliary power consumption estimates, and net plant heat rates. The net plant heat rate differentials between the cases are relatively insignificant. Alternates 1,2,3 require about 8300 lbm/hr of nitrogen at this MCR operating condition which represents a significant additional operating cost as compared to the base case. There are, however, capital cost differences for each of the alternatives as compared to the base case. Alternate 3 probably represents the lowest total plant capital cost although capital costs were not a part of this study and, therefore, were not estimated. The differences in total plant capital costs between these four cases are probably quite small relative to the total. Figure 8 shows a block flow diagram for Alternative 3 and Table 6 is the associated material and energy balance for this case.

D) Design Basis

The design basis for the plant was established as described above by selecting the system that best suited the needs of the host site. CWL&P has a primary need for the power that will be generated by this plant during the peak summer months. This condition includes a 95°F. ambient temperature. Several ways of generating this power requirement were investigated and after discussing these methods with CWL&P the design case heat and material balance were selected. This heat and material balance was then used to specify design conditions for all of the systems and equipment specifications. Additional heat and mass balance cases were done for a number of possible operating conditions and these were used to adjust design tolerances for equipment and systems.

A design document was generated which listed all of the conditions encountered by the location as well as the normal requirements of CWL&P. This document includes information on weather conditions, site building requirements, environmental codes, fuel composition and all the other information normally generated in building a power plant. This document and the design case heat and material balances constitute the design basis for the plant.

OVERALL SYSTEM BLOCK FLOW DIAGRAM (ALT-3)



1 RAW COAL
2 COAL + STEAM
3 PRESSURIZING & TRANSPORT STEAM
4 MILL AIR
5 BAGHOUSE VENT TO ATMOSPHERE
6 SLAG
7 RAW GAS
8 CHAR + STEAM
9 SOOTBLOWER & ANNULUS PRESSURIZATION STEAM
10 GASIFIER AIR
11 BLOWDOWN
12 MAKEUP WATER
13 SLAG
14 PARTICULATE FREE LBG
15 PRESSURIZING & TRANSPORT STEAM (INCLUDING BAGHOUSE)
16 OFFGAS
17 CLEAN LBG
18 HGCUS AIR
19 NATURAL GAS
20 AIR
21 GAS TURBINE EXHAUST
22 GAS TURBINE BLEED AIR
23 NOx REDUCTION STEAM
24 NATURAL GAS
25 FLUE GAS TO STACK
26 MAKEUP WATER
27 BLOWDOWN
28 NITROGEN
100 AUXILIARY ELECTRICITY
102 AUXILIARY ELECTRICITY
103 WW & SGC RECOVERED HEAT
104 AUXILIARY ELECTRICITY
105 REGEN. SYSTEM RECOVERED HEAT
106 ELECTRIC POWER
107 AUXILIARY ELECTRICITY
108 PRE-COOLER HEAT
109 RECOVERED HEAT
110 ELECTRIC POWER
111 CONDENSER HEAT REJECTION
112 AUXILIARY ELECTRICITY
113 HEAT REJECTION

FIGURE 8

E) Systems Studies

In 1992 numerous system studies were conducted to provide a sound theoretical basis for designs, to determine potential safety hazards and appropriate code application, to develop empirical data for component design, and to ensure constructability and reliability. The systems studied were the coal feed system, the char recycle system and the hot gas cleanup system. The outside resources used for various aspects of the system studies include:

- F. Zenz - Solids Flow
- J. R. Johanson, Inc. - Bin and Lockhopper Design
- T. Hamilton Consulting - NFPA Code
- Lummus Crest, Inc. - Safety, Constructability, and Materials
- PEMM Corp - Pulverized Coal Heat Transfer Rate
- General Electric - Hot Gas Clean Up

Considerable in house resources were also used for system studies. Of particular note is the Kreisinger Development Laboratory (KDL) for pneumatic conveying and metallurgy, and Resource Recovery Systems for operating considerations and material handling expertise.

System reliability is a prime consideration for the gasifier at this stage of the project design when the gasifier general arrangements, major component arrangements and P&ID's are being done. Design personnel with start-up and power plant operating experience are being used to access all components and their interfaces for reliable operation. Minor but important revisions have been made and continue to be made to provide the most simple and reliable systems possible for the chosen design. Brief summaries of the more important studies follow:

i) Coal Feed System

In the current design, raw coal discharges a storage bunker via a volumetric feeder into a pressurized bowl mill pulverizer. The bowl mill pulverizes and dries the raw coal heating it to a temperature of 200°F. A centrifugal fan upstream of the mill provides the mill air used to classify the coal and convey it to a bagfilter. The mill air is heated by two shell and tube heat exchangers in series located in the air duct upstream of the coal mill. The first heater uses hot condensate from the gasifier system, and the second heater uses saturated steam from the gasifier steam drum. The receiving bin discharges intermittently and alternately by gravity into two lockhoppers. The lockhoppers are pressurized and intermittently discharge to their associated feed bins. The feed bins continuously discharge coal at high pressure into pneumatic conveying lines. Pressurizing, fluidizing and conveying gas selection is discussed below. Each conveying line from the feed bins splits four ways to supply the four coal burner nozzles located at each firing elevation on the gasifier.

In December of 1992 the arrangement of the coal feed system began to be assembled and studied using PACE 3 dimensional CAD software. As a result, different space saving and cost cutting options are being studied. Under consideration is a hot gas generator in lieu of the condensate and steam air heaters.

ii) Pressurizing, Fluidizing, and Conveying Gas Study

Prior to refining the coal feed system lockhopper and feed bin sizes and cycle times, a study was performed to evaluate pressurizing, fluidizing and conveying gas options for the coal feed system. Air, nitrogen, steam, carbon dioxide, and flue gas were the possibilities. The early study looked at the economics and technical aspects of each gas. It concluded that steam was the best option from cost and functional point of view. Carbon dioxide and flue gas were rejected because of technical problems and bad economics. Nitrogen appeared feasible but more costly. Air also appeared more costly and could not be used for pressurizing due to NFPA considerations.

The use of steam would require the use of a fluidized bed steam coil heater between the coal bag filter discharge and the coal receiving bin inlet to bring the coal temperature up to 500°F to prevent condensation in the receiving bin and lockhoppers. As the system design progressed the coal heater became an object of increasing concern for technical, economic, and operating reasons. Also, due to significant reductions in the lockhopper and feed bin sizes the amount of gas to drive the system had decreased appreciably. Consequently, it was decided to do an updated economic evaluation and reliability study to compare nitrogen and steam. The new economic study showed steam to have higher capital cost, but lower operating costs. Although the nitrogen operating costs are higher, they were not prohibitive, and the development of commercial membrane type separation systems allows simple on site nitrogen generation at predictable prices. The reliability study showed that this type of operation with nitrogen has been proven and operated reliably at facilities by Shell, MHI, and Inland Steel. Similar precedent for steam is very limited and not encouraging. The current design will use nitrogen with provisions for possible future use of steam. Steam and air will continue to be studied for use as a pressurizing and/or conveying medium for coal.

iii) Coal Mill Outlet Temperature

Normal coal mill outlet temperature is about 140°F as practiced in the United States. Recent experience in Europe with mill outlet temperatures 200°F and above has demonstrated that pulverized coal systems operate with the same or less incidence of fire as in the U.S. T. Hamilton, a consultant on pulverizers and NFPA code, was employed to study this matter. His findings in Europe will be soon published by EPRI. KDL also tested the demonstration coal for characteristics at elevated temperatures. Fire risk factors did not increase significantly until temperature reached 700°F. Based on this study, ABB has opted to send 200°F coal to the baghouse. The study shows that mill operation will be safe and that condensation and subsequent hang up in the bagfilter hoppers will be discouraged.

iv) Lockhoppers and Feed Bin Design

J.R. Johanson, Inc. was employed to develop the parameters for coal and char receiving bin, lockhopper, and feed bin design and operation. Johanson tested coal and char samples to determine bulk and fluidized densities, critical arching and ratholing dimensions, hopper angles, and fluidizing characteristics. From these results and the use of their mass flow system models, specific design criteria was developed for the bin configurations, pipe sizes, fluidizing methodology, pressurizing and fluidizing flows, flow control and bin materials. A series of recommendations were issued by J.R. Johanson based on this work. Initial bin diameter was restricted to 12 ft. or less by ABB for fabrication reasons. Sizes for all the bins were later optimized to provide the best combination of building height and cycle time.

Further study was conducted by ABB to develop the hardware options and their corresponding performance curves for the pressurization and venting of the lockhoppers and feed bins using Johanson's design criteria. The high pressure differentials involved here require sonic flow in the control piping and valves. Careful consideration was taken to develop piping and valve configurations that would minimize abuse of the valves, keep the control loop simple, and maximize reliability.

Study is proceeding on options for fluidizing/pressurizing components in the high pressure bins. Although the flow criteria has been established, a specific means of introduction has not been selected. Several options are being investigated

The possibility of independently controlling double or triple material flows at the feed bin discharge was investigated with the assistance of J.R. Johanson, Inc. To date, a proven operation using this concept has not been found by Johanson or ABB. The instrumentation necessary to support such an operation reliably has not yet been developed. As a result, ABB has elected to design the demonstration plant with single discharge from the feed bins with provisions for the future use of dual discharge. Single discharge controlled flow is a proven concept and is in common use in commercial positive pressure pneumatic conveying systems. ABB plans to test any new instruments that show true promise in being able to reliably and accurately measure solids flow in a pneumatic transport line.

v) Lockhopper and Feed Bin Test

A test program has been developed to test full scale coal lockhopper and feed bin functions using high pressure air. It is intended to conduct this test prior to fabrication of certain components and construction of the demonstration plant. Because pneumatic systems, and especially unusual pneumatic systems, are not completely predictable from design models, it was decided that a test program would allow the quickest and most certain, if not most cost effective, method of developing a successful coal feed system. The test will be used specifically to finalize hardware details, select an optimum flow regime, and to develop an effective control sequence for pressurizing and fluidizing the lockhopper, feeding from the feed bin, and transport in the conveying lines.

vi) Material Handling Valve

A study was conducted to determine which valves in the feed system would require special selection and design to perform reliably with an adequate service life where abrasive solids and/or high pressure differentials on actuation are being controlled. An investigation of various valves in similar operations leaves two viable options for the lockhopper inlet and discharge valves, the feed bin discharge valves, and the lockhopper and feed bin vent valves. It was determined that many of these valves would require major maintenance approximately every 8000 hours of use. Provisions have been incorporated into the demonstration plant design to accommodate quick change out of these valves with minimal disruption, if any, to the gasifier operation.

vii) Char Recycle System

In the current demonstration plant design product gas and entrained char leave the gasifier heat exchanger at 1000°F and enter a char cyclone that separates a percentage of the char from the product gas. The char discharges the cyclone by gravity into a char seal bin that provides a pressure seal, and proceeds by gravity into the char receiving bin. The product gas and remaining char exits the cyclone and flows to two high pressure, high temperature 50% bag filters arranged in parallel to remove the remaining char from the product gas. The char discharges from each bag filter by gravity to the char receiving bin. The char receiving bin intermittently and alternately discharges by gravity into two lockhoppers. The lockhoppers are pressurized with super heated steam and intermittently discharge to a common char feed bin. The feed bin continuously discharges into one of two conveying lines using super heated-steam as a conveying media. Each conveying line from the feed bin splits four ways to supply the four char reinjection nozzles located at their associated reinjection elevation at the gasifier.

viii) Char Bagfilter Study

Early in 1992 a study was done to determine filter design philosophy. Because of the unusual high temperature and pressure requirements cutting edge technology would be necessary. For this reason the study concluded that the design philosophy should include testing, performance tolerances, and fall back positions for retrofitting filter materials and cleaning media if necessary.

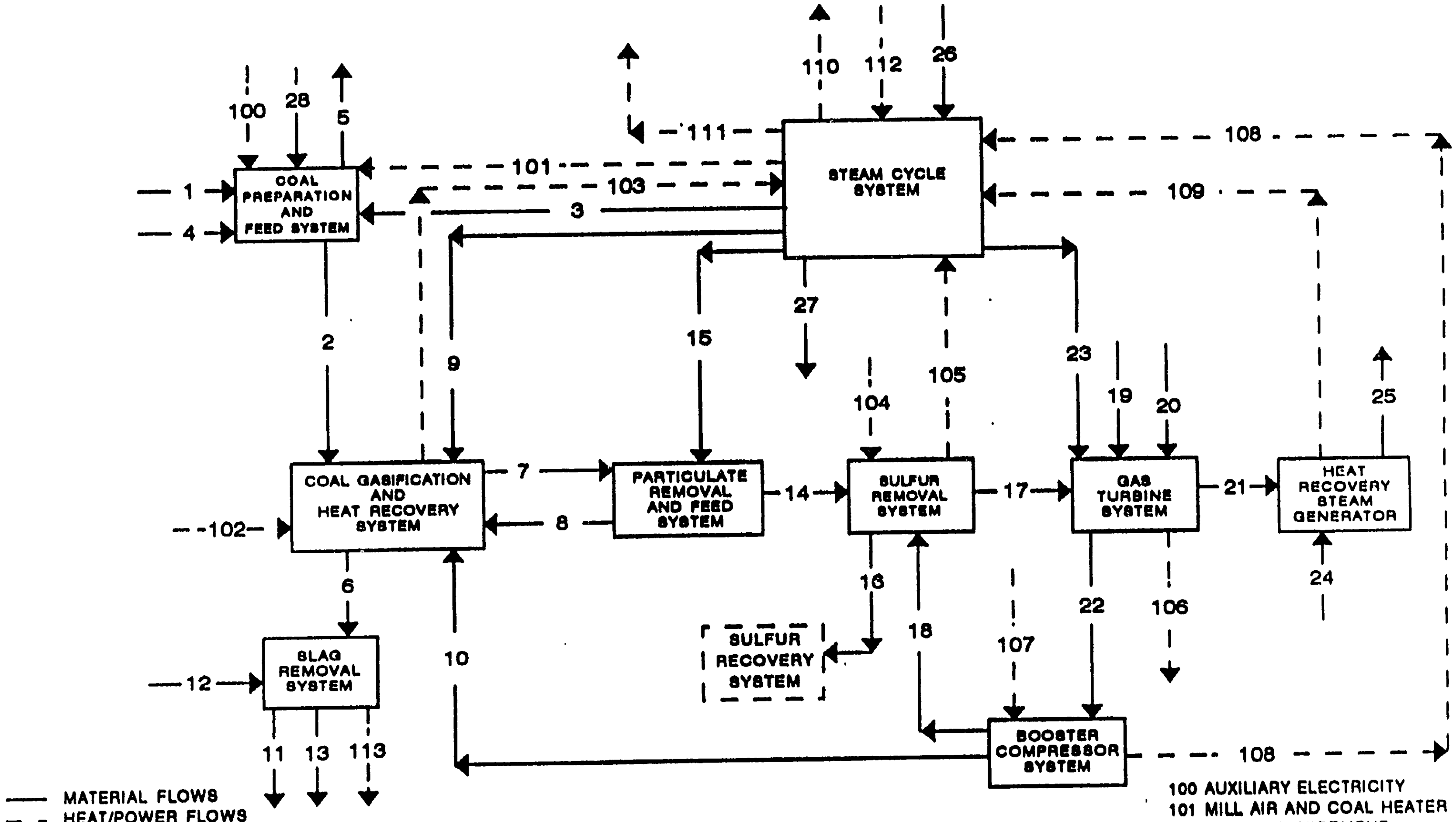
Since then, ABB has been collaborating with Mikropul, Flex-Kleen, Research Cottell, Acurex Environmental Corp, 3M, and Westinghouse on specific designs. Several high temperature filter media are being considered: Woven Ceramic (Nextel) Bags, Ceramic Candles, and Sintered Inconel. Although the Inconel and ceramic candles are in commercial use at high temperatures, none of these media are proven in our particular combination of high pressure (300 PSIA), and high temperature (1000°F) using superheated steam as a cleaning media. All of these media are viable candidates for our application. Our selection of a filter media is pending further investigation. Tests comparing Nextel to candle filters are scheduled to take place at the TIDD PFBC plant in Brillant, Ohio. ABB has also asked several bagfilter companies to propose test programs to demonstrate the use of their technology at high temperature and pressure. Other specific bag filter design concerns for this application are cleaning method (Jet pulse, reverse flow or combination), steam valve duty and design for filter cleaning, structural integrity of components, and corrosion. Investigations in these areas is on going, and significant progress is expected in these areas in early 1993.

ix) Char Vessel Material Study

Metallurgists at LCI and KDL were consulted to help select a bin material that could meet the temperature, corrosion resistance, and friction requirements of all the char vessels. Several options were selected as a result. J.R. Johanson conducted high temperature friction tests on the more promising materials, and a stainless steel alloy that best satisfied all the requirements was found.

LML
9/15/92

OVERALL SYSTEM BLOCK FLOW DIAGRAM WITH STEAM TRANSPORT



1 RAW COAL
2 COAL + STEAM
3 PRESSURIZING & TRANSPORT STEAM
4 MILL AIR
5 BAGHOUSE VENT TO ATMOSPHERE
6 SLAG
7 RAW GAS
8 CHAR + STEAM
9 SOOTBLOWER & ANNULUS PRESSURIZATION STEAM
10 GASIFIER AIR
11 BLOWDOWN
12 MAKEUP WATER
13 SLAG
14 PARTICULATE FREE LBG
15 PRESSURIZING & TRANSPORT STEAM (INCLUDING BAGHOUSE)
16 OFFGAS
17 CLEAN LBG
18 HGCUS AIR
19 NATURAL GAS
20 AIR
21 GAS TURBINE EXHAUST
22 GAS TURBINE BLEED AIR
23 NOx REDUCTION STEAM
24 NATURAL GAS
25 FLUE GAS TO STACK
26 MAKEUP WATER
27 BLOWDOWN
28 NITROGEN
100 AUXILIARY ELECTRICITY
101 MILL AIR AND COAL HEATER HEAT REQUIREMENT
102 AUXILIARY ELECTRICITY
103 WW & SGC RECOVERED HEAT
104 AUXILIARY ELECTRICITY
105 REGEN. SYSTEM RECOVERED HEAT
106 ELECTRIC POWER
107 AUXILIARY ELECTRICITY
108 PRE-COOLER HEAT
109 RECOVERED HEAT
110 ELECTRIC POWER
111 CONDENSER HEAT REJECTION
112 AUXILIARY ELECTRICITY
113 HEAT REJECTION

FIGURE 9

TABLE 7
NET PLANT HEAT RATE CALCULATION

		BASE STEAM
Coal Transport And LM Pressurization Fluid		
Combustion Turbine Generator Output	(kW)	32550
Steam turbine Generator Output	(kW)	36691
Gross Plant Output	(kW)	69241
Plant Auxilary Power	(kW)	8617
Net Plant Output	(kW)	60624
Coal Heat Input	(MM–Btu/hr HHV)	508.425
Natural Gas Heat Input (GT)	(MM–Btu/hr HHV)	0.000
Natural Gas Heat Input (HRSG)	(MM–Btu/hr HHV)	62.726
Natural Gas Heat Input (Mill System)	(MM–Btu/hr HHV)	0.000
Total Fuel Heat Input	(MM–Btu/hr HHV)	571.152
Net Plant Heat Rate	(Btu/kWhr)	9421
Plant Thermal Efficiency	(Percent)	36.23

x) Char Study

A plan has been developed to obtain and study char to aid char cyclone and bagfilter design. Cyclone and bag filter suppliers will use this char to obtain and to test the performance of Nextel woven ceramic bags. Secrecy agreements between all the concerned parties must be executed before the testing can begin. ABB expects char testing to begin in Summer 1993.

xi) Hot Gas Clean Up Study

General Electric Environmental Systems, Inc. (GEESI) submitted a proposal for doing test work specific to the Springfield Project. ABB reviewed the test proposal and is waiting for a response to comments. Answers are expected in early 1993. In the meantime GEESI continues on with their hot gas clean up test program at their corporate Research and Development Center in Schenectady, N.Y. More successful long duration tests were run with the Zinc Titanate Absorber, and the additive Nahcolite was tested to determine its effectiveness in removing halogens from product gas. The results to date are promising.

GEESI also submitted preliminary heat and material balances, process flow diagrams, general arrangements, and some equipment data sheets. These were used for estimating purposes and for arrangement of the gasifier island.

F) Heat and Material Balances

One of the more important requirements during the design process for the plant are the material and energy balances. The development of these balances is iterative. Changes to the balances are required for several reasons. Some of the typical reasons for revisions are process changes, actual equipment performance is refined, design requirements are modified, additional design requirements are imposed and others. These balances are therefore updated continuously as the plant design evolves.

The information contained in the material and energy balances is used for several purposes. System duty specifications are developed, overall process control system specifications are defined, equipment data sheets and material specifications are provided and overall plant performance and net plant heat rate are defined based on the information contained in the material and energy balance.

During this project several material and energy balance documents were developed. Several gas turbine loads and various ambient temperature conditions were used for this set of balances. Two levels of detail were defined for these material and energy balances. Level 1 represented a complete detailed material and energy balance. Every stream identified on the process flow diagrams is described in terms of flow, temperature, pressure, composition, and energy. Level 2 energy and material balances were also compiled. These were basically a summary version of the detailed level 1 balance. The level 2 balances were done on a block flow basis. Only the streams entering or leaving a major process block were identified. These streams were also described in terms of flow, temperature, pressure, composition, and energy. Included with the level 2 balance was a table summarizing plant auxiliary power requirements, gas and steam turbine power production, plant fuel heat inputs and net plant heat rate.

Figure 9 shows the block flow diagram for the plant. Table 7 shows the net plant heat rate for the MCR operating condition. This operating condition is defined as a 95°F ambient tempera-ture, base load gas turbine firing condition, and supplemental HRSG firing to obtain 60 MW net output from the plant. This balance was used as one of the primary design points for the plant.

G) Process Flow Diagrams and Process Descriptions

Conceptual process flow diagrams (PFD's) were generated during BP1. Six PFD's for the gasifier island were produced. During BP2 these PFD's were updated and more detailed information was added. Equipment was selected and the information was incorporated into the system design. Major control loops were added. With the increase in information that the PFD's were required to convey, the number of drawings was increased and each drawing represented a smaller portion of the system. PFD's were also generated for all of the balance of plant equipment and systems. A list of the PFD's is given in Table 8.

Table 8
PROCESS FLOW DIAGRAMS

NUMBER	DESCRIPTION
10001 A	COAL DELIVERY AND HANDLING SYSTEM
10001 B	COAL DELIVERY AND HANDLING SYSTEM
10001 C	COAL DELIVERY AND HANDLING SYSTEM
15001 A	COMBINED CYCLE
20001 A	COAL MILLING AND LIMESTONE
20001 A	COAL MILLING
20001 B	PULVERIZED COAL HEATING
20001 C	PULVERIZED COAL LOCKHOPPERS
20001 D	PULVERIZED COAL FEED SYSTEM
20001 E	OPERATING DESCRIPTION FOR PC
20001 F	PULVERIZED COAL 2 TPH KINETIC EXTRUDER
30001 A	GASIFIER LEVELS A,D,E,F
30001 B	GASIFIER LEVELS B,C AND HEAT EXCHANGER
30001 C	GASIFIER SLAG REMOVAL
30001 D	GASIFIER STEAM GENERATION
30001 E	COOLING WATER FOR GASIFIER
35001 A	CHAR REMOVAL
40001 A	CHAR LOCKHOPPERS
40001 B	CHAR FEED SYSTEM
40001 C	OPERATING DESCRIPTION FOR CHAR
45001 A	SLAG HANDLING SYSTEM
50001 A	HIGH TEMPERATURE SULFUR REMOVAL SYSTEM
85001 A	BOOSTER COMPRESSOR
95001 A	WASTE WATER COLLECTION AND TREATMENT
95001 B	WASTE WATER COLLECTION AND TREATMENT
115001 A	COMBINED CYCLE
115001 B	BLOWDOWN
115001 C	PROCESS STEAM DISTRIBUTION
150001 A	CONDENSATE POLISH & CHEM INJ SYSTEM
160001 A	LAKE WATER DISTRIBUTION
170001 A	PLANT AND INSTRUMENT AIR DISTRIBUTION
175001 A	POTABLE WATER BALANCE
180001 B	NATURAL GAS DISTRIBUTION

A simplified version of the PFD's is shown in Figures 10 through 13 These figures give the general configuration of the major systems in the gasifier island.

Process descriptions were written for each system. These process descriptions describe the way the system is supposed to operate and contain the preliminary control philosophy. They also contain information on how the system will operate in the startup and shut down mode. The following brief descriptions summarize the overall plant using the PFD's in Figure 10 through 13.

The coal preparation and feed system is designed to pulverize crushed coal, dry and heat it, feed it through a pressure barrier, and meter it into the gasifier. The system utilizes lockhoppers to overcome the pressure barrier and a pressurized feed bin with metering devices to smoothly feed pulverized coal into feed lines. Inert gas will be used to convey the coal to the gasifier, which avoids undesirable reactions between the coal and its transport medium.

Crushed coal from the raw coal bin will be metered into a pulverizer by the raw coal feeder. The pulverized coal will be dried and conveyed to a separation system which is positioned above the feed system (to promote gravity flow into the various feed system vessels). The coal flows by gravity through a coal heater, a receiving bin, then into one of two lockhoppers. Each lockhopper will be capable of pressurizing its contents from atmospheric pressure to the gasifier operating pressure and discharging its contents into a feed bin at this pressure. The lockhoppers will be sequenced in such a way that one will be filling will the other is dumping coal into the feed bin. The feed bin will provide a relatively stable inventory of coal which can be metered smoothly into the gasifier.

Metering devices drop the coal into their respective pickup devices, where an inert gas mixes with the coal and transports it through coal feed lines to the gasifier.

An alternate coal feeding system which is being considered involves the use of a Kinetic Extruder, designed by MPG (now Penn Trading Co.) and Lockheed. This device would feed coal through the pressure barrier and into the feed bin.

The particulate removal system is utilized to remove all the char in the product gas line and return it to the gasifier. There are two particulate removal devices in series. The first is a cyclone with a barrier filter following. The cyclone removes the larger size particles while the barrier filter removes the remainder. The cyclone may be either a single stage or two stages in series. The barrier filter may be any of the new technologies available. The leading candidate for the barrier filter is a design which is similar to a conventional baghouse, but with an advanced high temperature material for the bags. With the baghouse concept, the particles are collected on the outside of the bags. To remove the collected material a cleaning system and media is required. The method is periodic pulsing. This is called a pulse jet system and is integral with and supplied with the baghouse. The cleaning cycle is established by monitoring the pressure differential across the collector. When a target pressure differential is reached, either all or some of the collecting elements are cleaned.

FIGURE 10

ABB CE IGCC Flow Diagram

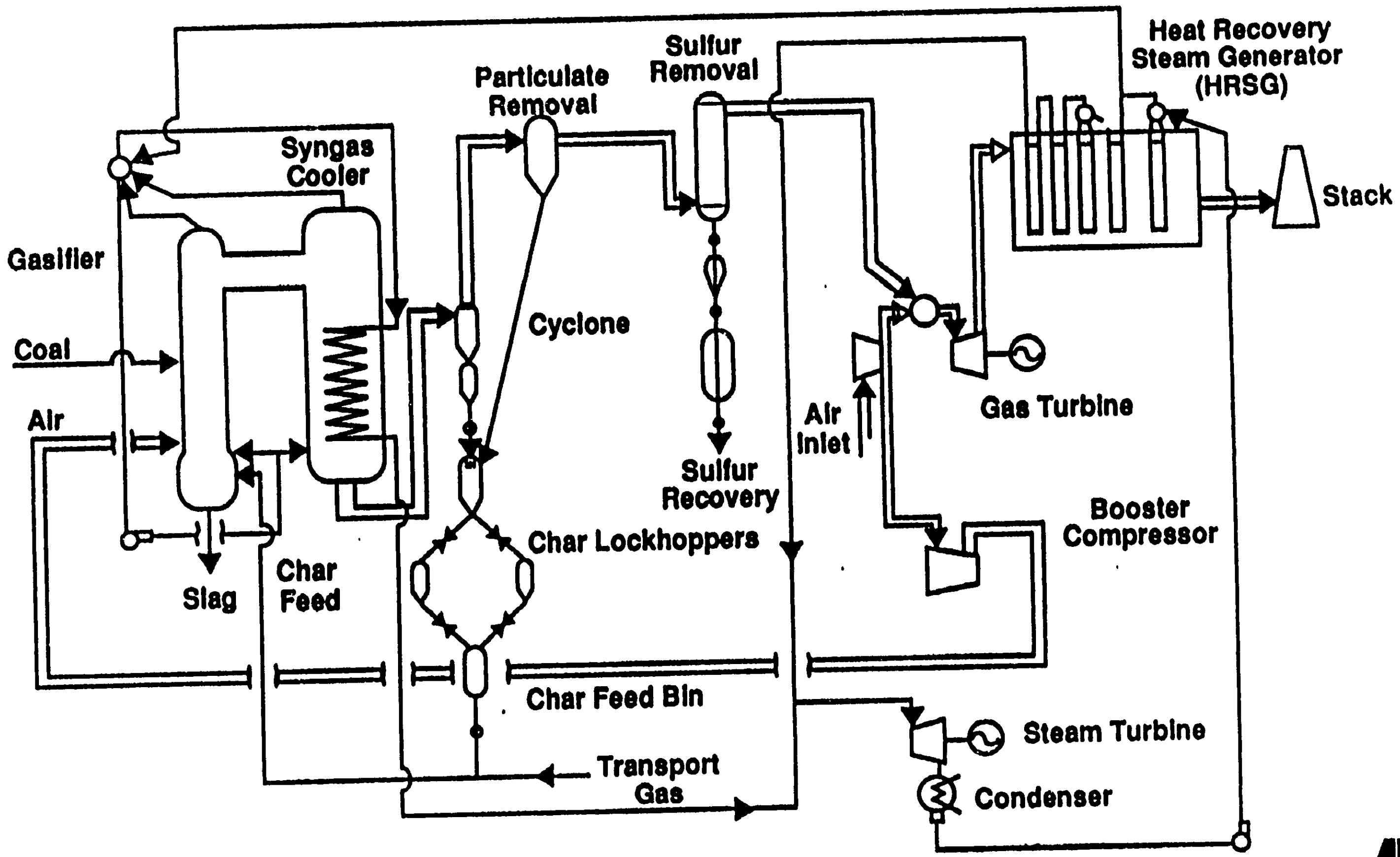
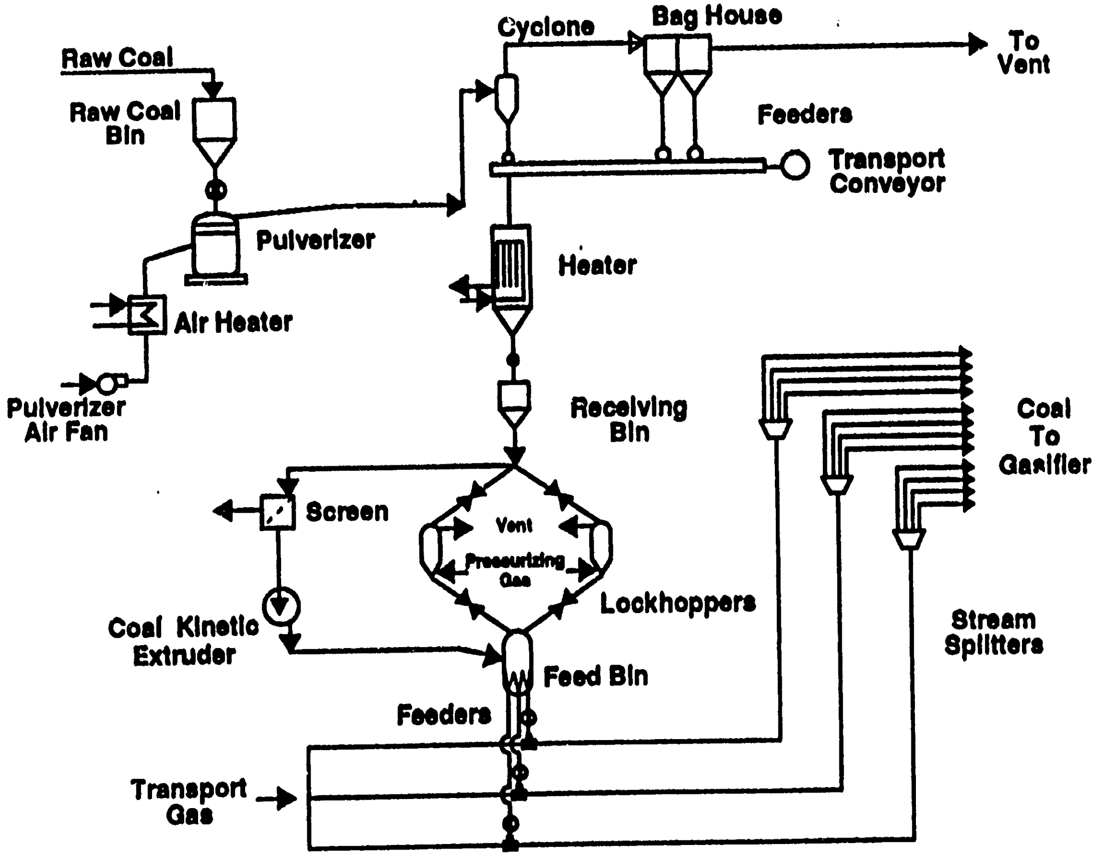


ABB
ASEA BROWN BOVERI

Coal Preparation and Feed System



ASEA BROWN BOVERI

FIGURE 11

Char Recycle System

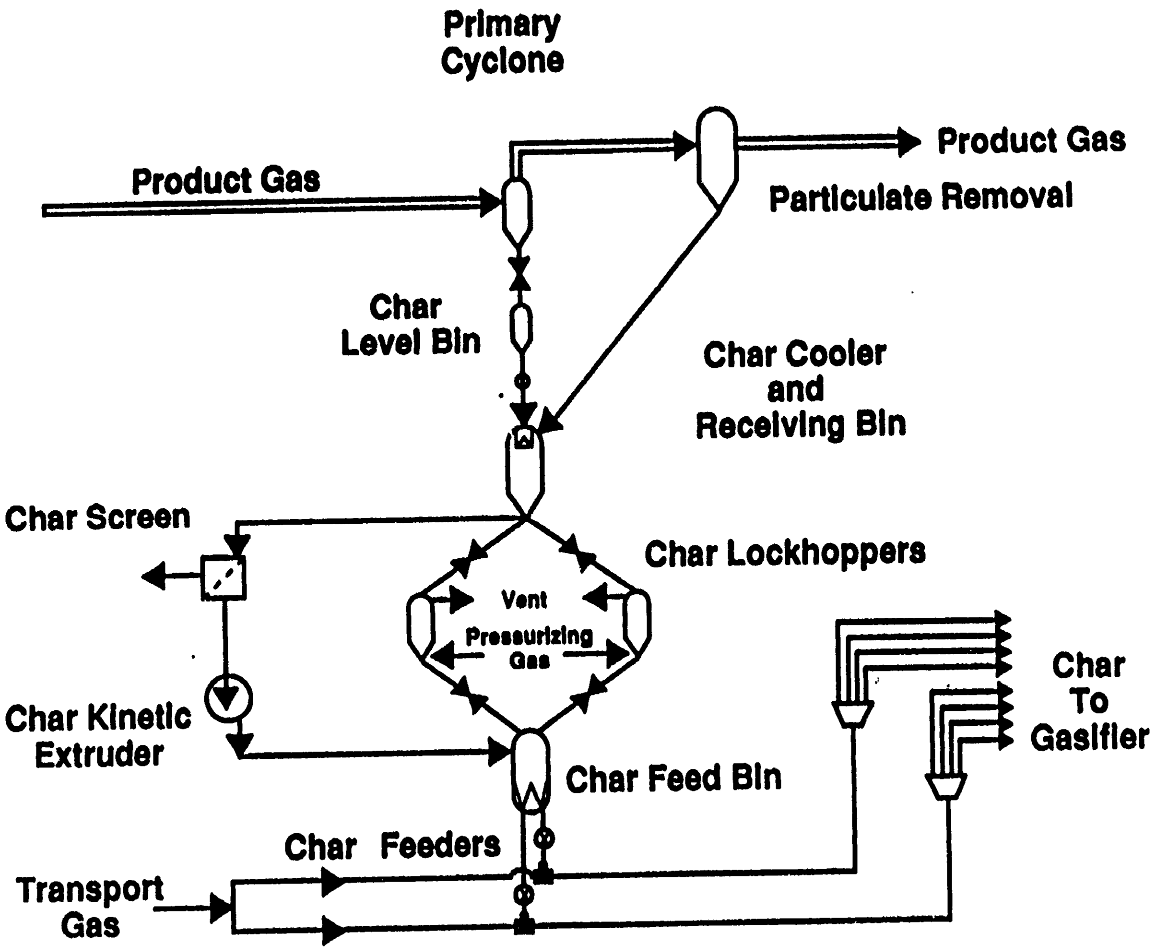


ABB
ASEA BROWN BOVERI

FIGURE 12

Sulfur Removal System

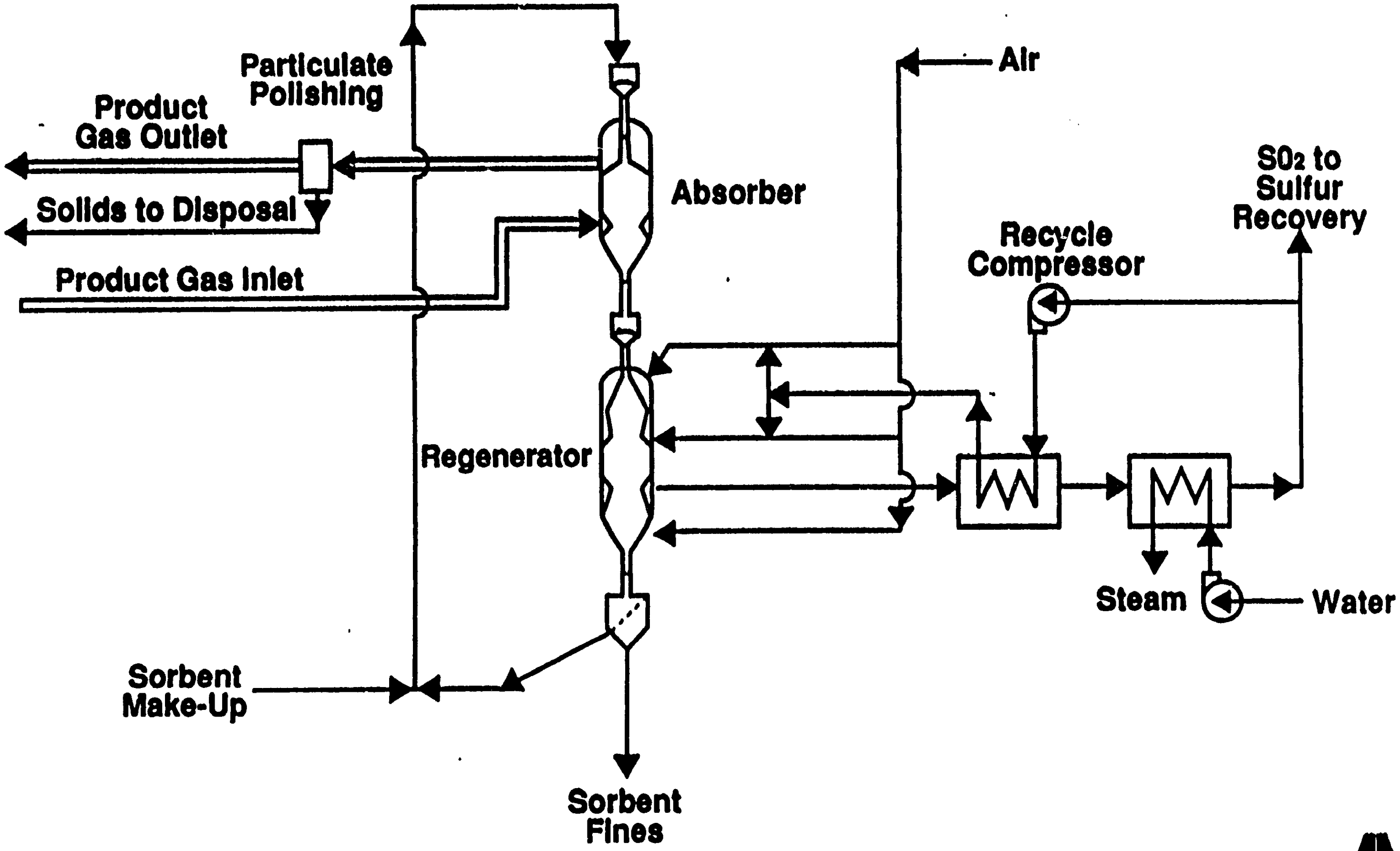


FIGURE 13

ABB
ASEA BROWN BOVERI

The ungasified char collected from the product gas is repressurized and fed back into the gasifier. Inert gas is utilized to convey the char to the gasifier.

Char reclaimed from the product gas is deposited in a receiving bin. From the receiving bin char flows by gravity into one of two lockhoppers, where it is pressurized and gravity fed into the char feed bin. The lockhoppers are sequenced in such a way that one will be filling while the other one is discharging into the feed bin. From the feed bin char is metered through pickup devices and conveyed through feed lines.

The gasifier and its heat exchanger are utilized to produce a pressurized product gas stream containing char and H_2S. Pulverized coal is delivered and combusted in a deficiency of air. Gasification occurs in an entrained reactor. Sensible energy is removed from the gas in the heat exchanger. The gas exits the system for char removal and desulfurization. Coal ash is fused and tapped from the bottom of the gasifier as molten slag. All streams to the gasifier are delivered pressurized.

Product gas leaves the gasifier and passes through a crossover and enters the heat exchanger. The bounding walls of the gasifier, crossover, and heat exchanger are water cooled. The product gas is cooled in the heat exchanger with both water cooled and superheat heat transfer surfaces. The heat transfer surface arrangement is of a configuration that will yield an outlet gas temperature over the operating load range which will satisfy the requirements of the hot desulfurization system. The steam flow generated and the superheating of steam is integrated into the steam cycle.

In the gasifier, the stream of molten slag continually flows through a slag tap into a slag tank. Quench slag is periodically let down from this tank. The slag tank is located just below the gasifier.

A sootblower system will be provided to clean all the water cooled bounding walls and the heat transfer surface in the heat exchanger. Cooling water via inlet and return lines is provided for those components that require it.

The hot gas desulfurization system that CE is considering to use for this system is being developed by GE. It is a sorbent system as developed by METC. The GE version of this system is known as a moving bed system. Hot product gas enters the absorber vessel at the bottom and reduced sulfur species are removed by reacting with a bed of zinc ferrite or zinc-titanate. Cleaned product gas leaves the reactor at the top. Spent sorbent is removed periodically from the absorber through a lockhopper and enters the regenerator vessel. The sorbent is regenerated with a stream of hot air and recycled back to the absorber. A stream of SO_2 laden gas is produced which is sent to a sulfur recovery system.

H) Piping and Instrumentation Diagrams

After completing the AFD PFD's and the process descriptions, piping and instrumentation diagrams were generated for the entire plant. These P&ID's contain most of the control loops and instrumentation required in the plant and are used to estimate piping and control equipment costs. A list if the P&ID's generated is given in Table 9.

Table 9
PIPING & INSTRUMENTATION DIAGRAMS

NUMBER	DESCRIPTION
20006 A	COAL PULVERIZING SYSTEM SH1
20006 B	COAL PULVERIZING SYSTEM SH2
20006 C	COAL PULVERIZING SYSTEM SH3
20006 D	COAL PULVERIZING SYSTEM SH4
20006 E	PC HEATER PACKAGE & CONDENSATE POT
20006 F	PC RECEIVING BIN
20006 G	PC LOCKHOPPER (FA 20-021)
20006 H	PC LOCKHOPPER (FA 20-021)
20006 J	PC FEED BIN
20006 K	PC TRANSPORT SYSTEM
20006 N	PC KINETIC EXTRUDER
20006 P	PC KINETIC EXTRUDER
20006 Q	PC KINETIC EXTRUDER
30006 A	GASIFIER LEVEL "F" - NATURAL GAS
30006 B	GASIFIER NOZZLES
30006 E	GASIFIER NOZZLES LEVELS "B" and "C"
30006 F	GASIFIER HEAT EXCHANGER - GAS SIDE
30006 G	GASIFIER SLAG COOLING & CRUSHING
30006 H	GASIFIER STEAM SIDE - STEAM DRUM
30006 J	GASIFIER STEAM SIDE RECIRCULATION PUMPS
30006 K	GASIFIER - STEAM SIDE
30006 L	GASIFIER STEAM SIDE HEAT EXCHANGER
35006 A	CHAR REMOVAL CYCLONE
35006 B	CHAR REMOVAL BAGHOUSE
40006 A	CHAR RECEIVING BIN
40006 B	CHAR LOCKHOPPER
40006 C	CHAR LOCKHOPPER
40006 D	CHAR FEED BIN
40006 E	CHAR TRANSPORT SYSTEM
45006 A	SLAG LOCKHOPPER
50005 A	ABSORBER AND SECONDARY CYCLONE
50005 B	SORBENT REGENERATOR SYSTEM
50005 C	REGENERATION SYSTEM
50005 D	SOLID TRANSPORT SYSTEM
50006 A	HOT GAS SULFURIZATION
85006 A	AIR BOOSTER COMPRESSOR
100007 A	GAS TURBINE/GENERATOR
100007 B	GAS TURBINE/GENERATOR AUXILIARIES
100007 C	VENTS AND DRAINS - GAS TURBINE/GENERATOR
110007 A	BOILER FEEDWATER SYSTEM
110007 B	STEAM DRUM - HRSG
110007 C	SUPERHEATER - HRSG
110007 D	EXHAUST GAS AND STACK - HRSG
110007 E	BURNER MANAGEMENT SYSTEM - HRSG
110007 F	HRSG DRAINS
110007 G	HRSG DRAIN SYSTEM
115007 A	MAIN STEAM SYSTEM