Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal

Technical Report

Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal

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Interim Report, December 2000

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REPORT SUMMARY

This interim report presents initial results of an ongoing study of the potential Cost of Electricity (COE) produced in both conventional and innovative fossil fueled power plants that incorporate CO_2 removal for subsequent sequestration or use. The baseline cases are natural gas combined cycle (NGCC) and ultra-supercritical Pulverized Coal (PC) plants, with and without post combustion CO_2 removal, and Integrated Gasification Combined Cycle (IGCC) plants, with and without pre-combustion CO_2 removal.

Background

Concern over the potential effect of CO_2 emissions from fossil fuel power plants on global climate is a key issue for the future of power generation worldwide. In 1990-1991 EPRI and the International Energy Authority (IEA) conducted pioneering studies on the effect of CO_2 removal on the COE from PC and IGCC plants that showed an advantage for the IGCC plants. Since that time all coal technologies have markedly improved but natural gas fired combustion turbines and combined cycle plants are currently the preferred choice for additional low-cost generation. In 1998 EPRI initiated a study to evaluate innovative fossil fuel plants incorporating CO_2 removal. Subsequently the U.S. Department of Energy (DOE) agreed to cosponsor this work.

Objectives

- To update the evaluations of the clean coal technologies and natural gas fired combined cycle plants both with and without CO_2 removal using the latest technical information.
- To identify the price of natural gas at which the coal technologies become competitive if CO_2 removal is required.
- To identify innovative improvements for future evaluation and development that have the potential to further reduce the COE.

Approach

In this interim report the project team documents twelve cases that have been completed to date to evaluate clean coal technologies and natural gas fired combined cycle plants both with and without CO_2 removal. The team presented technical descriptions, performance results, and equipment lists for each of these cases and developed heat and material balances for them using the commercial steady-state flowsheet simulator ASPEN™. They used the results to determine overall system efficiency, airborne emissions, and plant costs. In conjunction with future case studies incorporating potential improvements to both natural gas and coal based technologies, these results will establish a “measuring stick” that can be used to estimate the competitiveness of coal-fired advanced technology cycles.

Results

The results reported in this summary are for the cases using the H type combustion turbines for NGCC and IGCC plants and for an ultra-supercritical PC plant with steam conditions of 34.5 MPa/649°C/649°C/649°C. A coal cost of $1.18/GJ ($1.24/Mbtu) HHV basis, was assumed and a plant Capacity Factor of 80% was used for the COE.

Without CO_2 removal COEs are very similar for both the IGCC and PC and show a breakeven with the COE of an NGCC at a natural gas price of ~$4.65/ GJ ($4.9/Mbtu) HHV basis. If CO_2 removal is required for new fossil fuel power plants and if coal stays at its current price of $1.18/GJ, NGCC plants with post combustion removal of CO_2 offer the lowest COE up to a natural gas price of $3.8/GJ ($4.0/Mbtu). Above that price IGCC plants with CO_2 removal would have a lower COE than NGCC plants. IGCC plants would also have a COE 1.4-1.8c/kWh (~ 20%) lower than PC plants if both were designed for CO_2 removal. The cost of CO_2 emissions avoided with IGCC ($17.5/metric ton) was markedly less than that of an NGCC ($60.7/metric ton) or ultra-supercritical PC Plant ($43.1/metric ton).

Further analysis of the results show that adjustments normalizing the CO_2 removal cases to the same emissions of CO_2/kWh or taking into account the size of the plant do not significantly alter these main conclusions.

EPRI Perspective

If CO_2 removal is required, IGCC remains the coal technology most competitive with NGCC. Future improvements and innovations in air separation, gasification, gas clean-up, gas separation, and advanced power cycles should further reduce the COE and increase the efficiency of IGCC plants. Additional studies of such IGCC innovations and new cycles for natural gas, including pre-combustion removal of CO_2, combustion of both natural gas and coal using oxygen with CO_2 recycle, and the incorporation of high temperature fuel cells will also be evaluated in the future under this cooperative project with DOE. Since few new coal plants are currently planned, the options for CO_2 emissions reduction at existing coal plants should also be examined.

Keywords

CO_2 Removal
Sequestration
Economic evaluation
Pulverized coal plants
GCC Power Plants

EPRI ANALYSIS OF INNOVATIVE FOSSIL FUEL CYCLES INCORPORATING CO_2 REMOVAL

Abstract

EPRI and the U.S. DOE are jointly sponsoring and funding a series of engineering and economic evaluations of innovative fossil fuel based cycles including those incorporating CO_2 removal for subsequent sequestration, disposal or use. The interim results of this work conducted by Parsons are presented in this report. They showed that the costs of pre-combustion CO_2 removal from IGCC plants are markedly less that the costs of post- combustion CO_2 removal from NGCC and ultra supercritical PC plants. In this section further analyses of the results from the interim report by Parsons, et al. are presented to illustrate the sensitivity of the results to certain assumptions that were made in establishing the cases studied. A graphical presentation of the results has been used to establish at which cost of natural gas the IGCC and PC plants can compete with NGCC on a Cost of Electricity (COE) basis. These graphical plots can also be used to show what $/kW capital cost can be afforded by the coal technologies to compete with NGCC at various natural gas prices. The effects of normalizing the results to compare all cases at the same CO_2 emissions per kWh are shown. The effects of scale are also examined so that results are presented for plants compared at the same MW net output. The basic conclusion of these analyses confirms that if CO_2 removal is required for sequestration, the costs of CO_2 removal and the COE from IGCC will be markedly lower than from ultra-supercritical PC plants and should also be competitive with NGCC at a natural gas costs $3.5-3.8/GJ or $3.7-4.0/Million Btu (Mbtu) HHV basis. These results show essentially good agreement with other published papers by U.S authors but differ from the results shown in a recent paper from the IEA Greenhouse R&D Program.

Results of Parsons Case studies

The Parsons case studies key results considered in this analysis are shown in **Table 1** for the cases without CO_2 removal and in **Table 2** for the cases with CO_2 removal. Coal cost was assumed at $1.18/GJ or $1.24/Mbtu and natural gas at $2.56/GJ or $2.70/Mbtu (both HHV basis).

Table 1
Key Results of Parsons Studies without CO_2 Removal

Case Number	1 D	3 B	7 C	7 D
Description	NGCC – H	IGCC – H	SC PC	USC PC
Net MW output	384.4	424.5	462.1	506.2
TPC $/kW	496	1263	1143	1161
LCOE mills/kWh at 65% CF and at 80% CF	33.5 30.7	52.4 45.1	51.5 45.0	51.0 44.3
$kgCO_2/kWh$ $lbCO_2/kWh$	0.338 0.745	0.718 1.582	0.774 1.707	0.734 1.618

Table 2
Key Results of Parsons Studies incorporating CO_2 Removal

Case Number	1 B	3 A	7 A	7 B
Description	NGCC – H	IGCC – H	SC PC	USC PC
Net MW output	310.8	403.5	329.3	367.4
TPC $/kW	943	1642	1981	1943
LCOE mills/kWh at 65% CF and at 80% CF	54.1 48.8	65.7 56.4	85.6 74.4	82.4 71.6
kg/kWh $lbCO_2/kWh$	0.040 0.088	0.073 0.162	0.108 0.238	0.101 0.222

Cost of CO_2 Removed and CO_2 Avoided

In the main body of this report Parsons presents the cost of CO_2 removed. These values were determined by subtracting the COE of the reference case without CO_2 removal from the COE for the case with CO_2 removal and converting this differential COE to an annual cost and then dividing by the tonnes of CO_2 removed per year.

However, it is usually considered more appropriate in global climate related studies to express the costs as $/tonne of CO_2 avoided, which is also sometimes referred to as the mitigation cost [(4)]. The mitigation cost can be calculated by comparing a plant with removal to a reference plant without removal using the COE differential in mills/kWh and the quantities of CO_2 emitted (E) in kg/kWh for each plant. The mitigation cost (MC) in \$/tonne of CO_2 avoided is defined in the following equation:

$$MC = \frac{COE_{\text{with removal}} - COE_{\text{reference}}}{E_{\text{reference}} - E_{\text{with removal}}}$$

The \$/tonne of CO_2 removed and of CO_2 avoided are shown in **Table 3** for the NGCC, IGCC, SC PC and USC PC technologies.

Table 3
Costs of CO_2 Removed and CO_2 Avoided for NGCC, IGCC and PC

Technology	NGCC H Cases 1B & 1D	IGCC H Cases 3A & 3B	SC PC Cases 7A & 7C	USC PC Cases 7B & 7D
\$/tonne CO_2 removed At 65% CF	54.5	17.5	34.8	34.5
\$/tonne CO_2 avoided At 65% CF	69.1	20.6	51.1	49.6
\$/tonne CO_2 removed At 80% CF	48.2	14.8	30.0	30.0
\$/tonne CO_2 avoided At 80% CF	60.7	17.5	44.1	43.1

Stated in \$/tonne of CO_2 removed the IGCC cost is ~50% that of the PC plants, whereas stated as \$/tonne of CO_2 avoided the IGCC cost is only 40% of the PC costs. The costs of CO_2 removed or avoided with NGCC are even greater than the PC costs due the higher volume of flue gases, lower CO_2 partial pressure in the flue gas and higher oxygen content.

Allowable Capital Cost for Coal Technologies for Breakeven with NGCC

One way of analyzing the Parsons results is to calculate the allowable capital cost of the coal technologies so that their levelized cost of electricity (LCOE) breaks-even with the NGCC COE at various natural gas prices. The operating and maintenance costs estimated by Parsons for the coal and natural gas technologies have been used, together with the NGCC capital costs, to calculate an allowable capital cost for each of the coal technologies as a function of natural gas costs. Parsons has used a 65% capacity factor (CF) in some of their previous work for DOE. However at EPRI a larger CF of 80% is typically used for base load plants. The effect of using the higher CF is to improve the competitiveness of the coal technologies so that they breakeven with NGCC at lower natural gas prices. The calculated allowable Total Plant Cost (TPC) costs for breakeven power generation are shown in **Figure 1** for the IGCC and PC technologies evaluated at 80% CF using the Case 1 B costs for NGCC with H gas turbines. **Figure 2** shows the same cases evaluated at both 65% CF and 80% CF.

Fig. 1 Approximate Allowable Capital Costs for Break-Even COE
(Based on Class H NGCC and 80% Capacity Factor)

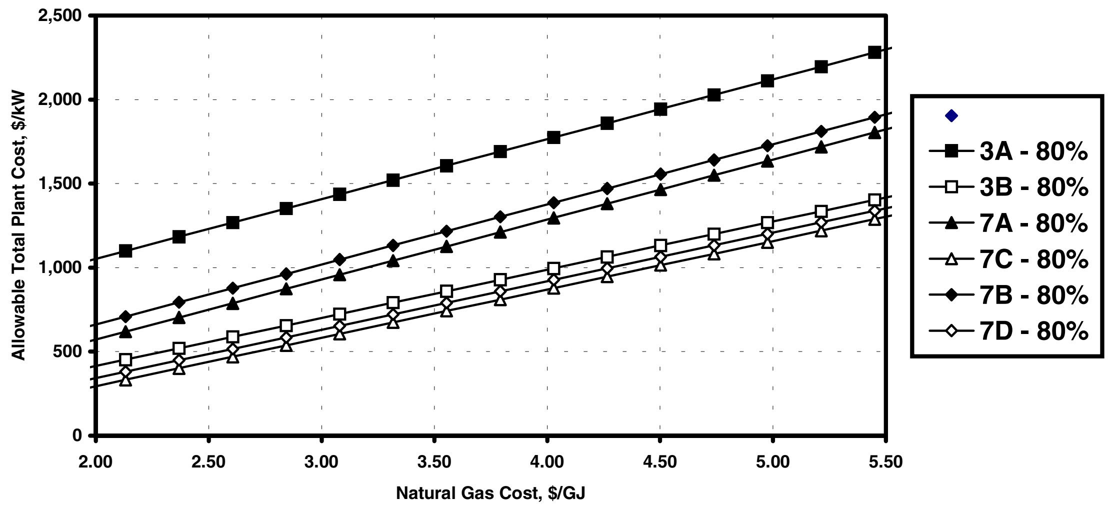
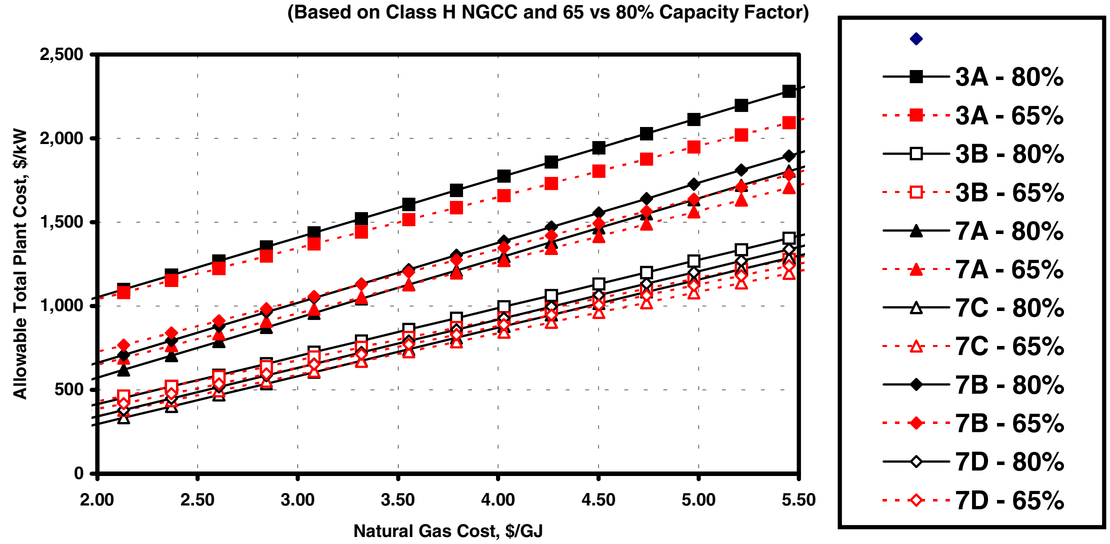


Fig. 2 Approximate Allowable Capital Costs for Break-Even COE
(Based on Class H NGCC and 65 vs 80% Capacity Factor)



From the upper curves in **Figures 1 and 2** the IGCC case (with a TPC of $1642/kW) shows a breakeven cost of natural gas of $3.98/GJ ($4.20/Mbtu) when evaluated at a 65% Capacity Factor (CF) and $3.53/GJ ($3.72/Mbtu) at 80% CF. Whereas for the two PC cases with TPC's of $1981 and $1943/kW the corresponding natural gas costs are $6.33 and $5.97/GJ ($6.68 and $6.30/Mbtu) when evaluated at the 65% CF and $5.80 and $5.45/GJ ($6.12 and $5.75/Mbtu) at the 80% CF.

The IGCC and PC cases without CO_2 removal are also shown in the lower curves of **Figures 1 and 2** compared to the NGCC H case without CO_2 removal. Without CO_2 removal the various coal technologies are much closer together with the IGCC breakeven cost for natural gas at $4.70/GJ ($4.96/Mbtu) versus $4.69/GJ ($4.95/Mbtu) and $4.59/GJ ($4.84/Mbtu) for the SC and USC cases respectively when evaluated at 80% CF.

The basic conclusion from these results was that if CO_2 removal was required for new fossil based power plants then IGCC would be much more competitive with NGCC than would either SC or USC PC plants. The LCOE of the PC plants was estimated ~14-18 mills/kWh higher than for the IGCC plant. The breakeven cost of natural gas for the IGCC at $3.53/GJ ($3.72/Mbtu) is about $1.92-2.27/GJ ($2.03-2.40/Mbtu) lower than for the PC plants.

Additional Analyses

It is very typical in case study work of this kind to observe, after the event and with the benefit of hindsight, that the cases were not quite set up in a wholly consistent manner. The authors therefore conducted some further analyses of these results to see if modification of the cases based on a more consistent, or at least different, set of basic assumptions would have any significant effect on the conclusion.

Adjustment to same CO_2 Emissions/kWh

The cases with CO_2 removal were all designed at 90% removal, since this was about the realistic upper limit for the CO_2 removal processes used. However, since NGCC plants have much lower emissions of CO_2 to begin with, this results in the NGCC plant with CO_2 removal having residual CO_2 emissions of 0.040 kg/kWh versus 0.073 kg/kWh for IGCC and 0.108 and 0.101 kg/kWh for the SC and USC PC cases.

It could be argued that the technologies should be compared at the same level of CO_2 emissions per kWh rather than the same percentage removal. This would mean that the NGCC could have a lower percentage of CO_2 removal than the coal technologies. This would reduce the LCOE for NGCC and have the effect of raising the natural gas breakeven cost of for the coal technologies.

To achieve the same emissions as the IGCC case the NGCC needs to remove only 82% of the CO_2. This reduces the auxiliary power consumption, increases the steam turbine output since less steam is needed for solvent regeneration, increases the net output and reduces the LCOE.

To achieve the same emissions as the SC PC case the NGCC needs to remove only 73% of the CO_2 with further increases in net plant output and reduction of LCOE.

The key plant characteristics of the NGCC 90%, 82% and 73% removal cases are shown in **Table 4**. The revised breakeven natural gas costs for the coal technologies based on these three NGCC H cases is shown in **Table 5**.

Table 4
Key Results of NGCC – H cases with 82% and 73% CO_2 Removal

Case Number	1 B	1 E	1 F
Description	NGCC – H	NGCC - H	NGCC - H
% CO_2 Removal	90	82	73
Net MW output	310.8	317.4	324.7
Heat Rate kJ/kWh Btu/kWh HHV	 8311 7879	 8134 7711	 7955 7542
TPC $/kW	943	903	866
LCOE mills/kWh at 80% CF	48.8	47.03	45.28
kgCO_2/kWh	0.040	0.073	0.108

Table 5
Revised Breakeven Natural Gas Costs for Coal Technologies Evaluated at the same CO_2 Emissions per kWh

Case Number	3 A	7 A	7 B
Description	IGCC H	SC PC	USC PC
% CO_2 Removal	90	90	90
kgCO_2/kWh	0.073	0.108	0.101
Breakeven Cost of Natural Gas $/GJ at 80% CF and 90% removal from NGCC 82% removal from NGCC 73% removal from NGCC	 3.53 **3.79** 4.09	 5.80 6.16 **6.56**	 5.45 5.79 6.18

When evaluated at the same CO_2 emissions per kWh the breakeven cost of natural gas to compete with IGCC rises from $3.53/GJ ($3.72/Mbtu) to $3.79/GJ ($4/Mbtu), and for SC PC the breakeven cost rises from $5.80/GJ ($6.12/Mbtu) to $6.56/GJ ($6.92/Mbtu). This larger increase for the PC plants is because of the higher residual CO_2 emissions (0.108 kg/kWh) than for the IGCC plants (0.073 kg/kWh).

Adjustments to Comparable Plant Sizes

For the IGCC case with CO_2 removal the coal feed was increased so as to fully load the gas turbine and the net MW output reduced from 424.5 to 403.5 MW. However for the PC cases the coal feed rate was kept the same and the MW output drop was much greater from 462 to 329.3 MW for SC PC and 506.2 to 367.4 MW for USC PC. It could reasonably be argued that the coal feed rate should have been increased for the PC cases so that the net plant output was about the same both with and without CO_2 removal.This would improve the PC coal cases since the plants with CO_2 removal would achieve some capital cost advantages of being at larger scale.

The key characteristics of the PC plants adjusted in this manner are shown in **Table 6**.

Table 6
Pulverized Coal (PC) Plants Scaled for no Reduction in Net Power

Case Number	**7 A**	**7 C**	**7 A Scaled**	**7 B**	**7 D**	**7 B Scaled**
Description	SC PC	SC PC	SC PC	USC PC	USC PC	USC PC
Net MW output	329.3	462.1	462.1	367.4	506.2	506.2
TPC $/kW	1981	1143	1802	1943	1161	1788
LCOE mills/kWh 65% CF and at 80% CF	85.6 74.4	51.5 45.0	80.7 70.4	82.4 71.6	51.0 44.3	78.2 68.1
Breakeven cost of Natural Gas at 80% CF $/GJ $/Mbtu HHV	5.80 6.12		5.17 5.45	5.45 5.75		4.88 5.15

Since this is basically a comparison of the PC and IGCC cases it could also be argued that the comparison should have been made with PC plants with the same net MW output as the IGCC case i.e. 403.5 MW. The results in **Table 6** can be therefore be taken as being generously weighted for the effect of plant size on PC competitiveness. However the PC LCOE at 68.1-70.4 mills/kWh is still significantly more than the IGCC at 56.4 mills/kWh at 80% CF. The breakeven cost of natural gas for the PC cases at 4.88-5.17$/GJ is also still much higher than that for the IGCC case at $3.53/GJ at 80% CF.

If scaled to the same MW output as the 403.5 MW for the IGCC case the breakeven cost for the PC cases is $5.3-5.45 /GJ versus $3.53/GJ for IGCC at 80% CF.

Many of the ultra-supercritical PC plants currently entering service in Japan are about 800-1000 MW size. It has therefore been suggested that a two train IGCC should be compared to single large ultra-supercritical PC plant. However a preliminary examination by the authors investigating such a comparison and incorporating CO_2 removal in both cases suggested that at this large scale this would not affect the outcome. The preliminary TPC estimate at 807 MW net output was ~ \$1700/kW for the SC PC and ~ \$1440/KW for the two train IGCC. At this TPC differential and with the other performance characteristics (heat rate, operating costs) similar to the 400-450 MW units there would be very little change in the overall COE differential between the two coal technologies at this larger size. In turn the NGCC could also be a two-train unit with some additional savings in TPC. It has therefore been concluded that doubling the size of the plants would make very little change to the overall relative comparison of the NGCC, IGCC and PC technologies.

Comparison with Other Studies

Fluor Daniel conducted the pioneering studies of this topic for EPRI and the IEA in 1990-1991[1]. The results of these studies were also reported at the EPRI Gasification Power Plants Conference in October 1990 [2]. Several other sources have undertaken similar updated studies in recent years [3,4,5,]. The key results of the Parsons study reported here are compared with those from other recent papers (Audus/IEA[3], Herzog/MIT [4] and Simbeck/SFA Pacific[5]) in **Table 7**.

There is a broad agreement about many aspects of these studies. The percentage of power loss in the PC, IGCC and NGCC cases is very similar in all these studies - ~28% for PC, ~5-6% for IGCC and 16-19% for NGCC plants. The ratio of TPC costs with and without post combustion CO_2 removal are similar for PC plants (~1.7-1.83) and for the NGCC plants (1.9-2.2) in all studies.

The results in the Audus paper, one of the many studies conducted for the IEA Greehouse R&D program, do differ from the other studies in some important respects. The NGCC plants are much larger than the corresponding PC and IGCC plants. The fuel costs used of \$2/GJ (\$2.11/Mbtu) for natural gas and \$1.5/GJ (\$1.58/Mbtu) for coal (low natural gas cost and low natural gas-coal cost differential) together with the large NGCC plant show NGCC to its maximum advantage in this study. It is also the only paper that suggests that the COE for an IGCC plant with CO_2 removal (6.9c/kWh) would be more than the COE for a PC plant with CO_2 removal (6.4c/kWh). The consensus of the other studies is that the IGCC with CO_2 removal COE would be 1.1-1.9c/kWh lower than the PC plant with CO_2 removal. The basic IGCC TPC cost in the Audus paper is for a Shell IGCC with a GE 9 FA gas turbine and is the highest of the IGCC estimates. The IGCC case with CO_2 removal seems to be significantly higher than the other estimates and the incremental capital for CO_2 removal is very much greater than all other estimates. The costs for the Shell cases appear inconsistent with previously published estimates. The Supercritical PC TPC cost is the lowest of the PC estimates. It reflects a very high efficiency of 46% LHV that is claimed to be achieved with 5-10°C cooling water and a low sulfur high heating value coal. The efficiency of such a plant with the same steam conditions would be ~ 41% LHV in typical U.S. conditions with consequent increases in the TPC and LCOE.

Table 7
Comparison of Parsons Key Results with Other Recent Studies

Technology	**USC PC**		**IGCC**		**NGCC**		**Notes**
	TPC $/kW		**TPC $/kW**		**TPC $/kW**		
Author	With CO2 removal	Base Refer-ence	With CO_2 Removal	Base Refer-ence	With CO_2 Removal	Base Refer-ence	
Audus	1860	1020	2200	1470	790	410	F GT
Herzog 2000	2090	1150	1909	1401	1013	542	
Herzog 2012	1718	1095	1459	1145	894	525	
Simbeck	2075	1192	1474	1100	897	400	
Parsons	1981 1871	1143 1161	1642	1263	1010 943	505 496	SC PC, F GT USC PC, H GT
	MW Net output		MW Net output		MW Net output		
Audus	362	501	382	408	663	790	NGCC 2 train
Herzog							~400MW?
Simbeck	~ 400 MW						
Parsons	329 367	462 506	404	425	399 311	509 384	SC PC, F GT USC PC, H GT
	Levelized Cost of Electricity LCOE c/kWh						
Audus	6.4	3.7	6.9	4.8	3.2	2.2	NG $2/GJ Coal $1.5/GJ LHV basis
Herzog 2000	7.71	4.39	6.69	4.99	4.91	3.3	NG $2.78/GJ Coal $1.18/GJ LHV Basis
Herzog 2012	6.26	4.1	5.14	4.1	4.33	3.1	
Simbeck	7.0	4.2	5.1	3.9	4.9	3.1	NG $3.32/GJ Coal $0.95/GJ LHV basis
Parsons	7.16	4.43	5.64	4.51	4.88	3.07	USC PC, H GT NG $2.88/GJ Coal $1.22/GJ LHV basis

The authors believe, that if cases used in the Audus paper were updated to include the more recent information from Shell, GE, Siemens etc, the COE for the base reference IGCC and PC plants would be very close and that with CO_2 removal the IGCC COE would be significantly better than a PC plant COE.

Planned Future Work

EPRI and DOE plan to continue these studies on innovative fossil technologies incorporating CO_2 removal. These will include configurations with potential advances in various aspects of IGCC technology including improvements in air separation, gasification, and gas clean up, gas separation and advanced cycles including fuel cells and advanced gas turbines.

A paper(6) delivered by a team from Texaco, GE and Praxair at the 1999 Gasification Technologies Conference showed a coal based IGCC plant with a TPC of $860/kW (U.S.Gulf Coast basis) and an efficiency of 43.3% LHV. This plant was a High Efficiency Quench (HEQ) design with a gasification pressure of 8.5 MPa (1230 psia) and a GE 9 FA gas turbine. The team seems to have focussed on a comprehensive approach to bring the costs down to meet the competition from PC and NGCC plants. If the costs are adjusted to account for changing the location to the Mid West U.S.,as used in the Parsons studies, and the contingency added as in other EPRI IGCC studies, the TPC cost would still be a very attractive $1043/kW. The high-pressure design of the gasifier and the water added by the quench in this Texaco, GE, Praxair flow scheme would be very advantageous for the shift reaction and subsequent CO_2 removal should that be required. It is hoped that a study with these latter features can be conducted in the near future.

Conclusion

If CO_2 removal is required from fossil fuel based power plants in the future, and if coal stays at its current price of $1.18/GJ (~$1.24/Mbtu), NGCC plants with post combustion CO_2 removal offer the lowest COE up to a natural gas price of about $3.8/GJ ($4/Mbtu). Above that price IGCC plants with CO_2 removal should be able to compete effectively with NGCC and produce electricity at a COE 1.4-1.8 c/kWh (~20%) lower than PC plants with post combustion CO_2 removal. The sensitivity studies conducted on the key results from the Parsons study have shown that adjustments for consistency of emissions of CO_2/kWh and plant size do not significantly alter these main conclusions.

Innovations in various aspects of the IGCC technology should be able to significantly reduce the costs of pre-combustion removal of CO_2 and increase overall efficiency. The use of IGCC in a refinery (or future coal based processing center) for co-production of power and other energy products such as steam and hydrogen is already economically attractive and resource utilization efficient in many locations. In a future carbon constrained world such co-production plants would be of increasing importance.

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EXECUTIVE SUMMARY

In 1998 EPRI initiated a project with Parsons to conduct evaluations of innovative fossil fuel cycles incorporating CO_2 removal for subsequent sequestration or use. In 1999 the U.S. Department of Energy (DOE) joined EPRI as a cosponsor of this work.

Over the past decade, a growing concern has developed about the potential impacts of carbon dioxide (CO_2) emissions on the future global environment. Much of this concern has focused on the coal-fired power plants that now produce 56 percent of U.S. electricity. The main reason for the continued use of coal as the major power plant fuel in the U.S. is its significantly lower cost compared to other fossil fuels.

There are several choices of power plant fuels available today including coal, oil, and natural gas. Since deregulation of the electric utility industry was initiated several years ago, the use of natural gas by electricity generating companies has steadily grown. Coal use is projected to continue to rise slowly in the U.S. as the total amount of electricity that is generated increases. As a result, the coal-fired option for new electricity generating plants remains important to utility generating companies that have been historically dependent on coal for the bulk of their power generation.

However, there have been recent indications that permissible levels of CO_2 emissions may be curbed in the future. A natural gas-based power plant will produce less CO_2 per kW of power output compared to a coal-based plant with the same net plant power output. This is a result of two fundamental factors: (1) natural gas has a lower carbon-to-hydrogen ratio compared to that of coal for the same level of thermal input, and, (2) natural gas-based systems have higher power-generating efficiencies compared to coal-based systems utilizing the same, or similar, power generation equipment.

In *conventional* gas- and coal-fired units, CO_2 can be removed from the exhaust gas following heat recovery in an absorber/stripper system. As such, the partial pressure of CO_2 is usually low due to the near ambient pressure of the stack gas as well as the dilution effect of substantial amounts of N_2 contained in the flue gas. Low CO_2 partial pressure yields large and costly removal equipment. However, *advanced* coal-based technologies, such as *gasification* -- because they produce concentrated streams of CO_2 at high pressure -- offer convenient opportunities that may be exploited for low-cost CO_2 removal.

In an oxygen-blown integrated gasification combined cycle power plant, CO_2 may be removed from the synthesis gas prior to power generation. The high pressure of the synthesis gas stream, as well as the absence of diluent nitrogen, yields high CO_2 partial pressures. This, in turn, results in a relatively cheaper separation due to increased driving force. Innovative coal gasification-based systems may therefore be the most cost-effective coal-based power plants if CO_2 removal is required.

The objective of the work presented in this interim report is to evaluate preliminary designs of several *advanced* coal-fired power plants to determine whether they have the potential to be competitive, in the period after year 2010, with *conventional* natural gas- and coal-fired power plants. Future conventional natural gas-fired power plants are assumed to be H class combined cycles. Conventional coal-fired plants are assumed to be pulverized coal (PC) supercritical steam power plants. Each power plant concept evaluated was configured both with and without a CO_2 removal system. For the advanced coal-fired power plant designs that meet competitive cost targets, DOE will define the R&D effort required to develop and demonstrate the technology to be a commercially attractive alternative.

The scope of the study includes identifying and defining advanced technology concepts that can be effectively integrated with both gas- and coal-fired power generation to provide high efficiency and low emissions. In order to quantify the performance and economic improvement generated through the use of each advanced technology concept, gas- and coal-fired base cases were identified. These cases include:

- Base Case Natural Gas-Fired Configurations

  Case 1A – Base NGCC with CO_2 Removal (Class F Gas Turbine)

  Case 1B – Base NGCC with CO_2 Removal (Class H Gas Turbine)

  Case 1C – Base NGCC without CO_2 Removal (Class F Gas Turbine)

  Case 1D – Base NGCC without CO_2 Removal (Class H Gas Turbine)

- Advanced Natural Gas-Fired Configurations

  Case 2A – Advanced Combined Cycle (CHAT/SOFC) with CO_2 Removal

  Case 2B – Advanced Combined Cycle (CHAT/SOFC) without CO_2 Removal

- Advanced Coal-Fired Configurations

  Case 3A – Base Case IGCC Plant with CO_2 Removal

  Case 3B – Base Case IGCC Plant without CO_2 Removal

  Case 3C – 83.5 Percent CGE IGCC without CO_2 Removal

  Case 3D – 83.5 Percent CGE IGCC with CO_2 Removal

  Case 4 – Base Advanced Coal Plant (SOFC/Gas Turbine Combined Cycle)

  Case 5 – Advanced Cycle Variation A

  Case 6 – Advanced Cycle Variation B

- Conventional Coal-Fired Configurations

  Case 7A – Conventional Supercritical Pulverized Coal with CO_2 Removal

  Case 7B – Ultra-Supercritical Pulverized Coal with CO_2 Removal

Case 7C – Conventional Supercritical Pulverized Coal without CO_2 Removal

Case 7D – Ultra-Supercritical Pulverized Coal without CO_2 Removal

Case 7E - Advanced Ultra-Supercritical Pulverized Coal without CO_2 Removal

This interim report documents twelve cases that have been completed to date. These twelve cases correspond to the various "base" cases listed above: 1A through 1D, 2B, 3A and 3B, and 7A through 7E. Technical descriptions, performance results, and equipment lists are presented for each of these cases. Heat and material balances were developed using the commercial steady-state flowsheet simulator ASPEN™. Results from the energy and mass balances were used to determine parasitic loads and overall system efficiency. They were also used to determine airborne emissions, size process equipment, and generate an equipment list. This information was used to generate plant costs. These results will establish a "measuring stick" that can be used to estimate the competitiveness of coal-fired advanced technology cycles that are expected to mature around the year 2010.

Table 1 summarizes the estimated performance results of the base case gas-fired combined cycles. Cases 1A and 1C feature two GE 7FA gas turbines each coupled with a single heat recovery steam generator (HRSG) feeding a single steam turbine. Cases 1B and 1D are based on GE's H-type single spool combined cycle package. In cases 1A and 1B, CO_2 is removed from the flue gas stream with an aqueous solution of inhibited (oxygen tolerant) monoethanolamine (MEA). The CO_2 is concentrated into a product stream and then dried and compressed to a supercritical condition. These market-based designs reflect current information and design preferences, the availability of newer combustion and steam turbines, and the relative latitude of a greenfield site.

Table 1
Plant Performance – Gas-Fired Combined Cycles

	Case 1A	**Case 1B**	**Case 1C**	**Case 1D**	**Case 2A**	**Case 2B**
Gross Plant Power, kWe	446,867	343,107	519,366	391,644	TBD	561,314
Auxiliary Power Load, kWe	47,990	32,290	9,960	7,210	TBD	4,790
Net Plant Power, kWe	398,877	310,817	509,406	384,434	TBD	556,524
Net Plant Efficiency, % HHV	39.2	43.3	50.1	53.6	TBD	59.7
Net Heat Rate, kJ/kWh HHV Btu/kWh HHV	9,175 8,698	8,311 7,879	7,184 6,811	6,715 6,366	TBD TBD	6,029 5,716
CO_2 Removed, tonne/day ton/day	3,996 4,405	2,817 3,105	0 0	0 0	TBD TBD	0 0

As can be seen in Table 1, the configurations with CO_2 removal, cases 1A and 1B each decrease plant CO_2 emissions by 90 percent, have lower net plant power output (21.6 and 19.3 percent, respectively) and increased heat rates (27.7 and 23.7 percent, respectively) as compared to their corresponding case with no CO_2 removal (cases 1C and 1D). Net plant power output decreases for two distinct reasons: (1) large amounts of low-pressure steam are diverted from the steam turbine and used to regenerate the CO_2 absorbent solution and, (2) the auxiliary power associated with CO_2 removal and pressurization increases the total plant auxiliary load by more than 400 percent. For these two reasons, net plant heat rate also increases.

Also shown in Table 1 is a performance summary estimate for case 2B. This is the CHAT/SOFC advanced gas-fired case with no CO_2 removal. Net plant power output is approximately 556 MWe, generated at a net plant efficiency of 59.7 percent HHV (66.2 percent LHV). This efficiency level, developed with SOFC and F-based gas turbine technology, is 6.1 points higher than the 53.6 percent HHV (59.5 percent LHV), generated with the H-based NGCC case 1D. Case 2A, which includes 90 percent CO_2 removal, will be developed in the future

Table 2 summarizes the performance results of the base case coal-fired IGCC and PC power plants. The configuration with CO_2 removal, case 3A, removes and recovers 90 percent of the available CO_2, and has a lower net plant power output with an increased heat rate as compared to the corresponding case with no CO_2 removal (case 3B). Case 3A generates an estimated net power output of 403.5 MWe, while case 3B generates approximately 424.5 MWe. Correspondingly, case 3A operates with an estimated net plant efficiency of 37 percent (HHV), while case 3B operates with a net plant efficiency of 43.1 percent (HHV).

Table 2
Plant Performance – Coal-Fired Configurations

	Case 3A	Case 3B	Case 7A	Case 7B	Case 7C	Case 7D
Gross Plant Power, kWe	490,396	474,040	402,254	442,611	491,108	535,970
Auxiliary Power Load, kWe	86,890	49,500	72,730	75,180	29,050	29,760
Net Plant Power, kWe	403,506	424,540	329,294	367,431	462,058	506,210
Net Plant Efficiency, % HHV	37.0	43.1	28.9	31.0	40.5	42.7
Net Heat Rate, kJ/kWh HHV Btu/kWh HHV	9,732 9,226	8,349 7,915	12,464 11,816	11,602 10,999	8,882 8,421	8,422 7,984
CO_2 Removed, tonne/day ton/day	7,389[1] 8,145[1]	0 0	7,734 8,525	8,032 8,854	0 0	0 0

(1) Case 3A uses a high-pressure gasifier, water-gas shift, and a double-stage Selexol unit to remove CO_2 from the synthesis gas.

There are several reasons for the decreased power output and increased heat rate of case 3A. A moderate amount of steam -- less than that required by the NGCC cases that remove CO_2 from the HRSG flue gas -- is diverted from the steam turbine and used to regenerate the CO_2 absorbent solution. Also, the auxiliary power associated with CO_2 removal and pressurization increases the total plant auxiliary load. A third effect is that conditioning the coal-derived fuel gas via the catalytic water-gas shift reactors introduces unrecoverable first-law thermodynamic losses due to an increase in heat rejection to the bottoming cycle. All else being equal, any sub-process that rejects energy directly to the bottoming component of a combined cycle decreases the overall net plant efficiency because the higher temperature topping cycle is, by definition, more efficient than the lower temperature bottoming cycle.

Cases 7A through 7D are conventional pulverized coal-fired steam cycles. Cases 7A and 7C utilize supercritical conditions 24.1 MPa/566°C/566°C/566°C (3,500 psig/1,050°F/1,050°F/ 1,050°F), while 7B and 7D are based on ultra-supercritical 34.5MPa/649°C/649°C/649°C (5,000psia/1,200°F/ 1,200°F/1,200°F) steam conditions. Cases 7A and 7B employ CO_2 removal and recovery, while 7C and 7D have no provision for CO_2 removal. Table 2 summarizes the system performance for each of these cases. As before, the cases with CO_2 removal have substantially increased auxiliary power load demands, and decreased gross plant power outputs due to reboiler steam demands and poor system performance. These power plant configurations will be unable to compete with IGCC from a strict system performance perspective.

The IGCC-based values in Table 2 represent base case coal-fired IGCC performance numbers. As such, they represent a lower limit in system performance that will be used to measure the competitiveness of the advanced technology coal-fired cases (cases 4, 5, and 6). It is important to determine the level of system performance improvement attributable to each individual advanced technology. If the system efficiency of the advanced coal-fired cases is not increased above the system efficiency numbers shown in Table 2, then the applied advanced technology may have difficulty competing against natural gas. The cycle or technology may have to be rethought or reconfigured to become competitive.

The power consumption (in MWe) required for CO_2 removal with each of the technologies so far investigated is shown in Table 3. Table 3 also lists this power consumption as a percentage of the net power output. This is shown graphically in Figure 1 for three broad classes of technology. Table 3 and Figure 1 illustrate the major economic challenge facing existing conventional gas and coal-fired plants if CO_2 removal is required. Not only would these power plants be faced with the extra capital, fuel, and operating costs for adding CO_2 removal, but they would also be faced with the cost of providing over 20 percent of the initial power plant output to replace the power used to accomplish the CO_2 removal.

Table 3
Net Power Output Consumption for CO_2 Removal

Technology	Power Consumption, MW	Power Consumption as % of Total Net Power
NGCC 2x 7FA	110.5	21.7
NGCC 1x 7H	73.6	19.2
IGCC 1x 7H	21	4.9
Conventional PC Supercritical	132.8	28.7
Conventional PC Ultra-Supercritical	138.8	27.4

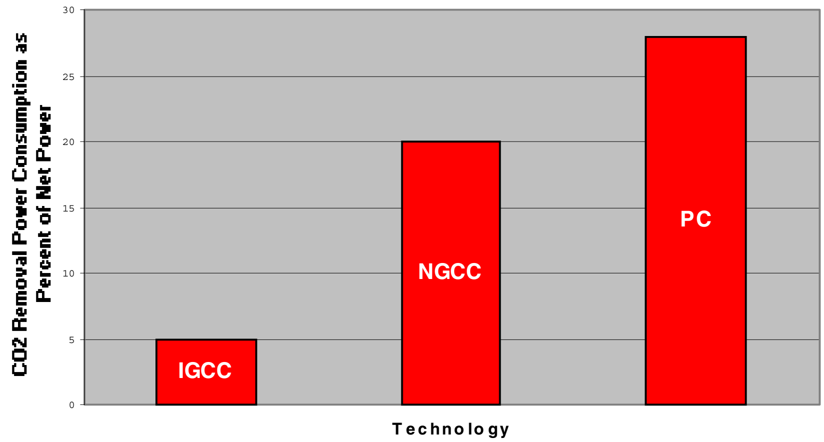

Figure 1
Net Power Output Consumption for CO_2 Removal

The performance results shown in Tables 1 and 2 were used to generate total plant cost and the cost of electricity. The coal-fired cases must achieve equal or superior cost results if they hope to be competitive with natural gas. The only way to determine these answers and resolve such questions is to evaluate each of the desired cases with a single study approach and estimate system performance on a consistent basis.

Table 4 contains an economic performance summary for the gas-fired cases. The corresponding summary for the coal-fired cases is shown in Table 5. The data in both of these tables are based on a plant operating capacity factor of 65 percent. COE results are 20-year levelized values in constant year 2000 dollars. The cases with CO_2 removal require greater capital costs and incur higher cost of electricity compared to the companion case without CO_2 removal. Also shown in these two tables is cost per tonne of CO_2 removed. This value is determined by subtracting the COE of the non-removal case from the COE of the corresponding case with CO_2 removal. This incremental COE value is then converted to an annual cost and then divided by tonnes of CO_2 removed per year. This result is shown graphically in Figure 2.

Table 4
Economic Performance – Gas-Fired Combined Cycles

	Case 1A	Case 1B	Case 1C	Case 1D	Case 2A	Case 2B
Total Plant Cost (TPC), $/kW	1,010	943	505	496	TBD	TBD
Total Capital Requirement, $/kW	1,099	1,026	549	539	TBD	TBD
Total Production Cost, ¢/kWh	3.13	2.92	2.09	2.04	TBD	TBD
COE, ¢/kWh	5.79	5.41	3.42	3.35	TBD	TBD
CO_2 Removed, $/tonne $/ton	56.91 51.63	54.49 49.43	N/A N/A	N/A N/A	TBD TBD	N/A N/A

Table 5
Economic Performance – Coal-Fired Configurations

	Case 3A	Case 3B	Case 7A	Case 7B	Case 7C	Case 7D
Total Plant Cost (TPC), $/kW	1,642	1,263	1,981	1,943	1,143	1,161
Total Capital Requirement, $/kW	1,844	1,420	2,219	2,175	1,281	1,301
Total Production Cost, ¢/kWh	2.10	1.79	3.18	2.97	2.04	1.95
COE, ¢/kWh	6.57	5.24	8.56	8.24	5.15	5.10
CO_2 Removed, $/tonne $/ton	17.49 15.87	N/A N/A	34.84 31.61	34.52 31.32	N/A N/A	N/A N/A

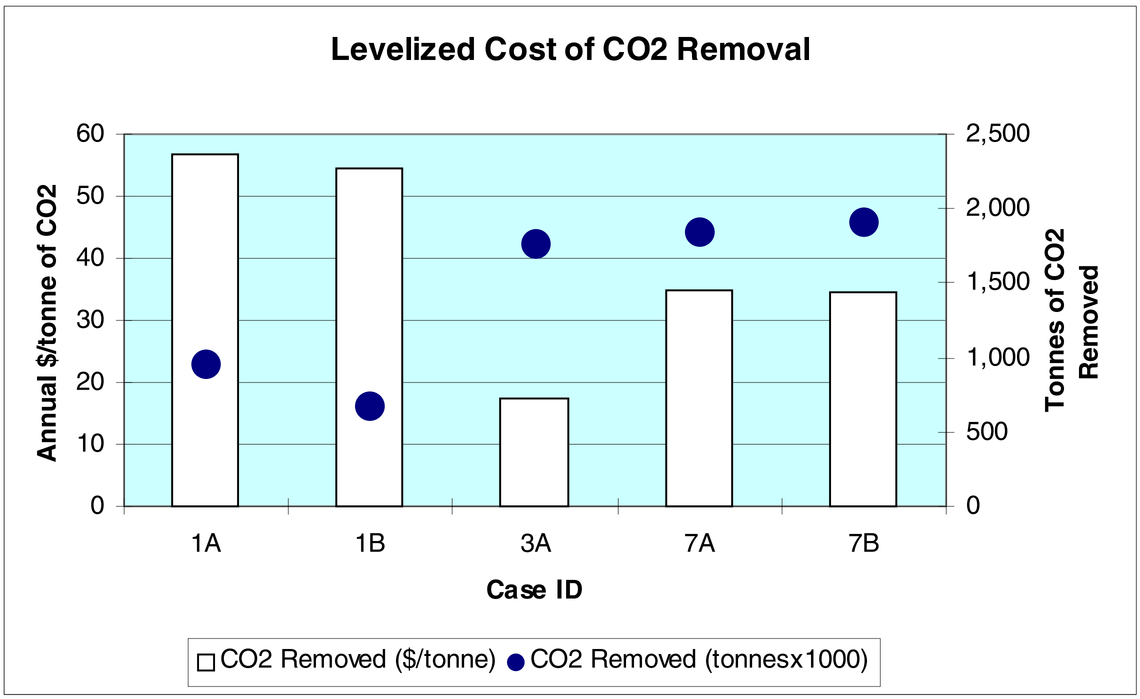

Figure 2
Levelized Cost of CO_2 Removal

It can be seen from Tables 4 and 5 that the impact of post combustion CO_2 removal on the NGCC and PC cases adds 60-70% to the COE whereas the pre-combustion removal of CO_2 from the syngas adds only 25% to the COE for the IGCC case. Without CO_2 removal the COE for the IGCC and PC cases are very close with a slight advantage to the PC, however with CO_2 removal the PC COE is 25-30% greater than the IGCC COE.

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ACRONYMS AND ABBREVIATIONS

acfm	Actual cubic feet per minute
AGR	Acid gas removal
ASU	Air separation unit
ATS	Advanced turbine system
Btu	British thermal unit
cfm	Cubic feet per minute
CGE	Cold gas efficiency
CHAT	Cascaded humidified advanced turbine
CO2	Carbon dioxide
CRT	Cathode ray tube
CS	Carbon steel
CT	Combustion turbine
CWT	Cold water temperature
dB	Decibel
DCS	Distributed control system
DOE	Department of Energy
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
gpm	Gallons per minute
GT	Gas turbine
h	Hour
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
in. H_2O	Inches water
in. Hga	Inches mercury
IGCC`	Integrated gasification combined cycle
IP	Intermediate pressure
ISO	International Standards Organization
kV	Kilovolt
kWe	Kilowatts electric
kWh	Kilowatt-hour
lb	Pound

LHV	Lower heating value
LP	Low pressure
MCR	Maximum coal burning rate
MDEA	Methyldiethanolaamine
MEA	Monoethanolamine
MHz	Megahertz
MMBtu	Million British thermal units (shown as 106 Btu on tables and charts)
MWe	Megawatts electric
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NOx	Oxides of nitrogen
OD	Outside diameter
ppmv	Parts per million volume
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
rpm	Revolutions per minute
scfm	Standard cubic feet per minute
SCOT	Shell Claus Off-gas Treating
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SO2	Sulfur dioxide
SOFC	Solid oxide fuel cell
SS	Stainless steel
TGTU	Tail gas treating unit
Tonne	Metric ton
tpd	Tons per day
tph	Tons per hour
WB	Wet bulb
wt%	Weight percent

1
INTRODUCTION

In 1998 EPRI initiated a project with Parsons to evaluate innovative fossil fuel power generation technologies incorporating CO_2 removal for subsequent sequestration or use. In 1999 DOE agreed to cosponsor this project. This report is an interim report of some of the cases studied under this cooperative agreement between EPRI and DOE.

The coal-fired option for new electricity generating plants remains important to many utilities. The key competitor to coal-fired generation is the natural gas-fired combined cycle (NGCC). The greatest promise for coal to achieve future competitiveness with NGCC plants is through the use of advanced coal-fired power plants that utilize power conversion technologies currently under development by the United States Department of Energy (DOE) and its industry partners.

Recently, there has been considerable attention given to the possible detrimental effect of carbon dioxide (CO_2) emissions on the global climate. If the appropriate legislation is approved, CO_2 emissions from stationary power plants may have to be limited by active control systems. Coal-based power plant systems will be acutely affected because coal contains a greater amount of carbon per unit of energy input compared to natural gas. If coal is to remain a viable and competitive fuel source, creative options that efficiently utilize coal in generating electrical power while minimizing CO_2 emissions are required.

This interim report presents preliminary results of an effort to establish a baseline definition of gas- and coal-fired systems. The scope of the study includes identifying and defining advanced technology concepts that can be effectively integrated with both gas- and coal-fired power generation to provide high efficiency and low emissions. The objective of this study was to determine whether advanced coal-fired power plants have the potential to be competitive, in the period after 2010, with NGCC power plants of the G or H class. Five advanced technology cases were identified – four coal-based and one natural gas-based. Each cycle incorporated a process to reduce CO_2 emissions by 90 percent. Once identified, a heat and material balance was used to estimate system performance. The results of the system performance estimate, and the heat and material balance, were then used to determine the total plant cost and cost of electricity for each plant.

Of the five advanced cases identified, only two have been completely defined. One of the advanced cases defined is gas-fired, while the other is coal-fired. An advanced natural gas case based on the use of a solid oxide fuel cell (SOFC) stack coupled with a cascaded humidified advanced turbine (CHAT) has been defined. This case will be investigated with and without CO_2 removal (thus, a single set of two advanced natural gas-fired cases).

The advanced coal-fired case identified also consists of a single set of two cases. Both are integrated gasification combined cycle (IGCC) plants utilizing H class turbine technology. Both cases utilize entrained flow gasification technology that has been demonstrated at commercial scale under DOE's Clean Coal Technology demonstration program. The primary difference between the two coal-fired cases is that one case shifts the carbon monoxide in the fuel gas to CO_2 and then removes the CO_2 from the fuel gas prior to combustion, while the other case makes no attempt to limit CO_2 emissions. This set of cases will serve as the base case for the advanced coal-fired cases.

In order to quantify the performance and economic improvement generated through the use of each advanced technology concept, gas- and coal-fired base cases were identified. Four base case NGCCs were identified. Two of the gas-fired cases are based on the General Electric Frame 7FA gas turbine, one case with CO_2 removal and one case without CO_2 removal. The other two gas-fired cases are based on the General Electric class H combined cycle system, one case with CO_2 removal and one case without CO_2 removal. CO_2 is removed with an oxygen-tolerant amine from the power plant's flue gas.

Four conventional coal-fired configurations were identified as well. Two of the conventional coal-fired cases power a conventional supercritical steam turbine, one case with CO_2 removal and one case with no CO_2 removal. The other two conventional coal-fired cases power ultra-supercritical steam turbines, one case with CO_2 removal and one case without CO_2 removal. CO_2, for these conventionally fired coal plants, is removed with an oxygen-tolerant amine from the power plant's flue gas.

Each of the identified cases, both base case and advanced, are labeled and listed below:

- Base Case Natural Gas-Fired Configurations

  <u>Case 1A</u> – Base NGCC with CO_2 Removal (Class F Gas Turbine)

  <u>Case 1B</u> – Base NGCC with CO_2 Removal (Class H Gas Turbine)

  <u>Case 1C</u> – Base NGCC without CO_2 Removal (Class F Gas Turbine)

  <u>Case 1D</u> – Base NGCC without CO_2 Removal (Class H Gas Turbine)

- Advanced Natural Gas-Fired Configurations

  <u>Case 2A</u> – Advanced Combined Cycle (CHAT/SOFC) with CO_2 Removal

  <u>Case 2B</u> – Advanced Combined Cycle (CHAT/SOFC) without CO_2 Removal

- Advanced Coal-Fired Configurations

  <u>Case 3A</u> – Base Case IGCC Plant with CO_2 Removal

  <u>Case 3B</u> – Base Case IGCC Plant without CO_2 Removal

  <u>Case 3C</u> – 83.5 Percent CGE IGCC without CO_2 Removal

  <u>Case 3D</u> – 83.5 Percent CGE IGCC with CO_2 Removal

  <u>Case 4</u> – Base Advanced Coal Plant (SOFC/Gas Turbine Combined Cycle)

  <u>Case 5</u> – Advanced Cycle Variation A (to be defined)

  <u>Case 6</u> – Advanced Cycle Variation B (to be defined)

- Conventional Coal-Fired Configurations

  Case 7A – Conventional Supercritical Pulverized Coal with CO_2 Removal

  Case 7B – Ultra-Supercritical Pulverized Coal with CO_2 Removal

  Case 7C – Conventional Supercritical Pulverized Coal without CO_2 Removal

  Case 7D – Ultra-Supercritical Pulverized Coal without CO_2 Removal

  Case 7E – Advanced Ultra-Supercritical Pulverized Coal without CO_2 removal

In this interim report, technical descriptions, performance results, equipment lists, and economic analyses are provided for the following cases: four base case natural gas-fired combined cycles (1A through 1D), one case of the advanced natural gas-fired set (2B), the set of advanced coal-fired base cases (3A and 3B), and all of the conventional coal-fired cases (7A through 7D). For each case presented in this report, heat and material balances were developed using the commercial steady-state flowsheet simulator ASPEN™. Results from the energy and mass balances were used to determine parasitic loads and overall system efficiency. They were also used to determine airborne emissions, size process equipment, generate an equipment list, and define input into the economic evaluation. These results will establish a "measuring stick" that can be used to estimate the performance competitiveness of coal-fired advanced technology cycles that are expected to mature around the year 2010.

1.1 Objective and Approach

The project objective was to evaluate three preliminary designs for advanced coal-fired power plants to determine if they have the potential to be competitive, in the period after 2010, with natural gas combined cycle power plants of the G or H class or conventional coal-fired plants. The inputs to the coal-fired power plants were coal, air, and water. The outputs were electricity, slag, sulfur, and pressurized high purity CO_2. The plants were equipped with state-of-the-art emissions control systems and designed to have essentially zero emissions of air pollutants, water pollutants, and solid wastes. All wastes were collected in a form suitable for reuse or sequestration. For example, solid wastes were assumed acceptable for recycling into building and construction uses, and sulfur was sold to the chemical industry. CO_2 was collected in a form suitable for local sequestration or transportation to another site.

1.2 General Evaluation Basis

The performance analysis will use the information in Table 1-1 as the evaluation basis:

- Average annual ambient air conditions for material balances, thermal efficiencies and other performance related parameters will be at a dry bulb temperature of 17.2°C (63°F) and an air pressure of 0.099 MPa (14.4 psia). For equipment sizing, the maximum dry bulb temperature is 35°C(95°F), and the minimum for mechanical design dry bulb temperature –6.7°C (20°F). These were the same conditions as those used by Parsons for previous fossil fuel technology evaluations conducted for DOE.

- For NGCC and IGCC cases (1A, 1B, 1C, 1D, 3A, 3B, 3C, and 3D), performance sensitivity were calculated at 15°C (59°F) and 1.014 Bar (14.7 psia) (sea level) for comparison with other studies at International Standards Organization (ISO) conditions.

Table 1-1
SITE CHARACTERISTICS

Topography	Level
Elevation	152.4m (500 ft)
Design Air Pressure	0.099 MPa (14.4 psia)
Design Temperature, dry bulb	17.2°C (63°F)
Design Temperature, max.	35°C (95°F)
Design Temperature, min.	-6.7°C (20°F)
Relative Humidity	55%
Transportation	Rail access
Water	Municipal
Ash Disposal	Off site

- Coal -Illinois No. 6 — See Table 1-2
- Natural gas — See Table 1-3
- Greer limestone — See Table 1-4
- Condenser pressure — 67.8 mbara (2 in. Hga) at 17.2°C(63°F)
- CO_2 delivery pressure — 8.38 MPa (1200 psig)
- CO_2 specification — -40°C(-40°F) dew point, 1.25% H_2 maximum, 100 ppm SO_2 maximum, and 50 ppm H_2S maximum
- Sulfur removal — >98%
- NOx emissions — < 0.0086 kg/GJ(<0.02 lb/10^6 Btu)
- Cases 3C and 3D will be performance cases only and completed at end of study.

1.3 Case Descriptions

The following power system configurations will be evaluated. Performance results for cases 1A through 1D, 2B, 3A and 3B, and 7A through 7D are presented in this interim report. The remaining cases will be documented in the final report.

- Natural Gas Base Configurations:

  Case 1A – Two trains GE 7FA natural gas combustion turbines, each with its own heat recovery steam generator (HRSG) feeding a single steam turbine.

  Case 1B – Single train GE H class natural gas combined cycle with a single HRSG and steam turbine.

Table 1-2
BASE COAL ANALYSIS – ILLINOIS NO. 6 SEAM, OLD BEN NO. 26 MINE

Proximate Analysis	**As-Received (wt%)**	**Dry Basis (wt%)**
Moisture	11.12	
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
TOTAL	100.00	100.00
HHV MJ/kg(Btu/lb)	27.12 (11,666)	30.52 (13,126)
Ultimate Analysis	**As-Received (wt%)**	**Dry Basis (wt%)**
Moisture	11.12	-
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen (by difference)	6.88	7.75
TOTAL	100.00	100.00

Table 1-3
NATURAL GAS ANALYSIS

	Volume, %
CH_4	90
C_2H_6	5
Inerts/N_2	5
HHV,kJ/scm (Btu/scf)	37.33 (1,002)
HHV MJ/kg (Btu/lb)	50.75(21,824)

Table 1-4
GREER LIMESTONE ANALYSIS

	Dry Basis, %
Calcium Carbonate, $CaCO_3$	80.40
Magnesium Carbonate, $MgCO_3$	3.50
Silica, SiO_2	10.32
Aluminum Oxide, Al_2O_3	3.16
Iron Oxide, Fe_2O_3	1.24
Sodium Oxide, Na_2O	0.23
Potassium Oxide, K_2O	0.72
Balance	0.43

Case 1C – As Case 1A but without CO_2 removal.

Case 1D – As Case 1B but without CO_2 removal.

Case 2 – Advanced natural gas-fired combined cycle with CO_2 removal. The advanced cycle comprises solid oxide fuel cell (SOFC) (planar or tubular) followed by a cascaded humidified advanced turbine (CHAT) cycle, water removal from the recuperator stack, and CO_2 removal.

- Advanced Coal-Fired Configurations:

Case 3A – Base IGCC plant with CO_2 removal. Conventional pressure air separation unit (ASU), E-Gas™ gasifier, fire tube syngas cooler, particulate removal by hot side filter, sour gas two-stage shift (will also accomplish COS hydrolysis), gas cooling with heat recovery including raising hot water for gas (H_2) saturation, two-stage Selexol for H_2S and then CO_2 removal, CO_2 compression, Claus plant plus tail gas treating unit (TGTU), fuel gas (H_2) saturation plus addition of intermediate pressure steam to control NOx in the gas turbine. Evaluate the performance and cost impact to boost the CO_2 delivery pressure to 15.27MPa (2200 psig).

Case 3B – Base IGCC plant without CO_2 removal. High-pressure ASU, E-Gas™ gasifier, fire tube syngas cooler, particulate removal by hot side filter, economizer, water scrub, COS hydrolysis, hot water recovery for fuel gas saturation, MDEA sulfur removal, Claus plant with TGTU, fuel gas saturation, addition of intermediate pressure steam to saturated fuel gas at gas turbine (7H) to reduce gas to 5.59 GJ/scm (150 Btu/scf) LHV basis.

Case 3C – As Case 3B but with E-Gas™ gasifier at CGE as in EPRI report TR-102034, i.e., 83.5 percent HHV basis.

Case 3D – As Case 3A but with E-Gas™ gasifier at 83.5 percent CGE and 5.6 MPa (800 psig) pressure.

Case 4 – Gasification island as in Case 3D without gas saturation with H_2 gas to SOFC (planar or tubular), SOFC exhaust to gas turbine. Optimize H_2 usage – examine sending some H_2 (with saturation) to the gas turbine to improve the efficiency by using a high-temperature gas turbine and determine whether it is worth adding a steam cycle or at least steam raising for NOx control, shift, and other plant use.

Case 5 – Advanced coal plant variation A.

Case 6 – Advanced coal plant variation B.

- Conventional Coal-Fired Base Configurations:

Case 7A – Conventional supercritical with CO_2 removal. Steam conditions 24.1MPa/566°C/566°C/566°C (3500 psia/1050°F/1050°F/1050°F), i.e., double reheat. Electrostatic precipitator (ESP) for particulate removal, limestone scrubbing for SO_2 removal, selective catalytic reduction (SCR) for NOx removal, and MEA absorption for CO_2 removal.

Case 7B – As Case 7A but with steam conditions 34.5 MPa/649°C/649°C/649°C (5000 psia/1200°F/1200°F/1200°F).

Case 7C – As Case 7A but without CO_2 removal.

Case 7D – As Case 7B but without CO_2 removal.

Case 7E – As Case 7A but with steam conditions 37.6MPa/700°C/700°C/720°C (5455 psia/1290°F/1290°F/1330°F).

2
NATURAL GAS COMBINED CYCLES (NGCC) – TECHNICAL DESCRIPTIONS

Four natural gas-fired combined cycle power plants were evaluated and are presented in this section. Each design is competitive market-based and consists of a commercially available combustion turbine coupled with a reheat steam cycle. Plant performance was estimated and a heat and material balance diagram is presented for each case. An equipment list was generated based on the estimated plant performance and used to generate total plant and operating cost as well as cost of CO_2 emissions avoided. A plant description is also presented.

The four cases evaluated are:

- <u>Case 1A</u> – F Class Combined Cycle with CO_2 Removal and Recovery
- <u>Case 1B</u> – H Class Combined Cycle with CO_2 Removal and Recovery
- <u>Case 1C</u> – F Class Combined Cycle without CO_2 Removal
- <u>Case 1D</u> – H Class Combined Cycle without CO_2 Removal

In cases 1A and 1B, CO_2 was removed from the flue gas stream with an aqueous solution of inhibited (oxygen tolerant) monoethanolamine (MEA). MEA absorption is the conventional technology of choice for CO_2 removal from an oxygen-bearing flue gas stream. The CO_2 was concentrated into a product stream and dried and compressed to a supercritical condition. The four cases are described in greater detail below.

2.1 Case 1A -- NGCC, F CLASS TURBINE AND CO_2 REMOVAL

2.1.1 Introduction

This competitive market-based design is based on the use of *two* natural gas-fired combustion turbines (CTs) each coupled with a heat recovery steam generator (HRSG) to generate steam for a *single* steam turbine generator. CO_2 is removed from the HRSG flue gas with an amine-based absorption system. Plant configuration and performance reflects current information and design preferences, the availability of newer combustion and steam turbines, and the relative latitude of a greenfield site.

This rendition of CT/HRSG technology is based on the General Electric 7FA machine. This particular machine provides values of power output, airflow, and exhaust gas temperature that effectively couple with a HRSG to generate steam for the companion steam turbine plant to produce an estimated total net output of 399 MWe, at an efficiency of 43.5 percent (LHV) and

39.2 percent (HHV). For this study, two gas turbines are used in conjunction with one 12.4 MPa/565.6°C/565.6°C (1800 psig/1050°F/1050°F) steam turbine.

Cool flue gas exiting the two HRSGs is further cooled and partially compressed and routed to an inhibited MEA absorber-stripper system. In the absorber, a solution of aqueous inhibited MEA is used to remove 90 percent of the CO_2 in the flue gas. Above this level of CO_2 removal the costs of removal rise very rapidly. In the stripper, low-pressure steam is used to strip (remove) CO_2 from the solution. Low-pressure, concentrated CO_2 from the stripper is then compressed to supercritical conditions for subsequent transportation off-site.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections are:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Production Cost, and Economics
- Case 1A Sensitivity

The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost. Three sensitivity performance cases are presented at the end of the section.

- Case 1A at ISO conditions
- Case 1A with back pressure turbine
- Case 1A with back pressure turbine at ISO conditions

2.1.2 Thermal Plant Performance

Table 2-1 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant. Gross power output (prior to the generator terminals) for the two General Electric 7FA gas turbines is estimated to be 334.9 MWe. This number is less than the oft quoted 346 MWe (2 x 173 MWe) available at ISO conditions. The assumed ambient conditions (see Table 1-1) correspond to lower pressure and higher temperature (i.e., lower air density) compared to ISO. The geometry of the gas turbine is fixed. As a result, the mass flow of less dense air through the compressor will be less than that of relatively more dense air. That is the case we have here -- less dense ambient air, lower compressor air suction, lowered fuel usage and turbo-set power output. Simple cycle efficiency for the CT remains essentially unchanged. For comparison, this case was also run at ISO conditions. This will be discussed later in the write-up at the end of Section 2.1.

Also shown in Table 2-1 is the gross steam turbine power output of 120 MWe. This number is much lower than that expected for a natural gas combined cycle with a gross CT power output of 334.9 MWe. Normally, a rule-of-thumb estimate is that steam turbine power is roughly half that of the CT in a gas-fired combined cycle. However, in this case, most of the low-pressure steam available at the ST crossover is diverted from the low-pressure (LP) turbine and used in the MEA stripper reboiler. Diverting this LP steam results in a marked decrease in steam turbine power output.

Plant auxiliary power is also summarized in Table 2-1. The total is estimated to be 48 MWe. This value, much higher than that anticipated for a gas-fired combined cycle, is due to the presence of the CO_2 removal/compression equipment. In particular, the flue gas blower, which requires 22.4 MWe of auxiliary power, and the CO_2 compressor, which requires 16.2 MWe of auxiliary power are the major users of auxiliary power.

Net plant power output, which considers generator losses and auxiliary power, is 398.9 MWe. This plant power output results in a net system thermal efficiency of 43.5 percent (LHV) with a corresponding heat rate of 8,269 kJ/kWh (7,838 Btu/kWh) (LHV). The corresponding HHV values for efficiency and heat rate are 39.2 percent and 9,176 kJ/kWh (8,698 Btu/kWh), respectively. These plant efficiency and heat rate numbers are low in comparison to those expected for gas-fired combined cycles of the F-class technology. This low system thermal efficiency is due to the increased auxiliary power and steam requirements of the CO_2 removal equipment.

Figure 2-1 contains a heat and material balance diagram for the 100 percent load condition. CT and ST cycles are shown schematically along with the appropriate state point condition data. An open Brayton cycle (CT) using air and combustion products as working fluid is used in conjunction with the conventional sub-critical Rankine cycle (ST). The two cycles are coupled by the generation and superheating of steam in the HRSG, and by feedwater heating in the HRSG. The HRSG uses a triple pressure configuration. The low-pressure drum provides steam for an integral deaerator. Also shown in the diagram is the basic equipment required to remove CO_2 from the flue gas stream and concentrate it as a pure, high-pressure product.

The heat and material balance in Figure 2-1 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9×10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Table 2-1
CASE 1A – (2) 7FA x 1 NGCC WITH CO_2 REMOVAL
FLUE GAS BLOWER OPTION
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	334,892
Steam Turbine Power	120,037
Generator Loss	(8,062)
Gross Plant Power (Note 1)	446,867
AUXILIARY POWER SUMMARY, kWe	
Condensate Pumps	320
High Pressure Boiler Feed Pump	2,270
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,700
Cooling Tower Fans	960
Flue Gas Blower	22,410
MEA CO_2 Removal	1,440
CO_2 Compression and Drying (Note 3)	16,220
Transformer Loss	1,370
Total Auxiliary Power Requirement	47,990
NET PLANT POWER, kWe	398,877
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	43.5
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	8,269 (7,838)
Net Efficiency, % HHV	39.2
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	9,176 (8,698)
CONDENSER COOLING DUTY, GJ/h (10^6 Btu/h)	672 (637)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 4)	72,116 (158,986)

Note 1 - Loads are presented for two gas turbines, and one steam turbine
Note 2 - Includes plant control systems, lighting, HVAC, etc
Note 3 – Final CO_2 pressure is 8.3 MPa (1,200 psia)
Note 4 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb)

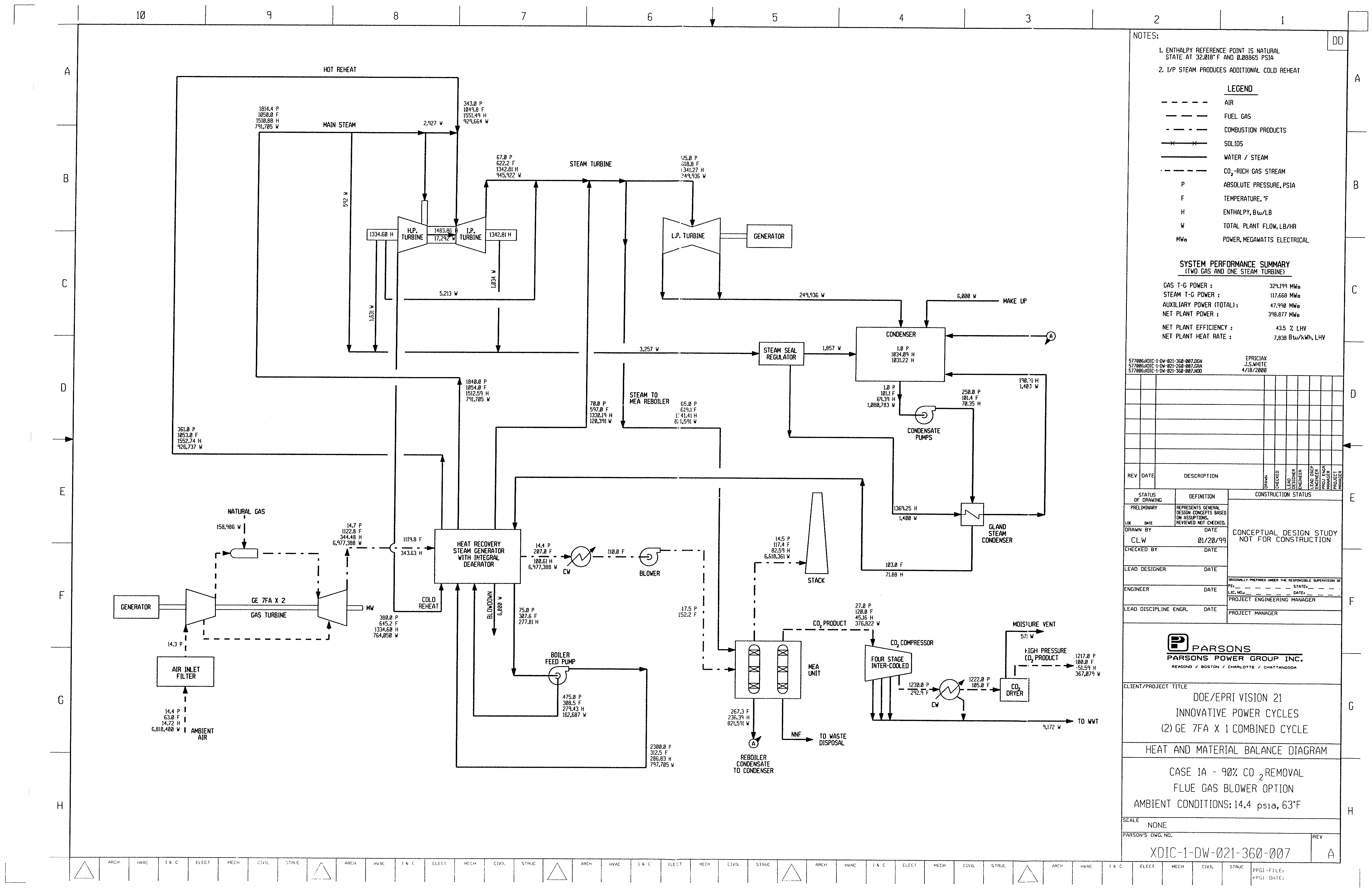

Figure 2-1
Heat and Material Balance Diagram – (2) GE 7FA x 1 Combined Cycle – Case 1A – 90% CO_2 Removal (Flue Gas Blower Option)

2.1.3 Power Plant Emissions

The operation of the modern, commercially available gas turbine fueled by natural gas, coupled to a HRSG, is projected to result in very low levels of SO_2, NOx, and CO_2 emissions. A summary of the estimated plant emissions for this case is presented in Table 2-2. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four basis: (1) kilograms per gigajoules of HHV thermal input (pound per million Btu of HHV thermal input), (2) tonnes per year for a 65 percent capacity factor (tons per year for a 65 percent capacity factor), (3) tonnes per year for an 85 percent capacity factor (tons per year for an 85 percent capacity factor), and, (4) kilograms per hour per MWe of power output (pounds per hour per MWe of power output).

Table 2-2
CASE 1A AIRBORNE EMISSIONS
(2) 7FA x 1 NGCC WITH CO_2 REMOVAL

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
NOx	< 0.014 (< 0.033)	295 (325)	381 (420)	0.127 (0.28)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	4.89 (11.36)	101,848 (112,266)	133,185 (146,809)	44.84 (98.86)

As shown in the table, values of SO_2 emission and particulate discharge are negligible. This is a direct consequence of using natural gas as the plant fuel supply. Pipeline natural gas contains minor amounts of reduced sulfur species that produce negligible SO_2 emissions when combusted and diluted with a large amount of air. As for particulate discharge, when natural gas is properly combusted in a state-of-the-art CT the amount of solid particulate produced is very small (less than 9.1 kg/h (20 lb/h), 0.03 kg/MWh (0.06 lb/MWh), for both 7FA machines).

The low level of NOx production is achieved through use of GE's dry low-NOx (DLN) combustion system. This combustor arrangement should limit NOx emissions to 9 ppm adjusted to 15 percent O_2 content in the flue gas.

In this power plant configuration, approximately 90 percent of the CO_2 in the flue gas is removed and concentrated into a highly pure product stream. This greatly limits CO_2 emissions as can be seen in Table 2-2.

2.1.4 System Description

The major subsystems in this natural gas-fired combined cycle power plant are:

- Combustion Turbine
- Heat Recovery Steam Generator
- CO_2 Removal and Compression
- Steam Turbine Generator
- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief discussion about the power plant equipment and operating conditions. This discussion is based on the heat and material balance diagram shown in Figure 2-1. The equipment list, which follows this section, is based on the material presented here.

2.1.4.1 Combustion Turbine

The CT, or gas turbine, generator selected for this application is based on the General Electric MS 7001FA model. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. Each CT operates in an open cycle mode. Two 7FAs, each equipped with an individual HRSG, are used to power a single steam turbine in a traditional 2 on 1 arrangement.

Inlet air at 429.6 kg/sec (947 lb/sec) (per CT) is compressed in a single spool compressor to a pressure ratio of approximately 15.5:1. This airflow is lower than the ISO airflow of 442.7 kg/sec (976 lb/sec) due to the choice of ambient conditions used in this specific study. (The ambient conditions chosen here correspond to a standard EPRI/DOE fossil-plant site. They result in a less dense ambient air, and subsequently, less airflow and power output in the gas turbine.) The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the natural gas. Compressed air is also used in burner, transition and film cooling services.

Pressurized pipeline natural gas at a rate of 36,058 kg/h (79,493 lb/h) (per CT) is combusted in several (14) parallel dry low-NOx combustors that use staged combustion to limit NOx formation. The CT combustors are can-annular in configuration. In the can-annular arrangement, individual combustion cans are placed side-by-side in an annular chamber. Each can is equipped with six fuel nozzles. This allows for higher mass flows over earlier machines and higher operating temperatures. In the estimated performance provided here, the machine will develop a rotor inlet temperature of about 1315.6°C (2400°F).

Hot combustion products are expanded in the three-stage turbine-expander. The CT exhaust temperature is estimated as 606.1°C (1123°F) given the assumed ambient conditions, back-end loss, and HRSG pressure drop. This value, slightly higher than the ISO quoted value of 602.8°C (1117°F) for a simple cycle gas turbine, is due to increased back-pressure on the CT due to the HRSG.

Gross turbine power, as measured prior to the generator terminals, is estimated as 334.9 MWe. The CT generator is a standard hydrogen-cooled machine with static exciter. Net CT power from the generator is estimated at 329.2 MWe. These power values are lower than those quoted at ISO conditions because the CT compressor airflow is lower at the assumed ambient conditions. This lower airflow results in lower power output. The CT fuel fed is decreased proportionately such that the CT simple cycle efficiency is relatively unchanged.

2.1.4.2 Heat Recovery Steam Generator

High-temperature flue gas at 1,582,472 kg/h (3,488,694 lb/h) (per turbine) exiting the CT is conveyed through a HRSG (one for each turbine) to recover the large quantity of thermal energy that remains. For analysis purposes, it is assumed that the flue gas heat loss through the HRSG duct corresponds to 1.6°C (3°F). Flue gases travel through the HRSG gas path and exit at 97.2°C (207°F).

The HRSG is configured with high-pressure (HP), intermediate-pressure (IP), and LP steam drums and circuitry. The HP drum is supplied with feedwater by the HP boiler feed pump while the IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump. IP steam from the drum is mixed with cold reheat steam; the combined flow is then passed to the reheat section. The LP drum produces steam for superheat as well as saturated steam for an integral deaerator.

Condensate at 490,251 kg/h (1,080,800 lb/h) flows from the gland steam condenser to the HRSG feedwater heater (low-temperature economizer). In this heater, the condensate temperature is raised from 39.4°C (103°F) to 144.4°C (292°F). The condensate is then routed to the integral deaerator, which operates at 152.8°C (307°F) and 0.5 MPa (75 psia). Feedwater from the integral deaerator is then conveyed to the boiler feed pump.

High-pressure water from the boiler feed pump at 15.9 MPa (2300 psia) is heated to 315.6°C (600°F) in a series of three economizers. The high-pressure economizers are staggered within the HRSG in order to maximize flue gas heat flux. The high-pressure evaporator operates 13.4 MPa (1950 psia), resulting in a nominal 18.3°C (33°F) evaporator temperature approach. The gas to water pinch is 11.1°C (20°F). A continuous drum blowdown of 2,721.6 kg/h (6,000 lb/h) was used in this analysis. Saturated steam removed from the HP drum is superheated to 567.8°C (1054°F) and then routed to the HP steam turbine throttle valves.

Feedwater from an interstage bleed on the HP boiler feed pump at a rate of 73,795 kg/h (162,687 lb/h) feeds the IP steam drum. The IP drum operates with a 13.9°C (25°F) approach and an 11.1°C (20°F) gas-to-water pinch. Saturated steam from the IP drum at 2.8 MPa (410 psia) is superheated to 315.6°C (600°F) and then mixed with cold reheat from the HP steam turbine. The combined flow is then reheated to 565.6°C (1050°F) and routed to the IP section of the steam turbine.

The LP steam drum operates at 0.52 MPa (75 psia). Saturated steam not utilized in the integral deaerator is removed from the LP drum and superheated to 313.9°C (597°F). This steam then flows to the steam turbine crossover area at a rate of 54,609 kg/h (120,390 lb/h).

The HRSG tube surface is typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 material; the low-temperature portions (< 398.9°C (750°F)) will be carbon steel.

2.1.4.3 CO_2 Removal and Compression

Part of the criteria of this combined cycle power plant design is the limitation of CO_2 emissions. This power plant configuration is based on removing 90 percent of the CO_2 in the HRSG flue gas. An inhibited aqueous solution of MEA is used to remove the CO_2.

Cool flue gas exiting the HRSG at 98.9°C (210°F) is indirectly cooled to 43.3°C (110°F) with circulating cooling water. The cool flue gas is partially compressed to 0.12 MPa (17.5 psia) in a centrifugal blower in order to overcome the gas-path pressure drop. There are four flue gas coolers and blowers operating in parallel. The partially compressed flue gas stream is then routed to a traditional absorber/stripper arrangement.

Flue gas enters the bottom of the absorber and flows upward and counter to the lean MEA solution. CO_2 is removed from the flue gas in the packed-bed absorber column through direct contact of MEA. The packing is 5.08 cm (2-inch) stainless steel rings. There are four absorber columns, operating in parallel, each 8.84 meters (29 feet) in diameter and 24.38 meters (80 feet) vertical. MEA circulation through each absorber is approximately 17.8 m^3/min (4700 gpm).

Flue gas exiting the top of the absorber columns is collected in a common duct and routed to an exhaust stack. Rich solution off the bottom of the columns is heated in the rich-lean heat exchanger through indirect contact with lean solution flowing from the bottom of the stripper column.

Hot rich solution enters the top of the stripper column and flows downward and counter to the stripping agent, which is primarily steam. LP steam from the steam turbine crossover generates the stripping steam in the reboiler. CO_2 liberated through the application of heat flows upward along with the stripping steam. This vapor phase is routed to the reflux condenser where it is cooled to 48.9°C (120°F), thereby condensing a large portion of the water vapor. This condensed phase is returned to the stripper. The condenser vapor phase, which is saturated CO_2, is routed to the multi-staged, intercooled CO_2 compressor. Lean solution removed from the bottom of the stripper is cooled in the rich-lean heat exchanger, cooled in a secondary exchanger, and then returned to the absorber.

There are four strippers operating in parallel. Each stripper column is 4.88 meters (16 feet) in diameter and equipped with stainless steel trays that promote good inter-phase contact. The height of each stripper column is 22.86 meters (75 feet). Total reboiler steam requirement is approximately 372,678 kg/h (821,600 lb/h) of 0.34 MPa (50 psig) LP steam.

SO_2 in the flue gas may react with the MEA solvent to form heat stable salts. Once formed, the MEA cannot be easily regenerated and must be removed from the reclaimer system as a solid. If solvent makeup becomes unacceptable, an alkali scrubber system can be installed before the absorber. However, solvent losses through salt formation are expected to be low for NGCC.

NO_x components NO and NO_2 will be present in the flue gas stream. NO is unreactive with the solvent. NO_2, on the other hand, may react with the solvent to form nitrates. If nitrate formation cannot be controlled with normal filtering and treating systems, a cold-water scrubber may be installed as a means to control NO_2 flow into the absorber. NO_2, which usually accounts for less than ten percent of the NOx species, should not pose much of a problem to this system.

CO_2 from the stripper is compressed to a pressure of 8.4 MPa (1222 psia) by the multi-stage CO_2 compressor. The compression includes interstage cooling as well as knockout drums to remove and collect condensate. CO_2 is dehydrated to remove water vapor. Water vapor stripped from the CO_2 is vented to the atmosphere. After drying, the CO_2 enters the pipeline for transport and/or disposal/sequestration.

2.1.4.4 Steam Turbine Generator

The Rankine cycle used in this case is based on a state-of-the-art 12.4 MPa/565.6°C/565.6°C (1800 psig/1050°F/1050°F) single reheat configuration. The steam turbine is a single machine consisting of tandem HP, IP, and double-flow LP turbine sections connected via a common shaft and driving a 3,600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a pitch diameter of 152.4 cm (60 inches) and a last-stage bucket length of 50.8 cm (20 inches).

Main steam at a rate of 359,115 kg/h (791,700 lb/h) from the HP boiler located in the HRSG passes through HP stop valves and control valves and enters the turbine at 12.5 MPa/565.6°C (1815 psia/1050°F). Steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. Reheat steam flows through the IP stop valves and intercept valves and enters the IP section at 2.4 MPa/565.6°C (343 psig/1050°F). After passing through the IP section, the steam enters a crossover pipe. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the crossover line. A tee is provided to extract a controlled amount of LP steam from the crossover. This steam is used in the MEA reboiler located below the MEA stripper column. The remaining crossover steam is divided into two paths and flows through the LP sections exhausting downward into the condenser.

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

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

The generator is a synchronous type rated at 140 MWe. It operates with a 0.85 power factor and generates power at 23 kV. A static, transformer type exciter is provided. Gross generator output is 120.04 MWe. The generator operates with an efficiency of approximately 98 percent. Net steam turbine generator power output is 117.67 MWe.

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

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

2.1.4.5 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the HRSG. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity motor-driven feed pumps are provided for HP/IP service. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

2.1.4.6 Balance of Plant

The balance of plant items discussed in this section include:

- Natural Gas Lines and Metering
- Steam Systems
- Circulating Water System
- Accessory Electric Plant
- Instrumentation and Control

Natural Gas Lines and Metering

In this design, it is assumed that a natural gas main with adequate capacity and pressure is at the fence line of the site and that a suitable right of way is available to install a branch line to the site. A gas line comprised of Schedule 40 carbon steel pipe, 40.64 cm (16 inches) nominal OD, is required to convey the gas to the site. The buried pipeline is coated and wrapped, and cathodically protected with a zinc ribbon-type sacrificial anode to protect the pipe from corrosion.

A new gas metering station is located on the site, adjacent to the new combustion turbine. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording, or may be of the positive displacement type. In either case, a complete time-line record of gas consumption rates and cumulative consumption is provided.

Steam Systems

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

Main steam exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, then is routed to the HP turbine.

Cold reheat steam exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbine.

Circulating Water System

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

Accessory Electric Plant

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

Instrumentation and Control

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

2.1.5 Case 1A Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 2-1. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and used in the financial analysis. In the following, all meters (m) (feet (ft)) conditions specified for process pumps correspond to meters (feet) of liquid being pumped. All other symbols can be referenced in the Nomenclature section.

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter)

Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Gallon,gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832 x 10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9×10^{-3} = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

ACCOUNT 1 COAL AND SORBENT HANDLING

Not Applicable

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Gas Pipeline	Underground, carbon steel, coated and wrapped, cathodic protection	158,990 lb/h @ 600 psig 6 in. OD, Sch. 40	16.1 km
2	Gas Metering Station		158,990 lb/h	1

ACCOUNT 2B SORBENT PREPARATION AND FEED

Not Applicable

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cyl., outdoor	70,000 gal	1
2	Condensate Pumps	Vert. canned	1080 gpm @ 580 ft	2
3	Boiler Feed Pumps	Horizontal split case Multi-staged, centr. with interstage bleed for IP feedwater	870 gpm @ 5,800 ft	2

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty
2	Fuel Oil Storage Tank	Vertical, cylindrical	20,000 gal	2
3	Fuel Oil Unloading Pump	Gear	50 psig, 100 gpm	1
4	Fuel Oil Supply Pump	Gear	150 psig, 5 gpm	2
5	Service Air Compressors	Recip., single-stage, double-acting, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exchanger	Plate and frame	50% cap. Each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
11	Fire Service Booster Pump	Two-stage horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1000 gpm	1
13	Raw Water	S.S., single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	S.S., single suction	160 ft, 120 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

Not Required

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A CO_2 REMOVAL AND COMPRESSION

Equipment No.	Description	Type	Design Condition	Qty.
1	Flue Gas Cooler	Shell and tube cooling water service	5 psig / 250°F 43 x 10^6 Btu/h	4
2	Flue Gas Fan	Centrifugal	1,750,000 lb/h 441,000 acfm 90 in.H_2O (gauge) 7,250 hp	4
3	Absorber	Packed bed 2" rings Three 20-foot stages	30 psig / 300°F	4
4	Stripper	Tray tower	50 psig / 300°F	4
5	Reflux Drum	Horizontal cooling water	50 psig / 250°F	4
6	Reboiler	Horizontal shell 50 psig steam	75 psig / 350°F	4
7	Cartridge Filter	Horizontal	100 psig / 200°F	4
8	Carbon Filter	Horizontal	100 psig / 200°F	4
9	Rich Amine Pump	Centrifugal	4,700 gpm @ 250 ft	4
10	Lean/Rich Amine Heat Exchanger	Horizontal shell	100 psig / 280°F	4
11	Lean Amine Pump	Centrifugal	4,700 gpm @ 250 ft	4
12	CO_2 Compressor and Auxiliaries	Centrifugal Multi-staged	25 psia / 1300 psia	1
13	Dehydration Package	Triethylene glycol	1300 psia	1
14	Final CO_2 Cooler	Shell and tube cooling water service	28.9 x 10^6 Btu/h	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	170 MWe Gas Turbine Generator	Axial flow single spool based on GE 7FA	950 lb/sec airflow 2410°F rotor inlet temp. 15.5 pressure ratio	2
2	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	2
3	Air Inlet Filter/Silencer	Two-stage	950 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	2
4	Starting Package	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	2
5	Air to Air Cooler			2
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		2
7	Oil Cooler	Air-cooled, fin fan		2
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	2
9	Generator Glycol Cooler	Air-cooled, fin fan		2
10	Compressor Wash Skid			2
11	Fire Protection Package	Halon		2

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, triple-pressure, with economizer section and integral deaerator	HP-1950 psig/632°F 791,600 lb/h, superheat to 1050°F IP-410 psig/447°F 163,000 lb/h, superheat to 600°F LP-60 psig/307°F 120,182 lb/h, superheat to 600°F	2
2	Stack	Carbon steel plate, lined with type 409 stainless steel	213 ft high x 28 ft dia.	2

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	135 MW Turbine Generator	TC2F20, triple admissions	1815 psia 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	1,081,000 lb/h steam @ 2.0 in. Hga with 74°F water, 20°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water-sealed	2000/20 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	70,000 gpm @ 80 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	83°F WB/88°F CWT/ 96°F HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Not Applicable

2.1.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the 2 x 1 7FA natural gas-fired combined cycle power plant with CO_2 removal, case 1A, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 1A represents a plant with a net output of 398.9 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 2-3. A detailed estimate for case 1A is included in Appendix A.

The production costs for case 1A consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal) and Fuel costs. The costs were determined on a first-year basis that includes evaluation at a 65 percent equivalent plant operating capacity factor. The results are summarized in Table 2-4 and supporting detail is contained in Appendix A.

Table 2-3
CASE 1A SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
5B	CO_2 Removal and Compression	121,940
6	Combustion Turbine and Accessories	73,900
7	HRSG, Ducting and Stack	34,120
8&9	Steam T-G Plant, including Cooling Water System	35,980
11	Accessory Electric Plant	26,400
	Balance of Plant	31,150
	SUBTOTAL	323,490
	Engineering, Construction Management Home Office and Fee	19,410
	Process Contingency	9,060
	Project Contingency	51,000
	TOTAL PLANT COST (TPC)	$402,960
	TPC $/kW	1,010

Table 2-4
CASE 1A ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	2,064	0.09
Maintenance	6,806	0.30
Administrative & Support Labor	1,196	0.05
Consumables	7,685	0.34
Byproduct Credits	N/A	N/A
Fuel	53,338	2.35
TOTAL PRODUCTION COST	71,089	3.13

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 1A. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per ton. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI is included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 2-5.

Table 2-5
CASE 1A LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	3.13
Annual Carrying Charge (¢/kWh)	2.66
Levelized Busbar Cost of Power Charge (¢/kWh)	5.79
Levelized Cost per Tonne of CO_2 Removed ($/tonne of CO_2)	139

2.1.7 Case 1A Sensitivity

In the course of completing this case, three sensitivity cases were identified and evaluated as follows:

- Case 1A at ISO conditions,
- Case 1A with back pressure gas turbine,
- Case 1A with back-pressure gas turbine at ISO conditions.

For each case, plant performance was estimated and a heat and material balance diagram was produced. There will be no cost estimate for these sensitivity cases.

2.1.7.1 Case 1A at ISO Conditions

This case was developed so that the results of this study could be compared to other studies that assumed ISO conditions for ambient. As such, the power plant configuration in this case is a direct duplicate of that described in detail in the previous section. However, due to the assumption of ISO ambient conditions -- which are 15°C (59°F), 0.101 MPa (14.696 psia), and 60 percent relative humidity -- there are several differences in plant performance.

Operation of the gas turbine at ISO conditions, as opposed to the ambient conditions of 17.2°C (63°F) and 0.099 MPa (14.4 psia) assumed for the primary case, results in greater flow through the gas turbine set. More air is compressed and utilized due to density changes at the compressor inlet. Increased airflow and a higher ambient (inlet) pressure results in a relatively higher firing pressure, higher fuel input, and increased power output. However, in the case presented here, the simple cycle efficiency at ISO conditions compared to those assumed for the body of this report is more or less unchanged.

Estimated performance is presented in Table 2.1-6. A heat and material balance is in Figure 2.1-2. As can be seen by comparing this heat and material balance with that in Figure 2.1-1, airflow for each compressor has increased from 429.6 kg/sec (947 lb/sec) to 442.7 kg/sec (976 lb/sec). Fuel flow to each turbine has increased from 36,058 kg/h (79,493 lb/h) to 37,306 kg/h (82,244 lb/h). Also, the steam turbine back-pressure has decreased from 68 mbara (2 inches HgA) to 41 mbara (1.2 inches HgA).

The heat and material balance in Figure 2-2 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 $\times 10^{-3}$	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

As shown in Table 2-6, gas turbine shaft power output has increased from 334.8 MW to 346.6 MW. This power increase is due entirely to the change in ambient conditions; operation at ISO allows greater volume throughput. Also, due to the increase in power plant thermal input, as well as a decrease in condenser back-pressure, steam turbine shaft power output has increased from 120 MW to 124 MW. The overall effect is increased plant output at a similar efficiency performance level.

2.1.7.2 Case 1A with Back-Pressure Gas Turbine

As can be seen in Table 2-1, the flue gas blower -- which conveys flue gas from the HRSG exhaust to the MEA absorber -- is the largest single component of the auxiliary power. Due to this, an alternative configuration without a flue gas blower was identified. With this approach, pressure head for the MEA absorber resistance was made up by holding a back-pressure on the gas turbine expander.

Table 2-7 shows a summary of estimated performance for this case. There is a slight increase in net plant power output, 401.3 MWe versus 398.9 MWe, as compared to the base case (shown in Table 2-1). Auxiliary power is markedly decreased, 26.3 MWe as compared to 47.9 MWe, but gas turbine power output decreases substantially due to the increased exit pressure and temperature of the gas turbine expander. There is also a modest increase in efficiency, 43.8 percent LHV versus 43.5 percent LHV.

Figure 2-3 shows the plant heat and material balance diagram. Gas turbine exhaust pressure is 0.123 MPa (17.9 psia) rather than the 0.101 MPa (14.7 psia) of the base case (shown in Figure 2-1). This high gas turbine expander back-pressure leads to an increase in expander exhaust temperature. The exhaust temperature with the back-pressure expander is 642.2°C (1188°F). This value is 18.9°C (66°F) above that of the base case. This temperature is very high and may contribute to equipment failure at some part-load conditions. Unless the OEM can ensure that this operating temperature would not lead to equipment failure, the slight increase in plant efficiency cannot be justified. A cost analysis would be required to determine if there is a significant capital cost advantage or investment incentive.

The heat and material balance in Figure 2-3 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 $x10^{-3}$	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

2.1.7.3 Case 1A with Back-Pressure Gas Turbine at ISO Conditions

The approach with back-pressure gas turbine was run at ISO conditions. The results are shown in Table 2-8.

Table 2-6
CASE 1A – ISO CONDITIONS
(2) 7FA x 1 NGCC WITH CO_2 REMOVAL
FLUE GAS BLOWER OPTION
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	346,645
Steam Turbine Power	124,445
Generator Loss	(8,340)
Gross Plant Power (Note 1)	462,750
AUXILIARY POWER SUMMARY, kWe	
Condensate Pumps	330
High Pressure Boiler Feed Pump	2,350
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,730
Cooling Tower Fans	980
Flue Gas Blower	22,660
MEA CO_2 Removal	1,490
CO_2 Compression and Drying (Note 3)	16,730
Transformer Loss	1,420
Total Auxiliary Power Requirement	48,990
NET PLANT POWER, kWe	413,760
PLANT EFFICIENCY	
Net Efficiency, % LHV	43.6
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	8,246 (7,818)
Net Efficiency, % HHV	39.3
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	9,151 (8,676)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	683.5 (648)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 4)	74,612 (164,488)

Note 1 – Loads are presented for two gas turbines, and one steam turbine.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 8.27 MPa (1200 psia).
Note 4 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV) 50,763 kJ/kg (21,824 Btu/lb).

Table 2-7
CASE 1A – (2) 7FA x 1 NGCC WITH CO_2 REMOVAL
BACK PRESSURE TURBINE OPTION
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	294,332
Steam Turbine Power	139,803
Generator Loss	(6,459)
Gross Plant Power (Note 1)	427,676
AUXILIARY POWER SUMMARY, kWe	
Condensate Pumps	340
High Pressure Boiler Feed Pump	2,620
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,990
Cooling Tower Fans	1,130
MEA CO_2 Removal	1,440
CO_2 Compression and Drying (Note 3)	16,220
Transformer Loss	1,310
Total Auxiliary Power Requirement	26,350
NET PLANT POWER, kWe	401,326
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	43.8
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	8,217 (7,790)
Net Efficiency, % HHV	39.5
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	9,120 (8,646)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	786.9 (746)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 4)	72,116 (158,986)

Note 1 – Loads are presented for two gas turbines, and one steam turbine.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 8.27 MPa (1200 psia).
Note 4 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

Table 2-8
CASE 1A – ISO CONDITIONS
(2) 7FA x 1 NGCC WITH CO_2 REMOVAL
BACK-PRESSURE TURBINE OPTION
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	308,955
Steam Turbine Power	144,451
Generator Loss	(8,043)
Gross Plant Power (Note 1)	445,363
AUXILIARY POWER SUMMARY, kWe	
Condensate Pumps	350
High Pressure Boiler Feed Pump	2,660
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	2,070
Cooling Tower Fans	1,170
MEA CO_2 Removal	1,490
CO_2 Compression and Drying (Note 3)	16,730
Transformer Loss	1,370
Total Auxiliary Power Requirement	27,140
NET PLANT POWER, kWe	418,223
PLANT EFFICIENCY	
Net Efficiency, % LHV	44.1
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	8,159 (7,735)
Net Efficiency, % HHV	39.8
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	9,053 (8,583)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	804.8 (763)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 4)	74,612 (164,488)

Note 1 – Loads are presented for two gas turbines, and one steam turbine.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 8.27 MPa (1200 psia).
Note 4 – Heating value(LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

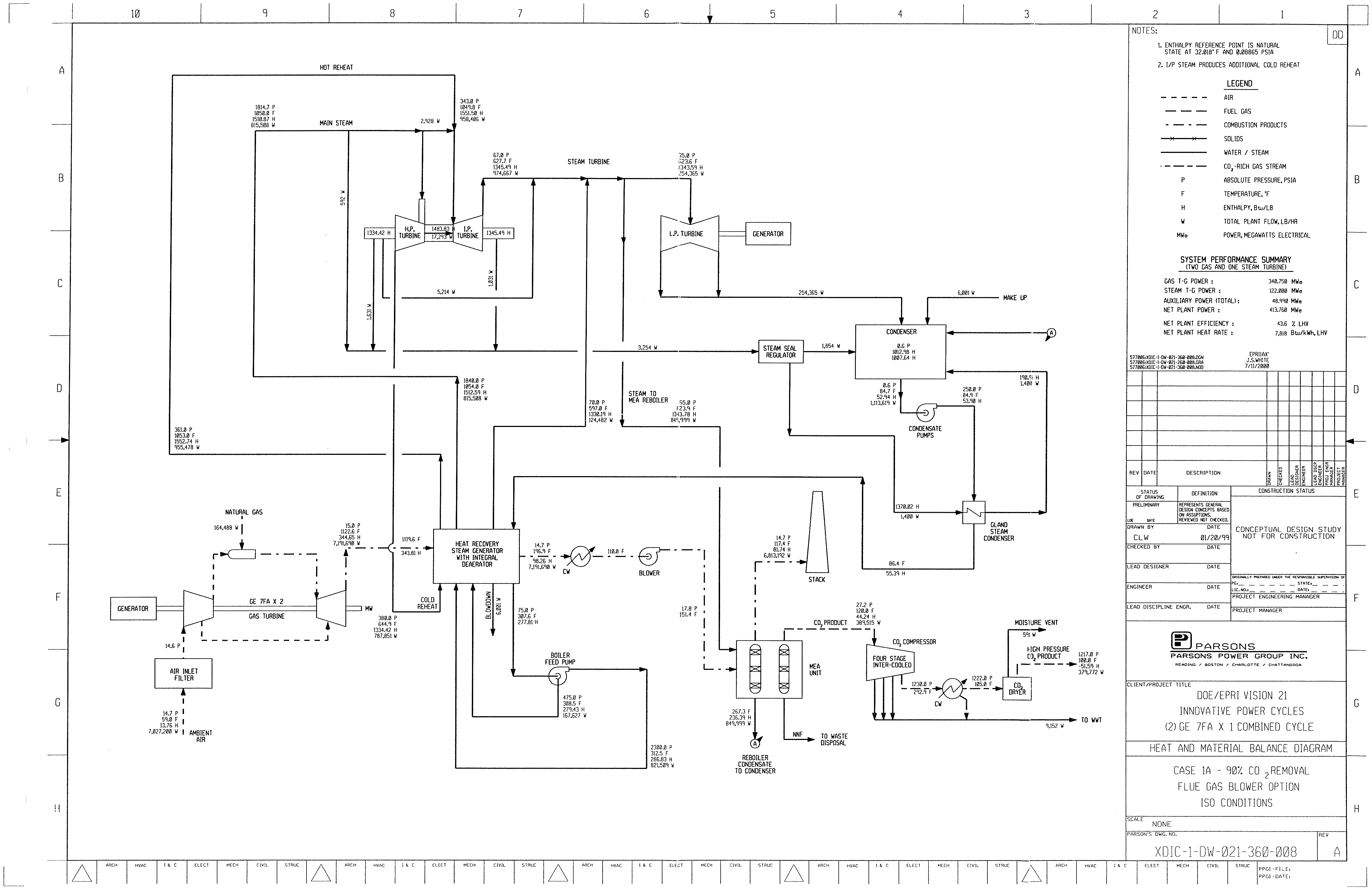

Figure 2-2
Heat and Material Balance Diagram – (2) GE 7FA x 1 Combined Cycle – Case 1A – 90% CO_2 Removal (Flue Gas Blower Option) – ISO Conditions

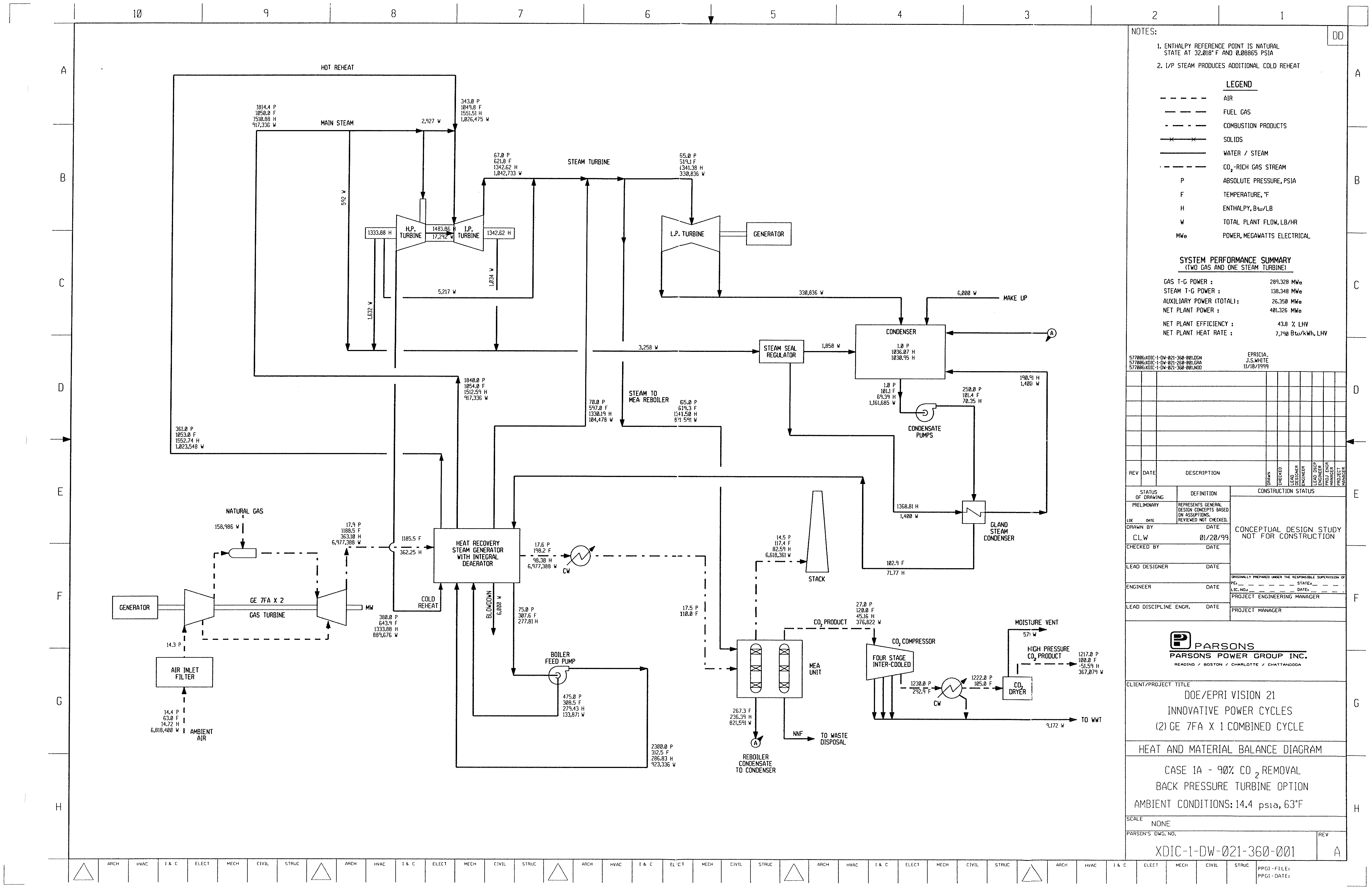

Figure 2-3
Heat and Material Balance Diagram – (2) GE 7FA x 1 Combined Cycle – Case 1A – 90% CO_2 Removal (Back Pressure Turbine Option)

2.2 CASE 1B – NGCC, H CLASS TURBINE WITH CO_2 REMOVAL

2.2.1 Introduction

This design is based on the use of one advanced natural gas-fired combustion turbine (CT), coupled with a heat recovery steam generator (HRSG) to generate steam for a single steam turbine generator. CO_2 is removed from the HRSG flue gas with an amine-based absorption process. The plant configuration reflects current information and design preferences, the availability of newer combustion and steam turbines, and the relative latitude of a greenfield site.

The gas turbine chosen is the General Electric H-type advanced turbine system (ATS) machine. This particular machine features a gas turbine and steam turbine connected on one shaft to single generator. The gas turbine provides values of power output, airflow, and exhaust gas temperature that effectively couple with a HRSG to generate steam for the companion steam cycle plant to produce an estimated total net output of 321 MWe, at an efficiency of 48.1 percent (LHV) and 43.4 percent (HHV). For this study, the steam turbine was assumed to have the following throttle and reheat conditions:12.48 MPa/565.6°C/565.6°C(1810 psig/1050°F/1050°F).

Flue gas exiting the HRSG is cooled, partially compressed, and routed to an inhibited MEA absorber-stripper system. In the absorber, a solution of aqueous MEA is used to remove 90 percent of the CO_2 in the flue gas. In the stripper, low-pressure steam is used to strip (remove) and purify the CO_2. Low-pressure, concentrated CO_2 from the stripper is then compressed to supercritical conditions for subsequent transportation off-site.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections are:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Production Cost, and Economics
- Case 1B Sensitivities

The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost. Three sensitivity performance cases are presented at the end of the section.

2.2.2 Thermal Plant Performance

The market-based plant described in this section is based on use of one General Electric H-type ATS gas turbine coupled with a triple-pressure HRSG supplying steam to one steam turbine generator. The resulting power plant thus utilizes a combined cycle for conversion of thermal energy to electric power. Table 2-9 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant. Gross power output (prior to the generator terminals) for the H-type turbo-set is estimated to be 348.3 MWe.

The assumed ambient conditions (see Table 2-1) correspond to lower pressure and higher temperature (i.e., lower density) compared to ISO. The geometry of the gas turbine is fixed. As a result, the mass flow of less dense air through the compressor will be less than that of relatively more dense air. That is the case we have here -- less dense ambient air, lower compressor air suction, lowered fuel usage and turbo-set power output. Simple cycle efficiency for the CT remains essentially unchanged. For comparison, this case was also run at ISO conditions. This will be discussed at the end of Section 2.2.

Also shown in Table 2-9 is the estimated gross steam turbine power output of 76.5 MWe. This number is much lower than that expected for a natural gas combined cycle with an estimated gross CT power output of 271 MWe. Normally, a rule-of-thumb estimate is that steam turbine power is roughly half that of the CT in a gas-fired combined cycle. However, in this case, most of the low-pressure steam available at the ST crossover is diverted from the low pressure (LP) turbine and used in the MEA stripper reboiler. Diverting this LP steam results in a marked decrease in steam turbine power output.

Plant auxiliary power is also summarized in Table 2-9. The total is estimated to be 32.3 MWe. This value, much higher than that anticipated for a gas-fired combined cycle, is due to the presence of the CO_2 removal/compression equipment. In particular, the flue gas blower, which requires 14.1 MWe of auxiliary power, and the CO_2 compressor, which requires 11.4 MWe of auxiliary power are responsible.

Net plant power output, which considers generator losses and auxiliary power, is estimated at 310.8 MWe. This plant power output results in a net system thermal efficiency of 48.1 percent (LHV) with a corresponding heat rate of 7,489 kJ/kWh (7,100 Btu/kWh) (LHV). The corresponding HHV values for efficiency and heat rate are 43.3 percent and 8,311 kJ/kWh (7,879 Btu/kWh), respectively. These plant efficiency and heat rate numbers are low in comparison to that expected for gas-fired combined cycles of the H-class technology. This low system thermal efficiency is due to the increased auxiliary power and the steam requirements of the CO_2 removal equipment.

Figure 2-4 contains a heat and material balance diagram for the 100 percent load condition. CT and ST cycles are shown schematically along with the appropriate state point condition data. An open Brayton cycle (CT) using air and combustion products as working fluid is used in conjunction with the conventional sub-critical Rankine cycle (ST). The two cycles are coupled by the generation and superheating of steam in the HRSG, and by feedwater heating in the HRSG.

Table 2-9
CASE 1B – GE H x 1 NGCC WITH CO_2 REMOVAL
FLUE GAS BLOWER OPTION
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	271,812
Steam Turbine Power	76,520
Generator Loss	(5,225)
Gross Plant Power (Note 1)	343,107
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	220
High Pressure Boiler Feed Pump	1,510
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,030
Cooling Tower Fans	590
Flue Gas Blower	14,110
MEA CO_2 Removal	1,020
CO_2 Compression and Drying (Note 3)	11,450
Transformer Loss	1,060
Total Auxiliary Power Requirement	32,290
NET PLANT POWER, kWe	310,817
PLANT EFICIENCY, kWe	
Net Efficiency, % LHV	48.1
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	7,489 (7,100)
Net Efficiency, % HHV	43.3
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	8,311 (7,879)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	409.3 (388)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 4)	50, 873 (112,153)

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 8.27 MPa (1200 psia).
Note 4 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

The HRSG uses a triple-pressure configuration. The low-pressure drum provides steam for the crossover of the steam turbine as well as steam for an integral deaerator. Intermediate-pressure steam provides additional cold reheat. High-pressure steam is the primary working fluid of the Brayton cycle. Also shown in the diagram is the basic equipment required to remove CO_2 from the flue gas stream and concentrate it as a pure, high-pressure product.

The heat and material balance in Figure 2-4 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

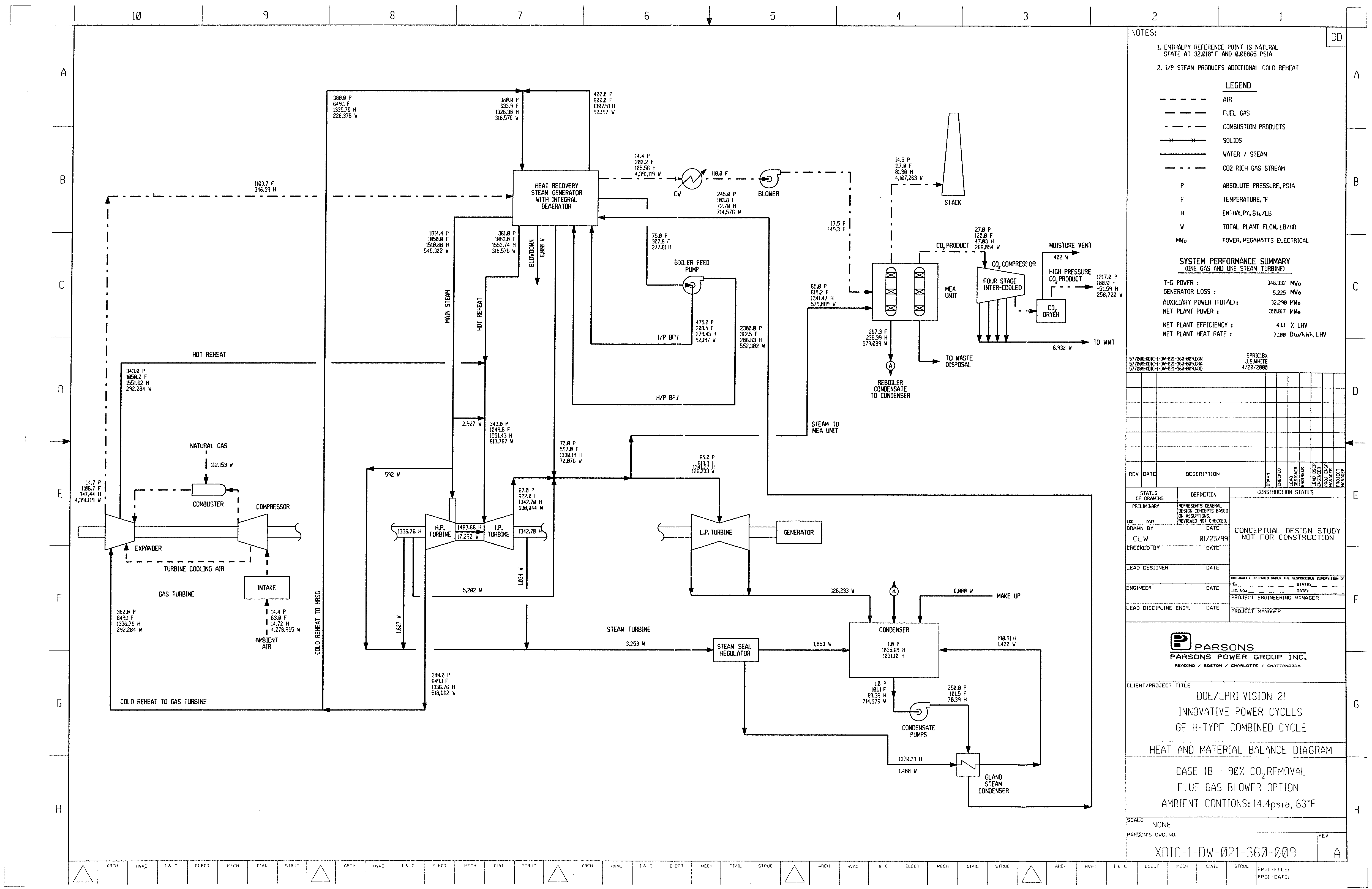

Figure 2-4
Heat and Material Balance Diagram – GE H-Type Combined Cycle – Case 1B – 90% CO_2 Removal (Flue Gas Blower Option)

2.2.3 Power Plant Emissions

The operation of the modern, state-of-the-art gas turbine fueled by natural gas, coupled to a HRSG, is projected to result in very low levels of SO_2, NOx, and CO_2 emissions. A summary of the estimated plant emissions for this case is presented in Table 2-10. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four basis: (1) kilogram per gigajoule of HHV thermal input (pound per million Btu of HHV thermal input), (2) tonnes per year for a 65 percent capacity factor (tons per year for a 65 percent capacity factor), (3) tonnes per year for an 85 percent capacity factor (tons per year for an 85 percent capacity factor), and, (4) kilograms per hour per MWe of power output (pounds per hour per MWe of power output).

Table 2-10
CASE 1B AIRBORNE EMISSIONS
H-TYPE NGCC WITH CO_2 REMOVAL

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
NOx	< 0.012 (< 0.028)	174.2 (192)	227.7 (251)	0.095 (0.21)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	5.07 (11.8)	74,567 (82,195)	188,355 (207,600)	39.98 (88.14)

As shown in the table, values of SO_2 emission and particulate discharge are negligible. This is a direct consequence of using natural gas as the plant fuel supply. Pipeline natural gas contains minor amounts of reduced sulfur species that produce negligible SO_2 emissions when combusted and diluted with a large amount of air. As for particulate discharge, when natural gas is properly combusted in a state-of-the-art CT the amount of solid particulate produced is very small (less than 9.1 kg/hour (20 lb/hour), 0.027 kg/MWh (0.06 lb/MWh)).

The low level of NOx production is achieved through use of GE's dry low-NOx (DLN) combustion system. This combustor arrangement should limit NOx emissions to less than 10 ppm adjusted to 15 percent O_2 content in the flue gas.

In this power plant configuration, approximately 90 percent of the CO_2 in the flue gas is removed and concentrated into a highly pure product stream. This greatly reduces CO_2 emissions as can be seen in Table 2-10.

2.2.4 System Description

The major subsystems in this natural gas-fired combined cycle power plant are:

- Combustion Turbine
- Heat Recovery Steam Generator
- CO_2 Removal and Compression
- Steam Turbine Generator
- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief discussion about the power plant equipment and operating conditions. This discussion is based on the heat and material balance diagram shown in Figure 2-4. The equipment list, which follows this section, is based on the material presented here.

2.2.4.1 Combustion Turbine

The CT, or gas turbine, generator selected for this application is based on the General Electric model H. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. The gas turbine compressor and expander, as well as the steam turbine and generator, are connected on a single rotating shaft.

Inlet air at 539.3 kg/sec (1,189 lb/sec) is compressed in a single spool compressor to a pressure ratio of approximately 23:1. This airflow is lower than the ISO airflow of 555.7 kg/sec (1,225 lb/sec) due to the choice of ambient conditions used in this specific study. (The ambient conditions chosen in this correspond to a standard EPRI/DOE fossil-plant site. They result in a less dense ambient air, and subsequently, less airflow and power output in the gas turbine.) The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the natural gas. Compressed air is also used in burner, transition and film cooling services.

Pressurized pipeline natural gas at a rate of 50,873 kg/hour (112,153 lb/hour) is combusted in several (12) parallel dry low-NOx combustors that use staged combustion to limit NOx formation. The CT combustors are can-annular in configuration. In the can-annular arrangement, individual combustion cans are placed side-by-side in an annular chamber. Each can is equipped with multiple fuel nozzles. This allows for higher mass flows than were possible with earlier machines and higher operating temperatures. In the estimated performance the machine will develop a rotor inlet temperature of about 1426.7°C (2600°F) with higher efficiency than the Model FA.

Hot combustion products are expanded in the four-stage turbine-expander. It is assumed that the first two expander stages are steam-cooled and that the third stage is air-cooled. No cooling is expected in the fourth expander stage. The CT exhaust temperature is estimated as 597.2°C

(1107°F), given the assumed ambient conditions, back-end loss, and HRSG pressure drop. This value, slightly higher than the ISO assumed value of 594.4°C (1102°F) for a simple cycle gas turbine, is due to increased back-pressure on the CT due to the HRSG.

Gross turbine shaft power, as measured prior to the generator terminals, is estimated as 271.8 MWe. The CT generator is a standard hydrogen-cooled machine with static exciter. The generator is shared with the steam turbine. Net CT power (following generator losses) is estimated at 267.7 MWe. These power values are lower than those quoted at ISO conditions because the CT compressor airflow is lower at the assumed ambient conditions. Lower airflow results in lower power output. The CT fuel fed is decreased proportionately such that the CT simple cycle efficiency is relatively unchanged.

2.2.4.2 Heat Recovery Steam Generator

High temperature flue gas at 1,991,812 kg/hour (4,391,119 lb/hour) exiting the CT is conveyed through the HRSG to recover the large quantity of thermal energy that remains. For analysis purposes, it is assumed that the flue gas heat loss through the HRSG duct corresponds to 1.6°C (3°F). Flue gases travel through the HRSG gas path and exit at 94.4°C (202°F).

The HRSG is configured with high-pressure (HP), intermediate-pressure (IP), and LP steam drums and circuitry. The HP drum is supplied with feedwater by the HP boiler feed pump, while the IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump. IP steam from the drum is mixed with cold reheat steam; the combined flow is then passed to the reheat section. The LP drum produces steam for superheat as well as saturated steam for an integral deaerator.

Condensate at 324,132 kg/hour (714,576 lb/hour) flows from the gland steam condenser to the HRSG feedwater heater (low-temperature economizer). In this heater, the condensate temperature is raised from 39.4°C (103°F) to 144.4°C (292°F). The condensate is then routed to the integral deaerator, which operates at 152.8°C (307°F) and 0.52 MPa (75 psia). Feedwater from the integral deaerator is then conveyed to the boiler feed pump.

High-pressure water from the boiler feed pump at 15.86 MPa (2300 psia) is heated to 315.6°C (600°F) in a series of three economizers. The high-pressure economizers are staggered within the HRSG in order to maximize flue gas heat flux. The high-pressure evaporator operates at 13.44 MPa (1950 psia) resulting in a nominal 18.3°C (33°F) evaporator temperature approach. The gas to water pinch is 11.1°C (20°F). A continuous drum blowdown of 2722 kg/hour (6,000 lb/hour) was used in this analysis. Saturated steam removed from the high-pressure drum is superheated to 567.8°C (1054°F) and then routed to the high-pressure steam turbine throttle valves.

Feedwater from an interstage bleed on the HP boiler feed pump at a rate of 41,820 kg/hour (92,197 lb/hour) feeds the IP steam drum. The IP drum operates with a 13.9°C (25°F) approach and an 11.1°C (20°F) gas-to-water pinch. Saturated steam from the IP drum at 2.83 MPa (410 psia) is superheated to 315.6°C (600°F) and then mixed with cold reheat from the high-pressure steam turbine. The combined flow is then reheated to 565.6°C (1050°F) and routed to the IP section of the steam turbine.

The LP steam drum operates at 0.52 MPa (75 psia). Saturated steam not utilized in the integral deaerator is removed from the LP drum and superheated to 313.9°C (597°F). This steam then flows to the steam turbine crossover area at a rate of 31,786 kg/hour (70,076 lb/hour).

The HRSG tube surface is typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 material; the low-temperature portions (< 398.9°C (750°F)) will be carbon steel.

2.2.4.3 CO_2 Removal and Compression

Part of the criteria of this combined cycle power plant design is the limitation of CO_2 emissions. This power plant configuration is based on removing 90 percent of the CO_2 in the HRSG flue gas. An inhibited aqueous solution of MEA is used to remove the CO_2.

Cool flue gas exiting the HRSG at 98.9°C (210°F) is indirectly cooled to 43.3°C (110°F) with circulating cooling water. The cool flue gas is partially compressed to 0.12 MPa (17.5 psia) in a centrifugal blower in order to overcome the gas-path pressure drop. There are four flue gas coolers and blowers operating in parallel. The partially compressed flue gas stream is then routed to a traditional absorber/stripper arrangement.

Flue gas enters the bottom of the absorber and flows upward and counter to the lean MEA solution. CO_2 is removed from the flue gas in the packed-bed absorber column through direct contact of MEA. The packing is 5.08 cm (2-inch) stainless steel rings. There are four absorber columns, operating in parallel, each 8.23 m (27 feet) in diameter and 24.39 m (80 feet) vertical. MEA circulation through each absorber is approximately 17.22 m^3/min (4,550 gpm).

Flue gas exiting the top of the absorber columns is collected in a common duct and routed to an exhaust stack. Rich solution off the bottom of the columns is heated in the rich-lean heat exchanger through indirect contact with lean solution flowing off the bottom of the stripper column.

Hot rich solution enters the top of the stripper column and flows downward and counter to the stripping agent, which is primarily steam. LP steam from the steam turbine crossover generates the stripping steam in the reboiler. CO_2 liberated through the application of heat flows upward along with the stripping steam. This vapor phase is routed to the reflux condenser where it is cooled to 48.9°C (120°F), thereby condensing a large portion of the water vapor. This condensed phase is returned to the stripper. The condenser vapor phase, which is saturated CO_2, is routed to the multi-staged, intercooled CO_2 compressor. Lean solution removed from the bottom of the stripper is cooled in the rich-lean heat exchanger, cooled in a secondary exchanger, and then returned to the absorber.

There are four strippers operating in parallel. Each stripper column is 4.88 meters (16 feet) in diameter and equipped with stainless steel trays that promote good inter-phase contact. The height of each stripper column is 22.86 meters (75 feet). Total reboiler steam requirement is approximately 262,675 kg/hour (579,089 lb/hour) of 0.34 MPa (50 psig) LP steam.

SO_2 in the flue gas may react with the MEA solvent to form heat stable salts. Once formed, the MEA can not be easily regenerated and must be removed from the reclaimer system as a solid. If solvent makeup becomes unacceptable, an alkali scrubber system can be installed before the absorber. However, solvent losses through salt formation are expected to be low for NGCC.

NOx components NO and NO_2 will be present in the flue gas stream. NO is unreactive with the solvent. NO_2, on the other hand, may react with the solvent to form nitrates. If nitrate formation cannot be controlled with normal filtering and treating systems, a cold-water scrubber may be installed before the absorber as a means to control NO_2 flow into the absorber. NO_2, which usually accounts for less than 10 percent of the NOx species, should not pose much of a problem to this system.

CO_2 from the stripper is compressed to a pressure of 8.43 MPa (1222 psia) by the multi-stage CO_2 compressor. The compression includes interstage cooling as well as knockout drums to remove and collect condensate. CO_2 is dehydrated to remove water vapor. Water vapor stripped from the CO_2 is vented to the atmosphere. After drying, the CO_2 enters the pipeline for transport and/or disposal/sequestration.

2.2.4.4 Steam Turbine Generator

The Rankine cycle used in this case is based on a state-of-the-art 12.4 MPa/565.6°C/565.6°C (1800 psig/1050°F/1050°F) single reheat configuration. The steam turbine is a single machine consisting of tandem high-pressure (HP), intermediate-pressure (IP), and double-flow low-pressure (LP) turbine sections connected via a common shaft and driving a 3600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a pitch diameter of 146 cm (57-1/2 inches) and a last-stage bucket length of 41.9 cm (16-1/2 inches).

Main steam at a rate of 247,802 kg/hour (546,300 lb/hour) from the HP boiler located in the HRSG passes through the HP stop valves and control valves and enters the turbine at 12.5 MPa/565.6°C (1815 psia/1050°F). The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the IP stop valves and intercept valves and enters the IP section at 2.36 MPa/565.6°C (343 psig/1050°F). After passing through the IP section, the steam enters a crossover pipe. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the crossover line. A tee is provided to extract a controlled amount of LP steam from the crossover. This steam is used in the MEA reboiler located below the MEA stripper column. The remaining crossover steam is divided into two paths and flows through the LP sections exhausting downward into the condenser.

2.2.4.5 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the HRSG. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity motor-driven feed pumps are provided for HP/IP service. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

2.2.4.6 Balance of Plant

The balance-of-plant items discussed in this section include:

- Natural Gas Lines and Metering
- Steam Systems
- Circulating Water System
- Accessory Electric Plant
- Instrumentation and Control

Natural Gas Lines and Metering

In this design, it is assumed that a natural gas main with adequate capacity and pressure is at the fence line of the site and that a suitable right of way is available to install a branch line to the site. A gas line comprised of Schedule 40 carbon steel pipe, 40.6 cm (16 inches) nominal OD, is required to convey the gas to the site. The buried pipeline is coated and wrapped, and cathodically protected with a zinc ribbon-type sacrificial anode to protect the pipe from corrosion.

A new gas metering station is located on the site, adjacent to the new combustion turbine. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording, or may be of the positive displacement type. In either case, a complete time-line record of gas consumption rates and cumulative consumption is provided.

Steam Systems

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

Main steam exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine.

Cold reheat steam exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Circulating Water System

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

Accessory Electric Plant

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

Instrumentation and Control

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

2.2.5 Case 1B Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 2-4. This list, along with the heat and material balance and supporting performance data, was used both to generate plant costs and in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the nomenclature section.

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter)

Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Gallon,gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832 x 10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9 $x10^{-3}$ = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above
to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

ACCOUNT 1 COAL AND SORBENT HANDLING

Not Applicable

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Gas Pipeline	Underground, carbon steel, coated and wrapped, cathodic protection	112,150 lb/h @ 600 psig 16 in. OD, Sch. 40	10 miles
2	Gas Metering Station		112,150 lb/h	1

ACCOUNT 2B SORBENT PREPARATION AND FEED

Not Applicable

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cyl., outdoor	70,000 gal	1
2	Condensate Pumps	Vert. canned	718 gpm @ 580 ft	2
3	Boiler Feed Pumps	Horizontal split case Multi-staged, centr. with interstage bleed for IP feedwater	680 gpm @ 5,810 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

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

ACCOUNT 4 BOILER AND ACCESSORIES

Not Required

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A CO_2 REMOVAL AND COMPRESSION

Equipment No.	Description	Type	Design Condition	Qty.
1	Flue Gas Cooler	Shell and tube Cooling water service	5 psig / 250 °F 27 x 10^6 Btu/h	4
2	Flue Gas Fan	Centrifugal	1,100,000 lb/h 276,000 acfm 90 in. H_2O (gauge) 3,500 hp	4
3	Absorber	Packed bed 2" rings Three 20-foot stages	30 psig / 300°F	4
4	Stripper	Tray tower	50 psig / 300°F	4
5	Reflux Drum	Horizontal Cooling water	50 psig / 250°F	4
6	Reboiler	Horizontal-shell 50 psig steam	75 psig / 350°F	4
7	Cartridge Filter	Horizontal	100 psig / 200°F	4
8	Carbon Filter	Horizontal	100 psig / 200°F	4
9	Rich Amine Pump	Centrifugal	3,320 gpm @ 250 ft	4
10	Lean/Rich Amine Heat Exchanger	Horizontal shell	100 psig / 280°F	4
11	Lean Amine Pump	Centrifugal	3,320 gpm @ 250 ft	4
12	CO_2 Compressor and Auxiliaries	Centrifugal Multi-staged	25 psia / 1300 psia	1
13	Final CO_2 Cooler	Shell and tube	20.37 x 10^6 Btu/h	1
14	Dehydration Package	Triethylene glycol	1300 psia	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	272 MWe Gas Turbine Generator	Axial flow single spool based on H	1,190 lb/sec airflow 2,600°F rotor inlet temp. 23:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1,190 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2,500 hp, time from turning gear to full load ~30 minutes	1
5	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
6	Oil Cooler	Air-cooled, fin fan		1
7	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
8	Generator Glycol Cooler	Air-cooled, fin fan		1
9	Compressor Wash Skid			1
10	Fire Protection Package	Halon		1

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, triple-pressure, with economizer section and integral deaerator	HP-1950 psia/632°F 552,295 lb/h, superheat to 1050°F IP-410 psia/447°F 92,000 lb/h, superheat to 600°F LP-75 psia/30°F 70,000 lb/h, superheat to 597°F	1
2	Stack	Carbon steel plate, lined with type 409 stainless steel	213 ft high x 24 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	76 MW Turbine Generator	TC1F17, triple admissions	1800 psig 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single-pass, divided waterbox	720,000 lb/h steam @ 2.0 in. Hga with 74°F water, 20°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water-sealed	2000/20 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	42,000 gpm @ 80 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	83°F WB/88°F CWT/ 96°F HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Not Applicable

2.2.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the 1 x 1 H natural gas-fired combined cycle power plant with CO_2 removal, case 1B, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 1B represents a plant with a net output of 310.8 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 2-11. A detailed estimate for case 1B is included in Appendix A.

The production costs for case 1B consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal) and Fuel costs. The costs were determined on a first-year basis that includes evaluation at a 65 percent equivalent plant operating capacity factor. The results are summarized in Table 2-12 and supporting detail is contained in Appendix A.

Table 2-11
CASE 1B SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
5B	CO_2 Removal and Compression	85,020
6	Combustion Turbine and Accessories	52,610
7	HRSG, Ducting and Stack	20,740
8&9	Steam T-G Plant, including Cooling Water System	24,980
11	Accessory Electric Plant	19,950
	Balance of Plant	27,030
	SUBTOTAL	230,330
	Engineering, Construction Management Home Office and Fee	13,820
	Process Contingency	11,260
	Project Contingency	37,550
	TOTAL PLANT COST (TPC)	$292,970
	TPC $/kW	940

Table 2-12
CASE 1B ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	2,064	0.12
Maintenance	5,846	0.33
Administrative & Support Labor	1,101	0.06
Consumables	5,014	0.28
By-Product Credits	N/A	N/A
Fuel	37,649	2.13
TOTAL PRODUCTION COST	51,674	2.92

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 1B. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per tonne. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI are included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 2-13.

Table 2-13
CASE 1B LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	2.92
Annual Carrying Charge (¢/kWh)	2.49
Levelized Busbar Cost of Power Charge (¢/kWh)	5.41
Levelized Cost per Tonne of CO_2 Removed ($/tonne of CO_2)	130

2.2.7 Case 1B Sensitivity

In the course of completing this case, three sensitivity cases were identified and evaluated. The three are as follows:

- Case 1B at ISO conditions.
- Case 1B with back-pressure gas turbine.
- Case 1B with back-pressure gas turbine at ISO conditions.

For each case, plant performance was estimated and a heat and material balance diagram was produced. There will be no cost estimate for these sensitivity cases.

2.2.7.1 Case 1B at ISO Conditions

This case was developed so that the results of this study could be compared to other studies that assumed ISO conditions for ambient. As such, the power plant configuration in this case is a direct duplicate of that described in detail in the previous section. However, due to the assumption of ISO ambient conditions -- which are 15°C (59°F), 0.101 MPa (14.696 psia), and 60 percent relative humidity -- there are several differences in plant performance.

Operation of the gas turbine at ISO conditions, as opposed to the ambient conditions of 17.2°C (63°F) and 0.099 MPa (14.4 psia) assumed for the primary case, results in greater flow through the gas turbine set. More air is compressed and utilized due to density changes at the compressor inlet. Increased airflow and a higher ambient (inlet) pressure result in a relatively higher firing pressure, higher fuel input, and increased power output. However, in the case presented here, the simple cycle efficiency at ISO conditions compared to those assumed for the body of this report is more or less unchanged.

Estimated performance is presented in Table 2-14. A heat and material balance is in Figure 2-5. As can be seen by comparing this heat and material balance with that in Figure 2-4, airflow to the compressor has increased from 539.3 kg/sec (1,189 lb/sec) to 555.7 kg/sec (1,225 lb/sec). Fuel flow to the combustor has increased from 50,873 kg/hour (112,153 lb/hour) to 52,496 kg/hour (115,733 lb/hour). Also, the steam turbine back-pressure has decreased from 68 mbara (2 inches HgA) to 41 mbara (1.2 inches HgA).

The heat and material balance in Figure 2-5 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9×10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

As shown in Table 2-14, gas turbine shaft power output has increased from 271.8 MW to 281.2 MW. This power increase is due entirely to the change in ambient conditions; operation at ISO allows greater volume throughput. Also, due to the increase in power plant thermal input, as well as a decrease in condenser back-pressure, steam turbine shaft power output has increased from 76.5 MW to 78.5 MW. The overall effect is increased plant output at a similar efficiency performance level.

2.2.7.2 Case 1B with Back-Pressure Gas Turbine

As can be seen in Table 2-9, the flue gas blower -- which conveys flue gas from the HRSG exhaust to the MEA absorber -- is the largest single component of the auxiliary power. Due to this, an alternative configuration without a flue gas blower was identified. With this approach, pressure head for the MEA absorber resistance was made up by holding a back-pressure on the gas turbine expander.

Table 2-15 shows a summary of estimated performance for this case. There is a slight increase in net plant power output, 311.6 MWe versus 310.8 MWe, as compared to the base case (shown in Table 2-9). Auxiliary power is markedly decreased, 18.8 MWe as compared to 32.3 MWe, but gas turbine power output decreases substantially due to the increased exit pressure and temperature of the gas turbine expander. There is also a slight increase in efficiency, 48.2 percent LHV versus 48.1 percent LHV.

Figure 2-6 shows the plant heat and material balance diagram. Gas turbine exhaust pressure is 0.123 MPa (17.9 psia) rather than the 0.101 MPa (14.7 psia) of the base case (shown in Figure 2.2-1). This high gas turbine expander back-pressure leads to an increase in expander exhaust temperature. The exhaust temperature with the back-pressure expander is 634.4°C (1174°F). This value is 28.8°C (52°F) above that of the base case. This temperature is very high and may contribute to equipment failure at some part-load conditions. Unless the OEM can ensure that this operating temperature would not lead to equipment failure, the slight increase in plant efficiency cannot be justified. A cost analysis would be required to determine if there is a significant capital cost advantage or investment incentive.

The heat and material balance in Figure 2-6 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

2.2.7.3 Case 1B with Back-Pressure Gas Turbine at ISO Conditions

The approach with back-pressure gas turbine was run at ISO conditions. The results are shown in Table 2-16.

Table 2-14
CASE 1B – ISO CONDITIONS
GE H x 1 NGCC WITH CO_2 REMOVAL
FLUE GAS BLOWER OPTION
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	281,219
Steam Turbine Power	78,541
Less Generator Loss	(5,396)
Gross Plant Power (Note 1)	354,364
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	130
High Pressure Boiler Feed Pump	1,590
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,380
Cooling Tower Fans	790
Flue Gas Blower	14,240
MEA CO_2 Removal	1,050
CO_2 Compression and Drying (Note 3)	11,810
Transformer Loss	1,100
Total Auxiliary Power Requirement	33,390
NET PLANT POWER, kWe	320,974
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	48.1
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	7,479 (7,091)
Net Efficiency, % HHV	43.4
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	8,300 (7,869)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	547.4 (519)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 4)	52,496 (115,733)

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 8.27 MPa (1200 psia).
Note 4 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

Table 2-15
CASE 1B – GE H x 1 NGCC WITH CO_2 REMOVAL
BACK PRESSURE TURBINE OPTION
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	247,103
Steam Turbine Power	89,043
Generator Loss	(5,714)
Gross Plant Power (Note 1)	330,432
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	220
High Pressure Boiler Feed Pump	1,770
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,280
Cooling Tower Fans	730
MEA CO_2 Removal	1,010
CO_2 Compression and Drying (Note 3)	11,440
Transformer Loss	1,030
Total Auxiliary Power Requirement	18,780
NET PLANT POWER, kWe	311,652
PLANT EFICIENCY, kWe	
Net Efficiency, % LHV	48.2
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	7,465 (7,077)
Net Efficiency, % HHV	43.4
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	8,283 (7,853)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	508.4 (482)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 4)	50,873 (112,153)

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 8.27 MPa (1200 psia).
Note 4 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

Table 2-16
CASE 1B – ISO CONDITIONS
GE H x 1 NGCC WITH CO_2 REMOVAL
BACK PRESSURE TURBINE OPTION
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	12.4 (1,800)
Throttle Temperature, °F	565.6 (1,050)
Reheat Outlet Temperature, °F	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	256,247
Steam Turbine Power	91,461
Less Generator Loss	(5,911)
Gross Plant Power (Note 1)	341,797
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	240
High Pressure Boiler Feed Pump	1,820
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,310
Cooling Tower Fans	750
MEA CO_2 Removal	1,050
CO_2 Compression and Drying (Note 3)	11,810
Transformer Loss	1,060
Total Auxiliary Power Requirement	19,340
NET PLANT POWER, kWe	322,457
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	48.3
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	7,447 (7,060)
Net Efficiency, % HHV	43.5
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	8,264 (7,835)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	521 (494)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 4)	52,496 (115,733)

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 8.27 MPa (1200 psia).
Note 4 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

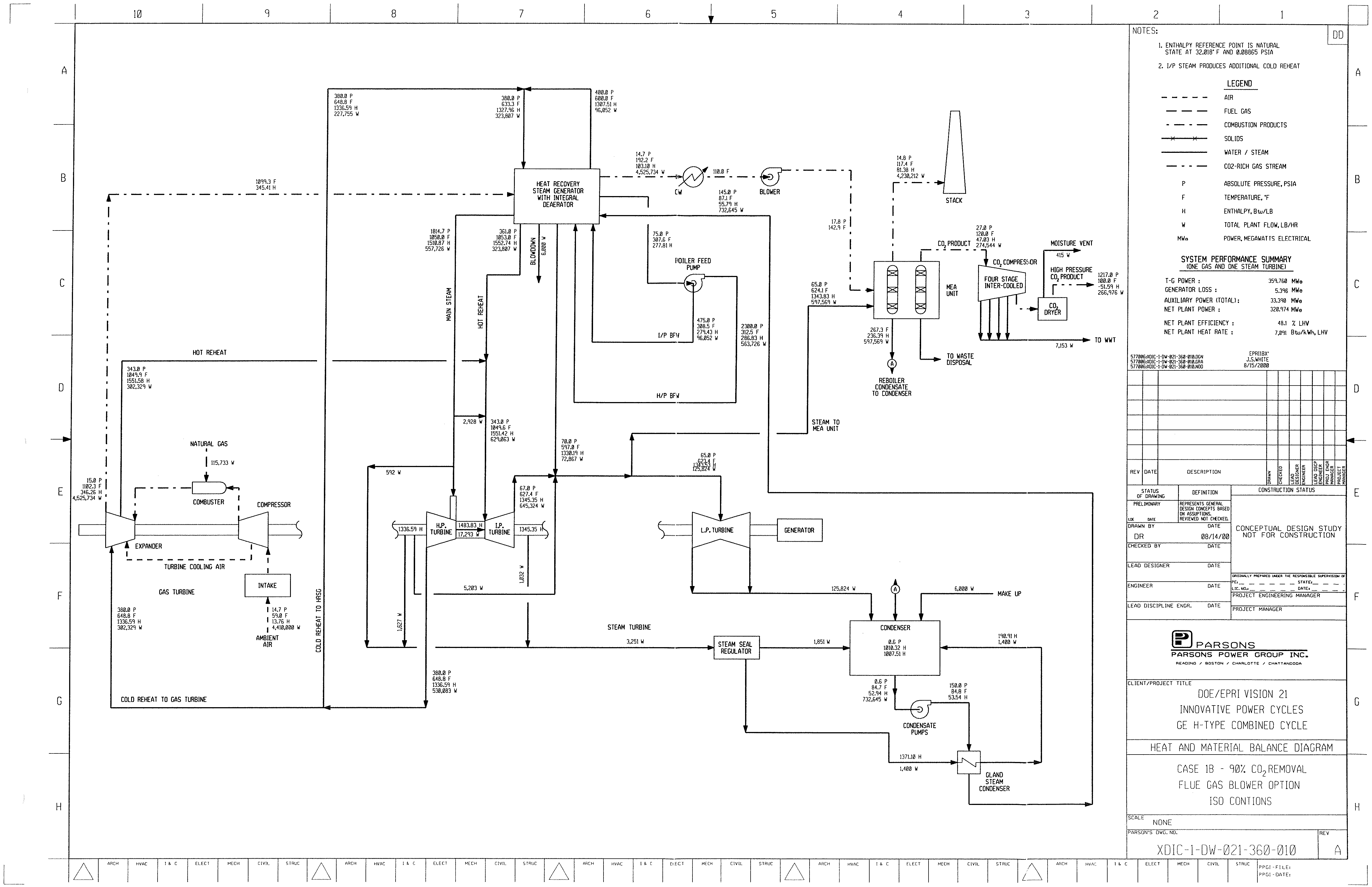

Figure 2-5
Heat and Material Balance Diagram – GE H-Type Combined Cycle – Case 1B – 90% CO_2 Removal (Flue Gas Blower Option) – ISO Conditions

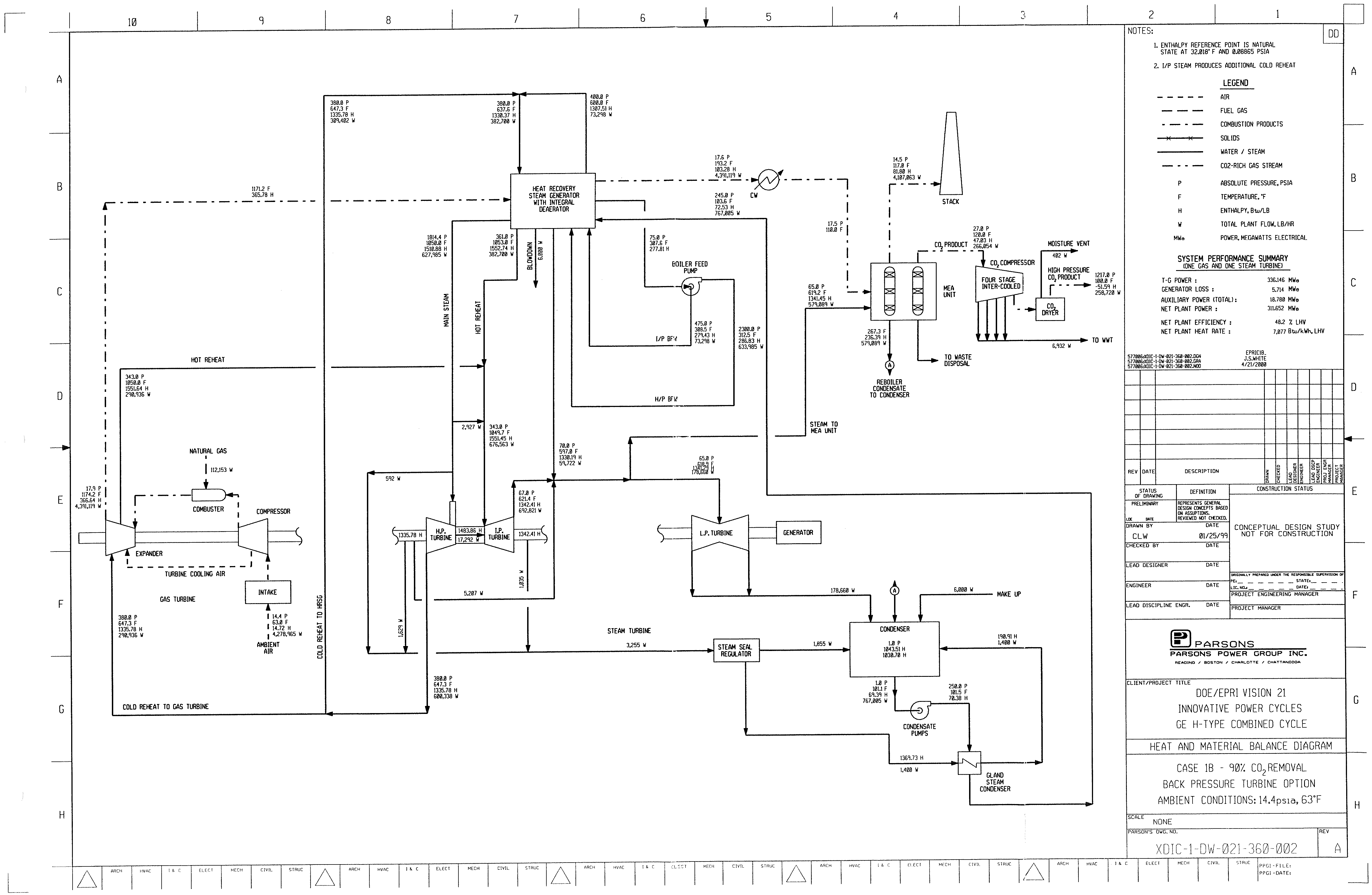

Figure 2-6
Heat and Material Balance Diagram – GE H-Type Combined Cycle – Case 1B – 90% CO_2 Removal (Back Pressure Turbine Option)

2.3 CASE 1C – NGCC, F CLASS TURBINE WITHOUT CO_2 REMOVAL

2.3.1 Introduction

This market-based design is based on the use of *two* natural gas-fired combustion turbines, each coupled with a heat recovery steam generator (HRSG) to generate steam for a *single* steam turbine generator. There is no CO_2 removal with this power plant configuration; it is a standard natural gas combined cycle. The plant configuration reflects current information and design preferences, the availability of newer combustion and steam turbines, and the relative latitude of a greenfield site.

This rendition of CT/HRSG technology is based on the General Electric 7FA machine. This particular machine provides power output, airflow, and exhaust gas temperature that effectively couple with a HRSG to generate steam for the companion steam cycle plant to produce a total net output of approximately 510 MWe, at an efficiency of 55.6 percent (LHV) and 50.1 percent (HHV). For this study, two gas turbines are used in conjunction with one 12.4 MPa/565.6°C/565.6°C (1800 psig/1050°F/1050°F) steam turbine.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections are:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Production Cost, and Economics
- Case 1C at ISO Conditions

The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost. A performance sensitivity at ISO conditions is presented at the end of the section.

2.3.2 Thermal Plant Performance

Table 2-17 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant. Gross power output (prior to the generator terminals) for the two General Electric 7FA gas turbines is estimated to be 334.9 MWe. This number is less than the oft quoted 346 MWe (2 x 173 MWe) available at ISO conditions. The assumed ambient conditions (see Table 1-1) correspond to lower pressure and higher temperature (i.e., lower density) compared to ISO. The geometry of the gas turbine is fixed. As a result, the mass flow of less dense air through the compressor will be less than that of relatively more dense air. That is the case we have here -- less dense ambient air, lower compressor air suction, lowered fuel usage and turbo-set power output. Simple cycle efficiency for the CT remains essentially unchanged. For comparison, this case was also run at ISO conditions. This will be discussed later in the write-up. Also shown in Table 2-17 is the gross steam turbine power output of 194 MWe.

Plant auxiliary power is also summarized in Table 2-17. The total is estimated to be about 10 MWe. Net plant power output, which considers generator losses and auxiliary power, is 509.4 MWe. This plant power output results in a net system thermal efficiency of 55.6 percent (LHV) with a corresponding heat rate of 6,474 kJ/kWh (6,138 Btu/kWh) (LHV). The corresponding HHV values for efficiency and heat rate are 50.1 percent and 7,184 kJ/kWh (6,811 Btu/kWh), respectively.

Figure 2-7 contains a heat and material balance diagram for the 100 percent load condition. CT and ST cycles are shown schematically along with the appropriate state point condition data. An open Brayton cycle (CT) using air and combustion products as working fluid is used in conjunction with the conventional sub-critical Rankine cycle (ST). The two cycles are coupled by the generation and superheating of steam in the HRSG, and by feedwater heating in the HRSG. The HRSG uses a triple-pressure configuration. The low-pressure drum provides steam for an integral deaerator.

The heat and material balance in Figure 2-7 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Table 2-17
CASE 1C – (2) 7FA x 1 NGCC
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	334,892
Steam Turbine Power	194,198
Generator Loss	(9,724)
Gross Plant Power (Note 1)	519,366
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	320
High Pressure Boiler Feed Pump	2,280
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	2,810
Cooling Tower Fans	1,600
Transformer Loss	1,650
Total Auxiliary Power Requirement	9,960
NET PLANT POWER, kWe	509,406
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	55.6
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	6,474 (6,138)
Net Efficiency, % HHV	50.1
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	7,184 (6,811)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	1,102.3 (1,045)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 3)	72,116 (158,986)

Note 1 – Loads are presented for two gas turbines, and one steam turbine.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Heating value LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

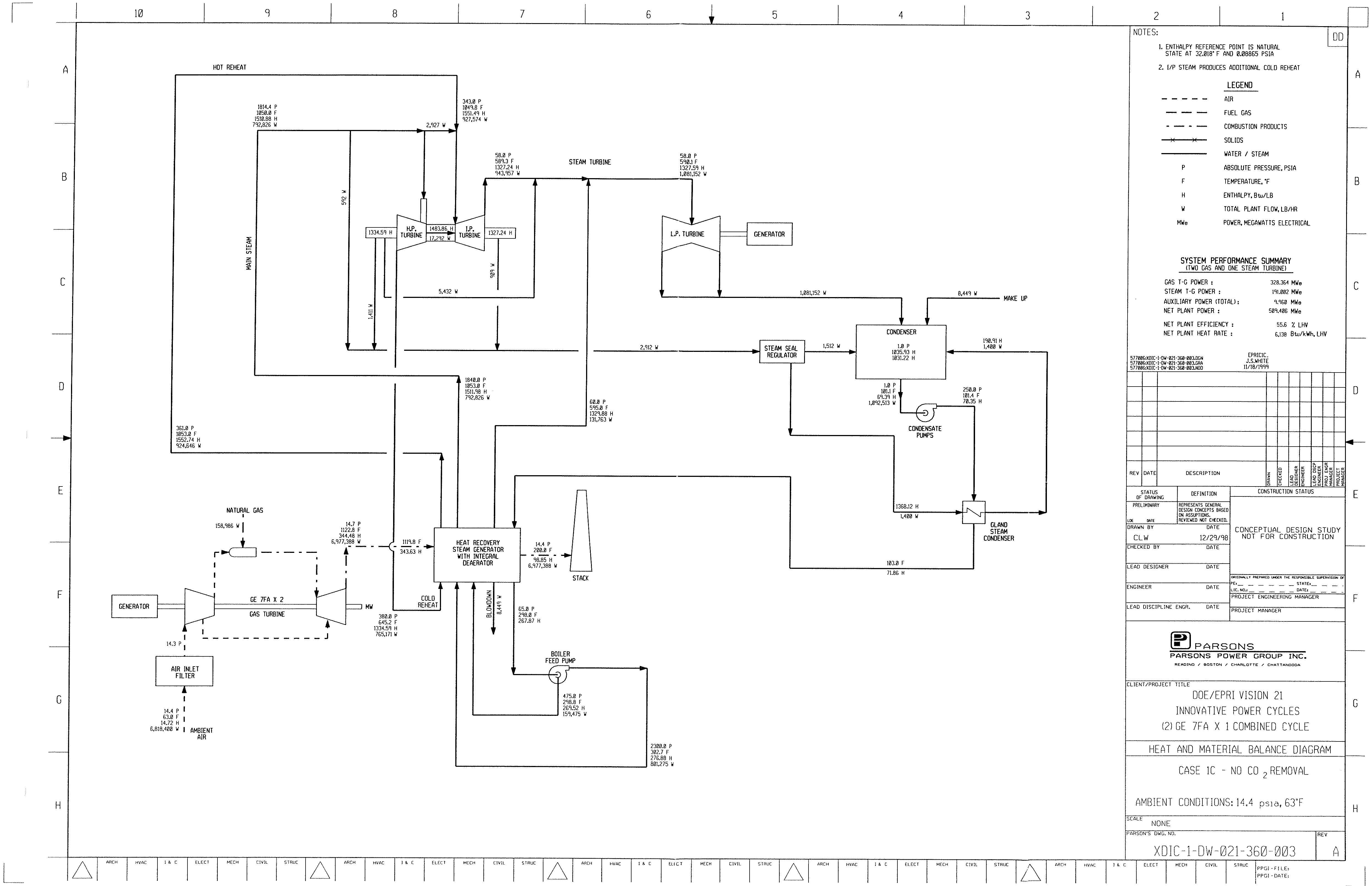

Figure 2-7
Heat and Material Balance Diagram – (2) GE 7FA x 1 Combined Cycle – Case 1C – No CO_2 Removal

2.3.3 Power Plant Emissions

The operation of the modern commercial gas turbine fueled by natural gas, coupled to a HRSG, is projected to result in very low levels of SO_2, NOx, and CO_2 emissions. A summary of the estimated plant emissions for this case is presented in Table 2-18. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four basis: (1) kilograms per gigajoules of HHV thermal input (pound per million Btu of HHV thermal input), (2) tonnes per year for a 65 percent capacity factor (tons per year for a 65 percent capacity factor), (3) tonnes per year for an 85 percent capacity factor (tons per year for an 85 percent capacity factor), and, (4) kilograms per hour per MWe of power output (pounds per hour per MWe of power output).

Table 2-18
CASE 1C AIRBORNE EMISSIONS
(2) 7FA x 1 NGCC

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
NOx	< 0.012 (< 0.028)	245 (270)	326.6 (360)	0.086 (0.19)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	50.7 (118)	1,057,069 (1,165,200)	1,382,337 (1,523,740)	364.3 (803.2)

As shown in the table, values of SO_2 emission and particulate discharge are negligible. This is a direct consequence of using natural gas as the plant fuel supply. Pipeline natural gas contains minor amounts of reduced sulfur species that produce negligible SO_2 emissions when combusted and diluted with a large amount of air. As for particulate discharge, when natural gas is properly combusted in a state-of-the-art CT, the amount of solid particulate produced is very small (less than 9.1 kg/hour (20 lb/hour), 0.027 kg/MWh (0.06 lb/MWh), for both 7FA machines).

The low level of NOx production is achieved through use of GE's dry low-NOx (DLN) combustion system. This combustor arrangement should limit NOx emissions to 9 ppm adjusted to 15 percent O_2 content in the flue gas.

2.3.4 System Description

The major subsystems in this natural gas-fired combined cycle power plant are:

- Combustion Turbine
- Heat Recovery Steam Generator
- CO_2 Removal and Compression

- Steam Turbine Generator
- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief discussion of the power plant equipment and operating conditions. This discussion is based on the heat and material balance diagram shown in Figure 2-7. The equipment list, which follows this section, is also based on the material presented here.

2.3.4.1 Combustion Turbine

The CT, or gas turbine, generator selected for this application is based on the General Electric MS 7001FA model. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. Each CT operates in an open cycle mode. Two 7FAs, each equipped with an individual HRSG, are used to power a single steam turbine in a traditional 2 on 1 arrangement.

Inlet air at 429.6 kg/sec (947 lb/sec) (per CT) is compressed in a single spool compressor to a pressure ratio of approximately 15.5:1. This airflow is lower than the ISO airflow of 442.7 kg/sec (976 lb/sec) due to the choice of ambient conditions used in this specific study. The ambient conditions chosen in this correspond to a standard EPRI/DOE fossil-plant site. They result in a less dense ambient air, and subsequently, less airflow and power output in the gas turbine. The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the natural gas. Compressed air is also used in burner, transition and film cooling services.

Pressurized pipeline natural gas at a rate of 36,058 kg/hour (79,493 lb/hour) (per CT) is combusted in several (14) parallel dry low-NOx combustors that use staged combustion to limit NOx formation. The CT combustors are can-annular in configuration. In the can-annular arrangement, individual combustion cans are placed side-by-side in an annular chamber. Each can is equipped with six fuel nozzles. This allows for higher mass flows over earlier machines and higher operating temperatures. In the estimated performance provided here, the machine will develop a rotor inlet temperature of about 1315°C (2400°F).

Hot combustion products are expanded in the three-stage turbine-expander. The CT exhaust temperature is estimated as 606.1°C (1123°F) given the assumed ambient conditions, back-end loss, and HRSG pressure drop. This value, slightly higher than the ISO quoted value of 602.8°C (1117°F) for a simple cycle gas turbine, is due to increased back-pressure (HRSG) on the CT.

Gross turbine power, as measured prior to the generator terminals, is estimated as 334.9 MWe. The CT generator is a standard hydrogen-cooled machine with static exciter. Net CT power from the generator is estimated at 329.2 MWe. These power values are lower than those quoted at ISO conditions because the CT compressor airflow is lower at the assumed ambient conditions. This lower airflow results in reduced power output. The CT fuel feed is decreased proportionally such that the CT simple cycle efficiency is relatively unchanged.

2.3.4.2 Heat Recovery Steam Generator

High-temperature flue gas at 1,582,472 kg/hour (3,488,694 lb/hour) (per turbine) exiting the CT is conveyed through a HRSG (one for each turbine) to recover the large quantity of thermal energy that remains. For analytical purposes, it is assumed that the flue gas heat loss through the HRSG duct corresponds to 1.7°C (3°F). Flue gases travel through the HRSG gas path and exit at 93.3°C (200°F).

The HRSG is configured with high-pressure (HP), intermediate-pressure (IP), and LP steam drums and circuitry. The HP drum is supplied with feedwater by the HP boiler feed pump while the IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump. IP steam from the drum is mixed with cold reheat steam; the combined flow is then passed to the reheat section. The LP drum produces steam for superheat as well as saturated steam for an integral deaerator.

Condensate at 495558 kg/hour (1,092,500 lb/hour) flows from the gland steam condenser to the HRSG feedwater heater (low-temperature economizer). In this heater, the condensate temperature is raised from 39.4°C (103°F) to 144.4°C (292°F). The condensate is then routed to the integral deaerator, which operates at 152.8°C (307°F) and 0.5 MPa (75 psia). Feedwater from the integral deaerator is then conveyed to the boiler feed pump.

High-pressure water from the boiler feed pump at 15.9 MPa (2300 psia) is heated to 315.6°C (600°F) in a series of three economizers. The high-pressure economizers are staggered within the HRSG in order to maximize flue gas heat flux. The high-pressure evaporator operates at 13.4 MPa (1950 psia) resulting in a nominal 18.3°C (33°F) evaporator temperature approach. The gas to water pinch is 11.1°C (20°F). A continuous drum blowdown of 2,721.6 kg/hour (6,000 lb/hour) was used in this analysis. Saturated steam removed from the high-pressure drum is superheated to 567.8°C (1054°F) and then routed to the high-pressure steam turbine throttle valves.

Feedwater from an interstage bleed on the HP boiler feed pump at a rate of 72,338 kg/hour (159,475 lb/hour) feeds the IP steam drum. The IP drum operates with a 13.9°C (25°F) approach and a 11.1°C (20°F) gas-to-water pinch. Saturated steam from the IP drum at 2.83 MPa (410 psia) is superheated to 315.6°C (600°F) and then mixed with cold reheat from the high-pressure steam turbine. The combined flow is then reheated to 565.6°C (1050°F) and routed to the IP section of the steam turbine.

The LP steam drum operates at 0.5 MPa (75 psia). Saturated steam not utilized in the integral deaerator is removed from the LP drum and superheated to 313.4°C (597°F). This steam then flows to the steam turbine crossover area at a rate of 59,768 kg/hour (131,763 lb/hour).

The HRSG tube surface is typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 material; the low-temperature portions (< 398.9°C (< 750°F)) will be carbon steel.

2.3.4.3 Steam Turbine Generator

The Rankine cycle used in this case is based on a state-of-the-art 12.4 MPa/565.6°C/565.6°C (1800 psig/1050°F/1050°F) single reheat configuration. The steam turbine is a single machine consisting of tandem high-pressure (HP), intermediate-pressure (IP), and double-flow low-pressure (LP) turbine sections connected via a common shaft and driving a 3600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last-stage bucket length of 101.6 cm (40 inches).

Main steam at a rate of 359,614 kg/hour (792,800 lb/hour) from the HP boiler located in the HRSG passes through the HP stop valves and control valves and enters the turbine at 12.5 MPa/565.6°C (1815 psia/1050°F). The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the IP stop valves and intercept valves and enters the IP section at 2.4 MPa/565.6°C (343 psig/1050°F). After passing through the IP section, the steam enters a crossover pipe. The crossover steam is divided into two paths and flows through the LP sections exhausting downward into the condenser.

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

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

The generator is a synchronous type rated at 225 MWe. It operates with a 0.85 power factor and generates power at 23 kV. A static, transformer type exciter is provided. Gross generator output is 194 MWe. The generator operates with an efficiency of approximately 98 percent. Net steam turbine generator power output is 191.0 MWe.

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

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

2.3.4.4 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the HRSG. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The function of the feedwater system is to pump various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity motor-driven feed pumps are provided for HP/IP service. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

2.3.4.5 Balance of Plant

The balance of plant items discussed in this section include:

- Natural Gas Lines and Metering
- Steam Systems
- Circulating Water System
- Accessory Electric Plant
- Instrumentation and Control

Natural Gas Lines and Metering

In this design, it is assumed that a natural gas main with adequate capacity and pressure is at the fence line of the site and that a suitable right of way is available to install a branch line to the site. A gas line comprised of Schedule 40 carbon steel pipe, 40.64 cm (16 inches) nominal OD, is required to convey the gas to the site. The buried pipeline is coated and wrapped, and cathodically protected with a zinc ribbon-type sacrificial anode to protect the pipe from corrosion.

A new gas metering station is located on the site, adjacent to the new combustion turbine. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording, or may be of the positive displacement type. In either case, a complete time-line record of gas consumption rates and cumulative consumption is provided.

Steam Systems

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

Main steam exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine.

Cold reheat steam exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Circulating Water System

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

Accessory Electric Plant

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

Instrumentation and Control

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

2.3.5 Case 1C Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 2-7. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the nomenclature section.

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter)

Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Gallon, gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm. multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832 x 10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9 $x10^{-3}$ = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

ACCOUNT 1 COAL AND SORBENT HANDLING

Not Applicable

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Gas Pipeline	Underground, carbon steel, coated and wrapped, cathodic protection	158,990 lb/h @ 600 psig 16 in. OD, Sch. 40	10 miles
2	Gas Metering Station		158,990 lb/h	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cyl., outdoor	70,000 gal	1
2	Condensate Pumps	Vert. canned	1100 gpm @ 580 ft	2
3	Boiler Feed Pumps	Horizontal split case Multi-staged, centr. with interstage bleed for IP feedwater	960 gpm @ 5,810 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
2	Fuel Oil Storage Tank	Vertical, cylindrical	20,000 gal	2
3	Fuel Oil Unloading Pump	Gear	50 psig, 100 gpm	1
4	Fuel Oil Supply Pump	Gear	150 psig, 5 gpm	2
5	Service Air Compressors	Recip., single-stage, double-acting, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exchanger	Plate and frame	50% cap. each	2

9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
11	Fire Service Booster Pump	Two-stage horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1000 gpm	1
13	Raw Water	S.S., single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	S.S., single suction	160 ft, 120 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

Not Required

ACCOUNT 5 FLUE GAS CLEANUP

Not Required

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	170 MWe Gas Turbine Generator	Axial flow single spool based on GE 7FA	950 lb/sec airflow 2410°F rotor inlet temp. 15.5 pressure ratio	2
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	2
3	Air Inlet Filter/Silencer	Two-stage	950 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	2
4	Starting Package	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	2
5	Air to Air Cooler			2
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		2
7	Oil Cooler	Air-cooled, fin fan		2

Equipment No.	Description	Type	Design Condition	Qty
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	2
9	Generator Glycol Cooler	Air-cooled, fin fan		2
10	Compressor Wash Skid			2
11	Fire Protection Package	Halon		2

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, triple pressure, with economizer section and integral deaerator	HP-1950 psia/633°F 801,100 lb/h, superheat to 1050°F IP-410 psia/447°F 160,000 lb/h, superheat to 600°F LP-65 psia/298°F 132,815 lb/h, superheat to 595°F	2
2	Stack	Carbon steel plate, lined with type 409 stainless steel	213 ft high x 28 ft dia.	2

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	190 MW Turbine Generator	TC2F40, triple admissions	1,800 psig 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single-pass, divided waterbox	1,093,300 lb/h steam @ 2.0 in. Hga with 74°F water, 20°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water-sealed	2,000/20 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	132,000 gpm @ 80 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	83°F WB/88°F CWT/ 96° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Not Applicable

2.3.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the 2 x 1 7FA natural gas-fired combined cycle power plant without removal, case 1C, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 1C represents a plant with a net output of 509.4 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 2-19. A detailed estimate for case 1C is included in Appendix A.

The production costs for case 1C consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal) and Fuel costs. The costs were determined on a first-year basis that includes evaluation at a 65 percent equivalent plant operating capacity factor. The results are summarized in Table 2-20 and supporting detail is contained in Appendix A.

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 1C. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per tonne. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI are included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 2-21.

Table 2-19
CASE 1C SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
5B	CO_2 Removal and Compression	N/A
6	Combustion Turbine and Accessories	73,900
7	HRSG, Ducting and Stack	34,330
8&9	Steam T-G Plant, including Cooling Water System	52,280
11	Accessory Electric Plant	18,660
	Balance of Plant	33,610
	SUBTOTAL	212,780
	Engineering, Construction Management Home Office and Fee	12,770
	Process Contingency	N/A
	Project Contingency	31,880
	TOTAL PLANT COST (TPC)	$257,430
	TPC $/kW	510

Table 2-20
CASE 1C ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	1,720	0.06
Maintenance	4,164	0.14
Administrative & Support Labor	846	0.03
Consumables	490	0.02
By-Product Credits	N/A	N/A
Fuel	53,340	1.84
TOTAL PRODUCTION COST	60,559	2.09

Table 2-21
CASE 1C LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	2.09
Annual Carrying Charge (¢/kWh)	1.33
Levelized Busbar Cost of Power Charge (¢/kWh)	3.42
Levelized Cost per tonne of CO_2 Removed ($/tonne of CO_2)	(N/A)

2.3.7 Case 1C at ISO Conditions

In the course of completing this case, one sensitivity case was identified and evaluated; case 1C at ISO conditions. Plant performance was estimated and a heat and material balance diagram was produced. There will be no cost estimate for this sensitivity case.

This case was developed so that the results of this study could be compared to other studies that assumed ISO conditions for ambient. As such, the power plant configuration in this case is a direct duplicate of that described in detail in the previous section. However, due to the assumption of ISO ambient conditions -- which are 15°C (59°F), 0.101 MPa (14.696 psia), and 60 percent relative humidity -- there are several differences in plant performance.

Operation of the gas turbine at ISO conditions, as opposed to the ambient conditions of 17.2°C (63°F) and 0.099 MPa (14.4 psia) assumed for the primary case, results in greater flow through the gas turbine set. More air is compressed and utilized due to density changes at the compressor inlet. Increased airflow and a higher ambient (inlet) pressure results in a relatively higher firing pressure, higher fuel input, and increased power output. However, in the case presented here, the simple cycle efficiency at ISO conditions compared to those assumed for the body of this report is more or less unchanged.

Estimated performance is presented in Table 2-22. A heat and material balance is in Figure 2-8. As can be seen by comparing this heat and material balance with that in Figure 2-7, airflow for each compressor has increased from 429.6 kg/sec (947 lb/sec) to 442.7 kg/sec (976 lb/sec). Fuel flow to each turbine has increased from 36,058 kg/hour (79,493 lb/hour) to 37,305 kg/hour (82,244 lb/hour). Also, the steam turbine back-pressure has decreased from 68 mbara (2 inches HgA) to 41 mbara (1.2 inches HgA).

The heat and material balance in Figure 2-8 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

As shown in Table 2-22, gas turbine shaft power output has increased from 334.8 MW to 346.6 MW. This power increase is due entirely to the change in ambient conditions; operation at ISO allows greater volume throughput. Also, due to the increase in power plant thermal input, as well as a decrease in condenser back-pressure, steam turbine shaft power output has increased from 194 MW to 205 MW. The overall effect is increased plant output at a similar efficiency performance level.

Table 2-22
CASE 1C – (2) 7FA x 1 NGCC (ISO CONDITIONS)
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	346,645
Steam Turbine Power	204,934
Generator Loss	(9,713)
Gross Plant Power (Note 1)	541,866
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	330
High Pressure Boiler Feed Pump	2,340
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	2,900
Cooling Tower Fans	1,650
Transformer Loss	1,700
Total Auxiliary Power Requirement	10,220
NET PLANT POWER, kWe	531,646
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	56.1
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	6,418 (6,085)
Net Efficiency, % HHV	50.5
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	7,122 (6,752)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	1,105 (1,048)
CONSUMABLES	
Natural Gas, kg/h (lb/h) @ (Note 3)	74,612 (164,488)

Note 1 – Loads are presented for two gas turbines, and one steam turbine.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

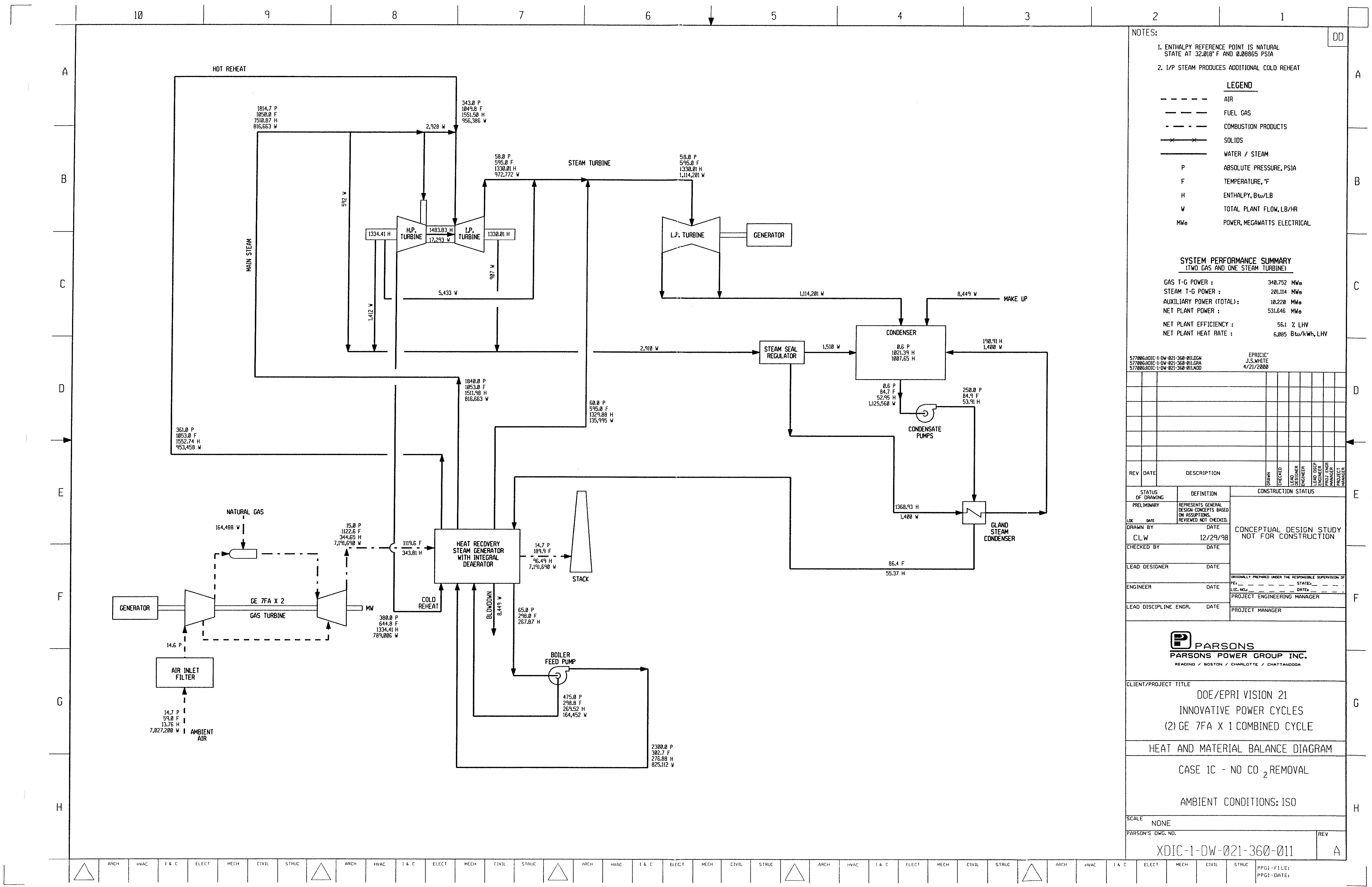

Figure 2-8
Heat and Material Balance Diagram – (2) GE 7FA x 1 Combined Cycle – Case 1C – No CO_2 Removal – ISO Conditions

2.4 CASE 1D – NGCC, H CLASS TURBINE WITH NO CO_2 REMOVAL

2.4.1 Introduction

This market-based design is based on the use of one natural gas-fired combustion turbine (CT), coupled with a heat recovery steam generator (HRSG) to generate steam for a single steam turbine generator. The plant configuration reflects current information and design preferences, the availability of newer combustion and steam turbines, and the relative latitude of a greenfield site.

This rendition of CT/HRSG technology is based on the General Electric H-type ATS machine. The configuration of this machine uses a single shaft to connect gas turbine and steam turbine along with a generator. This particular machine provides power output, airflow, and exhaust gas temperature that effectively couple with a HRSG to generate steam for the companion steam cycle plant to produce a total net output of 384 MWe, at an efficiency of 59.5 percent (LHV) and 53.6 percent (HHV). For this study, one gas turbine is used in conjunction with one 12.48 MPa/565.6°C/565.6°C (1810 psig/1050°F/1050°F) steam turbine.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections are:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Production Cost, and Economics
- Case 1D at ISO Conditions

The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost. A performance sensitivity at ISO conditions is presented at the end of the section.

2.4.2 Thermal Plant Performance

The market-based plant described in this section is based on use of one General Electric H-type ATS gas turbine coupled with a triple-pressure HRSG supplying steam to one steam turbine generator. The resulting power plant thus utilizes a combined cycle for conversion of thermal energy to electric power. Table 2-23 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant. Gross power output (prior to the generator terminals) for the H-type turbo-set is estimated to be 398.4 MWe. This number is a little less than the quoted +400 MWe available at ISO conditions.

The assumed ambient conditions (see Table 1-1) correspond to lower pressure and higher temperature (i.e., lower density) compared to ISO. The geometry of the gas turbine is fixed. As a result, the mass flow of less dense air through the compressor will be less than that of relatively more dense air. That is the case we have here -- less dense ambient air, lower compressor air suction, lowered fuel usage and turbo-set power output. Simple cycle efficiency for the CT remains essentially unchanged. For comparison, this case was also run at ISO conditions. This will be discussed later in Section 2.4.7.

Plant auxiliary power is also summarized in Table 2-23. The total is estimated to be 7.2 MWe. Net plant power output, which considers generator losses and auxiliary power, is estimated at 384 MWe. This plant power output results in a net system thermal efficiency of 59.5 percent (LHV) with a corresponding heat rate of 6,051 kJ/kWh (5,737 Btu/kWh) (LHV). The corresponding HHV values for efficiency and heat rate are 53.6 percent and 6,715 kJ/kWh (6,366 Btu/kWh), respectively.

Figure 2-9 contains a heat and material balance diagram for the 100 percent load condition. CT and ST cycles are shown schematically along with the appropriate state point condition data. An open Brayton cycle (CT) using air and combustion products as working fluid is used in conjunction with the conventional sub-critical Rankine cycle (ST). The two cycles are coupled by the generation and superheating of steam in the HRSG, and by feedwater heating in the HRSG.

The heat and material balance in Figure 2-9 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

The HRSG uses a triple pressure configuration. The low-pressure drum provides steam for the crossover of the steam turbine as well as steam for an integral deaerator. Intermediate-pressure steam provides additional cold reheat. High-pressure steam is the primary working fluid of the Brayton cycle.

Table 2-23
CASE 1D – GE H x 1 NGCC
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	271,812
Steam Turbine Power	126,605
Generator Loss	(6,773)
Gross Plant Power (Note 1)	391,644
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	220
High Pressure Boiler Feed Pump	1,560
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,850
Cooling Tower Fans	1,050
Transformer Loss	1,230
Total Auxiliary Power Requirement	7,210
NET PLANT POWER, kWe	384,434
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	59.5
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	6,051 (5,737)
Net Efficiency, % HHV	53.6
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	6,715 (6,366)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	728.9 (691)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 3)	50,873 (112,153)

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

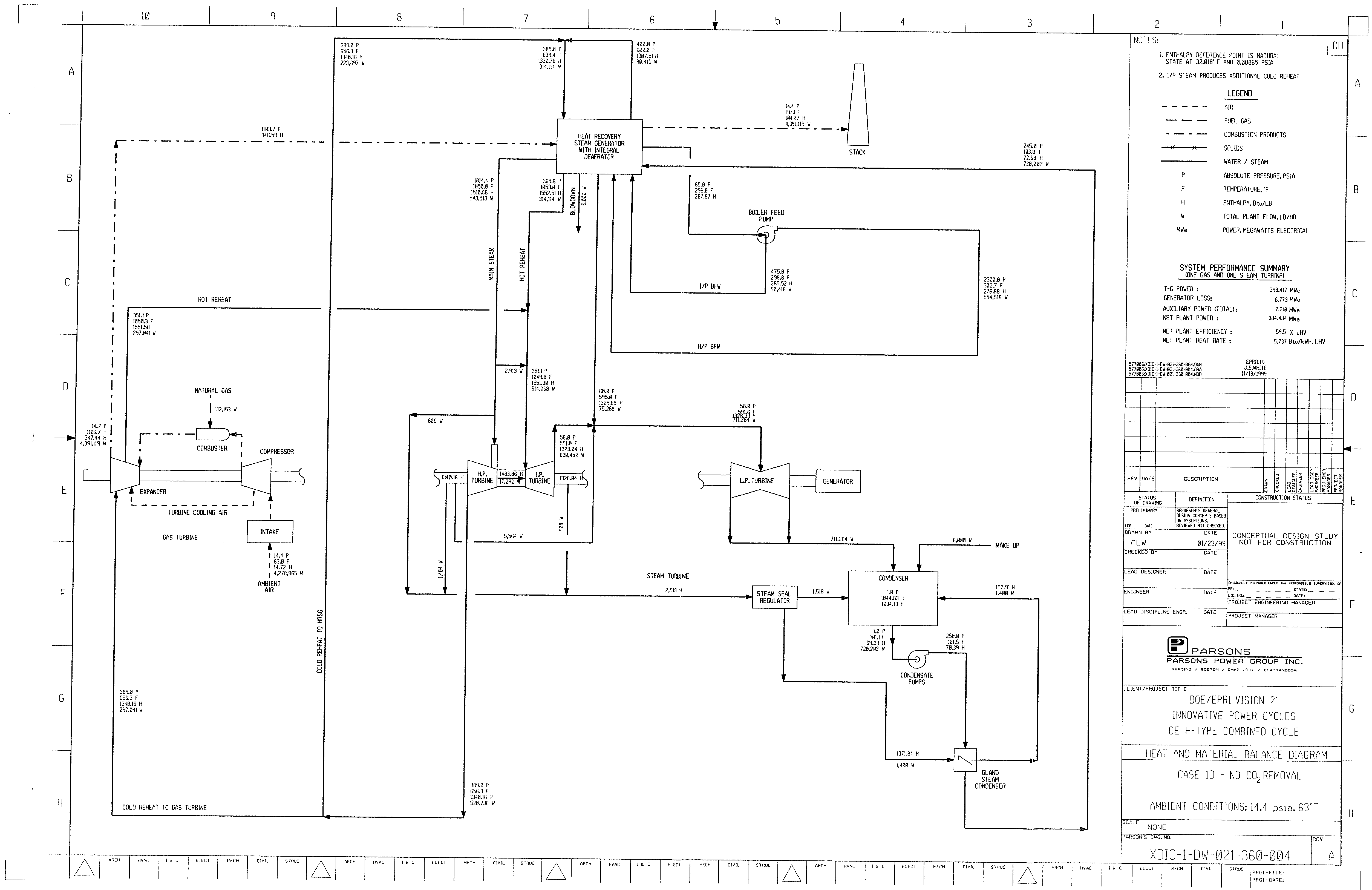

Figure 2-9
Heat and Material Balance Diagram – GE H-Type Combined Cycle – Case 1D – No CO_2 Removal

2.4.3 Power Plant Emissions

The operation of the modern, state-of-the-art gas turbine fueled by natural gas, coupled to a HRSG, is projected to result in very low levels of SO_2, NOx, and CO_2 emissions. A summary of the estimated plant emissions for this case is presented in Table 2-24. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four basis: (1) kilograms per gigajoules of JJV thermal input (pounds per million Btu of HHV thermal input), (2) tonnes per year for a 65 percent capacity factor (tons per year for a 65 percent capacity factor), (3) tonnes per year for an 85 percent capacity factor (tons per year for an 85 percent capacity factor), and, (4) kilograms per hour per MWe of power output (pounds per hour per MWe of power output).

Table 2-24
CASE 1D AIRBORNE EMISSIONS
H-TYPE NGCC

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
NOx	< 0.012 (< 0.028)	174 (192)	229 (252)	0.08 (0.18)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	50.7 (118)	745,691 (821,970)	975,149 (1,074,900)	338 (746)

As shown in the table, values of SO_2 emission and particulate discharge are negligible. This is a direct consequence of using natural gas as the plant fuel supply. Pipeline natural gas contains minor amounts of reduced sulfur species that produce negligible SO_2 emissions when combusted and diluted with a large amount of air. When natural gas is properly combusted in a state-of-the-art CT the amount of solid particulate produced is very small (less than 9.1 kg/hour (20 lb/hour), 0.027 kg/MWh (0.06 lb/MWh)).

The low level of NOx production is achieved through use of GE's dry low-NOx (DLN) combustion system. This combustor arrangement should limit NOx emissions to less than 10 ppmv adjusted to 15 percent O_2 content in the flue gas.

2.4.4 System Description

The major subsystems in this natural gas-fired combined cycle power plant are:

- Combustion Turbine
- Heat Recovery Steam Generator
- Steam Turbine Generator

- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief discussion about the power plant equipment and operating conditions. This discussion is based on the heat and material balance diagram shown in Figure 2-9. The equipment list, which follows this section, is based on the material presented here.

2.4.4.1 Combustion Turbine

The CT, or gas turbine, generator selected for this application is based on the General Electric model H. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. The gas turbine compressor and expander, as well as the steam turbine and generator, are connected on a single rotating shaft.

Inlet air at 539.9 kg/sec (1,189 lb/sec) is compressed in a single spool compressor to a pressure ratio of approximately 23:1. This airflow is lower than the ISO airflow of 555.7 kg/sec (1,225 lb/sec) due to the choice of ambient conditions used in this specific study. The ambient conditions chosen in this correspond to a standard EPRI/DOE fossil-plant site. They result in a less dense ambient air, and subsequently, less airflow and power output in the gas turbine. The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the natural gas. Compressed air is also used in burner, transition and film cooling services.

Pressurized pipeline natural gas at a rate of 50,873 kg/hour (112,153 lb/hour) is combusted in several (12) parallel dry low-NOx combustors that use staged combustion to limit NOx formation. The CT combustors are can-annular in configuration. In the can-annular arrangement, individual combustion cans are placed side-by-side in an annular chamber. Each can is equipped with multiple fuel nozzles. This allows for higher mass flows than earlier machines and higher operating temperatures. In the estimated performance provided here, the machine will develop a rotor inlet temperature of about 1426.7°C (2600°F).

Hot combustion products are expanded in the four-stage turbine-expander. It is assumed that the first two expander stages are steam-cooled and that the third stage is air-cooled. No cooling is expected in the fourth expander stage. The CT exhaust temperature is estimated as 597.2°C (1107°F) given the assumed ambient conditions, back-end loss, and HRSG pressure drop. This value, slightly higher than the ISO assumed value of 594.4°C (1102°F) for a simple cycle gas turbine, is due to increased back pressure on the CT due to the HRSG.

Gross turbine shaft power, as measured prior to the generator terminals, is estimated as 271.8 MWe. The CT generator is a standard hydrogen-cooled machine with static exciter. The generator is shared with the steam turbine. Net CT power (following generator losses) is estimated at 267.7 MWe. These power values are lower than those quoted at ISO conditions because the CT compressor airflow is lower at the assumed ambient conditions. This lower airflow results in lower power output. The CT fuel fed is decreased proportionately such that the CT simple cycle efficiency is relatively unchanged.

2.4.4.2 Heat Recovery Steam Generator

High temperature flue gas at 1,991,812 kg/hour (4,391,119 lb/hour) exiting the CT is conveyed through the HRSG to recover the large quantity of thermal energy that remains. For analytical purposes, it is assumed that the flue gas heat loss through the HRSG duct corresponds to 1.7°C (3°F). Flue gases travel through the HRSG gas path and exit at 91.7°C (197°F).

The HRSG is configured with high-pressure (HP), intermediate-pressure (IP), and LP steam drums and circuitry. The HP drum is supplied with feedwater by the HP boiler feed pump while the IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump. IP steam from the drum is mixed with cold reheat steam; the combined flow is then passed to the reheat section. The LP drum produces steam for superheat as well as saturated steam for an integral deaerator.

Condensate at 326,684 kg/hour (720,202 lb/hour) flows from the gland steam condenser to the HRSG feedwater heater (low-temperature economizer). In this heater, the condensate temperature is raised from 39.4°C (103°F) to 144.4°C (292°F). The condensate is then routed to the integral deaerator, which operates at 152.8°C (307°F) and 0.5 MPa (75 psia). Feedwater from the integral deaerator is then conveyed to the boiler feed pump.

High-pressure water from the boiler feed pump at 15.9 MPa (2300 psia) is heated to 315.6°C (600°F) in a series of three economizers. The high-pressure economizers are staggered within the HRSG in order to maximize flue gas heat flux. The high-pressure evaporator operates at 13.4 MPa (1950 psia) resulting in a nominal 18.3°C (33°F) evaporator temperature approach. The gas-to-water pinch is 11.1°C (20°F). A continuous drum blowdown of 2,721.6 kg/hour (6,000 lb/hour) was used in this analysis. Saturated steam removed from the high-pressure drum is superheated to 567.8°C (1054°F) and then routed to the high-pressure steam turbine throttle valves.

Feedwater from an interstage bleed on the HP boiler feed pump at a rate of 41,013 kg/hour (90,416 lb/hour) feeds the IP steam drum. The IP drum operates with a 13.9°C (25°F) approach and an 11.1°C (20°F) gas-to-water pinch. Saturated steam from the IP drum at 2.83 MPa (410 psia) is superheated to 315.6°C (600°F) and then mixed with cold reheat from the high-pressure steam turbine. The combined flow is then reheated to 565.6°C (1050°F) and routed to the IP section of the steam turbine.

The LP steam drum operates at 0.5 MPa (75 psia). Saturated steam not utilized in the integral deaerator is removed from the LP drum and superheated to 398.9°C (597°F). This steam then flows to the steam turbine crossover area at a rate of 34,142 kg/hour (75,268 lb/hour).

The HRSG tube surface is typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 material; the low-temperature portions (< 398.9°C (< 750°F)) will be carbon steel.

2.4.4.3 Steam Turbine Generator

The Rankine cycle used in this case is based on a state-of-the-art 12.4 MPa/565.6°C/565.6°C (1800 psig/1050°F/1050°F) single reheat configuration. The steam turbine is a single machine consisting of tandem high-pressure (HP), intermediate-pressure (IP), and double-flow low-pressure (LP) turbine sections connected via a common shaft and driving a 3600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a pitch diameter of 183 cm (72 inches) and a last-stage bucket length of 66 cm (26 inches).

Main steam at a rate of 248,800 kg/hour (548,500 lb/hour) from the HP boiler located in the HRSG passes through the HP stop valves and control valves and enters the turbine at 12.5 MPa/565.6°C (1815 psia/1050°F). The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the IP stop valves and intercept valves and enters the IP section at 2.4 MPa/565.6°C (343 psig/1050°F). After passing through the IP section, the steam enters a crossover pipe. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the crossover line. The crossover steam is divided into two paths and flows through the LP sections exhausting downward into the condenser.

2.4.4.4 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the HRSG. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity motor-driven feed pumps are provided for HP/IP service. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

2.4.4.5 Balance of Plant

The balance of plant items discussed in this section include:

- Natural Gas Lines and Metering
- Steam Systems
- Circulating Water System
- Accessory Electric Plant
- Instrumentation and Control

Natural Gas Lines and Metering

In this design, it is assumed that a natural gas main with adequate capacity and pressure is at the fence line of the site and that a suitable right of way is available to install a branch line to the site. A gas line comprised of Schedule 40 carbon steel pipe, 40.6 cm (16 inches) nominal OD, is required to convey the gas to the site. The buried pipeline is coated and wrapped, and cathodically protected with a zinc ribbon-type sacrificial anode to protect the pipe from corrosion.

A new gas metering station is located on the site, adjacent to the new combustion turbine. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording, or may be of the positive displacement type. In either case, a complete time-line record of gas consumption rates and cumulative consumption is provided.

Steam Systems

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

Main steam exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine.

Cold reheat steam exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Circulating Water System

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

Accessory Electric Plant

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

Instrumentation and Control

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

2.4.5 Case 1D Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 2-9. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the Nomenclature section.

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter)

Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Gallon, gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832 x 10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3} = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

ACCOUNT 1 COAL AND SORBENT HANDLING

Not Applicable

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Gas Pipeline	Underground, carbon steel, coated and wrapped, cathodic protection	112,150 lb/h @ 600 psig 16 in. OD, Sch. 40	10 miles
2	Gas Metering Station		112,150 lb/h	1

ACCOUNT 2B SORBENT PREPARATION AND FEED

Not Applicable

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cyl., outdoor	70,000 gal	1
2	Condensate Pumps	Vert. canned	725 gpm @ 580 ft	2
3	HP Feed Pumps	Horizontal split case Multi-staged, centr. with interstage bleed for IP feedwater	610 gpm @ 5,810 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
2	Fuel Oil Storage Tank	Vertical, cylindrical	30,000 gal	1
3	Fuel Oil Unloading Pump	Gear	50 psig, 100 gpm	1
4	Fuel Oil Supply Pump	Gear	150 psig, 5 gpm	2
5	Service Air Compressors	Recip., single stage, double-acting, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exchanger	Plate and frame	50% cap. Each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
11	Fire Service Booster Pump	Two-stage horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1000 gpm	1
13	Raw Water	S.S., single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	S.S., single suction	160 ft, 120 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

Not Required

ACCOUNT 5 FLUE GAS CLEANUP

Not Required

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	270 MWe Gas Turbine Generator	Axial flow single spool based on H	1,190 lb/sec airflow 2600°F rotor inlet temp. 23:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1,190 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2,500 hp, time from turning gear to full load ~30 minutes	1
5	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
6	Oil Cooler	Air-cooled, fin fan		1
7	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
8	Generator Glycol Cooler	Air-cooled, fin fan		1
9	Compressor Wash Skid			1
10	Fire Protection Package	Halon		1

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, triple-pressure, with economizer section and integral deaerator	HP-1,950 psia/633°F 550,000 lb/h, superheat to 1050°F IP-410 psia/447°F 91,000 lb/h, superheat to 600°F LP-65 psia/300°F 75,000 lb/h, superheat to 595°F	1
2	Stack	Carbon steel plate, lined with type 409 stainless steel	213 ft high x 23 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	90 MW Turbine Generator	TC2F26, triple admissions	1800 psig 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single-pass, divided waterbox	710,000 lb/h steam @ 2.0 in. Hga with 74°F water, 20°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water-sealed	2,000/20 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	87,000 gpm @ 80 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	83°F WB/88°F CWT/ 96°F HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Not Applicable

2.4.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the 1 x 1 H natural gas-fired combined cycle power plant without CO_2 removal, case 1D, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 1D represents a plant with a net output of 384.4 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 2-25. A detailed estimate for case 1D is included in Appendix A.

Table 2-25
CASE 1D SUMMARY TPC COST

Account Number	**Title**	**Cost ($x1000)**
	BARE ERECTED COST	
5B	CO_2 Removal and Compression	N/A
6	Combustion Turbine and Accessories	52,610
7	HRSG, Ducting and Stack	20,840
8&9	Steam T-G Plant, including Cooling Water System	36,320
11	Accessory Electric Plant	13,550
	Balance of Plant	28,80
	SUBTOTAL	152,300
	Engineering, Construction Management Home Office and Fee	9,140
	Process Contingency	5,140
	Project Contingency	24,140
	TOTAL PLANT COST (TPC)	$190,750
	TPC $/kW	500

The production costs for case 1D consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal) and Fuel costs. The costs were determined on a first-year basis that includes evaluation at a 65 percent equivalent plant operating capacity factor. The results are summarized in Table 2-26 and supporting detail is contained in Appendix A.

Table 2-26
CASE 1D ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	1,720	0.08
Maintenance	4,010	0.18
Administrative & Support Labor	831	0.04
Consumables	486	0.02
By-Product Credits	N/A	N/A
Fuel	37,625	1.72
TOTAL PRODUCTION COST	44,671	2.04

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 1D. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per tonne. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI is included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 2-27.

Table 2-27
CASE 1D LEVELIZED ECONOMIC RESULT SUMMARY

Component (Unit)	Value
Production Cost (¢/kWh)	2.04
Annual Carrying Charge (¢/kWh)	1.31
Levelized Busbar Cost of Power Charge (¢/kWh)	3.35
Levelized Cost per tonne of CO_2 Removed ($/tonne of CO_2)	(N/A)

2.4.7 Case 1D at ISO Conditions

In the course of completing this case, one sensitivity case was identified and evaluated: case 1D at ISO conditions. Plant performance was estimated and a heat and material balance diagram was produced. There will be no cost estimate for this sensitivity case.

This case was developed so that the results of this study could be compared to other studies that assumed ISO ambient conditions. As such, the power plant configuration in this case is a direct duplicate of that described in detail in the previous section. However, due to the assumption of ISO ambient conditions -- which are 15°C (59°F), 0.101 MPa (14.696 psia), and 60 percent relative humidity -- there are several differences in plant performance.

Operation of the gas turbine at ISO conditions, as opposed to the ambient conditions of 17.2°C (63°F) and 0.099 MPa (14.4 psia) assumed for the primary case, results in greater flow through the gas turbine set. More air is compressed and utilized due to density changes at the compressor inlet. Increased airflow and a higher ambient (inlet) pressure results in a relatively higher firing pressure, higher fuel input, and increased power output. However, in the case presented here, the simple cycle efficiency at ISO conditions compared to those assumed for the body of this report is more or less unchanged.

Estimated performance is presented in Table 2-28. A heat and material balance is in Figure 2-10. As can be seen by comparing this heat and material balance with that in Figure 2-9, airflow to the compressor has increased from 539.3 kg/sec (1,189 lb/sec) to 555.7 kg/sec (1,225 lb/sec). Fuel flow to the combustor has increased from 50,873 kg/hour (112,153 lb/hour) to 52,496 kg/hour (115,733 lb/hour). Also, the steam turbine back-pressure has decreased from 68 mbara (2 inches HgA) to 41 mbara (1.2 inches HgA).

The heat and material balance in Figure 2-10 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

As shown in Table 2-28, gas turbine shaft power output has increased from 271.8 MW to 281.2 MW. This power increase is due entirely to the change in ambient conditions; operation at ISO allows greater volume throughput. Also, due to the increase in power plant thermal input, as well as a decrease in condenser back-pressure, gross steam turbine shaft power output has increased from 126.6 MW to 133.5 MW. The overall effect is increased plant output at a similar efficiency performance level.

Table 2-28
CASE 1D – GE H x 1 NGCC (ISO CONDITIONS)
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	281,219
Steam Turbine Power	133,544
Generator Loss	(7,050)
Gross Plant Power (Note 1)	407,713
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	220
High Pressure Boiler Feed Pump	1,600
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,940
Cooling Tower Fans	1,100
Transformer Loss	1,290
Total Auxiliary Power Requirement	7,450
NET PLANT POWER, kWe	400,263
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	60.0
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	5,998 (5,686)
Net Efficiency, % HHV	54.1
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	6,656 (6,310)
CONDENSER COOLING DUTY, 10^6 Btu/h	746.7 (708)
CONSUMABLES	
Natural Gas, lb/h (Note 3)	52,496 (115,733)

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

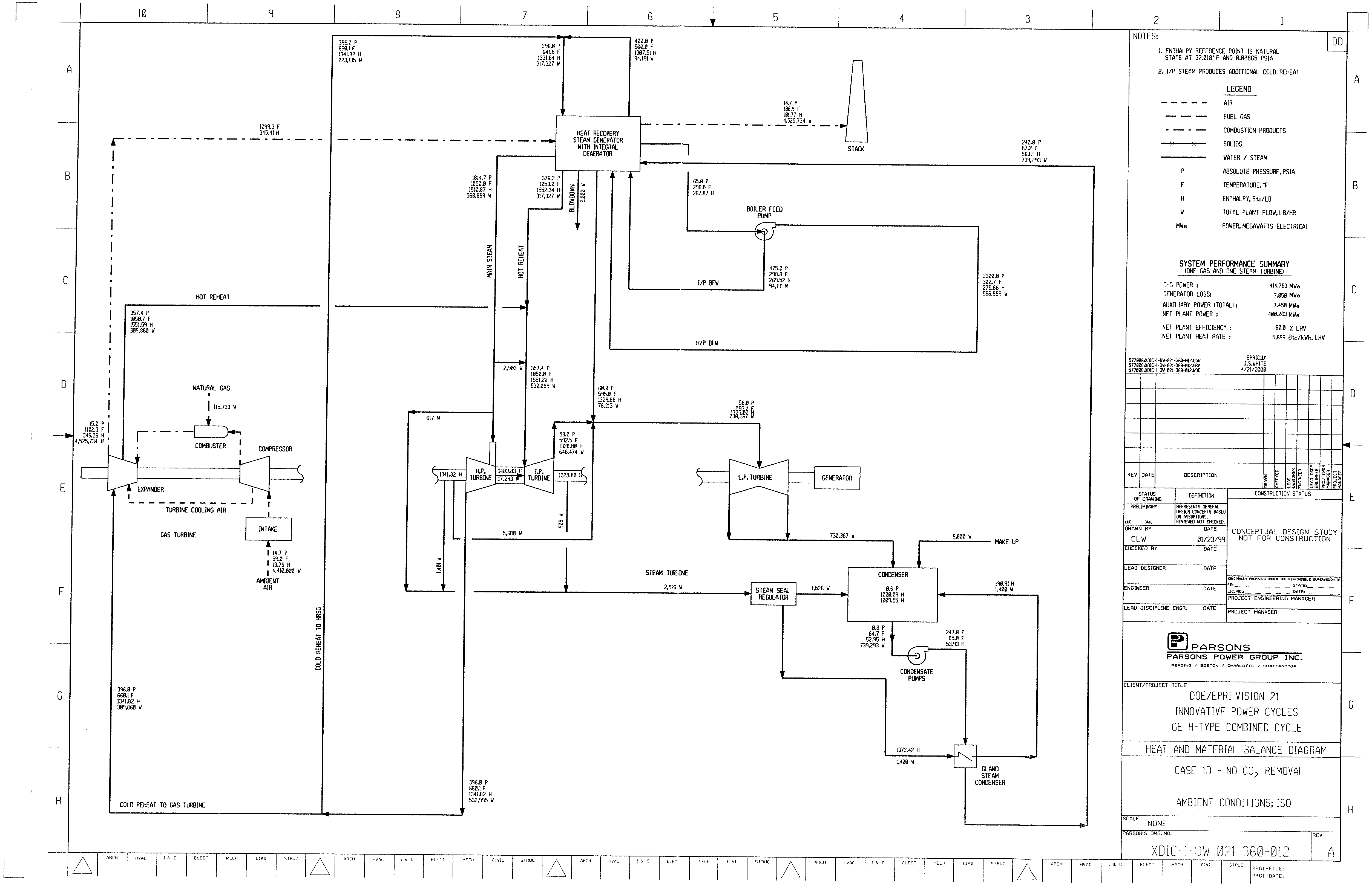

Figure 2-10
Heat and Material Balance Diagram – GE H-Type Combined Cycle – Case 1D – No CO_2 Removal – ISO Conditions

3
ADVANCED NGCC – TECHNICAL DESCRIPTIONS

Two "advanced" natural gas-fired combined cycle power plants were identified for this study. As of the writing of this report, only one case was evaluated and is presented in this section. The design consists of a solid oxide fuel cell coupled with a cascaded humidified advanced turbine cycle and is based on several assumptions about the future performance of these two developmental systems. Plant performance was estimated and a heat and material balance diagram is presented. An equipment list was generated based on the estimated plant performance and used to generate total plant and operating cost. A plant description is also presented.

The two cases identified are:

- Case 2A – Advanced NGCC with CO_2 Removal and Recovery
- Case 2B – Advanced NGCC with no CO_2 Removal and Recovery

As of the writing of this report, only case 2B has been completed. However, the cost analysis for 2B is incomplete and not presented. The next interim report will contain a complete analysis and cost of both cases 2A and 2B.

3.1 CASE 2A -- ADVANCED NGCC WITH CO_2 REMOVAL

Not Included In This Draft Report

3.2 CASE 2B -- ADVANCED NGCC WITH NO CO_2 REMOVAL

3.2.1 Introduction

This advanced power plant configuration consists of a tubular solid oxide fuel cell (SOFC) stack followed by a cascaded humidified advanced turbine (CHAT) cycle. This configuration has been labeled case 2B. The balanced shaft of the CHAT cycle is based on industrial-type turbo machinery. The power, or low-pressure, expander, is based on the Siemens-Westinghouse 501FA. Water for the air saturator is condensed and recycled from the low-temperature flue gas cooler.

The SOFC stack produces approximately 209 MW of dc electric power, which is inverted to 204.6 MWe of ac electric power. The low-pressure power expander produces an additional 356.7 MWe. Total plant auxiliary load is estimated at 4.79 MWe. This results in a net plant power output of 556 MWe. Net plant efficiency is estimated at 59.7 percent, HHV, with a corresponding heat rate of 6,029 kJ/kWh (5,716 Btu/kWh).

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections are:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List

The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost.

3.2.2 Thermal Plant Performance

Table 3-1 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant. The power turbine, or LP expander, develops 356 MWe while the solid oxide fuel cell generates an estimated 204 MWe. The estimated auxiliary power load is 4.79 MWe resulting in a net plant power output of 556.5 MWe. This power is generated with an expected HHV efficiency of 59.7 percent with a corresponding heat rate of 6,029 kJ/kWh (5,716 Btu/kWh).

A heat and material balance diagram (Figure 3-1) for the 100 percent load condition is not yet available. In the plant configuration all three compressors rotate on a single shaft with the balanced-shaft turbine (or HP expander). High-pressure air delivered by the compression system is saturated and heated before entering the cathode. Natural gas is heated and routed to the anode. Combustion products exiting the fuel cell combustor supports the firing of natural gas in the balanced turbine combustor. In turn, the flue gas exiting the balanced shaft turbine support firing additional natural gas in the power turbine. A heat recovery unit is used to manage and effectively recover any waste heat.

Table 3-1
CASE 2B – SOFC/CHAT CYCLE WITHOUT CO_2 REMOVAL
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	N/A (N/A)
Throttle Temperature, °C (°F)	N/A (N/A)
Reheat Outlet Temperature, °C (°F)	N/A (N/A)
GROSS POWER SUMMARY, kWe)	
SOFC Power	204,605
Turbine Expander Power	363,989
Generator Loss	(7,280)
Gross Plant Power	561,314
AUXILIARY LOAD SUMMARY, kWe	
Fuel Compressor	1,980
Saturated Water Pump	250
Miscellaneous Balance of Plant (Note 1)	500
Expander Auxiliaries	300
Transformer Loss	1,760
Total Auxiliary Power Requirement	4,790
NET PLANT POWER, kWe	556,524
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	66.2
Net Heat Rate, LHV, kJ/kWh (Btu/kWh)	5,436 (5,154)
Net Efficiency, % HHV	59.7
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	6,029 (5,716)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	N/A (N/A)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 2)	66,145 (145,845)

Note 1 – Includes plant control systems, lighting, HVAC, etc.
Note 2 – Heating value (LHV): 45,743 kJ/kg (19,666 Btu/lb); (HHV): 50,763 kJ/kg (21,824 Btu/lb).

Figure 3-1
Heat and Material Balance Diagram – SOFC/CHAT Cycle without CO_2 Removal – Case 2B
Not Included In This Draft Report

3.2.3 Power Plant Emissions

The operation of the modern, state-of-the-art turbo machinery fueled by natural gas is projected to result in very low levels of SO_2, NOx, and CO_2 emissions. A summary of the estimated plant emissions for this case is presented in Table 3-2. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four basis: (1) kilogram per gigajoule of HHV thermal input (pound per million Btu of HHV thermal input), (2) tonnes per year for a 65 percent capacity factor (tons per year for a 65 percent capacity factor), (3) tonnes per year for an 85 percent capacity factor (tons per year for an 85 percent capacity factor), and, (4) kilograms per hour per MWe of power output (pounds per hour per MWe of power output).

Table 3-2
CASE 2B AIRBORNE EMISSIONS
501FA-BASED CHAT CYCLE

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	Kg/MWh (lb/MWh)
SO_2	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
NOx				
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2				

As shown in the table, values of SO_2 emission and particulate discharge are negligible. This is a direct consequence of using natural gas as the plant fuel supply. Pipeline natural gas contains minor amounts of reduced sulfur species that produce negligible SO_2 emissions when combusted and diluted with a large amount of air. As for particulate discharge, when natural gas is properly combusted in a state-of-the-art combustion system the amount of solid particulate produced is very small.

The low level of NOx production is achieved through use of dry low-NOx (DLN) burners. This combustor arrangement should limit NOx emissions to 9 ppm adjusted to 15 percent O_2 content in the flue gas.

3.2.4 System Description

Ambient air is compressed to 0.66 MPa (95.2 psia) in the low-pressure compressor. The air stream is indirectly cooled to 22.2°C (72°F), first by exchange with process water for the saturator and then with plant cooling water. The air is further compressed to 4.22 MPa (612 psia) in the intermediate-pressure compressor. An inter-stage bleed provides turbine-cooling air to the power expander. The main air stream is cooled again to 22.2°C (72°F) and compressed to 6.41 MPa (929 psia).

The high-pressure air stream is directed to the bottom of the air saturation column. In the column, air will be directly contacted with warm water flowing down counter-currently. Contact with the warm water humidifies the air stream. Packing or trays will be used to enhance the rate of mass transfer. The moist air is heated to 613.3°C (1136°F) in the heat recovery unit and then routed to the fuel cell cathode.

Compressed and heated natural gas at 6.2 MPa (895 psia) and 103.3°C (218°F) is routed to the fuel cell anode. In the fuel cell, CH_4 in the natural gas is directly reformed to H_2 and CO. H_2 and CO react indirectly with O_2 through the transfer of ions across the electrolyte. This transfer generates electricity and heat. The electricity is inverted to ac power while the heat is either carried away with the reaction products or used by the endothermic reforming reactions. The saturated air streams and spent fuel stream are then combined and combusted. Flue gas exits the fuel cell at 6.14 MPa (890 psia) and 854.4°C (1570°F).

Flue gas from the fuel cell supports the combustion of natural gas in the balanced expander burner. Flue gas enters this expander at 5.9 MPa (855 psia) and 1093.3°C (2000°F). A stream of cool air from the saturator is used to cool the turbine surfaces. The expansion of these gases supplies enough shaft energy to power the three compressors.

Flue gas exiting the balance shaft expander supports combustion of more natural gas in the power turbine combustor. The combustion products enter the expander at 1376.7°C (2510°F) and 1.38 MPa (200 psia) and exit at 656.1°C (1213°F) and 0.103 MPa (15 psia). Shaft power is converted as product electricity in the turbine generator. Waste heat contained in the power turbine expander exhaust is recovered in the heat recovery unit.

The balance of plant items for this power plant include:

- Natural Gas Lines and Metering
- Circulating Water System
- Accessory Electric Plant
- Instrumentation and Control

Natural Gas Lines and Metering

In this design, it is assumed that a natural gas main with adequate capacity and pressure is at the fence line of the site and that a suitable right of way is available to install a branch line to the site. A gas line comprised of Schedule 40 carbon steel pipe, 39.2 cm (16 inches) nominal OD, is required to convey the gas to the site. The buried pipeline is coated and wrapped, and cathodically protected with a zinc ribbon-type sacrificial anode to protect the pipe from corrosion.

A new gas metering station is located on the site, adjacent to the new combustion turbine. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording, or may be of the positive displacement type. In either case, a complete time-line record of gas consumption rates and cumulative consumption is provided.

Circulating Water System

The function of the circulating water system is to supply cooling water to the process exchangers. The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping.

Accessory Electric Plant

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

Instrumentation and Control

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

3.2.5 Case 2B Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 3-1. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the Nomenclature section.

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter)

Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Gallon,gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832×10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9×10^{-3} = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0458 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

ACCOUNT 1 COAL AND SORBENT HANDLING

Not Applicable

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Gas Pipeline	Underground, carbon steel, coated and wrapped, cathodic protection	145,845 lb/h @ 600 psig 16 in. OD, Sch. 40	10 miles
2	Gas Metering Station		145,845 lb/h	1
3	Gas Heater	Shell and tube	44×10^6 Btu/h 200 psig / 200ºF	1
4	Gas Compressor	Axial	2,700 hp 2.5:1 PR	1

ACCOUNT 2B SORBENT PREPARATION AND FEED

Not Applicable

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty
1	Service Air Compressors	Recip., single-stage, double-acting, horizontal	100 psig, 450 cfm	2
2	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
3	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
4	Closed Cycle Cooling Heat Exchanger	Plate and frame	50% cap. each	2
5	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
6	Fire Service Booster Pump	Two-stage horizontal centrifugal	250 ft, 700 gpm	1
7	Engine-Driven Fire Pump	Vertical turbine, diesel engine	350 ft, 1000 gpm	1
8	Raw Water	S.S., single suction	60 ft, 100 gpm	2
9	Filtered Water Pumps	S.S., single suction	160 ft, 120 gpm	2
10	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
11	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
12	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

Not Applicable

ACCOUNT 5 FLUE GAS CLEANUP

Not Applicable

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	Solid Oxide Fuel Cell	Tubular, high pressure	205 MWe, 0.7 V/C	1
2	LP Air Compressor	Axial flow	2,854,800 lb/h 641,950 acfm 6.6:1 PR 114,000 hp	1
3	LP Air Compressor Intercooler	Shell and tube	300 x 10^6 Btu/h 1,100 psig / 500ºF	1
4	IP Air Compressor	Axial/centrifugal Hybrid design	2,843,700 lb/h 104,930 acfm 7.07:1 PR 107,000 hp	1
5	IP Air Compressor Intercooler	Shell and tube	300 x 10^6 Btu/h 1,130 psig / 550ºF	1
6	Cooling Air Cooler	Shell and tube	41 x 10^6 Btu/h 1020 psig / 500ºF	1
7	HP Air Compressor	Centrifugal flow	2,419,400 lb/h 12,745 acfm 1.5:1 PR 17,500 hp	1
8	HP Combustor	Can annular	58,000 acfm 855 psia, 2000ºF	1
9	HP Expander	Axial	58,000 acfm 236,000 hp 4.07 PR	1
10	LP Combustor	Can annular	580,000 acfm 210 psia, 2500ºF	1
11	Hot-Gas, Low-Pressure Gas Expander and Generator Set	Axial flow Based on 501FA	582,822 acfm 488,000 hp 13.4:1 PR	1
12	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	1
13	Air Inlet Filter/Silencer	Two-stage	800 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	1
14	Starting Package	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	1
15	Air to Air Cooler			1
16	Mechanical Package	CS oil reservoir and pumps dual vertical		1

Equipment No.	Description	Type	Design Condition	Qty
		cartridge filters air compressor		
17	Oil Cooler	Air-cooled, fin fan		1
18	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
19	Generator Glycol Cooler	Air-cooled, fin fan		1
20	Compressor Wash Skid			1
21	Fire Protection Package	Halon		1

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Air Saturator	Packed column with Chevron-type mist eliminators	9,820 acfm air 583 lb/sec water 1,050 psig / 500ºF	1
2	Saturator Water Pump	Centrifugal	2,300 gpm @ 200 ft	1
3	Heat Recovery Unit	Shell and tube	$1,978 \times 10^6$ Btu/h 4,300,000 acfm	1
4	Stack	Carbon steel plate, lined with type 409 stainless steel	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Not Applicable

ACCOUNT 9 COOLING WATER SYSTEM

Not Applicable

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Not Applicable

4

ADVANCED COAL-FIRED CONFIGURATIONS – TECHNICAL DESCRIPTIONS

Two advanced coal-fired combined cycle power plants were evaluated and are presented in this section. Each design is market-based and consists of a state-of-the-art combustion turbine coupled with a reheat steam cycle. Plant performance was estimated and a heat and material balance diagram is presented for each case. An equipment list was generated based on the estimated plant performance and used to generate total plant and operating cost as well as cost of CO_2 emissions avoided. A plant description is also presented.

The two cases evaluated are:

- Case 3A – Base Case IGCC Plant with CO_2 Removal and Recovery
- Case 3B – Base Case IGCC Plant without CO_2 Removal

Although undefined at this time, there are plans to evaluate additional "advanced" coal-fired configurations whose merit will be decided by comparison to these "base" cases.

In case 3A, raw synthesis gas generated with a high-pressure E-Gas™-type gasifier was catalytically water-gas shifted in order to increase the CO_2 concentration. CO_2, along with H_2S, was removed from the cool, particulate-free fuel gas stream with Selexol solvent. Selexol was chosen due to the high pressure of the gasification process. High pressure favors chemical absorption processes, such as Selexol, over physical and physical/chemical-hybrid processes, which are comparably more efficient at lower pressure. CO_2 removed with the Selexol process was dried and compressed to a supercritical condition for subsequent pipeline transport. There was no provision for CO_2 removal in case 3B. The two cases are described in greater detail below.

4.1 CASE 3A – E-Gas™ IGCC, H CLASS TURBINE WITH CO_2 REMOVAL

4.1.1 Introduction

This market-based design centers on the use of a single combustion turbine coupled with a heat recovery system that generates steam for a single steam turbine generator. The gas turbine technology chosen for this IGCC study is based on General Electric's H-type advanced turbine system (ATS) machine. This particular machine features a gas turbine and steam turbine connected on a single shaft and generator.

A high-pressure E-Gas™ gasifier was chosen as the basis for this IGCC configuration. Raw fuel gas exiting the gasifier is cooled and cleaned of particulate before being routed to a series of water-gas shift reactors and raw gas coolers. These components convert CO present in the raw gas to CO_2; thereby concentrating it in the high-pressure raw fuel gas stream. Once concentrated, CO_2 can be removed during the desulfurization process through use of a double-staged Selexol unit. CO_2 is then dried and compressed to supercritical conditions for pipeline transport. Clean fuel gas from the Selexol unit, now rich in H_2, is fired in the combustion turbine, then expanded. Waste heat is recovered from this process and used to raise steam to feed to a steam turbine.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections include:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Production Cost, and Economics
- Case 3A Sensitivities

The thermal performance section contains a block flow diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections, including a series of heat and material balance diagrams that completely describe the thermodynamics and chemistry of the power plant. An equipment list is enclosed that supports the detailed plant description. The equipment list and heat and material balance diagrams were used to estimated plant cost. Two sensitivity cases are presented at the end of this section.

4.1.2 Thermal Plant Performance

The market-based plant described in this section is based on use of one General Electric H-type ATS gas turbine coupled with a heat recovery system that supplies steam to one steam turbine generator. The resulting power plant thus utilizes a combined cycle for conversion of thermal energy to electric power. Table 4-1 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant; including gross plant power, auxiliary power load, net plant power, and net plant efficiency.

Table 4-1 shows an increase in estimated gas turbine power output compared to the appropriate natural gas-fired case 1B (or case 1D). This assumption is based on GE’s report that IGCC output can be enhanced when coal-derived synthesis gas is fired in their combustion turbines. They have reported that a fourteen-percent increase in expander throughput, while maintaining the same firing temperature, is possible. This can result in as much as a twenty- percent increase in net plant power output. As a result, gross combustion turbine power has been estimated at 345 MWe in this IGCC case as compared to 272 MWe estimated for case 1B (or case 1D).

Plant auxiliary power is also summarized in Table 4-1. The total is estimated to be 86.9 MWe. This value, much higher than that anticipated for a coal-fired IGCC of this size, is due to the presence of the CO_2 removal/compression equipment. In particular, the auxiliary power load of the CO_2 compressor, which requires 24 MWe of auxiliary power, accounts for 28 percent of the total auxiliary power load for the entire plant.

Net plant power output for this IGCC configuration is estimated at 403.5 MWe. This power output is generated with a net plant thermal efficiency of 37 percent, HHV, with a corresponding heat rate of 9,732 kJ/kWh (9,226 Btu/kWh). Plant efficiency and heat rate numbers are low in comparison to those expected for coal-fired IGCC of the H-class technology. As discussed above, low system thermal efficiency is primarily due to the increased auxiliary power requirements of the CO_2 removal equipment.

Figure 4-1 contains a block flow diagram depicting the overall layout of this IGCC power plant configuration. Combustion turbine and steam turbine cycles are shown schematically along with the appropriate state point data. An open Brayton cycle (CT) using air and combustion products as working fluid is used in conjunction with the conventional sub-critical Rankine cycle (ST). The two cycles are coupled by the generation and superheating of steam in the heat recovery system, which consists of the HRSG and gasifier island waste-heat-exchangers.

The heat and material balance in Figure 4-1 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Table 4-1
CASE 3A – IGCC WITH CO_2 REMOVAL
PLANT PERFORMANCE SUMMARY – 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	565.6 (1,000)
Reheat Outlet Temperature, °C (°F)	565.6 (1,000)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	345,355
Steam Turbine Power	143,366
Generator Loss	(7,330)
Turbo-Set Power (Note 1)	481,391
Fuel Gas Expander Power	9,005
Gross Plant Power	490,396
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	360
Coal Milling	830
Coal Slurry Pumps	220
Slag Handling and Dewatering	160
Recycle Gas Blower	340
Air Separation Plant	25,390
Oxygen Boost Compressor	14,720
Selexol Plant	8,570
Claus/TGTU	100
Tail Gas Recycle	1,000
Humidification Tower Pump	100
Humidifier Makeup Pump	240
Low Pressure CO_2 Compressor	810
High Pressure CO_2 Compressor (Note 3)	24,150
Condensate Pumps	370
High Pressure Boiler Feed Pump	3,180
Low Pressure Boiler Feed Pump	100
Miscellaneous Balance of Plant (Note 2)	1,000
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,840
Cooling Tower Fans	1,040
Flash Bottoms Pump	50
Transformer Loss	1,520
Total Auxiliary Power Requirement	86,890
NET PLANT POWER, kWe	403,506
PLANT EFFICIENCY	
Net Efficiency, % HHV	37.0
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	9,732 (9,226)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	144,748 (319,110)
Oxygen (95% pure), kg/h (lb/h)	118,488 (261,218)
Water, kg/h (lb/h)	298,068 (657,117)

Note 1 - Single shaft turbo set.
Note 2 - Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure 8.27 MPa (1,200 psia)
Note 4 - As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

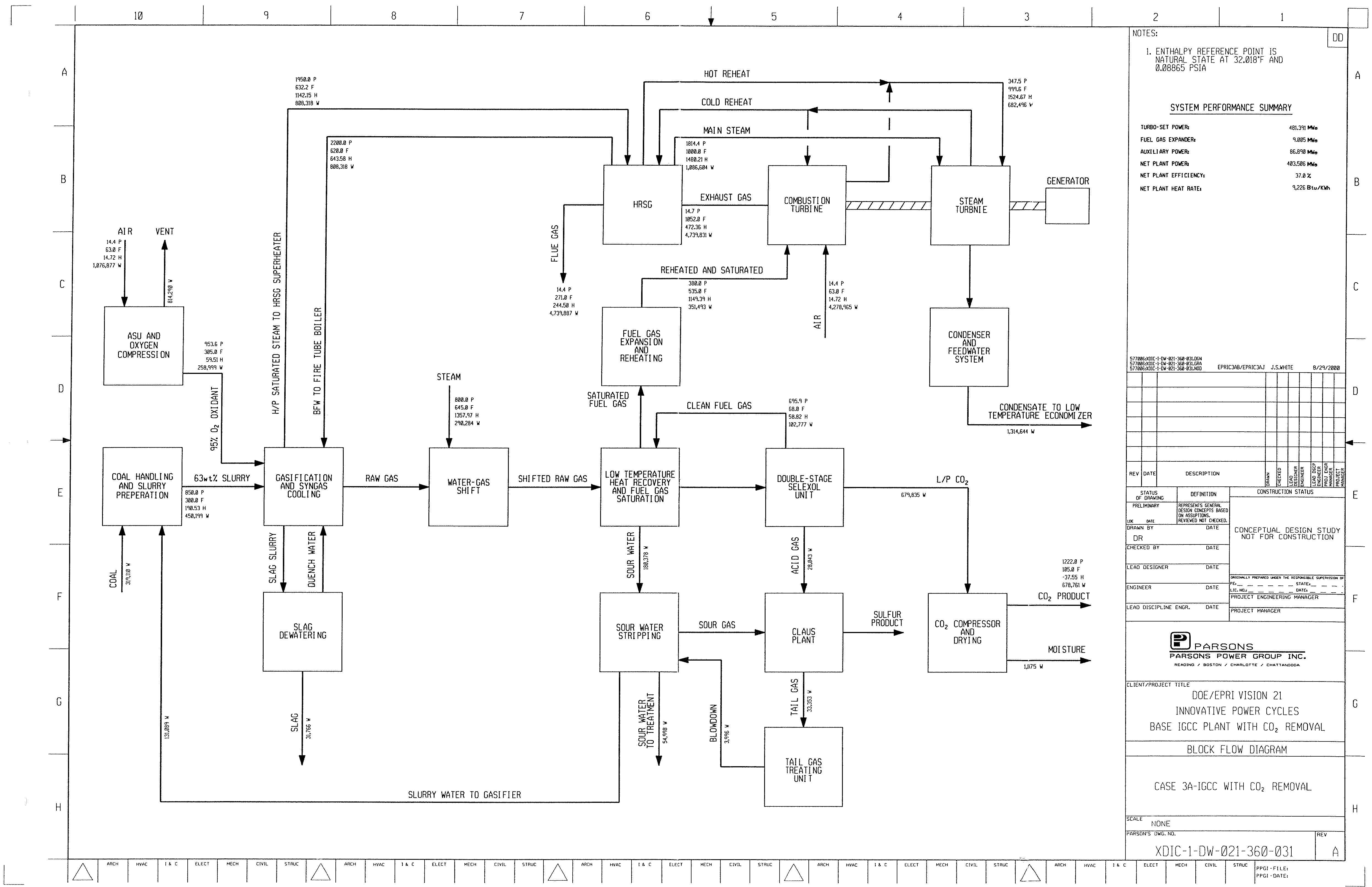

Figure 4-1
Block Flow Diagram – Case 3A – IGCC with CO_2 Removal

4.1.3 Power Plant Emissions

The operation of a modern, state-of-the-art gas turbine fueled by coal-derived synthesis gas generated with an oxygen-blown E-Gas™ gasifier is projected to result in very low levels of SO_2, NOx, and particulate (fly ash) emissions. Also, the inclusion of a CO_2 removal system will greatly decrease the ambient release of CO_2 from the power plant. A summary of the estimated plant emissions for this case is presented in Table 4-2. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four basis: (1) kilogram per gigajoule of HHV thermal input (pound per million Btu of HHV thermal input), (2) tonnes per year for a 65 percent capacity factor (tons per year for a 65 percent capacity factor), (3) tonnes per year for an 85 percent capacity factor (tons per year for an 85 percent capacity factor), and, (4) kilograms per hour per MWe of power output (pounds per hour per MWe of power output).

Table 4-2
CASE 3A AIRBORNE EMISSIONS
H-TYPE IGCC WITH CO_2 REMOVAL

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	Kg/MWh (lb/MWh)
SO_2	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
NOx	< 0.012 (< 0.028)	258.6 (285)	335.7 (370)	.113 (0.25)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	9.2 (21.4)	168,649 (185,900)	220,540 (243,100)	73.48 (162)

As shown in the table, values of SO_2 emission and are negligible. This is a direct consequence of using the Selexol absorption process to remove H_2S from the fuel gas stream prior to combustion. The Selexol process removes more than 99.8 percent of the sulfur present in the raw fuel gas stream. The sulfur is subsequently concentrated and processed in a Claus plant and tail gas treating unit to produce an elemental sulfur product that may be sold. Overall sulfur capture and recovery is approximately 99.7 percent. These steps result in very low sulfur emissions from the plant.

NOx emissions are limited to less than 10 ppm adjusted to 15 percent O_2 content in the flue gas. This low level of NOx production is achieved by diluting the heating value of the incoming combustion turbine fuel gas stream to less than 5,587 kJ/scm (150 Btu/scf). Dilution is accomplished by humidifying the desulfurized fuel gas stream and steam injection at the combustion turbine inlet. This water dilution serves a dual role; not only does water dilution mitigate NOx emissions, it also helps maintain a relatively lowered burner temperature with increased fuel input.

Particulate discharge to the atmosphere is limited by the use of the candle-type particulate filters and through the gas washing effect achieved by raw gas condensate knock out and the Selexol absorption process.

In this power plant configuration, approximately 90 percent of the CO_2 in the fuel gas is removed and concentrated into a highly pure product stream. This greatly limits CO_2 emissions as can be seen in Table 4-2. These levels are greater than those achieved with the same gas turbine fired on natural gas (case 1B or 1D). However, they are much less than those realized with coal-fired IGCC without CO_2 removal and recovery (case 3B).

4.1.4 System Description

This greenfield power plant is a 403 MW coal-fired IGCC power plant with CO_2 removal through the Selexol absorption process. The gasifier technology choice is Destec and the combustion turbine choice is based on GE’s H-type advanced turbine system. The major subsystems of the power plant are:

- Coal Receiving and Handling
- Coal-Water Slurry Preparation and Feeding
- Coal Gasification and Air Separation Unit
- Water-Gas Shift / Syngas Humidification
- Sulfur Removal and Recovery / Carbon Dioxide Removal and Compression
- Combined Cycle Power Generation
- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief description of these individual power plant subsystems. Also presented are heat and material balance diagrams for the individual plant sections, each annotated with state point data. The equipment list, which follows this section, is based on the system descriptions provided here. The equipment list, in turn, was used to generate plant cost and cost of CO_2 removal.

4.1.4.1 Coal Receiving and Handling

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the rod mill inlet. The system is designed to support short-term operation at 105 percent of the design load condition for a 16-hour period and long-term operation at 100 percent of the design load point for 90 days or more.

The 15.24 cm (6") x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 90.7-tonne (100-ton) rail cars. Each unit train consists of 100, 90.7-tonne (100-ton) rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 15.24 cm (6") x 0 coal from the feeder is discharged onto a belt conveyor and then transferred to a second conveyor that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 7.62 cm (3") x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 2.54 cm (1") x 0, then it is transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the three storage silos.

4.1.4.2 Coal-Water Slurry Preparation and Feeding

The slurry preparation and feeding system mills crushed coal and generates a 63 weight percent slurry for the gasifier. Three trains at 50 percent each are provided.

Crushed coal is reclaimed from the storage silo by a vibrating feeder, which delivers the coal to a weigh-belt feeder. Crushed coal is fed through the rod-mill (pulverizer) and then routed to a product storage tank. In the rod mill, recycled water from the sour gas stripper is added to the coal in order to form a slurry. Slurry from the rod mill storage tank is then either fed to the gasifier or routed to an agitated storage tank. The slurry storage tank is sized to hold 8 hours of slurry product.

Coal-water slurry is pumped via positive displacement pumps to the low-temperature slurry heater. Here, the high-pressure slurry is heated to approximately 121.1°C (250°F) by condensing low-pressure steam. The coal-water slurry is further heated in a second slurry heater to 148.9°C (300°F). The duty for this effort is provided by condensing, intermediate-pressure steam. The hot, high-pressure coal-water slurry then proceeds to the gasifier injection system.

4.1.4.3 Coal Gasification and Air Separation Unit

This section gives a cursory description of the gasification process and air separation unit. For ease of discussion, the topic has been organized under the following four sub-headings:

- Air Separation Unit
- Gasification
- Raw Gas Cooling
- Particulate Removal

Air Separation Unit

Two trains at 50 percent are used. Each train produces 1,415 tonne/day (1,560 tpd) of 95 percent oxygen product (1,352 tonne/day (1,490 tpd) on a 100 percent O_2 basis). Each train consists of a multi-staged air compressor, an air separation cold box, and an oxygen compression system. A liquid oxygen storage tank is used to ensure reliability. A slipstream of vent nitrogen is compressed and available for miscellaneous plant requirements.

A simplified schematic of the oxygen plant is shown in Figure 4-2. State point data is also shown. Ambient air at 0.099 MPa (14.4 psia) and 17.2°C (63ºF) is compressed in a three-staged, intercooled compressor to 0.46 MPa (67 psia). The high-pressure air stream is cooled and routed to a thermal swing absorption system, which removes H_2O, CO_2, and other ambient contaminants before flowing to the vendor-supplied cold box. In the cold box, cryogenic distillation is used to provide a 95 percent pure oxygen stream for use in the gasifier.

The low-pressure oxidant stream from the cold box is compressed to 6.6 MPa (957 psia) in a six-staged, intercooled compressor. This high-pressure stream is then heated indirectly with condensing intermediate-pressure steam to 151.7°C (305°F) before being routed to the gasifier injection system.

The heat and material balance in Figure 4-2 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Gasification

The gasification technology assumed for this study is that of E-Gas™ as exemplified at the Clean Coal Technology Wabash installation. It is assumed that the gasifier can operate at high pressure (5.5 MPa (800 psig)). This is a higher pressure than used at the Wabash plant, and was selected to take advantage of the improved performance of the shift and Selexol processes for CO_2 removal at higher pressure. Maximum coal throughput per gasifier is established as 1,134 tonne/day (1,250 tpd) dry. This power plant requires 3094 tonne/day (3,410 tpd) (dry) coal feed. Therefore, three gasification trains at 33.3 percent will be used.

Figure 4-2 contains a schematic of the gasifier. Approximately 90 percent of the preheated coal-water slurry is injected into the primary zone (or first stage) of the gasifier. Oxygen is injected along with the slurry in order to thoroughly atomize the feed stream. Char captured in the candle filter is also injected into the primary zone of the gasifier.

The primary gasification zone operates above the ash fusion temperature (1204°C (2200°F) to 1371°C (2500°F)), thereby ensuring the flow and removal of molten slag. This temperature is maintained by a controlled oxygen feed. All of the oxygen in the first stage is utilized in exothermic partial oxidation/gasification reactions. Slag is removed from the bottom of the gasifier and quenched in a water pool before being crushed and removed from the unit. Gaseous products from the primary zone flow into the second gasification zone.

The remaining 10 percent of preheated slurry is injected in the secondary zone of the gasifier. A small portion of the raw fuel gas stream is recycled in order to promote reactivity of the atomized coal slurry. Tail gas from the back-end treating unit is also recycled in an effort to minimize power plant emissions.

In the secondary zone, hot gaseous products from the primary zone provide the thermal energy required to heat and gasify the atomized slurry. These gasification reactions are endothermic and considerably decrease the sensible energy content of the primary zone gases. As a result, the exit temperature of the secondary zone, around 1037.8°C (1900°F), is much lower than that of the primary zone.

Char produced in the cooler secondary gasification zone leaves the gasifier entrained in the fuel gas stream. Downstream particulate control measures remove the char from the fuel gas stream and return it to the primary zone of the gasifier for reinjection. The gasifier operates with a coal gas efficiency of approximately 77 percent.

Raw Gas Cooling

Hot raw gas from the secondary gasification zone exits the gasifier at 5.5 MPa (800 psig) and 1040.6°C (1905°F). This gas stream is cooled to 343.3°C (650°F) in a fire-tube boiler. The waste heat from this cooling is used to generate high-pressure steam. Boiler feed water in the tube walls is saturated, and then steam and water are separated in a steam drum. Approximately 366,509 kg/hour (808,000 lb/hour) of saturated steam at 13.4 MPa (1950 psia) is produced. This steam then forms part of the general heat recovery system that provides steam to the steam turbine.

A shell and tube cooler is used to further cool the raw gas exiting the fire tube boiler and to maintain the input temperature to the ceramic candle filter. Raw gas exits this cooler at 287.8°C (550°F) and generates approximately 13,608 kg/hour (30,000 lb/hour) of low-pressure steam.

Particulate Removal

A metal candle filter is used to remove any particulate material exiting the secondary gasification zone. This material, char and fly ash, is recycled back to the gasifier. The filter is comprised of an array of metal candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with fuel gas to remove the fines material. Raw gas exits the candle filter at 285°C (545°F) and 5.5 MPa (791 psia).

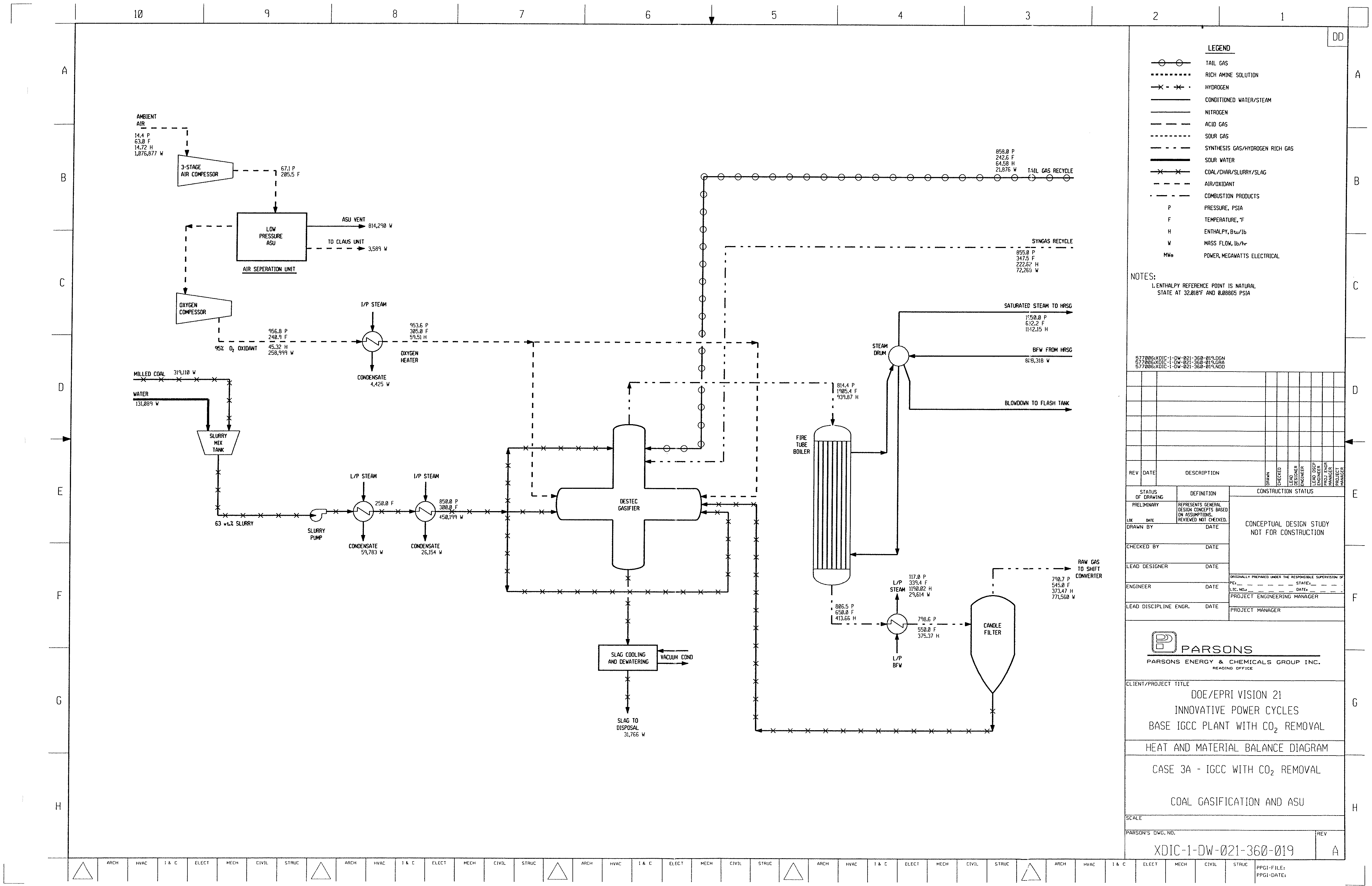

Figure 4-2
Heat and Material Balance Diagram – Case 3A – IGCC with CO_2 Removal – Coal Gasification and ASU

4.1.4.4 Water Gas Shift / Syngas Humidification

Raw fuel gas exits the metal candle filter at approximately 285°C (545°F). This fuel gas stream is virtually free of particulate matter. Steam is added to the particulate-free raw fuel gas stream in order to increase the H_2O/CO ratio over that developed in the secondary gasifier zone. The addition of this steam will promote the downstream water-gas shift reactions.

A set of high-temperature shift reactors is used to shift the bulk of the CO in the fuel gas to CO_2. A schematic of the shift converters can be found in Figure 4-3. Heat exchange between reaction stages helps maintain a moderate reaction temperature. Partially shifted fuel gas exiting the second high-temperature shift converter is cooled from 354°C (670°F) to 200°C (392°F) before entering the low temperature shift converter. The low-temperature shift converter takes advantage of the favorable equilibrium afforded by the low reaction temperature. A two-stage shift was utilized in order to maximize CO conversion while maintaining reasonable reactor volumes.

The heat and material balance in Figure 4-3 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

The shifted raw gas temperature exiting the LTSC is approximately 237.8°C (460°F). This stream is cooled to 154.4°C (310°F) in a low-temperature economizer. A portion of the main gas flow is split, recompressed, and then recycled back to the gasifier. The remaining fuel gas stream is cooled in a series of low-temperature economizers and then routed to the Selexol unit. Fuel gas condensate is recovered and routed to a sour water drum.

The fuel gas saturator can also be seen in Figure 4-3. Sweet, hydrogen-rich fuel gas from the Selexol unit is piped to the bottom of the saturator. The sweet fuel gas rises up through the column while warm water flows downward counter-currently. Internal trays are used to enhance the mass transfer of water vapor into the fuel gas. This process both humidifies the fuel gas as well as increases its sensible heat content.

Warm, humid fuel gas exits the top of the saturator at 193°C (380°F) and 4.8 MPa (690 psia). It is indirectly heated further to 271°C (520°F) by condensing high-pressure steam. The high-pressure fuel gas stream is then expanded to 2.7 MPa (385 psia) to recover approximately 9 MWe of electrical energy. Fuel gas out of the expander is then indirectly reheated to 279°C (535°F) by condensing high-pressure steam and then routed to the combustion turbine burner inlet.

Saturator water exits the column at 33.9°C (93°F) after being cooled down from 232°C (450°F). The water is then pumped through a series of raw gas coolers that economize the water back to 232°C (450°F). To avoid the buildup of soluble gases, a small blowdown to the sour water drum is taken from the pump discharge.

4.1.4.5 Sulfur Removal and Recovery / Carbon Dioxide Removal and Compression

A unique feature of this power plant configuration is that H_2S and CO_2 are removed within the same process system, the Selexol unit. This section will describe this removal process. The discussion is organized as follows:

- Selexol Unit
- CO_2 Compression and Drying
- Claus Plant
- Tail Gas Treating Unit

A heat and mass balance diagram of these systems can be seen in Figures 4-3 and 4-4. The discussion follows below.

The heat and material balances in Figures 4-3 and 4-4 are shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

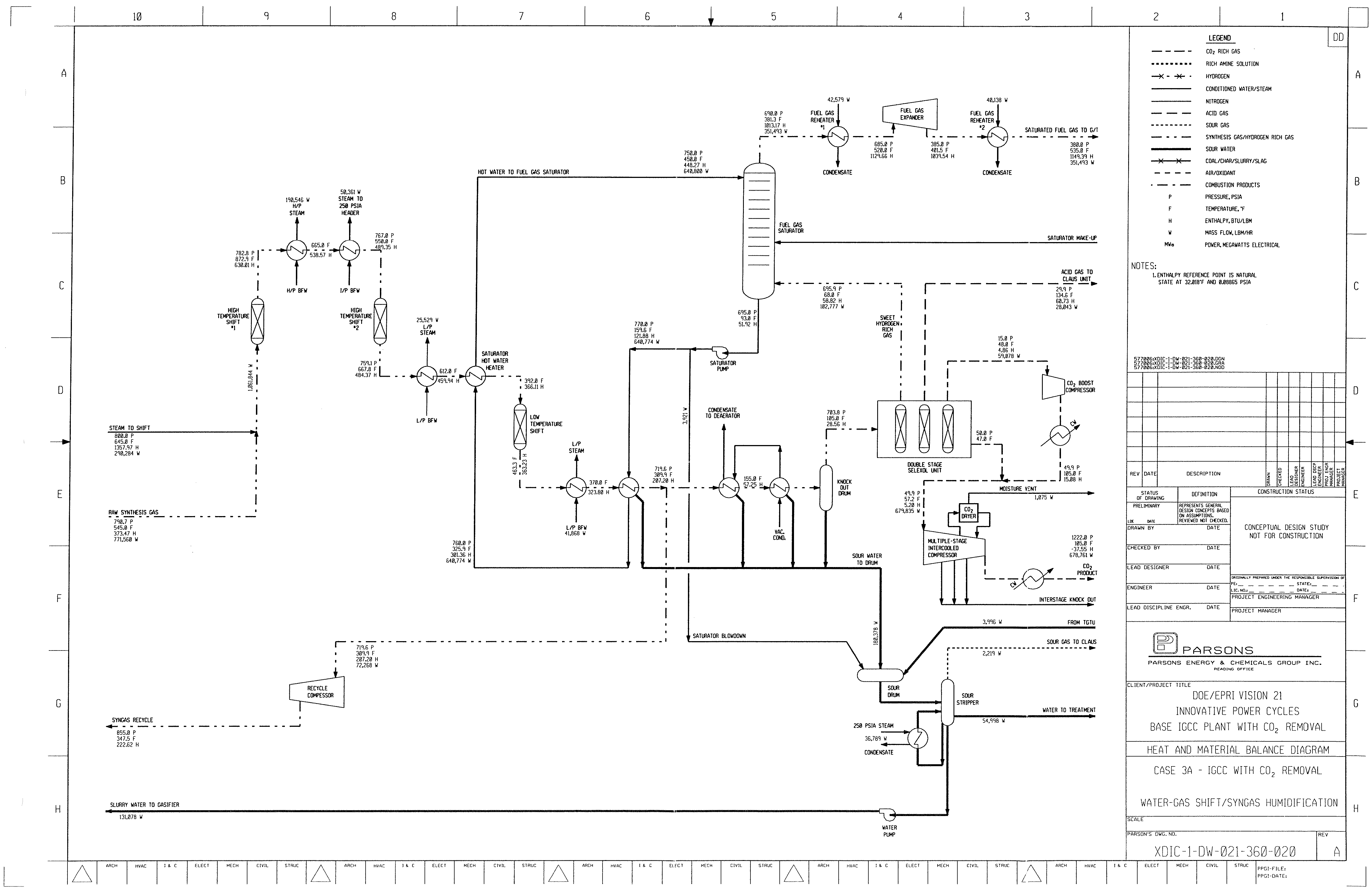

Figure 4-3
Heat and Material Balance Diagram – Case 3A – IGCC with CO_2 Removal – Water-Gas Shift/Syngas Humidification

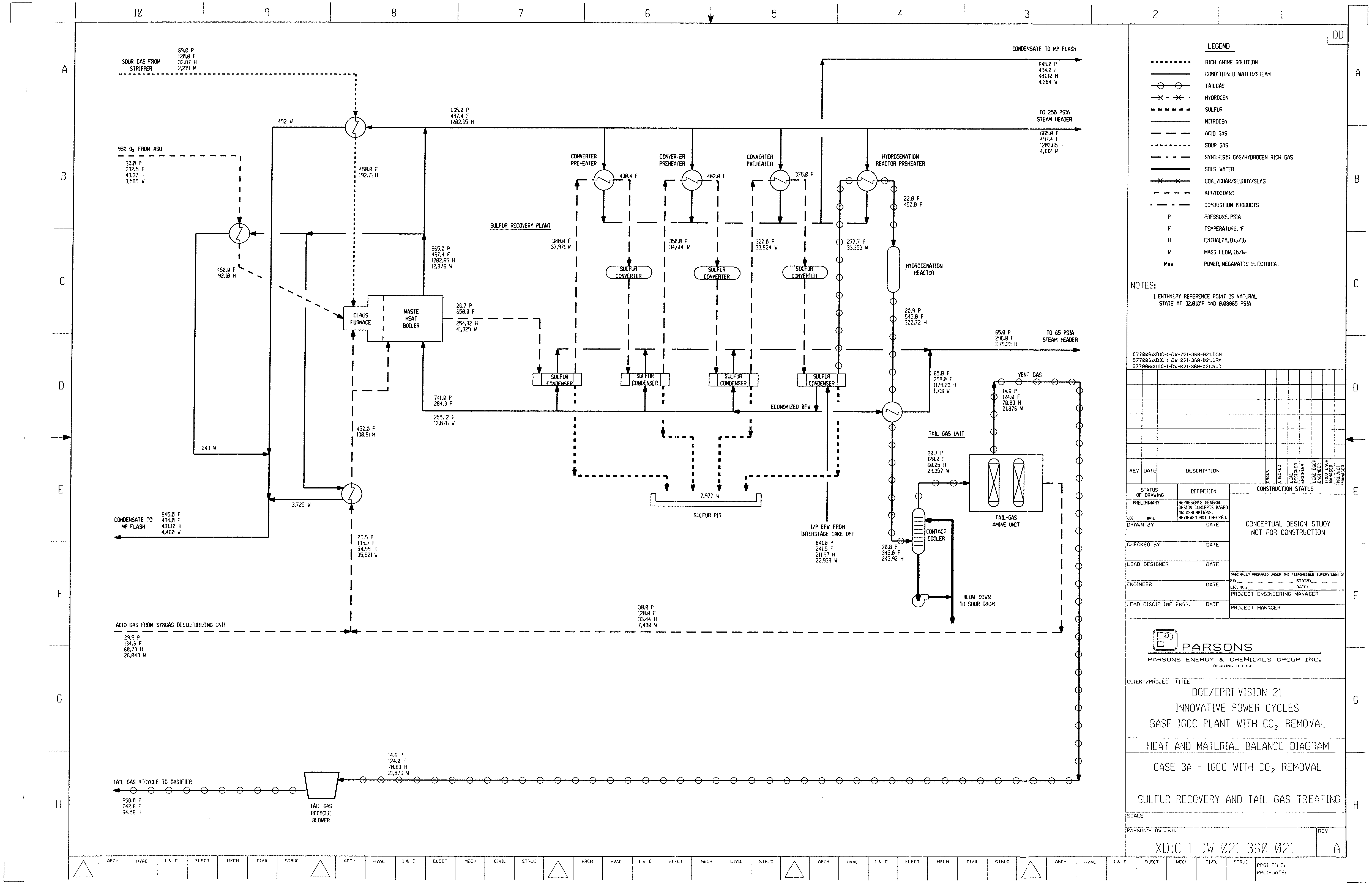

Figure 4-4
Heat and Material Balance Diagram – Case 3A – IGCC with CO_2 Removal – Sulfur Recovery and Tail Gas Treating

Selexol Unit

The purpose of the Selexol unit is to preferentially remove H_2S as a product stream and then to preferentially remove CO_2 as a separate product stream. This is achieved in the so-called double-stage or double-absorber Selexol unit.

Cool, dry, and particulate-free synthesis gas enters the first absorber unit at approximately 4.9 MPa (705 psia) and 39.4°C (103°F). In this absorber, H_2S is preferentially removed from the fuel gas stream. This is achieved by "loading" the lean Selexol solvent with CO_2. The solvent, saturated with CO_2, preferentially removes H_2S. The rich solution leaving the bottom of the absorber is regenerated in a stripper through the indirect application of thermal energy via condensing low-pressure steam in a reboiler. The stripper acid gas stream, consisting of 34 percent H_2S and 58 percent CO_2 (with the balance mostly H_2O), is then sent to the Claus unit.

Sweet fuel gas flowing from the first absorber is cooled and routed to the second absorber unit. In this absorber, the fuel gas is contacted with "unloaded" lean solvent. The solvent removes approximately 97 percent of the CO_2 remaining in the fuel gas stream. A CO_2 balance is maintained by hydraulically expanding the CO_2-saturated rich solution and then flashing CO_2 vapor off the liquid at reduced pressure. Sweet fuel gas off the second absorber is warmed and humidified in the fuel gas saturator, reheated and expanded, and then sent to the burner of the combustion turbine.

CO_2 Compression and Drying

CO_2 is flashed from the rich solution at two pressures. The bulk of the CO_2 is flashed off at approximately 0.345 MPa (50 psia), while the remainder is flashed off at atmospheric pressure. The second low-pressure CO_2 stream is "boosted" to 0.345 MPa (50 psia) and then combined with the first CO_2 stream. The combined flow is then compressed in a multiple-stage, intercooled compressor to supercritical conditions. During compression, the CO_2 stream is dehydrated with triethylene glycol. The virtually moisture-free supercritical CO_2 steam is then ready for pipeline transportation.

Claus Unit

Acid gas from the first-staged absorber of the Selexol unit is routed to the Claus plant. A heat and material balance diagram of the Claus plant can be seen in Figure 4-4. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. Approximately 3,629 kg/hour (8,000 lb/hour) of elemental sulfur is recovered from the fuel gas stream. This value represents an overall sulfur recovery efficiency of 99.7 percent.

Acid gas from the Selexol unit and tail gas amine unit are preheated to 232°C (450°F). Sour gas from the sour stripper and 95 percent O_2 oxidant from the ASU are likewise preheated. A portion of the acid gas along with all of the sour gas and oxidant are fed to the Claus furnace. In the furnace, H_2S is catalytically oxidized to SO_2. A furnace temperature greater than 1343°C (2450°F) must be maintained in order to thermally decompose all of the NH_3 present in the sour gas stream.

Combustion and decomposition products from the furnace are mixed with the remaining acid gas stream and cooled in a waste heat boiler. These gases are further cooled, and any sulfur formed during the catalytic and thermal furnace stages is condensed out and routed to the sulfur pit. The remaining gas stream is heated and sent to the sulfur converter, which catalytically oxidizes H_2S with SO_2 to elemental sulfur. The stream is then cooled, and any condensed sulfur removed and routed to the sulfur pit.

Three preheaters and three sulfur converters are used to obtain a per-pass H_2S conversion of approximately 97.8 percent. In the furnace waste heat boiler, 5,806 kg/hour (12,800 lb/hour) of 4.5 MPa (650 psia) steam is generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as 1,860 kg/hour (4,100 lb/hour) of steam to the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

Tail Gas Treating Unit

Tail gas from the Claus unit contains unreacted sulfur species such as H_2S, COS, and SO_2 as well as elemental sulfur species of various molecular weight. In order to maintain low sulfur emissions, this stream is processed in a tail gas treating unit in order to recycle sulfur back to the Claus plant.

Tail gas from the Claus plant is preheated to 232°C (450°F) and then introduced to the hydrogenation reactor. In the hydrogenation reactor, SO_2 and any elemental sulfur specie are catalytcally reduced with H_2 to H_2S. Also, COS is hydrolyzed to H_2S. This gas stream is then cooled and treated in an amine absorber unit. H_2S is removed by the amine solution, regenerated in a reboiler-stripper and recycled back to the Claus furnace. Sweet gas from the amine absorber, which contains fuel gas species such as H_2 and CO, is compressed and recycled to the gasifier secondary zone.

4.1.4.6 Combined Cycle Power Generation

The combustion turbine selected for this application is based on the General Electric Model H. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. The gas turbine compressor and expander, as well as the steam turbine and generator, are connected on a single rotating shaft. So, in essence, the gas and steam turbines are a single piece of rotating machinery coupled by a heat recovery system. For ease of discussion, these three primary components of the combined cycle will be broken out and discussed separately. A heat and material balance diagram for the combined cycle power generation portion of this power plant is shown in Figure 4-5.

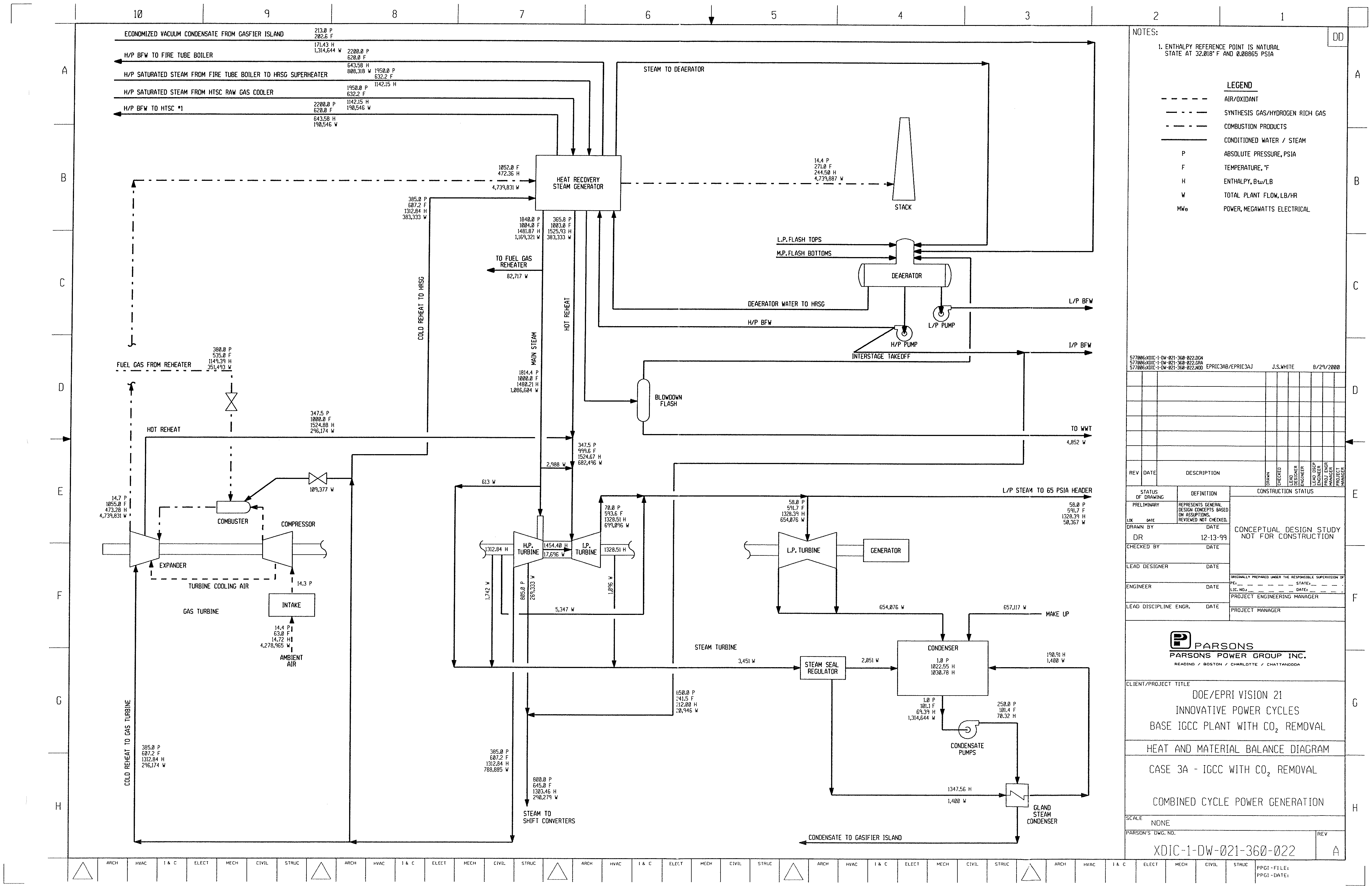

Figure 4-5
Heat and Material Balance Diagram – Case 3A – IGCC with CO_2 Removal – Combined Cycle Power Generation

The heat and material balance in Figure 4-5 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Combustion Turbine

Inlet air at 539 kg/sec (1,189 lb/sec) is compressed in a single spool compressor at a pressure ratio of approximately 23:1. This airflow is lower than the ISO airflow of 556 kg/sec (1,225 lb/sec) due to the choice of ambient conditions used in this specific study. (The ambient conditions chosen here correspond to a standard fossil-plant site used in other DOE studies. They result in a less dense ambient air, and, subsequently, less airflow and power output in the gas turbine.) The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the coal derived fuel-gas. Compressed air is also used in film cooling services.

Humidified fuel gas from the gasifier island is injected into the gas turbine along with cold reheat steam such that the combined mixture has a heating content less than 5,587 kJ/scm (150 Btu/scf). The fuel gas is combusted in 12 parallel combustors. NOx formation is limited by geometry and fuel gas dilution. The combustors are can-annular in configuration, where individual combustion cans are placed side-by-side in an annular chamber. Each can is equipped with multiple fuel nozzles, which allows for higher mass flows over earlier machines and higher operating temperatures. In the estimated performance provided here, the machine will develop a rotor inlet temperature of about 1427°C (2600°F).

Hot combustion products are expanded in the four-stage turbine-expander. It is assumed that the first two expander stages are steam cooled and that the third stage is air cooled. No cooling is expected in the fourth expander stage. The expander exhaust temperature is estimated as 568°C (1055°F), given the assumed ambient conditions, back-end loss, and HRSG pressure drop. This value, 26°C (50°F) lower than the ISO assumed value of 594°C (1102°F) for a natural gas-fired simple cycle gas turbine, is due to variations in firing temperature, flow rate, and flue gas specific heats.

Gross turbine shaft power, as measured prior to the generator terminals, is estimated as 345 MWe. The generator, which is shared with the steam turbine, is assumed to be a standard hydrogen-cooled machine with static exciter. Net combustion turbine power (following generator losses) is estimated at 339 MWe. This value reflects the expected increase of GE's H-type turbine power output when firing coal-derived fuel gas.

Heat Recovery System

The heat recovery system thermally couples the waste heat rejected by the gas turbine and gasifier island with the steam turbine. The heat recovery system is shown schematically in Figure 4-6. Waste heat rejected by the gas turbine is recovered by the HRSG. The HRSG, along with raw gas coolers and the fire tube boiler located in the gasifier island, generate steam utilized in the steam turbine to generate electrical power.

The heat and material balance in Figure 4-6 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

High temperature flue gas at 2,149,610 kg/hour (4,739,000 lb/hour) exiting the CT expander is conveyed through the HRSG to recover the large quantity of thermal energy that remains in the flue gas after expansion. For purposes of this analysis, it is assumed that the flue gas heat loss through the HRSG duct corresponds to 1.6°C (3°F). The HRSG flue gas exit temperature is assumed to be 132.8°C (271°F), which should be high enough to avoid sulfur dew-point complications.

The HRSG is configured with a HP superheater, HP evaporator and drum, and HP economizer. The economizer is supplied with feedwater by the HP boiler feed pump operating off the deaerator. Approximately 533,887 kg/hour (1,177,000 lb/hour) of 15.9 MPa (2300 psia) boiler feed water is heated to 327°C (620°F) in the economizer. This high-pressure economizer water stream is then split between the HRSG HP evaporator and drum, the fire tube boiler, and the HTSC raw gas cooler. Saturated steam returned from these three sources is superheated and then routed to the HP steam turbine inlet.

Cold reheat from the HP steam expander is split between gas turbine cooling duties, combustor turbine steam injection, and the HRSG. In the HRSG, 173,729 kg/hour (383,000 lb/hour) of cold reheat is heated from 319°C (607°F) to 540°C (1004°F). Combustion turbine cooling duties heat 134,266 kg/hour (296,000 lb/hour) of cold reheat to 538°C (1000°F). These two hot reheat streams are recombined and routed to the IP steam turbine inlet.

Steam Turbine

The Rankine cycle used in this case is based on a commercially available 12.4 MPa/565.6°C/565.6°C (1800 psig/1000°F/1000°F) single reheat configuration. The steam turbine is assumed to consist of tandem high-pressure (HP), intermediate-pressure (IP), and double-flow low-pressure (LP) turbine sections connected via a common shaft (along with the combustion turbine) and driving a 3600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine is assumed to have a pitch diameter of 183 cm (72 inches) and a last-stage bucket length of 66 cm (26 inches).

Main steam at a rate of 489,888 kg/hour (1,080,000 lb/hour) passes through the HP stop valves and control valves and enters the turbine at 12.5 MPa (1815 psia) and 538°C (1000°F). The steam initially enters the turbine near the middle of the high-pressure span, expands through the turbine, and then exits the section. This cold reheat steam is then either routed to the HRSG for reheating, utilized in the combustion turbine as injection steam, or used to cool the gas turbine.

Hot reheat is returned to the steam turbine from both the HRSG and gas turbine cooling loop. The combined hot reheat stream then flows through the IP stop valves and intercept valves and enters the IP section at 2.4 MPa (347 psia) and 538°C (1000°F). After passing through the IP section, the steam enters a crossover pipe. The crossover steam is divided into two paths and flows through the LP sections exhausting downward into the condenser.

Gross turbine shaft power, as measured prior to the generator terminals, is estimated as 143 MWe. The generator, which is shared with the combustion turbine, is assumed to be a standard hydrogen-cooled machine with static exciter. Net steam turbine power (following generator losses) is estimated around 142 MWe.

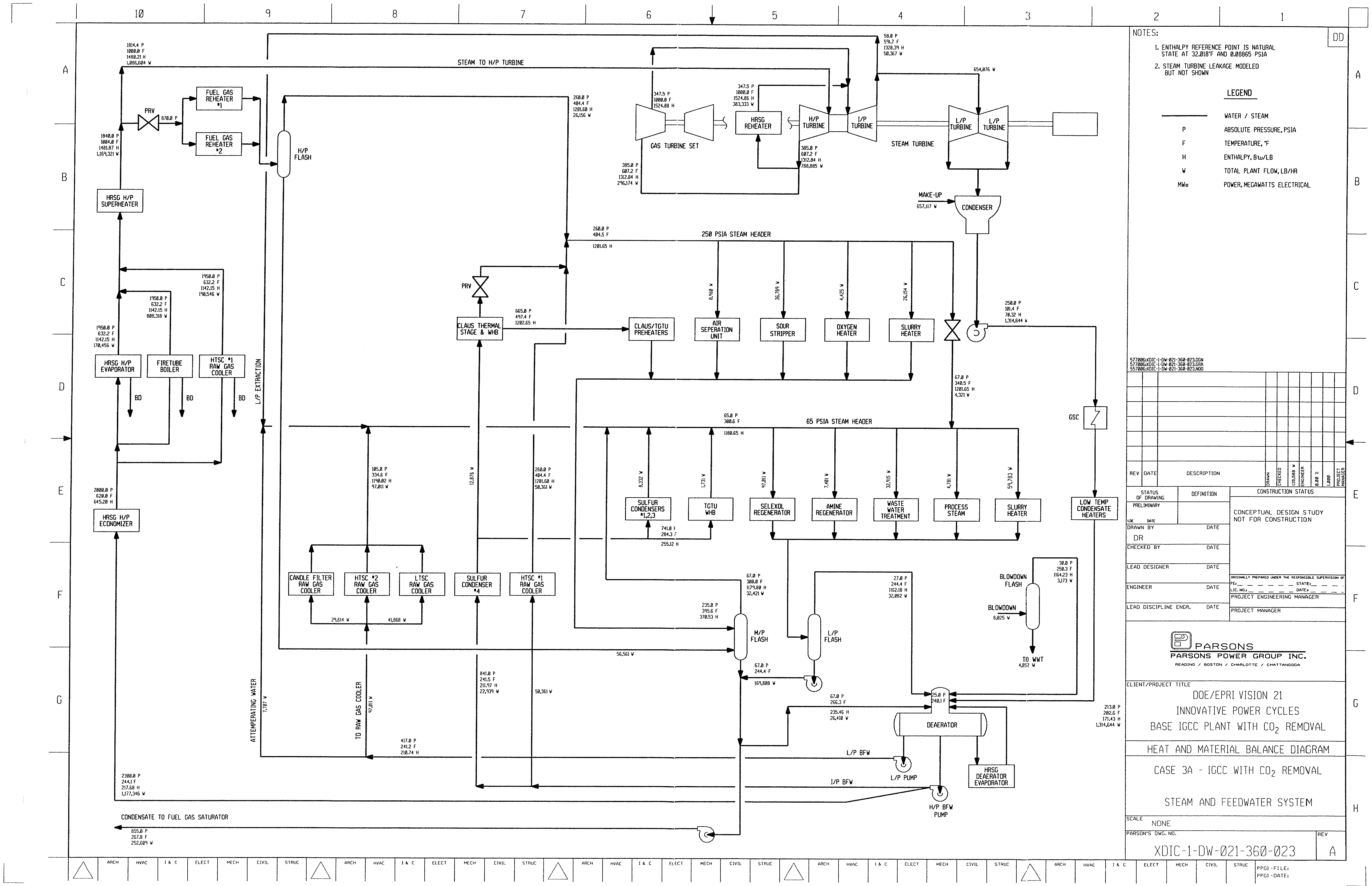

Figure 4-6
Heat and Material Balance Diagram – Case 3A – IGCC with CO_2 Removal – Steam and Feedwater System

4.1.4.7 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the gasifier island. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a series of low-temperature raw gas coolers located within the gasifier island.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The function of the feedwater system is to pump feedwater streams from the deaerator storage tank to their respective steam drums. Two 50 percent capacity motor-driven feed pumps are provided for HP/LP service. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

4.1.4.8 Balance of Plant

The balance of plant items discussed in this section include:

- Steam Systems
- Circulating Water System
- Accessory Electric Plant
- Instrumentation and Control
- Waste Treatment

Steam Systems

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

Main steam exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine.

Cold reheat steam exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Circulating Water System

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

Accessory Electric Plant

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

Instrumentation and Control

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

Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 45.4-tonne (50-ton) lime silo, a 0-907 kg/hour (0-1000 lb/hour) dry lime feeder, a 18.9 m^3 (5,000-gallon) lime slurry tank, slurry tank mixer, and 0.09 m^3/min (25 gpm) lime slurry feed pumps.

The oxidation system consists of a 1.4 scm/min (50 scfm) air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 757 m^3 (200,000-gallon) storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

4.1.5 Case 3A – Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 4-1. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the nomenclature section.

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter)

Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Ton, multiply by 0.9072 = tonne (metric ton) tph = tons per hour

Gallon,gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832 x 10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9 $x10^{-3}$ = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

ACCOUNT 1 COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1"x0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	600 ton	3

ACCOUNT 2 COAL-WATER SLURRY PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Qty.
1	Feeder	Vibrating	80 tph	3
2	Weigh Belt Feeder		48" belt	3
3	Rod Mill	Rotary	80 tph	3
4	Slurry Water Pumps	Centrifugal	180 gpm @ 500 ft	3
5	Slurry Water Storage Tank	Vertical	2,600 gal	1
6	Rod Mill Product Tank	Vertical	35,000 gal	3
7	Slurry Storage Tank with Agitator	Vertical	150,000 gal	3
8	Coal-Slurry Feed Pumps	Positive displacement	700 gpm @ 2,500 ft	3
9	LT Slurry Heater	Shell and tube	20 x 10^6 Btu/h	3
10	HT Slurry Heater	Shell and tube	7 x 10^6 Btu/h	3

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS BOP SYSTEMS

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cylindrical, outdoor	200,000 gal	1
2	Condensate Pumps	Vert. canned	2,900 gpm @ 400 ft	2
3	Low Temperature Economizers	Shell and tube	40 x 10^6 Btu/h	3
4	Deaerator	Horiz. spray type	1,500,000 lb/h 205°F to 240°F	1
5	LP Feed Pump	Horiz. centrifugal single stage	300 gpm/185 ft	2
6	HP Feed Pump	Barrel type, multi-staged, centr.	2,400 gpm @ 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F 70,000 lb/h	1
2	Service Air Compressors	Recip., single stage, double acting, horiz.	100 psig, 750 cfm	2
3	Inst. Air Dryers	Duplex, regenerative	750 cfm	1
4	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 1,200 gpm	2
5	Closed Cycle Cooling Heat Exchangers	Plate and frame	50% cap. each	2
6	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 1,200 gpm	2
7	Fire Service Booster Pump	Two-stage horiz. centrifugal	250 ft, 1,200 gpm	1
8	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
9	Raw Water Pumps	S.S., single suction	60 ft, 300 gpm	2
10	Filtered Water Pumps	S.S., single suction	160 ft, 120 gpm	2
11	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
12	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
13	Sour Water Stripper System	Vendor supplied	180,000 lb/h sour water	1
14	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 GASIFIER AND ACCESSORIES

ACCOUNT 4A GASIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Pressurized entrained bed/syngas cooler	1,135 std (dry-coal basis) @ 1000 psia	3
2	Syngas Cooler	Fire-tube with steam drum	135 x 10^6 Btu/h @ 1,950 psia, 630ºF	3
3	Low-Temperature Candle Filter	Ceramic	800 psia, 600ºF	3
4	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	770,000 lb/h, medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	125,000 scfm, 67 psia discharge pressure	2
2	Cold Box	Vendor supplied	1,600 ton/day O_2	2
3	Oxygen Compressor	Centrifugal, multi-stage	25,000 scfm, 950 psig discharge pressure	2
4	Liquid Oxygen Storage Tank	Vertical	60' dia x 80' vert	1
5	Oxygen Heater	Shell and tube	1.8 x 10^6 Btu/h @ 950 psia and 300ºF	2

ACCOUNT 5 FUEL GAS SHIFT AND CLEANUP

ACCOUNT 5A WATER-GAS SHIFT, RAW GAS COOLING AND HUMIDIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	High Temperature Shift Reactor 1	Fixed bed	800 psia, 750ºF	3
2	High Temperature Shift Reactor 2	Fixed bed	800 psia, 750ºF	3
3	HP Steam Generator	Shell and tube	35 x 10^6 Btu/h @ 2800 psia and 700ºF	3
4	IP Steam Generator	Shell and tube	20 x 10^6 Btu/h @ 300 psia and 500ºF	3
5	LP Steam Generator	Shell and tube	10 x 10^6 Btu/h @ 200 psia and 500ºF	3
6	Low Temperature Shift Reactor	Fixed bed	760 psia, 450ºF	3
7	Saturation Water Economizers	Shell and tube	50 x 10^6 Btu/h @ 1000 psia and 500ºF	3
8	Raw Gas Coolers	Shell and tube with condensate drain	100 x 10^6 Btu/h	9
9	Raw Gas Knock Out Drum	Vertical with mist eliminator	800 psia, 130ºF	3
10	Fuel Gas Saturator	Vertical tray tower	20 stages 750 psia, 450ºF	1
11	Saturator Water Pump	Centrifugal	1,500 gpm @ 120 ft	1
12	Fuel Gas Reheater 1	Shell and tube	41 x 10^6 Btu/h @ 690 psia, 550ºF	1
13	Fuel Gas Expander	Axial	PR=1.8 @ 685 psia	1
14	Fuel Gas Reheater 2	Shell and tube	39 x 10^6 Btu/h @ 690 psia, 550ºF	1

ACCOUNT 5B SULFUR REMOVAL AND RECOVERY

Equipment No.	Description	Type	Design Condition	Qty
1	Double-Stage Selexol Unit	Vendor design	240,000 scfm @ 700 psia	3
2	CO_2 Compressor and Auxiliaries	Centrifugal Multi-staged	25 psia / 1,300 psia	1
3	Dehydration Package	Triethylene glycol	1300 psia, 100ºF	1
4	Claus Unit	Vendor design	100 tpd sulfur product	1
5	Hydrogenation Reactor	Vertical fixed bed	7,000 scfm @ 22 psia	1
6	Contact Cooler	Spray contact, tray wash tower	7,000 scfm @ 21 psia	1
7	TGTU Amine Unit	Proprietary amine absorber/stripper	5,100 scfm @ 20 psia	1
8	Tail Gas Recycle Compressor	Centrifugal, multiple-stage	3,610 scfm, PR=58	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	337 MWe Gas Turbine Generator	Axial flow single spool based on H	1,190 lb/sec airflow 2600°F rotor inlet temp. 23:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1,190 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2,500 hp, time from turning gear to full load ~30 minutes	1
5	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
6	Oil Cooler	Air-cooled, fin fan		1
7	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
8	Generator Glycol Cooler	Air-cooled, fin fan		1

Equipment No.	Description	Type	Design Condition	Qty
9	Compressor Wash Skid			1
10	Fire Protection Package	Halon		1

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum	1800 psig/1000°F 1,170,000 lb/h	1
2	Raw Gas Cooler Steam Generator	Fire tube boiler	1800 psig/850°F 810,000 lb/h	3
3	Raw Gas Cooler Steam Generator	Shell and tube	1800 psig/850°F 190,000 lb/h	3
4	Stack	Carbon steel plate, type 409 stainless steel liner	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	140 MW Steam Turbine Generator	TC2F26	1800 psig 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	1,320,000 lb/h steam @ 2.0 in. Hga	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	2

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. Water Pumps	Vert. wet pit	75,000 gpm @ 60 ft	2
2	Cooling Tower	Mechanical draft	160,000 gpm	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A SLAG DEWATERING AND REMOVAL

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Dewatering System	Vendor proprietary	384 tpd	1

4.1.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the IGCC power plant with the "H" combustion turbine with CO_2 removal, case 3A, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 3A represents a plant with a net output of 403.5 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 4-3. A detailed estimate for case 3A is included in Appendix A.

Table 4-3
CASE 3A SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	Gasifier, ASU & Accessories	176,560
5A	Gas Cleanup & Piping	68,980
5B	CO_2 Compression	49,490
6	Combustion Turbine and Accessories	62,160
7	HRSG, Ducting and Stack	20,4120
8&9	Steam T-G Plant, including Cooling Water System	36,550
11	Accessory Electric Plant	27,980
	Balance of Plant	89,690
	SUBTOTAL	531,830
	Engineering, Construction Management Home Office and Fee	31,910
	Process Contingency	20,700
	Project Contingency	78,050
	TOTAL PLANT COST (TPC)	$662,480
	TPC $/kW	1,642

The production costs for case 3A consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal) and Fuel costs. The costs were determined on a first-year basis that includes evaluation at a 65 percent equivalent plant operating capacity factor. The results are summarized in Table 4-4 and supporting detail is contained in Appendix A.

Table 4-4
CASE 3A ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	5,502	0.23
Maintenance	12,861	0.56
Administrative & Support Labor	2,662	0.12
Consumables	1,967	0.09
By-Product Credits	(970)	-0.04
Fuel	26,285	1.14
TOTAL PRODUCTION COST	48,307	2.10

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 3A. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per tonne. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI are included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 4-5.

Table 4-5
CASE 3A LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	2.10
Annual Carrying Charge (¢/kWh)	4.47
Levelized Busbar Cost of Power Charge (¢/kWh)	6.57
Levelized Cost per tonne of CO_2 Removed ($/tonne of CO_2)	17.6

4.1.7 Case 3A Sensitivity

In the course of completing this case, two sensitivity cases were identified and evaluated. The two are as follows:

- Case 3A at ISO Conditions
- Case 3A with CO_2 Product Pressure of 15.2 MPa (2200 psig)

Plant performance was estimated for each case. A heat and material balance diagram will not be produced for these cases. Also, there will be no cost estimate.

4.1.7.1 Case 3A at ISO Conditions

This work has not yet been completed.

4.1.7.2 Case 3A with CO_2 Product Pressure of 2200 psig

The only difference between this case and the base case presented in Figure 4-1 is that the final CO_2 product pressure has been increased from 8.3 MPa (1200 psia) to 15.2 MPa (2200 psia). This required the addition of another compression stage to the CO_2 compressor. A summary of the estimated performance is shown in Table 4-6.

As can be seen by comparing Table 4-1 and Table 4-6, there is very little difference in performance due to the increase in CO_2 product pressure. Gross plant power output is the same for both cases. Auxiliary power increases from 86.890 MWe to 89.54 MWe. This is due entirely to the 10 percent increase in CO_2 compressor load from 24.15 MWe to 26.8 MWe. Once CO_2 is above the supercritical pressure point, additional pressurization is easily achievable with minimum negative impact on plant efficiency.

Table 4-6
CASE 3A – IGCC WITH CO_2 REMOVAL AND ELEVATED DELIVERY PRESSURE
PLANT PERFORMANCE SUMMARY – 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	538 (1,000)
Reheat Outlet Temperature, °C (°F)	538 (1,000)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	345,355
Steam Turbine Power	143,366
Generator Loss	(7,330)
Turbo-Set Power (Note 1)	481,391
Fuel Gas Expander Power	9.005
Gross Plant Power	490.396
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	360
Coal Milling	830
Coal Slurry Pumps	220
Slag Handling and Dewatering	160
Recycle Gas Blower	340
Air Separation Plant	25,390
Oxygen Boost Compressor	14,720
Selexol Plant	8,570
Claus/TGTU	100
Tail Gas Recycle	1,000
Humidification Tower Pump	100
Humidifier Makeup Pump	240
Low Pressure CO_2 Compressor	810
High Pressure CO_2 Compressor (Note 3)	26,800
Condensate Pumps	370
High Pressure Boiler Feed Pump	3,180
Low Pressure Boiler Feed Pump	100
Miscellaneous Balance of Plant (Note 2)	1,000
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,840
Cooling Tower Fans	1,040
Flash Bottoms Pump	50
Transformer Loss	1,520
Total Auxiliary Power Requirement	89,540
NET PLANT POWER, kWe	400,856
PLANT EFFICIENCY	
Net Efficiency, % HHV	36.7
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	9,796 (9,287)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	144,748 (319,110)
Oxygen (95% pure), kg/h (lb/h)	118,488 (261,218)
Water, kg/h (lb/h)	298,068 (657,117)

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure 15.2 MPa (2200 psia).
Note 4 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV).

4.2 CASE 3B – E-Gas™ IGCC, H CLASS TURBINE WITHOUT CO_2 REMOVAL

4.2.1 Introduction

This market-based design centers on the use of a single combustion turbine coupled with a heat recovery system that generates steam for a single steam turbine generator. The gas turbine technology chosen for this IGCC study is based on General Electric's H-type advanced turbine system (ATS) machine. This particular machine features a gas turbine and steam turbine connected on one shaft to a single generator.

An E-Gas™ gasifier was chosen as the basis for this IGCC configuration. Raw fuel gas exiting the gasifier is cooled and cleaned of particulate before being routed to a series of raw gas coolers. After desulfurization in an amine unit, the fuel gas is reheated and fired in the combustion turbine. There is no provision for CO_2 removal in this coal-fired configuration.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections include:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Production Cost, and Economics
- Case 3B at ISO Conditions

The thermal performance section contains a block flow diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections, including a series of heat and material balance diagrams that completely describe the thermodynamics and chemistry of the power plant. An equipment list supports the detailed plant description and, along with the heat and material balance diagrams, are used in generating the estimated plant cost. A single sensitivity case is presented at the end of this section.

4.2.2 Thermal Plant Performance

The market-based plant described in this section is based on use of one General Electric H-type ATS gas turbine coupled with a heat recovery system that supplies steam to one steam turbine generator. The resulting power plant thus utilizes a combined cycle for conversion of thermal energy to electric power. Table 4-7 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant; including gross plant power, auxiliary power load, net plant power, and net plant efficiency.

Table 4-7 shows an estimated gas turbine power output compared to the appropriate natural gas-fired case 1B (or case 1D). This assumption is based on GE's report that IGCC output can be enhanced when coal-derived synthesis gas is fired in their combustion turbines. They have reported that a 14 percent increase in expander throughput, while maintaining the same firing temperature, is possible. This can result in as much as a 20 percent increase in net plant power output. As a result, gross combustion turbine power has been estimated at 337 MWe in this IGCC case as compared to 272 MWe estimated for case 1B (or case 1D).

Gross plant power output after accounting for generator losses is 474 MWe. The auxiliary power load has been estimated as 49.5 MWe, which corresponds to an estimated net plant power output for this IGCC configuration of 424.5 MWe. This power output is generated with a net plant thermal efficiency of 43.1 percent, HHV, with a corresponding heat rate of 8,349 kJ/kWh (7,915 Btu/kWh).

Figure 4-7 contains a block flow diagram depicting the overall layout of this IGCC power plant configuration. Combustion turbine and steam turbine cycles are shown schematically, along with the appropriate state point data. An open Brayton cycle (CT) using air and combustion products as working fluid is used in conjunction with the conventional sub-critical Rankine cycle (ST). The two cycles are coupled by the generation and superheating of steam in the heat recovery system consisting of the HRSG and gasifier island waste-heat-exchangers.

The heat and material balance in Figure 4-7 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 $\times 10^{-3}$	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Table 4-7
CASE 3B - IGCC POWER CASE
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	12.4 (1,800)
Throttle Temperature, °F	538 (1,000)
Reheat Outlet Temperature, °F	538 (1,000)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	337,472
Steam Turbine Power	143,783
Generator Loss	(7,215)
Gross Plant Power (Note 1)	474,040
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	330
Coal Milling	750
Coal Slurry Pumps	200
Slag Handling and Dewatering	150
Scrubber Pumps	300
Recycle Gas Blower	600
Tail Gas Recycle Blower	1,410
Air Separation Plant	23,330
Oxygen Boost Compressor	11,910
Amine Units	1,300
Claus/TGTU	100
Humidification Tower Pump	100
Humidifier Makeup Pump	60
Condensate Pumps	280
High Pressure Boiler Feed Pumps	2,940
Miscellaneous Balance of Plant (Note 2)	1,000
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,790
Cooling Tower Fans	1,010
Flash Bottoms Pump	50
Transformer Loss	1,090
Total Auxiliary Power Requirement	49,500
NET PLANT POWER, kWe	424,540
PLANT EFFICIENCY	
Net Efficiency, % HHV	43.1%
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)	8,349 (7,915)
CONDENSER COOLING DUTY, 10^6 Btu/h	
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 3)	130,655 (288,040)
Oxygen (95% pure), kg/h (lb/h)	109,287 (240,932)
Water, kg/h (lb/h)	158,574 (349,590)

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV).

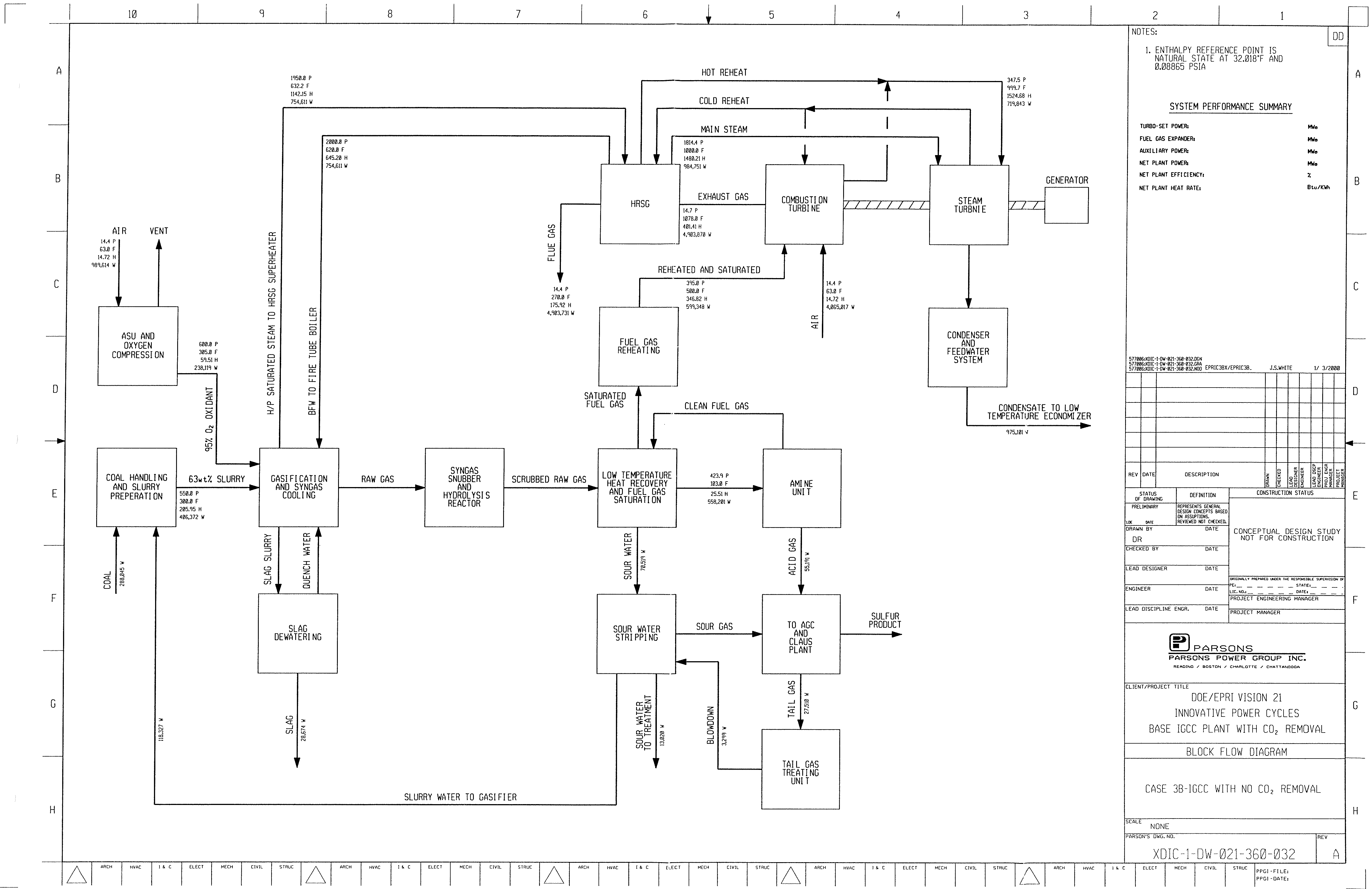

Figure 4-7
Block Flow Diagram – Case 3B – IGCC without CO_2 Removal

4.2.3 Power Plant Emissions

The operation of a modern, state-of-the-art gas turbine fueled by coal-derived synthesis gas generated with an oxygen-blown E-Gas™ gasifier is projected to result in very low levels of SO_2, NOx, and particulate (fly ash) emissions. Also, the inclusion of a CO_2 removal system will greatly decrease the ambient release of CO_2 from the power plant. A summary of the estimated plant emissions for this case is presented in Table 4-8. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four bases: (1) kilogram per gigajoule of HHV thermal input (pound per million Btu of HHV thermal input), (2) tonnes per year for a 65 percent capacity factor (tons per year for a 65 percent capacity factor), (3) tonnes per year for an 85 percent capacity factor (tons per year for an 85 percent capacity factor), and, (4) kilograms per hour per MWe of power output (pounds per hour per MWe of power output).

Table 4-8
CASE 3B AIRBORNE EMISSIONS
IGCC H CLASS TURBINE WITHOUT CO_2 REMOVAL

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
NOx	< 0.012 (< 0.028)	259 (285)	336 (370)	0.11 (0.25)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	86 (200)	1,732,752 (1,910,000)	2,268,000 (2,500,000)	717.6 (1,582)

As shown in the table, the amounts of SO_2 emissions are negligible. This is a direct consequence of using a proprietary amine absorption process to remove H_2S from the fuel gas stream prior to combustion. The amine process removes more than 99.8 percent of the sulfur present in the raw fuel gas stream. The sulfur is subsequently concentrated and processed in a Claus plant and tail gas treating unit to produce an elemental sulfur product. Overall sulfur capture and recovery is approximately 99.7 percent. These steps result in very low sulfur emissions from this IGCC power plant configuration.

NOx emissions are limited to less than 10 ppm adjusted to 15 percent O_2 content in the flue gas. This low level of NOx production is achieved by diluting the heating value of the incoming combustion turbine fuel gas stream to less than 5,587 kJ/scm (150 Btu/scf). Dilution is accomplished by humidifying the desulfurized fuel gas stream and steam injection at the combustion turbine inlet. This water dilution serves a dual role; not only does water dilution mitigate NOx emissions, it also helps maintain a relatively lower burner temperature with increased fuel input.

Particulate discharge to the atmosphere is limited by the use of the candle-type particulate filter as well as the gas washing effect achieved through raw gas condensate knock out and the amine absorption process. CO_2 emissions are high as would be expected from a coal plant of this power output.

4.2.4 System Description

This greenfield power plant is a 424 MW coal-fired IGCC power plant with no provision for CO_2 removal. The gasifier technology choice is E-Gas™ and the combustion turbine choice is based on GE's H-type advanced turbine system. The major subsystems of the power plant are:

- Coal Receiving and Handling
- Coal-Water Slurry Preparation and Feeding
- Coal Gasification and Air Separation Unit
- Raw Gas Cooling / Syngas Humidification
- Sulfur Removal and Recovery
- Combined Cycle Power Generation
- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief description of these individual power plant subsystems. Also presented are heat and material balance diagrams for the individual plant sections, each annotated with state point data. The equipment list, which follows this section, is based on the system descriptions provided here. The equipment list, in turn, was used to generate plant cost and cost of CO_2 removal.

4.2.4.1 Coal Receiving and Handling

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the rod mill inlet. The system is designed to support short-term operation at 105 percent of the design load condition for a 16-hour period and long-term operation at 100 percent of the design load point for 90 days or more.

The 15.24 cm (6") x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 91-tonne (100-ton) rail cars. Each unit train consists of 100, 91-tonne (100-ton) rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 15.24 cm (6") x 0 coal from the feeder is discharged onto a belt conveyor and then transferred to a second conveyor that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 7.62 cm (3") x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 2.54 cm (1") x 0, which is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the three storage silos.

4.2.4.2 Coal-Water Slurry Preparation and Feeding

The slurry preparation and feeding system mills crushed coal and generates a 63 weight percent slurry for the gasifier. Two trains at 50 percent each are provided.

Crushed coal is reclaimed from the storage silo by a vibrating feeder, which delivers the coal to a weigh-belt feeder. Crushed coal is fed through the rod-mill (pulverizer) and then routed to a product storage tank. In the rod mill, recycled water from the sour gas stripper is added to the coal to form a slurry. Slurry from the rod mill storage tank is then either fed to the gasifier or routed to an agitated storage tank. The slurry storage tank is sized to hold 8 hours of slurry product.

Coal-water slurry is pumped via positive displacement pumps to the low temperature slurry heater. Here, the high-pressure slurry is heated to approximately 121°C (250°F) by condensing low-pressure steam. The coal-water slurry is further heated in a second slurry heater to 149°C (300°F). The duty for this effort is provided by condensing, intermediate-pressure steam. The hot, high-pressure coal-water slurry then proceeds to the gasifier injection system.

4.2.4.3 Coal Gasification and Air Separation Unit

This section gives a cursory description of the gasification process and air separation unit. For ease of discussion, the topic has been organized under the following four sub-headings:

- Air Separation Unit
- Gasification
- Raw Gas Cooling
- Particulate Removal

Air Separation Unit

Two trains at 50 percent are used. Each train produces 1,333 tonne/day (1,470 tpd) of 95 percent oxygen product (1,274 tonne/day (1,404 tpd) on a 100 percent O_2 basis). Each train consists of a multi-staged air compressor, an air separation cold box, and an oxygen compression system. A liquid oxygen storage tank is used to ensure reliability. A slipstream of vent nitrogen is compressed and available for miscellaneous plant requirements.

A simplified schematic of the oxygen plant is shown in Figure 4-8. State point data is also shown. Ambient air at 0.099 MPa (14.4 psia) and 17.2°C (63ºF) is compressed in a three-staged, intercooled compressor to 0.46 MPa (67 psia). The high-pressure air stream is cooled and routed to a thermal swing absorption system, which removes H_2O, CO_2, and other ambient contaminants before flowing to the vendor-supplied cold box. In the cold box, cryogenic distillation is used to provide a 95 percent pure oxygen stream for use in the gasifier.

The heat and material balance in Figure 4-8 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 $x10^{-3}$	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.325	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

The low-pressure oxidant stream from the cold box is compressed to 4.2 MPa (603 psia) in a six-stage, intercooled compressor. This high-pressure stream is then heated indirectly with condensing intermediate-pressure steam to 152°C (305°F) before being routed to the gasifier injection system.

Gasification

E-Gas™ gasification technology, as exemplified at the Clean Coal Technology Wabash installation, is assumed for this study. It is assumed that the gasifier operates at a moderate pressure of 3.45 MPa (500 psig). Maximum coal throughput for an E-Gas™ gasifier operating at this pressure approximately 2,177 tonne/day (2,400 tpd) dry. This power plant requires 2,794 tonne/day (3,080 tpd) (dry) coal feed. Therefore, two gasification trains at 50 percent will be used.

Figure 4-8 contains a schematic of the gasifier. Approximately 90 percent of the preheated coal-water slurry is injected into the primary zone (or first stage) of the gasifier. Oxygen is injected along with the slurry in order to thoroughly atomize the feed stream. Char captured in the candle filter is also injected into the primary zone of the gasifier.

The primary gasification zone operates above the ash fusion temperature (1204°C (2200°F) to 1371°C (2500°F)) thereby ensuring the flow and removal of molten slag. This temperature is maintained by controlled oxygen feed. All of the oxygen in the first stage is utilized in exothermic partial oxidation/gasification reactions. Slag is removed from the bottom of the gasifier and quenched in a water pool before being crushed and removed from the unit. Gaseous products from the primary zone flow into the second gasification zone.

The remaining 10 percent of preheated slurry is injected in the secondary zone of the gasifier. A small portion of the raw fuel gas stream is recycled in order to promote reactivity of the atomized coal slurry. Tail gas from the back-end treating unit is also recycled in an effort to minimize power plant emissions.

In the secondary zone, hot gaseous products from the primary zone provide the thermal energy required to heat and gasify the atomized slurry. These gasification reactions are endothermic and considerably decrease the sensible energy content of the primary zone gases. As a result, the exit temperature of the secondary zone, around 1038°C (1900°F), is much lower than the primary zone.

Char produced in the cooler secondary gasification zone leaves the gasifier entrained in the fuel gas stream. Downstream particulate control measures remove the char from the fuel gas stream and return it to the primary zone of the gasifier for reinjection. The gasifier operates with a coal gas efficiency of approximately 77 percent.

Raw Gas Cooling

Hot raw gas from the secondary gasification zone exits the gasifier at 3.45 MPa (500 psig) and 1041°C (1905°F). This gas stream is cooled to 343°C (650°F) in a fire-tube boiler. The waste heat from this cooling is used to generate high-pressure steam. Boiler feed water in the tube walls is saturated, and then steam and water are separated in a steam drum. Approximately 342,014 kg/h (754,000 lb/h) of saturated steam at 13.45 MPa (1950 psia) is produced. This steam then forms part of the general heat recovery system that provides steam to the steam turbine.

Particulate Removal

A metal candle filter is used to remove any particulate material exiting the secondary gasification zone. This material, char and fly ash, is recycled back to the gasifier. The filter is comprised of an array of metal candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with fuel gas to remove the fines material. Raw gas exits the candle filter at 341°C (645°F) and 3.34 MPa (484 psia).

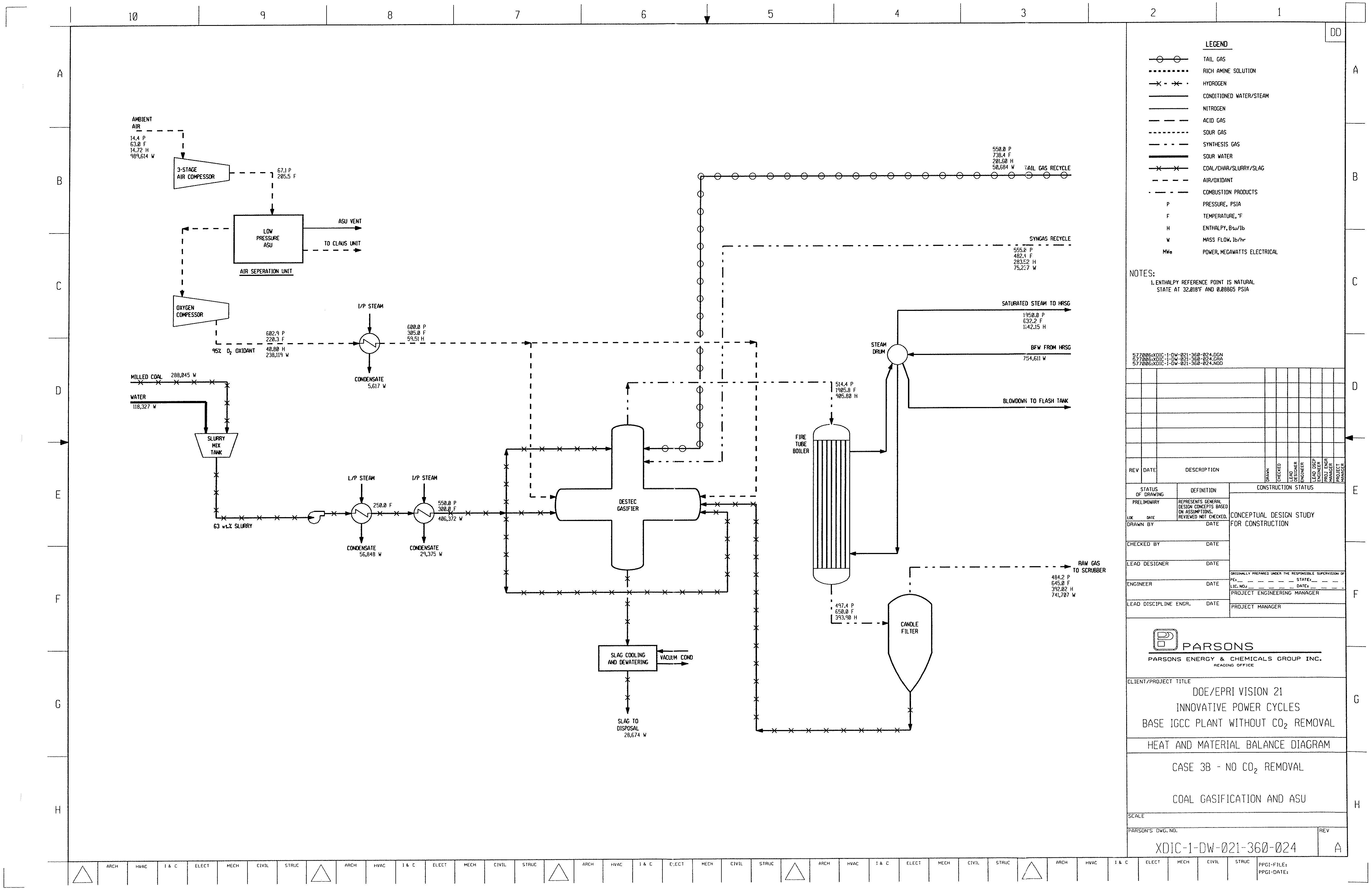

Figure 4-8
Heat and Material Balance Diagram – Case 3B – IGCC without CO_2 Removal – Coal Gasification and ASU

4.2.4.4 Raw Gas Cooling / Syngas Humidification

As shown schematically in Figure 4-9, raw gas from the filter at 341°C (645°F) is indirectly cooled to 187.8°C (370°F) before entering the syngas scrubber. In the syngas scrubber the raw gas is directly cooled to 149°C (300°F) through contact with cool water. Particulate-free gas exits the scrubber and is reheated in a regenerative heat exchanger and then routed to the hydrolysis reactor. A temperature of 210°C (410°F) is used for the hydrolysis reaction which hydrolyzes COS to H_2S. The reaction is exothermic but ineffective in raising the fuel gas temperature due to the very small amounts of COS in the fuel gas.

The heat and material balance in Figure 4-9 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

A portion of the raw gas exiting the hydrolysis reactor is split from the main flow, recompressed, and then recycled back to the gasifier. The remaining fuel gas stream is cooled in a series of low-temperature economizers and then routed to the amine unit for acid gas removal. Fuel gas condensate is recovered and routed to a sour drum.

The fuel gas saturator can also be seen in Figure 4-9. Sweet synthesis gas from the amine absorber is piped to the bottom of the saturator. The sweet fuel gas rises up through the column while warm water flows counter-currently. Internal trays are used to enhance the mass transfer of water vapor into the fuel gas. This process humidifies the fuel gas as well as increases its sensible heat content.

Warm, humid fuel gas exits the top of the saturator at 149°C (300°F) and 2.76 MPa (400 psia). It is indirectly heated further to 260°C (500°F) by condensing high-pressure steam. The fuel gas steam is then routed to the combustion turbine burner inlet.

Saturator water exits the column at 93°C (200°F) after being cooled down from 165.6°C (330°F). The water is then pumped through a series of raw gas coolers that economize the water back to 165.6°C (330°F). To avoid the buildup of soluble gases, a small blowdown to the sour water drum is taken from the pump discharge.

4.2.4.5 Sulfur Removal and Recovery

This IGCC power plant configuration will use a proprietary amine solvent in a traditional absorber/stripper arrangement to remove H_2S from the fuel gas stream. Elemental sulfur will be recovered in a Claus plant. The sulfur removal and recovery process will be presented as follows:

- Amine Unit/Acid Gas Concentrator
- Claus Plant
- Tail Gas Treating Unit

A heat and mass balance diagram of these systems can be seen in Figures 4-9 and 4-10.

The heat and material balances in Figure 4-9 and 4-10 are shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Amine Unit/Acid Gas Concentrator

The purpose of the amine unit is to remove acid gas, in particular H_2S, from the fuel gas stream. This step is necessary in order to minimize plant sulfur emissions. The solvent used in this case is a proprietary formulation based on MDEA. A traditional absorber/stripper arrangement will be used.

Cool, dry, and particulate-free synthesis gas enters the absorber unit at approximately 2.93 MPa (425 psia) and 39.4°C (103°F). In the absorber H_2S along with some CO_2 is removed from the fuel gas stream. Clean fuel gas exits the top of the absorber and is then routed to the saturator column.

The rich solution leaving the bottom of the absorber is regenerated in a stripper through the indirect application of thermal energy via condensing low-pressure steam in a reboiler. The stripper acid gas stream, consisting of 16 percent H_2S and 78 percent CO_2 (with the balance mostly H_2O), requires further treatment before entering the Claus unit.

Typically, for good performance and operation, the minimum H_2S concentration in the acid gas feed to a Claus plant should be above 27 percent. In this case we are much below that number. So, an acid gas concentrator was used to further concentrate the H_2S stream.

An absorber with a proprietary MDEA-based solvent is used. Sweet gas off the top is combined with the tail gas treating unit's vent gas and recycled back to the gasifier. Rich solution from the bottom of the absorber is regenerated, along with rich solution from the tail gas unit, in a reboiling-stripper. The acid gas to the Claus unit has a H_2S concentration of 36 percent.

Claus Unit

Acid gas from the regenerator, which includes that removed in the concentrator and the tail gas unit, is routed to the Claus plant. A heat and material balance diagram of the Claus plant can be seen in Figure 4-10. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. Approximately 3,266 kg/hour (7,200 lb/hour) of elemental sulfur is recovered from the fuel gas stream. This value represents an overall sulfur recovery efficiency of 99.7 percent.

Acid gas from the regenerator is preheated to 232°C (450°F). Sour gas from the sour stripper and 95 percent O_2 oxidant from the ASU are likewise preheated. A portion of the acid gas along with all of the sour gas and oxidant are fed to the Claus furnace. In the furnace, H_2S is catalytically oxidized to SO_2. A furnace temperature greater than 1343°C (2450°F) must be maintained in order to thermally decompose all of the NH_3 present in the sour gas stream.

Combustion and decomposition products from the furnace are mixed with the remaining acid gas stream and cooled in a waste heat boiler. These gases are further cooled and any sulfur formed during the catalytic and thermal furnace stages is condensed out and routed to the sulfur pit. The remaining gas stream is heated and sent to the sulfur converter, which catalytically oxidizes H_2S with SO_2 to elemental sulfur. The stream is then cooled and any condensed sulfur is removed and routed to the sulfur pit.

Three preheaters and three sulfur converters are used to obtain a per-pass H_2S conversion of approximately 97.7 percent. In the furnace waste heat boiler, 5,307 kg/hour (11,700 lb/hour) of 4.48 MPa (650 psig) steam is generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as 2,041 kg/hour (4,500 lb/hour) of steam to the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

Tail Gas Treating Unit

Tail gas from the Claus unit contains unreacted sulfur species such as H_2S, COS, and SO_2 as well as elemental sulfur species of various molecular weight. In order to maintain low sulfur emissions, this stream is processed in a tail gas treating unit to recycle sulfur back to the Claus plant.

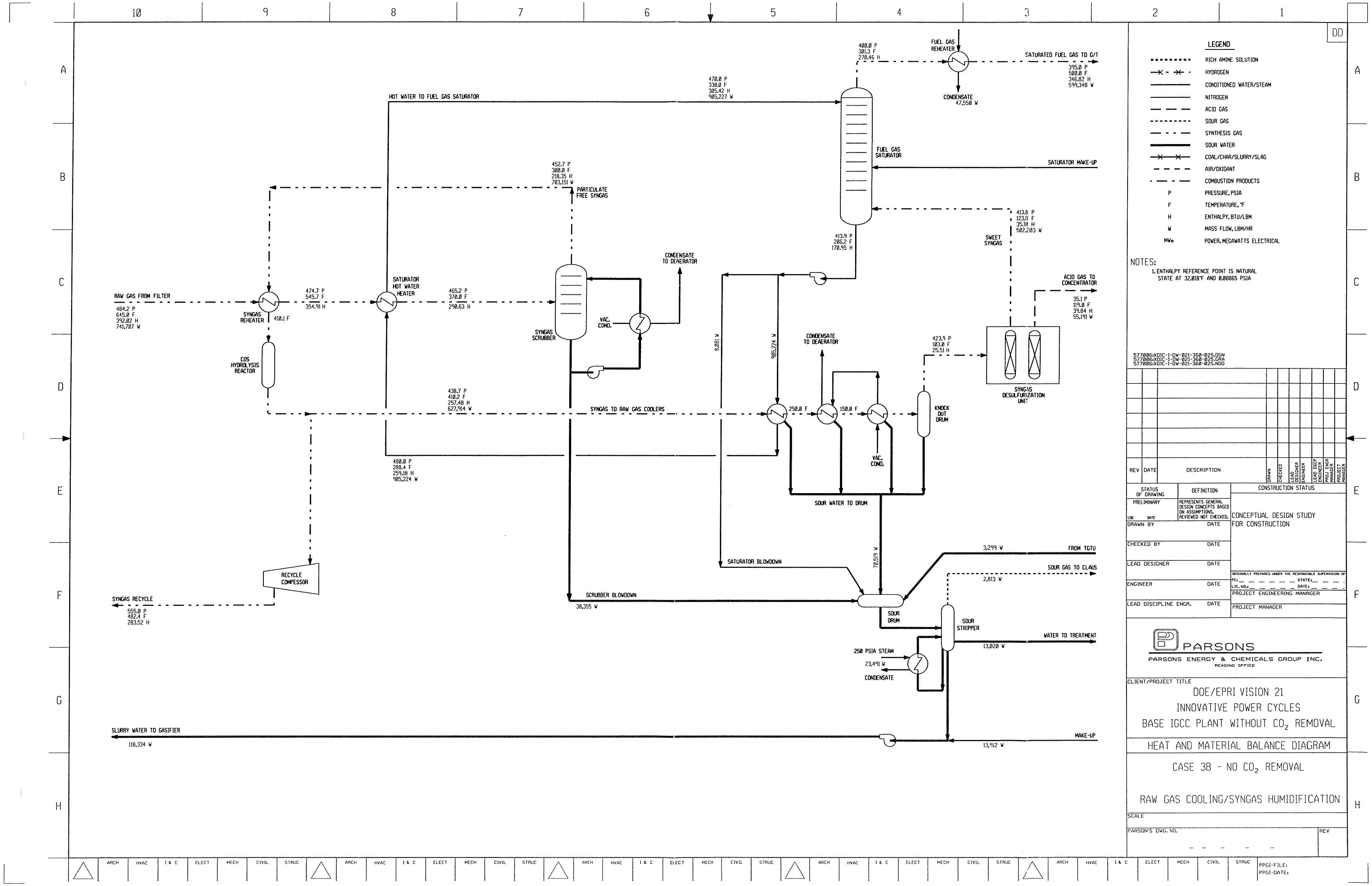

Figure 4-9
Heat and Material Balance Diagram – Case 3B – IGCC without CO_2 Removal – Raw Gas Cooling/Syngas Humidification

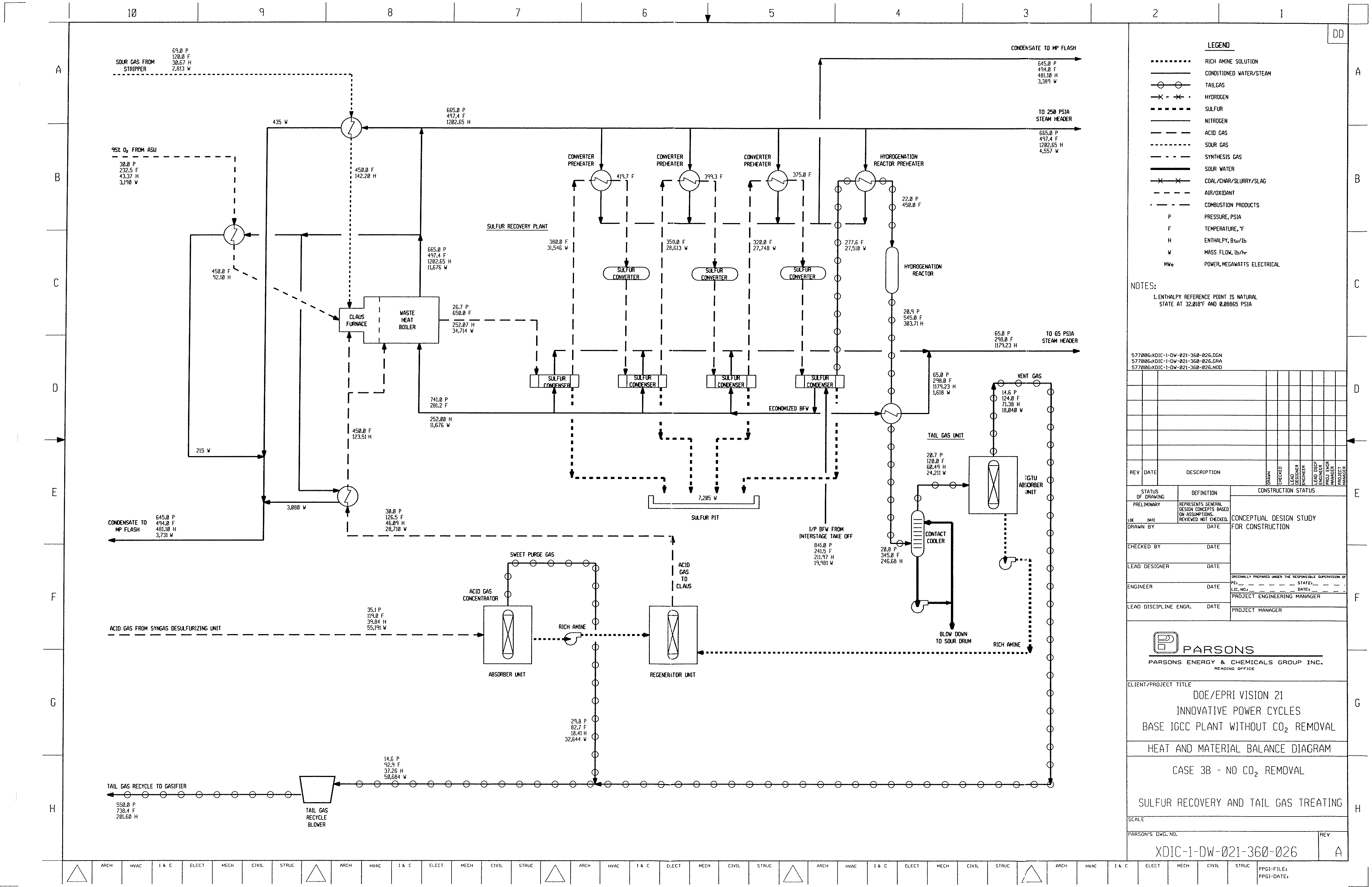

Figure 4-10
Heat and Material Balance Diagram – Case 3B – IGCC without CO_2 Removal – Sulfur Recovery and Tail Gas Treating

Tail gas from the Claus plant is preheated to 232°C (450°F) and then introduced to the hydrogenation reactor. In the hydrogenation reactor, SO_2 and any elemental sulfur specie is catalytcally reduced with H_2 to H_2S. Also, COS is hydrolyzed to H_2S. This gas stream is then cooled and treated in an amine absorber unit. H_2S is removed by the amine solution, regenerated in a reboiler-stripper, and recycled back to the Claus furnace. Sweet gas from the amine absorber, which contains fuel gas species such as H_2 and CO, is compressed and recycled to the gasifier secondary zone.

4.2.4.6 Combined Cycle Power Generation

The combustion turbine selected for this application is based on the General Electric Model H. This machine is an axial flow, constant speed unit, with variable guide vanes. The gas turbine compressor and expander, as well as the steam turbine and generator, are connected on a single rotating shaft. So, in essence, the gas and steam turbines are a single piece of rotating machinery coupled by a heat recovery system. For ease of discussion, these three primary components of the combined cycle will be broken out and discussed separately. A heat and material balance diagram for the combined cycle power generation portion of this power plant is shown in Figure 4-11.

The heat and material balance in Figure 4-11 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Combustion Turbine

Inlet air at 512 kg/sec (1,129 lb/sec) is compressed in a single spool compressor at a pressure ratio of approximately 23:1. This airflow is lower than the ISO airflow of 556 kg/sec (1,225 lb/sec) due to the choice of ambient conditions used in this specific study. (The ambient conditions chosen in this correspond to a standard EPRI/DOE fossil-plant site. They result in a less dense ambient air, and subsequently, less airflow and power output in the gas turbine.) The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the coal derived fuel-gas. Compressed air is also used in film cooling services.

Humidified fuel gas from the gasifier island is injected into the gas turbine along with cold reheat steam such that the combined mixture has a heating content less than 5,587 kJ/scm (150 Btu/scf). The fuel gas is combusted in 12 parallel combustors. NOx formation is limited by geometry and fuel gas dilution. The combustors are can-annular in configuration, where individual combustion cans are placed side-by-side in an annular chamber. Each can is equipped with multiple fuel nozzles, which allows for higher mass flows over earlier machines and higher operating temperatures. In the estimated performance provided here, the machine will develop a rotor inlet temperature of about 1427°C (2600°F).

Hot combustion products are expanded in the four-stage turbine-expander. It is assumed that the first two expander stages are steam cooled and that the third stage is air cooled. No cooling is expected in the fourth expander stage. The expander exhaust temperature is estimated as 583°C (1081°F), given the assumed ambient conditions, back-end loss, and HRSG pressure drop. This value, 11.1°C (20ºF) lower than the ISO assumed value of 594°C (1102°F) for a natural gas-fired simple cycle gas turbine, is due to variations in firing temperature, flowrate, and flue gas specific heats.

Gross turbine shaft power, as measured prior to the generator terminals, is estimated as 337 MWe. The generator, which is shared with the steam turbine, is assumed to be a standard hydrogen-cooled machine with static exciter. Net combustion turbine power (following generator losses) is estimated at 332 MWe. This value reflects the expected increase of GE's H-type turbine power output when firing coal-derived fuel gas.

Heat Recovery System

As schematically illustrated in Figure 4-12, the heat recovery system thermally couples the waste heat rejected by the gas turbine and gasifier island with the steam turbine. Waste heat rejected by the gas turbine is recovered by the HRSG. The HRSG, along with raw gas coolers and the fire tube boiler located in the gasifier island, generate steam, which is utilized in the steam turbine to generate electrical power.

The heat and material balance in Figure 4-12 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

High temperature flue gas at 2,224,454 kg/hour (4,904,000 lb/hour) exiting the CT expander is conveyed through the HRSG to recover the large quantity of thermal energy that remains in the flue gas after expansion. For purposes of this analysis, it is assumed that the flue gas heat loss through the HRSG duct corresponds to 1.6°C (3°F). The HRSG flue gas exit temperature is assumed to be 132°C (270°F), which should be high enough to avoid sulfur dew-point complications.

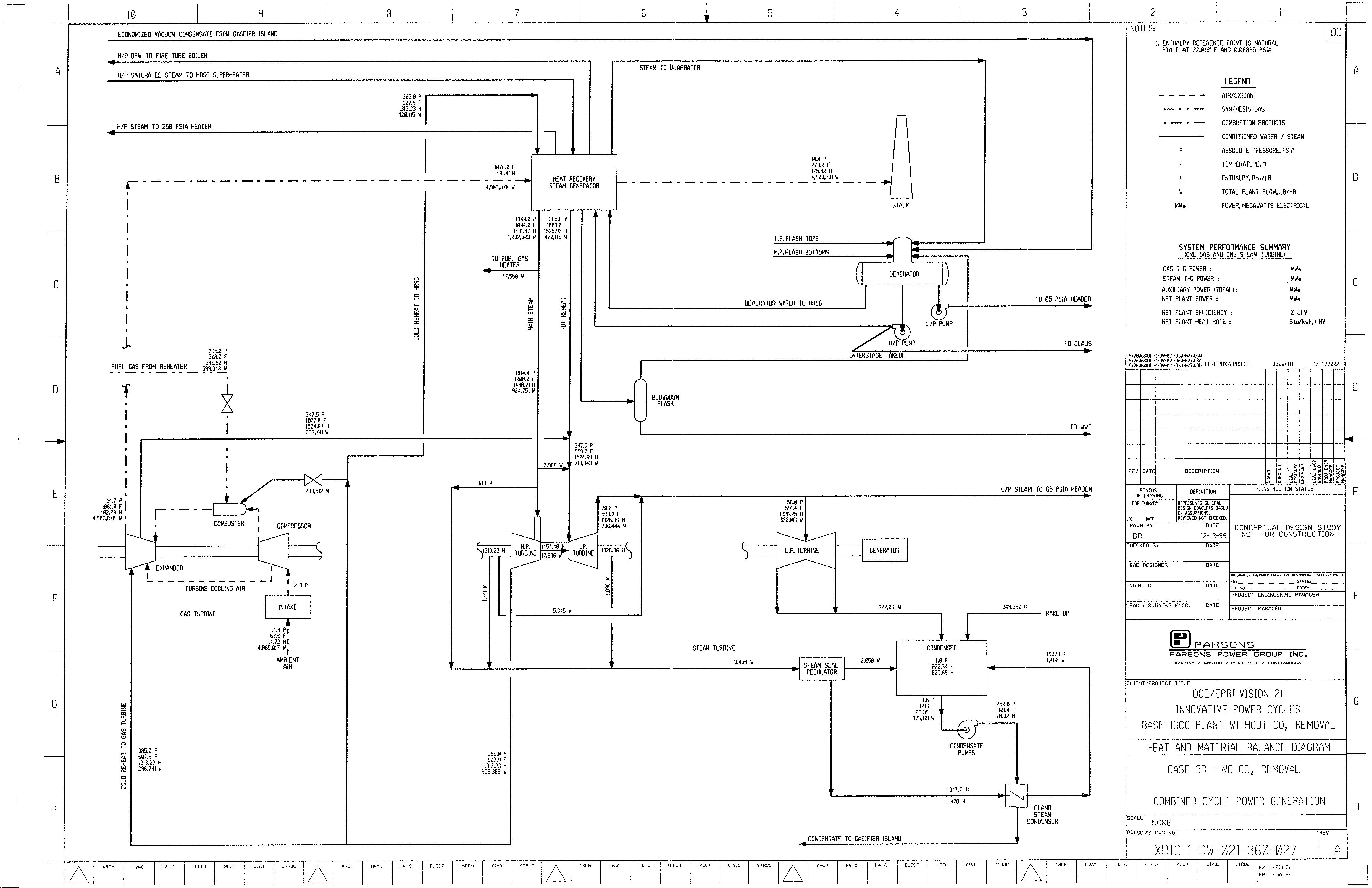

Figure 4-11
Heat and Material Balance Diagram – Case 3B – IGCC without CO_2 Removal – Combined Cycle Power Generation

The HRSG is configured with a HP superheater, HP evaporator and drum, and HP economizer. The economizer is supplied with feedwater by the HP boiler feed pump operating off the deaerator. Approximately 493,063 kg/hour (1,087,000 lb/hour) of 15.86 MPa (2300 psia) boiler feed water is heated to 327°C (620°F) in the economizer. This high-pressure economizer water stream is then split between the HRSG HP evaporator and the fire tube boiler. Saturated steam returned from these sources is superheated and then routed to the HP steam turbine inlet.

Cold reheat from the HP steam expander is split between gas turbine cooling duties, combustor turbine steam injection, and the HRSG. In the HRSG, 190,512 kg/hour (420,000 lb/hour) of cold reheat is heated from 319°C (607°F) to 540°C (1004°F). Combustion turbine cooling duties heat 134,266 kg/hour (296,000 lb/hour) of cold reheat to 538°C (1000°F). These two hot reheat streams are recombined and routed to the IP steam turbine inlet.

Steam Turbine

The Rankine cycle used in this case is based on a commercially available 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) single reheat configuration. The steam turbine is assumed to consist of tandem high-pressure (HP), intermediate-pressure (IP), and double-flow low-pressure (LP) turbine sections connected via a common shaft with each other (as well as the combustion turbine) and driving a 3600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine is assumed to have a pitch diameter of 183 cm (72 inches) and a last-stage bucket length of 66 cm (26 inches).

Main steam at a rate of 444,528 kg/hour (980,000 lb/hour) passes through the HP stop valves and control valves and enters the turbine at 12.5 MPa (1815 psia) and 538°C (1000°F). The steam initially enters the turbine near the middle of the high-pressure span, expands through the turbine, and then exits the section. This cold reheat steam is then either routed to the HRSG for reheating, utilized in the combustion turbine as injection steam, or used to cool the gas turbine.

Hot reheat is returned to the steam turbine from both the HRSG and gas turbine cooling loop. The combined hot reheat stream then flows through the IP stop valves and intercept valves and enters the IP section at 2.4 MPa (347 psia) and 538°C (1000°F). After passing through the IP section, the steam enters a crossover pipe. The crossover steam is divided into two paths and flows through the LP sections exhausting downward into the condenser.

Gross turbine shaft power, as measured prior to the generator terminals, is estimated as 143 MWe. The generator, which is shared with the combustion turbine, is assumed to be a standard hydrogen-cooled machine with static exciter. Net steam turbine power (following generator losses) is estimated around 141 MWe.

4.2.4.7 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the gasifier island. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a series of low-temperature raw gas coolers located within the gasifier island.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank to their respective steam drums. Two 50 percent capacity motor-driven feed pumps are provided for HP/LP service. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

4.2.4.8 Balance of Plant

The balance of plant items discussed in this section include:

- Steam Systems
- Circulating Water System
- Accessory Electric Plant
- Instrumentation and Control
- Waste Treatment

Steam Systems

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

Main steam exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine.

Cold reheat steam exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Circulating Water System

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

Accessory Electric Plant

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

Instrumentation and Control

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

Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 45.4-tonne (50-ton) lime silo, a 0-453.6 kg/h (0-1000 lb/h) dry lime feeder, a 18.93 m^3 (5,000-gallon) lime slurry tank, slurry tank mixer, and 0.09 m^3/min (25 gpm) lime slurry feed pumps.

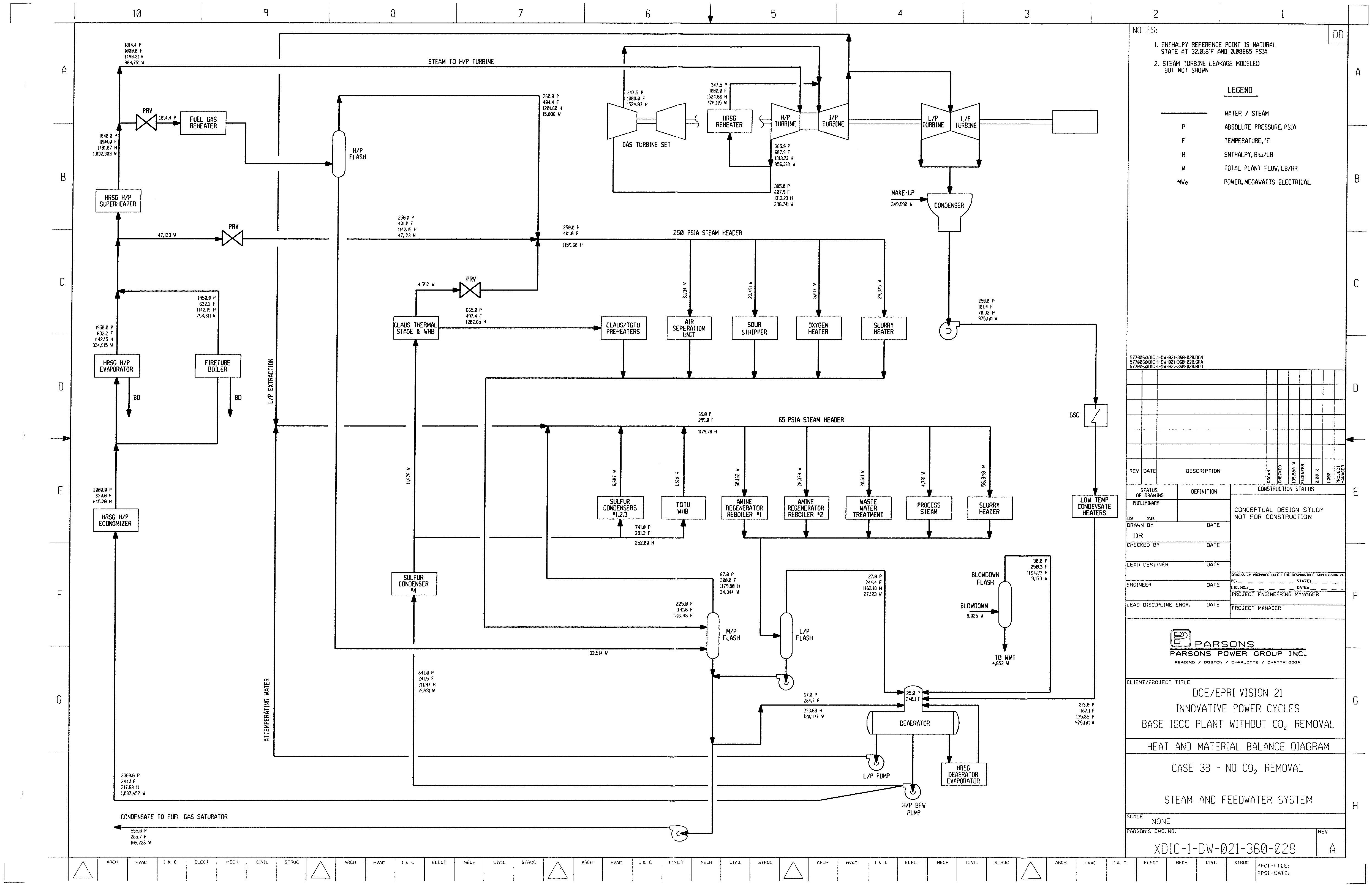

Figure 4-12
Heat and Material Balance Diagram – Case 3B – IGCC without CO_2 Removal – Steam and Feedwater System

The oxidation system consists of a 1.4 scmm (50 scfm) air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 757.1 m^3 (200,000-gallon) storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

4.2.5 Case 3B – Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 4-7. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the nomenclature section.

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter) Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Ton, multiply by 0.9072 = tonne (metric ton) tph = tons per hour

Gallon, gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm. multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832 x 10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9 $x10^{-3}$ = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

ACCOUNT 1 COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1"x0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	600 ton	3

ACCOUNT 2 COAL-WATER SLURRY PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Qty.
1	Feeder	Vibrating	120 tph	2
2	Weigh Belt Feeder		48” belt	2
3	Rod Mill	Rotary	120 tph	2
4	Slurry Water Pumps	Centrifugal	220 gpm @ 500 ft	2
5	Slurry Water Storage Tank	Vertical	2,600 gal	1
6	Rod Mill Product Tank	Vertical	45,000 gal	2
7	Slurry Storage Tank with Agitator	Vertical	200,000 gal	2
7	Slurry Feed Pumps	Positive displacement	990 gpm @ 2,500 ft	2
8	LT Slurry Heater	Shell and tube	28 x 10^6 Btu/h	2
9	HT Slurry Heater	Shell and tube	11 x 10^6 Btu/h	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS BOP SYSTEMS

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cylindrical, outdoor	200,000 gal	1
2	Condensate Pumps	Vert. canned	2,800 gpm @ 400 ft	2
3	Low Temperature Economizers	Shell and tube	53 x 10^6 Btu/h	2
4	Deaerator	Horiz. spray type	1,200,000 lb/h 205°F to 240°F	1
5	LP Feed Pump	Rotary	100 gpm/185 ft	1
6	HP Feed Pump	Barrel type, multi-staged, centr.	2,200 gpm @ 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F 70,000 lb/h	1
2	Service Air Compressors	Recip., single stage, double acting, horiz.	100 psig, 750 cfm	2
3	Inst. Air Dryers	Duplex, regenerative	750 cfm	1
4	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 1,200 gpm	2
5	Closed Cycle Cooling Heat Exchangers	Plate and frame	50% cap. each	2
6	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 1,200 gpm	2
7	Fire Service Booster Pump	Two-stage horiz. centrifugal	250 ft, 1,200 gpm	1
8	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
9	Raw Water Pumps	S.S., single suction	60 ft, 300 gpm	2
10	Filtered Water Pumps	S.S., single suction	160 ft, 120 gpm	2
11	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
12	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
13	Sour Water Stripper System	Vendor supplied	150,000 lb/h sour water	1
14	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 GASIFIER AND ACCESSORIES

ACCOUNT 4A GASIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Pressurized entrained bed/syngas cooler	1,530 std (dry-coal basis) @ 500 psig	2
2	Syngas Cooler	Fire-tube with steam drum	190 x 10^6 Btu/h	2
3	Low-Temperature Candle Filter	Metal	500 psia, 600°F	2
4	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	770,000 lb/h, medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	115,000 scfm, 67 psia discharge pressure	2
2	Cold Box	Vendor supplied	1,470 ton/day O_2	2
3	Oxygen Compressor	Centrifugal, multi-stage	22,970 scfm, 600 psig discharge pressure	2
4	Liquid Oxygen Storage Tank	Vertical	60' dia x 80' vert	1
5	Oxygen Heater	Shell and tube	3.6×10^6 Btu/h @ 600 psia and 300°F	2

ACCOUNT 5 FUEL GAS SHIFT AND CLEANUP

ACCOUNT 5A RAW GAS COOLING AND FUEL GAS HUMIDIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Syngas Cooler / Reheater	Shell and tube	15×10^6 Btu/h @ 500 psia, 650°F`	2
2	Saturator Hot Water Heater	Shell and tube	25×10^6 Btu/h @ 470 psia, 550°F	2
3	Syngas Scrubber	Vertical, water tower	470 psia, 550°F	2
4	Scrubber Pump	Centrifugal	4,500 gpm @ 120 ft	2
5	Scrubber Cooler	Shell and tube	17×10^6 Btu/h @ 500 psia, 550°F	2
6	Hydrolysis Reactor	Fixed bed	110,000 scfm (6,000 acfm) 500 psia, 410°F	2
7	Fuel Gas Recycle Compressor	Reciprocating	11,100 scfm (600 acfm) 1.3 PR @ 500 psia	2
8	Low Temperature Saturation Water Economizer	Shell and tube	40×10^6 Btu/h @ 450 psia and 400°F	2
9	Raw Gas Coolers	Shell and tube with condensate drain	30×10^6 Btu/h	2
10	Raw Gas Knock Out Drum	Vertical with mist eliminator	400 psia, 130°F	2
11	Fuel Gas Saturator	Vertical trayed tower	20 stages 400 psia, 350°F	1
12	Saturator Water Pump	Centrifugal	3,000 gpm @ 120 ft	1
13	Fuel Gas Reheater	Shell and tube	45×10^6 Btu/h @ 400 psia, 550°F	1

ACCOUNT 5B SULFUR REMOVAL AND RECOVERY

Equipment No.	Description	Type	Design Condition	Qty
1	Acid Gas Removal Unit	Absorber / stripper Tray column Proprietary amine	75,000 scfm (3,000 acfm) @ 430 psia	2
2	Acid Gas Concentrator	Absorber column Proprietary amine	8,500 scfm (4,000 acfm) 35 psia, 120°F	1
3	Amine Regenerator	Tray column with reboiler	8,000 scfm (3,800 acfm) 35 psia, 120°F	1
4	Claus Unit	Vendor design	87 tpd sulfur product	1
5	Hydrogenation Reactor	Vertical fixed bed	5,000 scfm (3,500 acfm) 25 psia, 500°F	1
6	Contact Cooler	Spray contact, tray wash tower	5,000 scfm (3,500 acfm) 25 psia, 300°F	1
7	TGTU Amine Absorber Unit	Absorber column Proprietary amine	3,900 scfm (3,300 acfm) 20 psia, 130°F	1
8	Tail Gas Recycle Compressor	Centrifugal	8,000 scfm, PR=38	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	337 MWe Gas Turbine Generator	Axial flow single spool based on H	1,150 lb/sec airflow 2,600°F rotor inlet temp. 23:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1,150 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2,500 hp, time from turning gear to full load ~30 minutes	1
5	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
6	Oil Cooler	Air-cooled, fin fan		1
7	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
8	Generator Glycol Cooler	Air-cooled, fin fan		1
9	Compressor Wash Skid			1
10	Fire Protection Package	Halon		1

ACCOUNT 7 WASTE HEAT BOILERS, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum	1800 psig/1000°F 325,000 lb/h	1
2	Raw Gas Cooler Steam Generator	Fire tube boiler	1800 psig/850°F 252,000 lb/h	3
3	Stack	Carbon steel plate, type 409 stainless steel liner	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	140 MW Steam Turbine Generator	TC2F26	1800 psig 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	1,320,000 lb/h steam @ 2.0 in. Hga	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	2

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. Water Pumps	Vert. wet pit	75,000 gpm @ 60 ft	2
2	Cooling Tower	Mechanical draft	160,000 gpm	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A SLAG DEWATERING AND REMOVAL

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Dewatering System	Vendor proprietary	350 tpd	1

4.2.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the IGCC power plant with the "H" combustion turbine and without CO_2 removal, case 3B, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 3B represents a plant with a net output of 424.5 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 4-9. A detailed estimate for case 3B is included in Appendix A.

Table 4-9
CASE 3B SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	Gasifier, ASU & Accessories	165,590
5A	Gas Cleanup & Piping	33,930
5B	CO_2 Removal and Compression	N/A
6	Combustion Turbine and Accessories	61,860
7	HRSG, Ducting and Stack	20,680
8&9	Steam T-G Plant, including Cooling Water System	36,620
11	Accessory Electric Plant	23,070
	Balance of Plant	85,290
	SUBTOTAL	427,040
	Engineering, Construction Management Home Office and Fee	26,620
	Process Contingency	19,950
	Project Contingency	63,370
	TOTAL PLANT COST (TPC)	$535,980
	TPC $/kW	1,262

The production costs for case 3B consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal) and Fuel costs. The costs were determined on a first-year basis that includes evaluation at a 65 percent equivalent plant operating capacity factor. The results are summarized in Table 4-10 and supporting detail is contained in Appendix A.

Table 4-10
CASE 3B ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	5,503	0.23
Maintenance	10,750	0.44
Administrative & Support Labor	2,450	0.10
Consumables	1,814	0.08
By-Product Credits	(876)	-0.04
Fuel	23,725	0.98
TOTAL PRODUCTION COST	43,366	1.79

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 3B. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per tonne. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI is included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 4-11.

Table 4-11
CASE 3B LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	1.79
Annual Carrying Charge (¢/kWh)	3.45
Levelized Busbar Cost of Power Charge (¢/kWh)	5.24
Levelized Cost per tonne of CO_2 Removed ($/tonne of CO_2)	N/A

4.2.7 Case 3B at ISO Conditions

This work has not yet been completed.

5
CONVENTIONAL COAL-FIRED STEAM CYCLES – TECHNICAL DESCRIPTIONS

Five conventional coal-fired power plant configurations were evaluated and are presented in this section. Each design is market-based and consists of a state-of-the-art pulverized coal combustor with heat recovery coupled with a steam turbine. Plant performance was estimated and a heat and material balance diagram is presented for each case. An equipment list was generated based on the estimated plant performance and used to generate total plant and operating cost as well as cost of CO_2 emissions avoided. A plant description is also presented.

The five cases evaluated are:

- <u>Case 7A</u> – Coal-Fired Supercritical Steam Plant with CO_2 Removal and Recovery
- <u>Case 7B</u> – Coal-Fired Ultra-Supercritical Steam Plant with CO_2 Removal and Recovery
- <u>Case 7C</u> – Coal-Fired Supercritical Steam Plant
- <u>Case 7D</u> – Coal-Fired Ultra-Supercritical Steam Plant
- <u>Case 7E</u> – Advanced Ultra-Supercritical Coal-Fired Steam Plant

In cases 7A and 7B, CO_2 was removed from the flue gas stream with an aqueous solution of inhibited (oxygen tolerant) monoethanolamine (MEA). MEA absorption is the conventional technology of choice for CO_2 removal from an oxygen-bearing flue gas stream. The CO_2 was concentrated into a product stream and dried and compressed to a supercritical condition. The four cases are described in greater detail below.

5.1 CASE 7A – COAL-FIRED SUPERCRITICAL STEAM PLANT WITH CO_2 REMOVAL

5.1.1 Introduction

Case 7A is a coal-fired supercritical steam plant with CO_2 removal and recovery from the flue gas. The plant design approach is market-based and the configuration reflects current information and design preferences, the availability of a newer generation steam turbine, and the relative latitude of a greenfield site.

The coal-fired boiler is staged for low NOx formation. The boiler is also equipped with an SCR. Wet limestone forced oxidation FGD is used to limit SO_2 emissions. A once-through steam generator is used to power a double-reheat supercritical steam turbine with a net power output of

402 MWe. The steam turbine conditions correspond to 24.1 MPa/565.6°C (3500 psig/1050°F) throttle with 565.6°C (1050°F) at both reheats. Net plant power, after consideration of the auxiliary power load, is 329 MWe. The plant operates with an estimated HHV efficiency of 28.9 percent with a corresponding heat rate of 12,463 kJ/kWh (11,816 Btu/kWh).

Flue gas exiting the FGD system is routed to an inhibited MEA absorber-stripper system. In this system, a solution of aqueous MEA is used to remove 90 percent of the CO_2 in the flue gas. Low-pressure steam is used to strip and purify the CO_2. Low-pressure CO_2 removed from the system is compressed to supercritical conditions.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections are:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Production Cost, and Economics

The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost.

5.1.2 Thermal Plant Performance

Table 5-1 shows a detailed breakdown of the estimated system performance for this conventional coal-fired steam turbine power plant. Plant performance is based on the use of Illinois No. 6 coal as fuel and reflects current state-of-the art turbine adiabatic efficiency levels, boiler performance, wet limestone FGD system capabilities, and CO_2 removal through a aqueous solution of inhibited MEA.

Gross power output for the steam turbine is estimated to be 402.2 MWe. Plant auxiliary power is estimated to be 72.7 MWe. This auxiliary load value, much higher than that anticipated for a traditional coal-fired supercritical steam plant, is due to the presence of the CO_2 removal/ compression equipment. In particular, the flue gas blower, which requires 19.9 MWe of auxiliary power, and the CO_2 compressor, which requires 29.7 MWe of auxiliary power, are responsible.

Net plant power output, which considers generator losses and auxiliary power, is estimated as 329.3 MWe. This plant power output results in a net system thermal efficiency of 28.9 percent (HHV) with a corresponding heat rate of 12,463 kJ/kWh (11,816 Btu/kWh) (HHV). Plant efficiency and heat rate numbers are low in comparison to those expected for coal-fired steam plants utilizing state-of-the-art supercritical steam turbines. There are two reasons for the low system thermal efficiency: (1) the increased auxiliary power associated with the CO_2 removal equipment (see above), and, (2) the large amount of steam diverted to the MEA stripper reboiler. Diverting this LP steam results in a marked decrease in steam turbine power output.

A heat and material balance diagram for this convention coal-fired steam plant is shown in Figure 5-1. The steam turbine power cycle is shown at 100 percent of design load. The supercritical Rankine cycle used for this case is based on a 24.2 MPa/565.6°C/565.6°C/565.6°C (3500 psig/1050°F/1050°F/1050°F) double-reheat configuration. Condensate is heated in the low-pressure feedwater heaters. Boiler feedwater is heated in the high-pressure feedwater heaters. Steam generation, superheat, and reheat is accomplished in the boiler house. Also shown in the diagram is the basic equipment of the FGD and that required to remove CO_2 from the flue gas stream and concentrate it as a pure, high-pressure product.

The heat and material balance in Figure 5-1 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Table 5-1
CASE 7A – SUPERCRITICAL PC PLANT WITH CO_2 REMOVAL
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	25.1 (3,500)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
2nd Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Steam Turbine Power	408,089
Generator Loss	(5,835)
Gross Plant Power	402,254
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	390
Limestone Handling & Reagent Preparation	920
Pulverizers	1,860
Ash Handling	1,670
Primary Air Fans	1,220
Forced Draft Fans	970
Induced Draft Fans	19,880
SCR	100
Seal Air Blowers	50
Precipitators	1,000
FGD Pumps and Agitators	3,450
Condensate Pumps	300
Boiler Feed Water Booster Pumps	3,090
High Pressure Boiler Feed Pump	(Note 1)
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	1,950
Cooling Tower Fans	1,110
MEA Unit	1,940
CO_2 Compressor (Note 3)	29,730
Transformer Loss	930
Total Auxiliary Power Requirement	72,730
NET PLANT POWER, kWe	329,294
PLANT EFFICIENCY	
Net Efficiency, % HHV	28.9%
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	12,463 (11,816)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	1,025 (972)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	151,295 (333,542)
Sorbent, kg/h (lb/h)	15,535 (34,248)

Note 1 – Boiler feed pumps are turbine driven
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 8.3 MPa (1200 psig)
Note 4 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

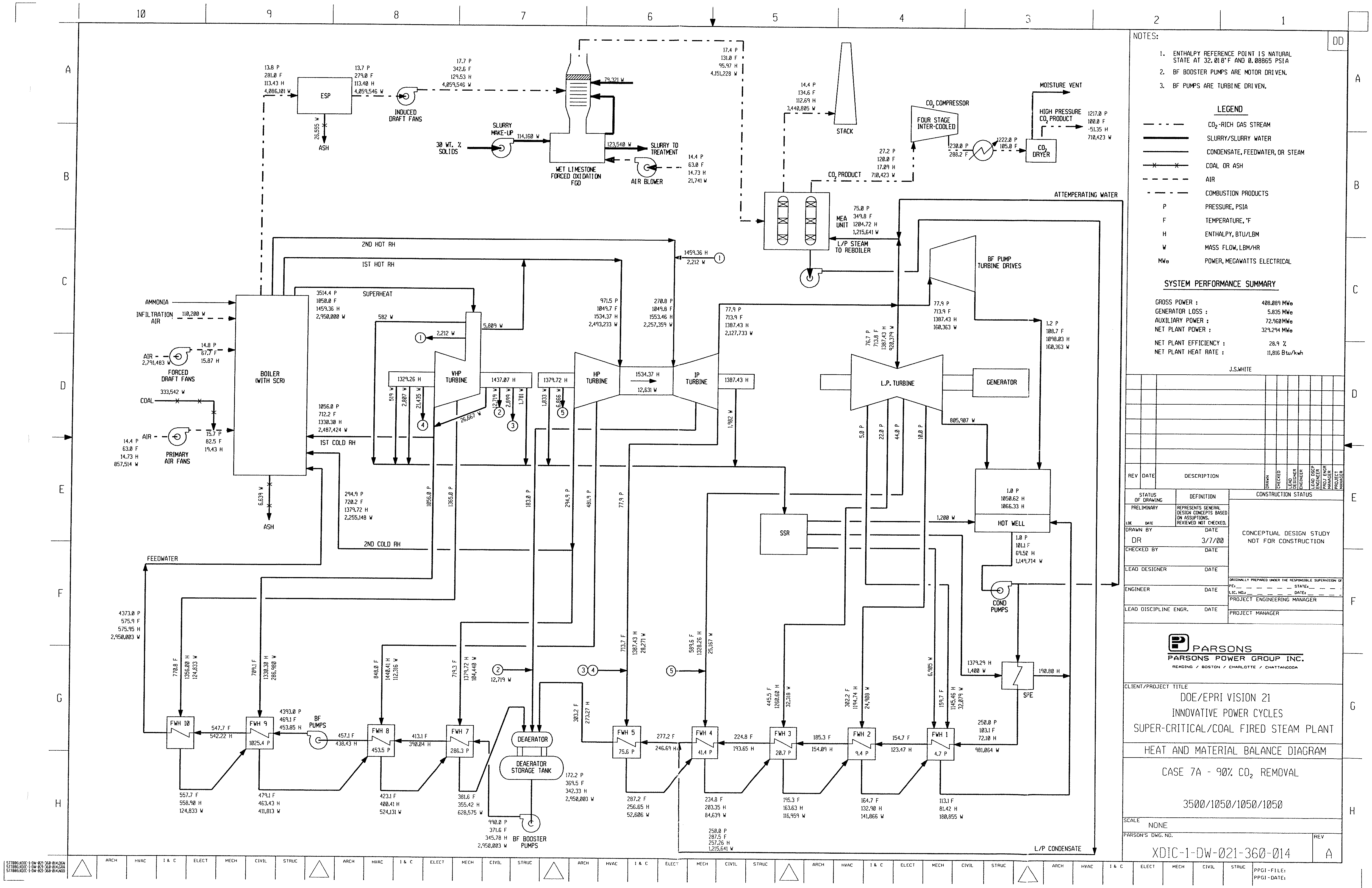

Figure 5-1
Heat and Material Balance Diagram – Case 7A – 90% CO_2 Removal – Supercritical/Coal-Fired Steam Plant

5.1.3 Power Plant Emissions

This supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the first decade of the next century. A summary of the plant emissions is presented in Table 5-2.

Table 5-2
CASE 7A AIRBORNE EMISSIONS
SUPERCRITICAL PC PLANT WITH FGD AND CO_2 REMOVAL

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	0.037 (0.086)	861.8 (950)	1,128 (1,243)	0.458 (1.01)
NOx	0.068 (0.157)	1,583 (1,745)	2,070 (2,282)	0.839 (1.85)
Particulates	0.004 (0.01)	99.8 (110)	129.7 (143)	0.054 (0.12)
CO_2	8.69 (20.2)	202,580 (223,303)	264,912 (292,011)	107.5 (237)

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 98 percent.

The minimization of NOx production and subsequent emission is achieved by a combination of low-NOx burners, overfire air staging, and selective catalytic reduction (SCR). The low-NOx burners utilize zoning and staging of combustion. Overfire air staging is employed in the design of this boiler. SCR utilizes the injection of ammonia and a catalyst to reduce the NOx emissions.

Particulate discharge to the atmosphere is reduced by the use of a modern fabric filter, which provides a particulate removal rate of 99.9 percent.

CO_2 emissions are reduced by the installation of an inhibited MEA CO_2 removal system. This unit treats flue gas exiting the FGD unit. CO_2 emissions are limited by 90 percent through contact with the MEA solution. CO_2 absorbed in the MEA is concentrated and released from the solution through the addition of heat in the stripper. CO_2 is then dried and compressed to 8.27 MPa (1200 psia).

5.1.4 System Description

This greenfield power plant is a 329 MW coal-fired supercritical steam plant with FGD and CO_2 removal through inhibited MEA. The major subsystems of the power plant are:

- Coal Handling
- Coal Combustion System

- Ash Handling System
- Flue Gas Desulfurization
- CO_2 Removal and Compression
- Steam Turbine Generator
- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief description of these individual power plant subsystems. The equipment list, which follows this section, is based on the system descriptions provided here. The equipment list, in turn, was used to generate plant cost and cost of CO_2 removal.

5.1.4.1 Coal Handling

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The 15.24 cm(6") x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 90.7-tonne (100-ton) rail cars. Each unit train consists of 100, 90.7-tonne (100-ton) rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 15.24 cm(6") x 0 coal from the feeder is discharged onto a belt conveyor and then transferred to a second conveyor that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 7.62 cm x 0 (3" x 0) by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 2.54 cm x 0 (1" x 0), which is transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the six silos.

The crushed coal is fed through pairs (six in parallel) of weight feeders and mills (pulverizers). The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls.

5.1.4.2 Coal Combustion System

The primary components of the pulverized-coal combustion system are:

- Air Handling and Preheat

- Coal Burners
- Steam Generation and Reheat
- NOx Control
- Soot and Ash Removal

Each of these is described below.

Air Handling and Preheat

Air from the FD fans is heated in two vertical Ljungstrom regenerative type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the primary air fans, is heated in the Ljungstrom type air preheaters for use as combustion air to the pulverizers. A portion of the air from the primary air fans is routed around the air preheaters and is used as tempering air for the pulverizers. Preheated air and tempering air are mixed at each pulverizer to obtain the desired pulverizer fuel-air mixture outlet temperature.

The pulverized coal and air mixture flows to the coal nozzles at the various elevations of the wall-fired furnace. The hot combustion products rise to the top of the boiler and pass horizontally through the secondary superheater and reheater in succession. The gases then turn downward, passing in sequence through the primary superheater, economizer, and air preheater. The gases exit the air preheater at this point and flow to the ESP.

Coal Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in six elevations, divided between the front and rear walls of the furnace. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, at least one elevation of overfire air nozzles is provided to introduce additional air to cool the rising combustion products to inhibit NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition and flame stabilization at startup and low loads.

Steam Generation and Reheat

The steam generator in this supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit. It is assumed for the purposes of this study that the power plant is designed for operation as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

Feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the lower and then the upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater. The fluid is mixed in cross-tie headers at various locations throughout this path.

The steam then exits the steam generator enroute to the HP turbine. Returning cold reheat steam passes through the reheater and then returns to either the HP or IP turbine.

NOx Control

The plant will be designed to achieve 0.0675 kg/GJ (0.157 lb/10^6 Btu) (0.84 kg/MWh (1.85 lb/MWh)) NOx emissions. Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. Low-NOx burners and overfire air reduce the emissions by 65 percent as compared to a boiler installed without low-NOx burners.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems – reactor vessel, ammonia storage and injection, and gas flow control. The SCR system will be designed to remove 63 percent of the incoming NOx. This along with the low-NOx burners will achieve the emission limit of 0.068 kg/GJ (0.158 lb/10^6 Btu).

Selective noncatalytic reduction (SNCR) was and could be considered for this application. However, with the installation of the low-NOx burners, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions of 0.067 kg/GJ (0.157 lb/10^6 Btu) difficult. SNCR works better in applications that contain medium to high quantities of NOx and removal efficiencies in the range of 40 to 60 percent. SCR, because of the catalyst used in the reaction, can achieve higher efficiencies with lower concentrations of NOx.

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NOx in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consist of the unloading facilities, bulk storage tank, transfer pumps, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer and SCR reactor bypass duct and dampers are also included.

Soot and Ash Removal

The soot-blowing system utilizes an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Electric motors drive the soot blowers through their cycles. The soot-blowing medium is steam.

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 22.9-cm-thick (9-inch-thick) refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to the ash pond. Particulate removal is achieved with an ESP.

5.1.4.3 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the ESP and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is discharged via a hydro-ejector and ash discharge piping to the ash pond.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) are conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

5.1.4.4 Flue Gas Desulfurization

For purposes of this discussion, the flue gas desulfurization system will be broken down into three subgroups:

- Limestone Handling and Reagent Preparation System
- Flue Gas Desulfurization System
- Byproduct Dewatering

Each of these three subtopics is presented below.

Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. The scope of the system is from the storage pile up to the limestone feed system. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent guarantee point (30 days). Truck roadways, turnarounds, and unloading hoppers are included in this reference plant design.

For the purposes of this conceptual design, limestone will be delivered to the plant by 22.7-tonne (25-ton) trucks. The limestone is unloaded onto a storage pile located above vibrating feeders. The limestone is fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create a limestone slurry. The reduced limestone slurry is then discharged into the mill slurry tank. Mill recycle pumps, two for the tank, pump the limestone water slurry to an assembly of hydroclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydroclone underflow is directed back to the mill for further grinding. The hydroclone overflow is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

Flue Gas Desulfurization System

The function of the FGD system is to scrub the boiler exhaust gases to remove 98 percent of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the ID fans to the stack inlet. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

The flue gas exiting the air preheater section of the boiler passes through an ESP, then through ID fans and into one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through a tray, which provides enhanced contact between gas and reagent. Multiple sprays above the tray maintain a consistent reagent concentration in the tray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These will consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed and dried flue gas exits at the top of the absorber vessel and is routed to the plant stack. The FGD system for this plant is designed to continuously remove 98 percent of the SO_2.

Formic acid is used as a buffer to enhance the SO_2 removal characteristics of the FGD system. The system will include truck unloading, storage, and transfer equipment.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfate, contained in the slurry, to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps transfer the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

Chemical equilibrium in the absorber is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The spent reagent is routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack. The system is designed to support operation on a 20-year life cycle.

The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis, as byproducts from the SO_2 absorption reactions process. Maintenance of the quality of the recirculating reagent requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off spent reagent and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The gypsum slurry, at approximately 15 percent solids, is pumped to a gypsum stacking area. A starter dike is constructed to form a settling pond so that the 15 percent solid gypsum slurry is pumped to the sedimentation pond, where the gypsum particles settle and the excess water is decanted and recirculated back to the plant through the filtrate system. A gypsum stacking system allows for the possibility of a zero discharge system. The stacking area consists of approximately 17.4 ha (42 acres), enough storage for 20 years of operation. The gypsum stack is rectangular in plan shape, and is divided into two sections. This allows one section to drain while the other section is in use. There is a surge pond around the perimeter of the stacking area, which accumulates excess water for recirculation back to the plant. The stacking area includes all necessary geotechnical liners and construction to protect the environment.

5.1.4.5 CO_2 Removal and Compression

Part of the criteria of this combined cycle power plant design is the limitation of CO_2 emissions. This power plant configuration is based on removing 90 percent of the CO_2 in the flue gas exiting the FGD system. An inhibited aqueous solution of MEA is used to remove the CO_2.

Cool flue gas exiting the FGD at 55°C (131°F) enters the bottom of the absorber and flows upward and counter to the lean MEA solution. CO_2 is removed from the flue gas in the packed-bed absorber column through direct contact of MEA. The packing is 5.1-cm (2-inch) stainless steel rings. There are four absorber columns, operating in parallel, each 8.8 meters (29 feet) in diameter and 24.4 meters (80 feet) vertical. MEA circulation through each absorber is approximately 23.1 m^3/min (6,100 gpm).

Flue gas exiting the top of the absorber columns is collected in a common duct and routed to an exhaust stack. Rich solution off the bottom of the columns is heated in the rich-lean heat exchanger through indirect contact with lean solution flowing off the bottom of the stripper column.

Hot rich solution enters the top of the stripper column and flows downward and counter to the stripping agent, which is primarily steam. LP steam from the steam turbine crossover generates the stripping steam in the reboiler. CO_2 liberated through the application of heat flows upward along with the stripping steam. This vapor phase is routed to the reflux condenser where it is cooled to 48.9°C (120°F), thereby condensing a large portion of the water vapor. This condensed phase is returned to the stripper. The condenser vapor phase, which is saturated CO_2, is routed to the multi-stage, intercooled CO_2 compressor. Lean solution removed from the bottom of the stripper is cooled in the rich-lean heat exchanger, cooled in a secondary exchanger, and then returned to the absorber.

There are four strippers operating in parallel. Each stripper column is 4.9 meters (16 feet) in diameter and equipped with stainless steel trays that promote good inter-phase contact. The height of each stripper column is 22.9 meters (75 feet). Total reboiler steam requirement is approximately 551,578 kg/hour (1,216,000 lb/hour) of 0.38 MPa (55 psig) low-pressure steam.

SO_2 in the flue gas may react with the MEA solvent to form heat stable salts. Once formed, the MEA cannot be easily regenerated and must be removed from the reclaimer system as a solid. If solvent makeup becomes unacceptable, an alkali scrubber system can be installed before the absorber. However, solvent losses through salt formation are expected to be low for NGCC.

NO_x components NO and NO_2 will be present in the flue gas stream. NO is unreactive with the solvent. NO_2, on the other hand, may react with the solvent to form nitrates. If nitrate formation cannot be controlled with normal filtering and treating systems, a cold-water scrubber may be installed before the absorber as a means to control NO_2 flow into the absorber. NO_2, which usually accounts for less than 10 percent of the NOx species, should not pose much of a problem to this system.

CO_2 from the stripper is compressed to a pressure of 8.4 MPa (1222 psia) by the multi-stage CO_2 compressor. The compression includes interstage cooling as well as knockout drums to remove and collect condensate. CO_2 is dehydrated to remove water vapor. Water vapor stripped from the CO_2 is vented to the atmosphere. After drying, the CO_2 enters the pipeline for transport and/or disposal/sequestration.

5.1.4.6 Steam Turbine Generator

The turbine consists of a very-high-pressure (VHP) section, high-pressure (HP) section, intermediate-pressure (IP) section, and two double-flow low-pressure (LP) sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 24.1 MPa/565.6°C (3500 psig/1050°F). The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The first reheat steam flows through the reheat stop valves and intercept valves and enters the HP section at 6.6 MPa/565.6°C (955 psig/1050°F). The second reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 1.9 MPa/565.6°C (270 psig/1050°F). After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam is divided into four paths which flow through the LP sections exhausting downward into the condenser.

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

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

The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. Water temperature is controlled by regulating heat exchanger bypass water flow. Stator cooling water flow is controlled by regulating stator inlet pressure.

The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Stator cooling water flows through these coils. Gas is prevented from escaping at the rotor shafts using a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

5.1.4.7 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with a storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The function of the feedwater system is to pump feedwater from the deaerator storage tank to the boiler economizer. One turbine-driven boiler feed pump is provided to pump feedwater through the HP feedwater heaters. The pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each VHP and HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

5.1.4.8 Balance of Plant

The balance of plant items discussed in this section include:

- Steam Systems
- Extraction Steam
- Circulating Water System
- Ducting and Stack
- Waste Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

These items are discussed in more detail below.

Steam Systems

The function of the main steam system is to convey supercritical steam from the boiler house to the very-high-pressure turbine stop valves. The function of the reheat system is to convey steam from the VHP and HP turbine exhaust to the reheaters and from the reheater outlet to the turbine reheat stop valves.

Main supercritical steam at approximately 25.2 MPa/565.6°C (3650 psig/1050°F) exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the VHP turbine. A branch line off the main steam line feeds the two boiler feed pump turbines during unit operation up to 60 percent load.

Cold reheat steam at approximately 7.24 MPa/371°C (1050 psig/700°F) exits the VHP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the reheater. Hot reheat steam at approximately 6.7 MPa/565.6°C (972 psig/1050°F) exits the reheater through a motor-operated gate valve and is routed to the HP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 9.

Cold reheat steam at approximately 1.99 MPa/382°C (290 psig/720°F) exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the reheater. Hot reheat steam at approximately 1.9 MPa/565.6°C (270 psig/1050°F) exits the reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From VHP turbine extraction to heater 10
- From VHP turbine exhaust (1^{st} cold reheat) to heater 9
- From HP turbine extraction to heater 8
- From HP turbine exhaust (2^{nd} cold reheat) to heater 7
- From IP turbine extraction to the deaerator
- From IP turbine exhaust (cross-over) to heater 5
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disk non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

Circulating Water System

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

Each pump has a motor-operated discharge gate valve. A motor-operated crossover gate valve and reversing valves permit each pump to supply both sides of the condenser when the other pump is shut down. The pump discharge valves are controlled manually, but will automatically close when its respective pump is tripped.

Ducting and Stack

One stack is provided with a single FRP liner. The stack is constructed of reinforced concrete, with an outside diameter at the base of 21.3 meters (70 feet). The stack is 146.3 meters (480 feet) high for adequate particulate dispersion. The stack has one 5.9-meter-diameter (19.5-foot-diameter) FRP stack liner.

Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 45.4-tonne (50-ton) lime silo, a 0-454 kg/hour (0-1000 lb/hour) dry lime feeder, a 18.9-m^3 (5,000-gallon) lime slurry tank, slurry tank mixer, and 0.09 m^3/min (25 gpm) lime slurry feed pumps.

The oxidation system consists of a 1.4 scm/min (50 scfm) air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system.

The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 757.1-m^3 (200,000-gallon) storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Accessory Electric Plant

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

Instrumentation and Control

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

Buildings and Structures

A soil-bearing load of 24,413 kg/m^2 (5,000 lb/ft^2) is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building
- Coal crusher building
- River water intake structure

- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

5.1.5 Case 7A - Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 5-1. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the nomenclature section.

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter) Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Ton, multiply by 0.9072 = tonne (metric ton)

Gallon,gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832 x 10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9 $x10^{-3}$ = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

Acre, multiply by 0.4047 = ha (hectare)

Fourteen codes of account are used. They are summarized below in conjunction with the equipment list.

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6" x 0 - 3" x 0	1
12	Crusher	Impactor reduction	3" x 0 - 1" x 0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	600 ton	6

ACCOUNT 1B LIMESTONE RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibrator	115 tph	2
3	Conveyor 1	30" belt	115 tph	1
4	Conveyor 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	400 tons	1

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A COAL PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Feeder	Gravimetric	40 tph	6
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		20 tph	1
2	Weigh Feeder	Gravimetric	20 tph	1
3	Limestone Ball Mill	Rotary	20 tph	1
4	Mill Slurry Tank with Agitator		10,000 gal	1
5	Mill Recycle Pumps	Horizontal centrifugal	600 gpm	2
6	Hydroclones	Radial assembly		1
7	Distribution Box	Three-way		1
8	Reagent Storage Tank with Agitator	Field erected	200,000 gal	1
9	Reagent Distribution Pumps	Horizontal centrifugal	300 gpm	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Field fab.	200,000 gal.	1
2	Surface Condenser	Two shell, transverse tubes	1.15×10^6 lb/h 2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vert. canned	1,170 gpm/800 ft	3
5	LP Feedwater Heater	Horiz. U tube	981,100 lb/h 102°F to 160°F	1
6	LP Feedwater Heater	Horiz. U tube	981,100 lb/h 150°F to 300°F	1
7	LP Feedwater Heater 3	Horiz. U tube	981,100 lb/h 179°F to 450°F	1
8	LP Feedwater Heater 4	Horiz. U tube	981,100 lb/h 225°F to 590°F	1
9	LP Feedwater Heater 5	Horiz U tube	1,149,500 lb/h 277°F to 720°F	1
10	Deaerator and Storage Tank	Horiz. spray type	2,950,000 lb/h 300°F to 700°F	1
11	Boiler Feed Water Booster Pump	Horiz. split	6800 gpm @ 2,400 ft	2
12	HP Feedwater Heater 7	Horiz. U tube	2,950,000 lb/h 370°F to 720°F	1
13	HP Feedwater Heater 8	Horiz. U tube	2,950,000 lb/h 410°F to 850°F	1
14	Boiler Feed Pump/ Turbine Drive	Barrel type, multi-staged, centr.	6,800 gpm @ 11,500 ft	2
15	Startup Boiler Feed Pump	Barrel type, multi-staged centr.	2,500 gpm @ 11,500 ft	2
16	HP Feedwater Heater 9	Horiz. U tube	2,950,000 lb/h 470°F to 710°F	1
17	HP Feedwater Heater 10	Horiz. U tube	2,950,000 lb/h 550°F to 810°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	S.S., double acting	100 psig, 800 scfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	S.S., double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell and tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	185 ft, 600 gpm	2
11	Fire Service Booster Pump	Two-stage cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water Pumps	S.S., single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	S.S., single suction	200 ft, 200 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System	-	10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Once-Through Steam Generator with Air Heater. SCR Before Air Heater Surface.	Universal pressure, wall-fired	2,950,000 lbs/hr steam at 3700 psig/ 1055°F	1
2	Primary Air Fan	Axial	428,757 lbs/hr, 96,482 acfm, 35" wg, 790 hp	2
3	FD Fan	Cent.	1,395,740 lbs/hr, 313,330 acfm, 10" wg, 630 hp	2
4	ID Fan	Cent.	2,029,770 lbs/hr, 658,134 acfm, 110" wg 13,000 hp	2
5	Seal Air Blower	3-stage recip	1300 acfm/350 psig	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Electrostatic Precipitator	Rigid frame, single-stage	656,500 acfm, total +99% removal efficiency	2

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,112,000 acfm	1
2	Recirculation Pump	Horizontal centrifugal	31,500 gpm	4
3	Bleed Pump	Horizontal centrifugal	650 gpm	2
4	Oxidation Air Blower	Centrifugal	5,600 scfm	1
5	Agitators	Side entering	25 hp motor	6
6	Formic Acid Storage Tank	Vertical, diked	1,000 gal	1
7	Formic Acid Pumps	Metering	0.1 gpm	2
8	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
9	Gypsum Stacking Area		42 acres	1
10	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
11	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
12	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

ACCOUNT 5C CO_2 REMOVAL AND COMPRESSION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber	Packed bed 2" rings Three 20-foot stages	30 psig / 300°F	4
2	Stripper	Tray tower	50 psig / 300°F	4
3	Reflux Drum	Horizontal cooling water	50 psig / 250°F	4
4	Reboiler	Horizontal shell 50 psig steam	75 psig / 350°F	4
5	Cartridge Filter	Horizontal	100 psig / 200°F	4
6	Carbon Filter	Horizontal	100 psig / 200°F	4
7	Rich Amine Pump	Centrifugal	6,200 gpm @ 250 ft	4
8	Lean/Rich Amine Heat Exchanger	Horizontal shell	100 psig / 280°F	4
9	Lean Amine Pump	Centrifugal	6,200 gpm @ 250 ft	4
10	CO_2 Compressor and Auxiliaries	Centrifugal Multi-staged	25 psia / 1300 psia	1
11	Final CO_2 Cooler	Shell and tube	54.16×10^6 Btu/h	1
12	Dehydration Package	Triethylene glycol	1300 psia	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Not Applicable

ACCOUNT 7 WASTE HEAT BOILER, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Qty.
1	Stack	Reinf. concrete, two FRP flues	60 ft/sec exit velocity 480 ft high x 15 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty.
1	435 MW Turbine Generator	TC2F26	3500 psig/1050°F/ 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Shell and tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell and tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid state brushless	-	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Cooling Tower	Mech draft	160,000 gpm 95°F to 75°F	1
2	Circ. W. Pumps	Vert. wet pit	80,000 gpm @ 80 ft	2

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A BOTTOM ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Economizer Hopper (part of boiler scope of supply)			4
2	Bottom Ash Hopper (part of boiler scope of supply)			2
3	Clinker Grinder		5 tph	2
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)			6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank		40,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	1,000 gpm	2
8	Ash Seal Water Pumps	Vertical, wet pit	1,000 gpm	2

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	ESP Hoppers (part of ESP scope of supply)			24
2	Air Heater Hopper (part of boiler scope of supply)			10
3	Air Blower		1,800 cfm	2
4	Fly Ash Silo	Reinf. concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

5.1.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the supercritical pulverized coal power plant with CO_2 removal, case 7A, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 7A represents a plant with a net output of 329.3 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 5-3. A detailed estimate for case 7A is included in Appendix A.

The production costs for case 7A consist of plant operating labor, maintenance (material and labor), an allowance for administrative and support labor, consumables (including solid waste disposal) and fuel costs. The costs were determined on a first-year basis that includes evaluation at an equivalent plant operating capacity factor. The results are summarized in Table 5-4 and supporting detail is contained in Appendix A.

Table 5-3
CASE 7A SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	PC Boiler and Accessories	108,950
5	Flue Gas Cleanup	59,410
5B	CO_2 Removal and Compression	111,770
6	Combustion Turbine and Accessories	N/A
7	Ducting and Stack	18,010
8&9	Steam T-G Plant, including Cooling Water System	79,380
11	Accessory Electric Plant	31,340
	Balance of Plant	121,570
	SUBTOTAL	530,430
	Engineering, Construction Management Home Office and Fee	31,830
	Process Contingency	6,020
	Project Contingency	84,140
	TOTAL PLANT COST (TPC)	$652,420
	TPC $/kW	1,981

Table 5-4
CASE 7A ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	5,272	0.28
Maintenance	8,724	0.47
Administrative & Support Labor	2,191	0.12
Consumables	15,936	0.85
By-Product Credits	N/A	N/A
Fuel	27,472	1.47
TOTAL PRODUCTION COST	59,595	3.18

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 7A. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per tonne. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI are included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 5-5.

Table 5-5
CASE 7A LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	3.18
Annual Carrying Charge (¢/kWh)	5.38
Levelized Busbar Cost of Power Charge (¢/kWh)	8.56
Levelized Cost per tonne of CO_2 Removed ($/tonne of CO_2)	87.1

5.2 CASE 7B – ULTRA-SUPERCRITICAL STEAM PLANT WITH CO_2 REMOVAL

5.2.1 Introduction

Case 7B is a coal-fired ultra-supercritical steam plant with CO_2 removal and recovery from the flue gas. The plant design approach is market-based and the configuration reflects current information and design preferences, the availability of a newer generation steam turbine, and the relative latitude of a greenfield site.

The coal-fired boiler is staged for low NOx formation. The boiler is also equipped with an SCR. Wet limestone forced oxidation FGD is used to limit SO_2 emissions. A once-through steam generator is used to power a double-reheat ultra-supercritical steam turbine with a net power output of 442 MWe. The steam turbine conditions correspond to 34.5 MPa/649°C (5000 psig/1200°F) throttle with 649°C (1200°F) at both reheats. Net plant power, after consideration of the auxiliary power load, is 367 MWe. The plant operates with an estimated HHV efficiency of 31.0 percent with a corresponding heat rate of 11,602 kJ/kWh (10,999 Btu/kWh).

Flue gas exiting the FGD system is routed to an inhibited MEA absorber-stripper system. In this system, a solution of aqueous MEA is used to remove 90 percent of the CO_2 in the flue gas. Low-pressure steam is used to strip and purify the CO_2. Low-pressure CO_2 removed from the system is compressed to supercritical conditions.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections are:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Production Cost, and Economics

The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost.

5.2.2 Thermal Plant Performance

Table 5-6 shows a detailed breakdown of the estimated system performance for this conventional coal-fired steam turbine power plant. Plant performance is based on the use of Illinois No. 6 coal as fuel and reflects current state-of-the art turbine adiabatic efficiency levels, boiler performance, wet limestone FGD system capabilities, and CO_2 removal through a aqueous solution of inhibited MEA.

Gross power output (prior to the generator terminals) for the steam turbine is estimated to be 455.5 MWe. Plant auxiliary power is estimated to be 75.2 MWe. This auxiliary load value, much higher than that anticipated for a traditional coal-fired supercritical steam plant, is due to the presence of the CO_2 removal/compression equipment. In particular, the flue gas blower, which requires 20.7 MWe of auxiliary power, and the CO_2 compressor, which requires 30.9 MWe of auxiliary power.

Net plant power output, which considers generator losses and auxiliary power, is 367 MWe. This plant power output results in a net system thermal efficiency of 31 percent (HHV) with a corresponding heat rate of 11,602 kJ/kWh (10,999 Btu/kWh) (HHV). This plant efficiency and heat rate numbers are low compared to those expected for coal-fired steam plants utilizing state-of-the-art supercritical steam turbines. There are two causes for low system efficiency: (1) the increased auxiliary power associated with the CO_2 removal equipment (see above), and, (2) the large amount of steam diverted to the MEA stripper reboiler. Diverting this LP steam results in a marked decrease in steam turbine power output.

A heat and material balance diagram for this conventional coal-fired steam plant is shown in Figure 5-2. The steam turbine power cycle is shown at 100 percent of design load. The ultra-supercritical Rankine cycle used for this case is based on a 34.5 MPa/649°C/649°C/649°C (5000 psig/1200°F/1200°F/1200°F) double-reheat configuration. Condensate is heated in the low-pressure feedwater heaters. Boiler feedwater is heated in the high-pressure feedwater heaters. Steam generation, superheat, and reheat are accomplished in the boiler house. Also shown in the diagram is the basic equipment of the FGD and that required to remove CO_2 from the flue gas stream and concentrate it as a pure, high-pressure product.

The heat and material balance in Figure 5-2 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Table 5-6
CASE 7B – ULTRA-SUPERCRITICAL PC PLANT WITH CO_2 REMOVAL
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	34.5 (5,000)
Throttle Temperature, °C (°F)	649 (1,200)
Reheat Outlet Temperature, °C (°F)	649 (1,200)
2nd Reheat Outlet Temperature, °C (°F)	649 (1,200)
GROSS POWER SUMMARY, kWe	
Steam Turbine Power	449,058
Generator Loss	(6,447)
Gross Plant Power	442,611
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	400
Limestone Handling & Reagent Preparation	960
Pulverizers	1,930
Ash Handling	1,730
Primary Air Fans	1,270
Forced Draft Fans	1,000
Induced Draft Fans	20,650
SCR	100
Seal Air Blowers	50
Precipitators	1,040
FGD Pumps and Agitators	3,580
Condensate Pumps	290
Boiler Feed Water Booster Pumps	3,050
High Pressure Boiler Feed Pump	(Note 1)
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	1,800
Cooling Tower Fans	1,020
MEA Unit	2,010
CO_2 Compressor (Note 3)	30,880
Transformer Loss	1,020
Total Auxiliary Power Requirement	75,180
NET PLANT POWER, kWe	367,431
PLANT EFFICIENCY	
Net Efficiency, % HHV	31.0%
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	11,602 (10,999)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	943 (894)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	157,140 (346,430)
Sorbent, kg/h (lb/h)	16,135 (35,571)

Note 1 – Boiler feed pumps are turbine driven
Note 2 - Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 8.3 MPa (1200 psig)
Note 4 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

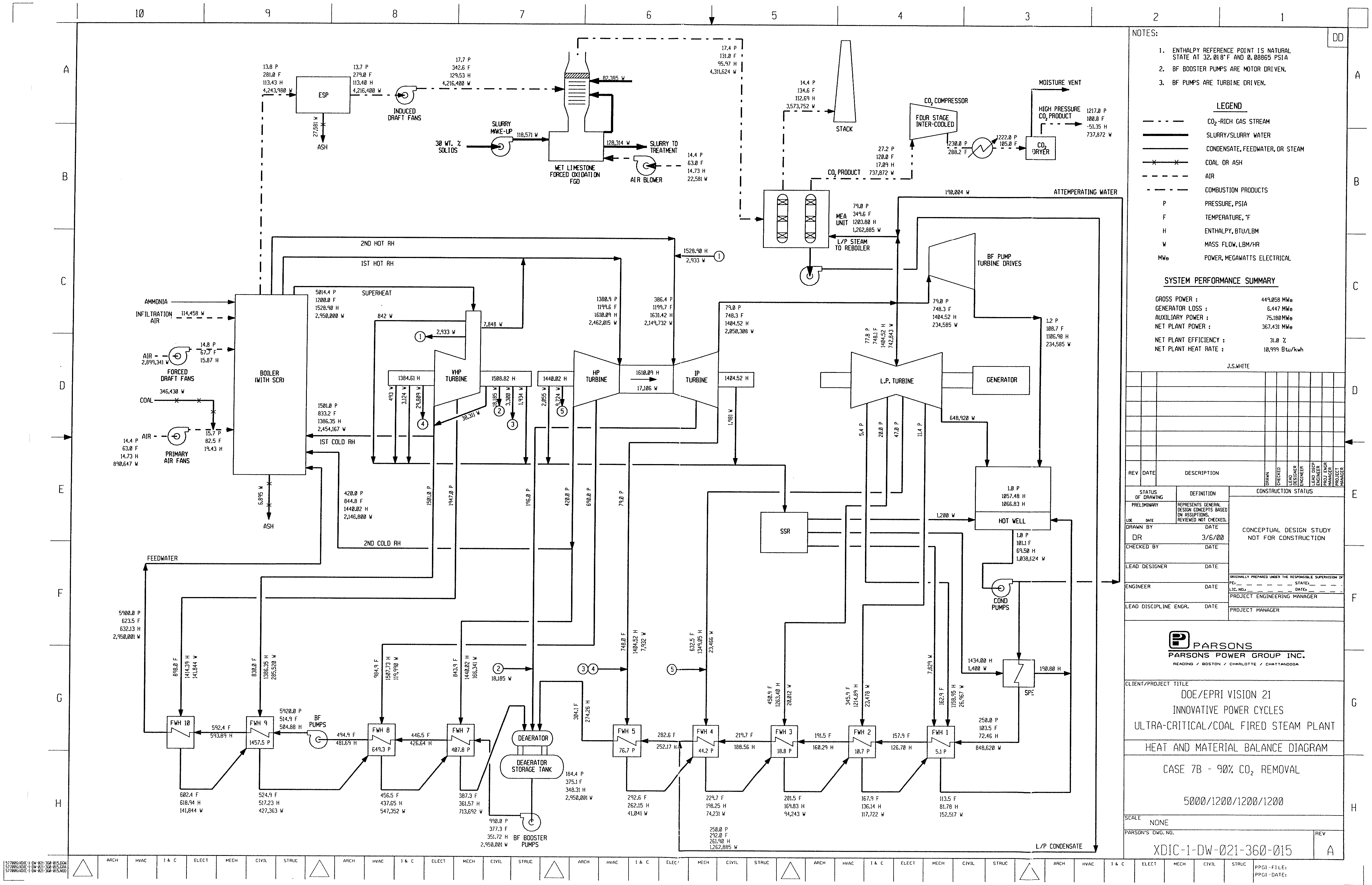

Figure 5-2
Heat and Material Balance Diagram – Case 7B – 90% CO_2 Removal – Ultra-Supercritical/Coal-Fired Steam Plant

5.2.3 Power Plant Emissions

This ultra-supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the first decade of the next century. A summary of the plant emissions is presented in Table 5-7.

Table 5-7
CASE 7B AIRBORNE EMISSIONS
ULTRA-SUPERCRITICAL PC PLANT WITH FGD AND CO_2 REMOVAL

	VALUES AT DESIGN CONDITION (65% AND 85% CAPACITY FACTOR)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	0.037 (0.086)	894 (985)	1,169 (1,289)	0.426 (0.94)
NOx	0.0675 (0.157)	1,642 (1,810)	2,147 (2,367)	0.667 (1.47)
Particulate	0.004 (0.01)	103.4 (114)	134 (148)	0.029 (0.065)
CO_2	8.69 (20.2)	210,171 (231,670)	274,845 (302,960)	60.3 (133)

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 98 percent.

The minimization of NOx production and subsequent emission is achieved by a combination of low-NOx burners, overfire air staging, and selective catalytic reduction (SCR). The low-NOx burners utilize zoning and staging of combustion. Overfire air staging is employed in the design of this boiler. SCR utilizes the injection of ammonia and a catalyst to reduce the NOx emissions.

Particulate discharge to the atmosphere is reduced by the use of a modern fabric filter, which provides a particulate removal rate of 99.9 percent.

CO_2 emissions are reduced by the installation of an inhibited MEA CO_2 removal system. This unit treats flue gas exiting the FGD unit. CO_2 emissions are limited by 90 percent through contact with the MEA solution. CO_2 absorbed in the MEA is concentrated and released from the solution through the addition of heat in the stripper. CO_2 is then dried and compressed to 8.3 MPa (1200 psig).

5.2.4 System Description

This greenfield power plant is a 367 MW coal-fired ultra-supercritical steam plant with FGD and CO_2 removal through inhibited MEA. The major subsystems of the power plant are:

- Coal Handling
- Coal Combustion System

- Ash Handling System
- Flue Gas Desulfurization
- CO_2 Removal and Compression
- Steam Turbine Generator
- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief description of these individual power plant subsystems. The equipment list, which follows this section, is based on the system descriptions provided here. The equipment list, in turn, was used to generate plant cost and cost of CO_2 removal.

5.2.4.1 Coal Handling

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The 15.24 cm (6") x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 90.7-tonne (100-ton) rail cars. Each unit train consists of 100, 90.7-tonne (100-ton) rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 15.24 cm(6") x 0 coal from the feeder is discharged onto a belt conveyor and then transferred to a second conveyor that sends the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron on the way to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 7.62 cm (3") x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 2.54 cm (1") x 0. The coal is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the six silos.

The crushed coal is fed through pairs (six in parallel) of weight feeders and mills (pulverizers). The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls.

5.2.4.2 Coal Combustion System

The primary components of the pulverized-coal combustion system are:

- Air Handling and Preheat
- Coal Burners
- Steam Generation and Reheat
- NOx Control
- Soot and Ash Removal

Each of these is described below.

Air Handling and Preheat

Air from the FD fans is heated in two vertical Ljungstrom regenerative type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters and is used as combustion air to the pulverizers. A portion of the air from the PA fans is routed around the air preheaters and is used as tempering air for the pulverizers. Preheated air and tempering air are mixed at each pulverizer to obtain the desired pulverizer fuel-air mixture outlet temperature.

The pulverized coal and air mixture flows to the coal nozzles at various elevations of the wall-fired furnace. The hot combustion products rise to the top of the boiler and pass horizontally through the secondary superheater and reheater in succession. The gases then turn downward, passing in sequence through the primary superheater, economizer, and air preheater. The gases exit the air preheater at this point and flow to the ESP.

Coal Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in six elevations, divided between the front and rear walls of the furnace. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, at least one elevation of overfire air nozzles is provided to introduce additional air to cool the rising combustion products to inhibit NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition and flame stabilization at startup and low loads.

Steam Generation and Reheat

The steam generator in this reference ultra-supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit. It is assumed for the purposes of this study that the power plant is designed to be operated as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

Feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the lower and then the upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the primary and secondary superheaters. The fluid is mixed in cross-tie headers at various locations throughout this path.

The steam then exits the steam generator enroute to the HP turbine. Returning cold reheat steam passes through the reheater and then returns to either the HP or IP turbine.

NOx Control

The plant will be designed to achieve 0.067 kg/GJ (0.157 lb/10^6 Btu) (0.84 kg/MWh (1.85 lb/MWh)) NOx emissions. Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. The low-NOx burners and overfire air reduce the emissions by 65 percent as compared to a boiler installed without low-NOx burners.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems – reactor vessel, ammonia storage and injection, and gas flow control. The SCR system will be designed to remove 63 percent of the incoming NOx. This along with the low-NOx burners will achieve the emission limit of 0.067 kg/GJ (0.158 lb/10^6 Btu).

Selective noncatalytic reduction (SNCR) was and could be considered for this application. However, with the installation of the low-NOx burners, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions of 0.067 kg/GJ (0.157 lb/10^6 Btu) difficult. SNCR works better in applications that contain medium to high quantities of NOx and removal efficiencies in the range of 40 to 60 percent. SCR, because of the catalyst used in the reaction, can achieve higher efficiencies with lower concentrations of NOx.

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NOx in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consist of the unloading facilities, bulk storage tank, transfer pumps, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass and SCR reactor bypass duct and dampers are also included.

Soot and Ash Removal

The soot-blowing system utilizes an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Electric motors drive the soot blowers through their cycles. The soot-blowing medium is steam.

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 22.9-cm-thick (9-inch-thick) refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to the ash pond. Particulate removal is achieved with an ESP.

5.2.4.3 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the ESP and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is discharged via a hydro-ejector and ash discharge piping to the ash pond.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) are conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

5.2.4.4 Flue Gas Desulfurization

For purposes of this discussion, the flue gas desulfurization system will be broken down into three subgroups:

- Limestone Handling and Reagent Preparation System
- Flue Gas Desulfurization System

- Byproduct Dewatering

Each of the three subtopics is presented below.

Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. The scope of the system is from the storage pile up to the limestone feed system. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent guarantee point (30 days). Truck roadways, turnarounds, and unloading hoppers are included in this reference plant design.

For the purposes of this conceptual design, limestone will be delivered to the plant by 25-ton trucks. The limestone is unloaded onto a storage pile located above vibrating feeders. The limestone is fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create a limestone slurry. The reduced limestone slurry is then discharged into the mill slurry tank. Mill recycle pumps, two for the tank, pump the limestone water slurry to an assembly of hydroclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydroclone underflow is directed back to the mill for further grinding. The hydroclone overflow is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

Flue Gas Desulfurization System

The function of the FGD system is to scrub boiler exhaust gases to remove 98 percent of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the ID fans to the stack inlet. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

The flue gas exiting the air preheater section of the boiler passes through an ESP, then through the ID fans and into the one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through a tray, which provides enhanced contact between gas and reagent. Multiple sprays above the tray maintain a consistent reagent concentration in the tray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. The moisture separators will consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed and dried flue gas exits at the top of the absorber vessel and is routed to the plant stack. The FGD system for this plant is designed to continuously remove 98 percent of the SO_2.

Formic acid is used as a buffer to enhance the SO_2 removal characteristics of the FGD system. The system will include truck unloading, storage, and transfer equipment.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfate, contained in the slurry, to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance the mixture of oxidation air and slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. Spent reagent is routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack. The system is designed to support operation on a 20-year life cycle.

The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis, as byproducts from the SO_2 absorption reactions process. Maintenance of the quality of the recirculating reagent requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off spent reagent and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The gypsum slurry, at approximately 15 percent solids, is pumped to a gypsum stacking area. A starter dike is constructed to form a settling pond so that the 15 percent solid gypsum slurry is pumped to the sedimentation pond, where the gypsum particles settle and the excess water is decanted and recirculated back to the plant through the filtrate system. A gypsum stacking system allows for the possibility of a zero discharge system. The stacking area spans approximately 17 ha (42 acres), enough storage for 20 years of operation. The gypsum stack is rectangular in plan shape, and is divided into two sections. This allows one section to drain while the other section is in use. There is a surge pond around the perimeter of the stacking area, which accumulates excess water for recirculation back to the plant. The stacking area includes all necessary geotechnical liners and construction to protect the environment.

5.2.4.5 CO_2 Removal and Compression

Part of the criteria of this combined cycle power plant design is the limitation of CO_2 emissions. This power plant configuration is based on removing 90 percent of the CO_2 in the flue gas exiting the FGD system. An inhibited aqueous solution of MEA is used to remove the CO_2.

Cool flue gas exiting the FGD at 55°C (131°F) enters the bottom of the absorber and flows upward and counter to the lean MEA solution. CO_2 is removed from the flue gas in the packed-bed absorber column through direct contact of MEA. The packing is 5.1-cm (2-inch) stainless steel rings. There are four absorber columns, operating in parallel, each 8.8 meters (29 feet) in diameter and 24.4 meters (80 feet) vertical. MEA circulation through each absorber is approximately 23.7 m^3/min (6,270 gpm).

Flue gas exiting the top of the absorber columns is collected in a common duct and routed to an exhaust stack. Rich solution off the bottom of the columns is heated in the rich-lean heat exchanger through indirect contact with lean solution flowing off the bottom of the stripper column.

Hot rich solution enters the top of the stripper column and flows downward and counter to the stripping agent, which is primarily steam. LP steam from the steam turbine crossover generates the stripping steam in the reboiler. CO_2 liberated through the application of heat flows upward along with the stripping steam. This vapor phase is routed to the reflux condenser where it is cooled to 49°C (120°F), thereby condensing a large portion of the water vapor. This condensed phase is returned to the stripper. The condenser vapor phase, which is saturated CO_2, is routed to the multi-staged, intercooled CO_2 compressor. Lean solution removed from the bottom of the stripper is cooled in the rich-lean heat exchanger, cooled in a secondary exchanger, and then returned to the absorber.

There are four strippers operating in parallel. Each stripper column is 4.9 meters (16 feet) in diameter and equipped with stainless steel trays that promote good inter-phase contact. The height of each stripper column is 22.9 meters (75 feet). Total reboiler steam requirement is approximately 572,851 kg/hour (1,262,900 lb/hour) of 0.44 MPa (64 psig) LP steam.

SO_2 in the flue gas may react with the MEA solvent to form heat stable salts. Once formed, the MEA can not be easily regenerated and must be removed from the reclaimer system as a solid. If solvent make-up becomes unacceptable, an alkali scrubber system can be installed upstream of the absorber. However, solvent losses through salt formation are expected to be low for NGCC.

NOx components NO and NO_2 will be present in the flue gas stream. NO is unreactive with the solvent. NO_2, on the other hand, may react with the solvent to form nitrates. If nitrate formation cannot be controlled with normal filtering and treating systems, a cold-water scrubber may be installed upstream of the absorber as a means to control NO_2 flow into the absorber. NO_2, which usually accounts for less than ten percent of the NOx species, should not pose much of a problem to this system.

CO_2 from the stripper is compressed to a pressure of 8.4 MPa (1222 psia) by the multi-stage CO_2 compressor. The compression includes interstage cooling as well as knockout drums to remove and collect condensate. CO_2 is dehydrated to remove water vapor, which is vented to the atmosphere. After drying, the CO_2 enters the pipeline for transport and/or disposal/sequestration.

5.2.4.6 Steam Turbine Generator

The turbine consists of a VHP section, HP section, IP section, and two double-flow LP sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 34.5 MPa/649°C (5000 psig/1200°F). The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The first reheat steam flows through the reheat stop valves and intercept valves and enters the HP section at 9.5 MPa/649°C (1380 psig/1200°F). The second reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 2.6 MPa/649°C (370 psig/1200°F). After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser.

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

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

The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. Water temperature is controlled by regulating heat exchanger bypass water flow. Stator cooling water flow is controlled by regulating stator inlet pressure.

The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Stator cooling water flows through these coils. Gas is prevented from escaping at the rotor shafts by using a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

5.2.4.7 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The function of the feedwater system is to pump feedwater from the deaerator storage tank to the boiler economizer. One turbine-driven boiler feed pump is provided to pump feedwater through the HP feedwater heaters. The pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

5.2.4.8 Balance of Plant

The balance of plant items discussed in this section include:

- Steam Systems
- Extraction Steam
- Circulating Water System

- Ducting and Stack
- Waste Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

These items are discussed in more detail below.

Steam Systems

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

Main steam at approximately 34.5 MPa/649°C (5000 psig/1200°F) exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the VHP turbine. A branch line off the main steam line feeds the two boiler feed pump turbines during unit operation up to 60 percent load.

First reheat steam at approximately 10.3 MPa/445°C (1500 psig/833°F) exits the VHP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam at approximately 9.5 MPa/649°C (1380 psig/1200°F) exits the boiler reheater through a motor-operated gate valve and is routed to reheater. A branch connection from the cold reheat piping supplies steam to feedwater heater 9.

Second reheat steam at approximately 2.9 MPa/452°C (420 psig/845°F) exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam at approximately 2.6 MPa/649°C (372 psig/1200°F) exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From VHP turbine extraction to heater 10
- From VHP turbine exhaust (1^{st} cold reheat) to heater 9
- From HP turbine extraction to heater 8
- From HP turbine exhaust (2^{nd} cold reheat) to heater 7
- From IP turbine extraction to the deaerator

- From IP turbine exhaust (cross-over) to heater 5
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip and from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disk non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

Circulating Water System

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

Each pump has a motor-operated discharge gate valve. A motor-operated crossover gate valve and reversing valves permit each pump to supply both sides of the condenser when the other pump is shut down. The pump discharge valves are controlled manually, but will automatically close when its respective pump is tripped.

Ducting and Stack

One stack is provided with a single FRP liner. The stack is constructed of reinforced concrete, with an outside diameter at the base of 21.3 meters (70 feet). The stack is 146.3 meters (480 feet) high for adequate particulate dispersion. The stack has one 5.9-meter-diameter (19.5-foot-diameter) FRP stack liner.

Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 45.4-tonne (50-ton) lime silo, a 0-453.6 kg/h (0-1000 lb/h) dry lime feeder, a 18.9-m^3 (5,000-gallon) lime slurry tank, slurry tank mixer, and 0.09-m^3/min (25 gpm) lime slurry feed pumps.

The oxidation system consists of a 1.4 scm/min (50 scfm) air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed of off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 5,663-m^3 (200,000-gallon) storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Accessory Electric Plant

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

Instrumentation and Control

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

Buildings and Structures

A soil-bearing load of 24,413 kg/m^2 (5,000 lb/ft^2) is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building

- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building
- Coal crusher building
- River water intake structure
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

5.2.5 Case 7B - Major Equipment List

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter)

Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Ton, multiply by 0.9072 = tonne (metric ton)

Gallon, gal. multiply by 3.785×10^{-3} = m^3 (cubic meters)

Gallons per minute, gpm. multiply by 3.785×10^{-3} = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832×10^{-2} = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832×10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9×10^{-3} = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

Acre, multiply by 0.4047 = ha (hectare)

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6" x 0 - 3" x 0	1
12	Crusher	Impactor reduction	3" x 0 - 1" x 0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	600 ton	6

ACCOUNT 1B LIMESTONE RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibrator	115 tph	2
3	Conveyor 1	30" belt	115 tph	1
4	Conveyor 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	400 tons	1

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A COAL PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Feeder	Gravimetric	40 tph	6
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		20 tph	1
2	Weigh Feeder	Gravimetric	20 tph	1
3	Limestone Ball Mill	Rotary	20 tph	1
4	Mill Slurry Tank with Agitator		10,000 gal	1
5	Mill Recycle Pumps	Horizontal centrifugal	600 gpm	2
6	Hydroclones	Radial assembly		1
7	Distribution Box	Three-way		1
8	Reagent Storage Tank with Agitator	Field erected	200,000 gal	1
9	Reagent Distribution Pumps	Horizontal centrifugal	300 gpm	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Field fab.	200,000 gal.	1
2	Surface Condenser	Two shell, transverse tubes	1.04×10^6 lb/h 2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vert. canned	1,170 gpm/800 ft	3
5	LP Feedwater Heater	Horiz. U tube	848,620 lb/h 102°F to 160°F	1
6	LP Feedwater Heater	Horiz. U tube	848,620 lb/h 150°F to 350°F	1
7	LP Feedwater Heater 3	Horiz. U tube	848,620 lb/h 190°F to 450°F	1
8	LP Feedwater Heater 4	Horiz. U tube	848,620 lb/h 219°F to 650°F	1
9	LP Feedwater Heater 5	Horiz U tube	2,111,505 lb/h 277°F to 750°F	1
10	Deaerator and Storage Tank	Horiz. spray type	2,950,000 lb/h 300°F to 700°F	1
11	Boiler Feed Water Booster Pump	Horiz. split	6800 gpm @ 2,400 ft	2
12	HP Feedwater Heater 7	Horiz. U tube	2,950,000 lb/h 370°F to 840°F	1
13	HP Feedwater Heater 8	Horiz. U tube	2,950,000 lb/h 450°F to 980°F	1
14	Boiler Feed Pump/ Turbine Drive	Barrel type, multi-staged, centr.	6,800 gpm @ 15,500 ft	2
15	Startup Boiler Feed Pump	Barrel type, multi-staged centr.	2,500 gpm @ 15,500 ft	2
16	HP Feedwater Heater 9	Horiz. U tube	2,950,000 lb/h 510°F to 830°F	1
17	HP Feedwater Heater 10	Horiz. U tube	2,950,000 lb/h 550°F to 870°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	S.S., double acting	100 psig, 800 scfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	S.S., double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell and tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	185 ft, 600 gpm	2
11	Fire Service Booster Pump	Two-stage cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water Pumps	S.S., single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	S.S., single suction	200 ft, 200 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System	-	10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Once-Through Steam Generator with Air Heater. SCR Before Air Heater Surface.	Universal pressure, wall-fired, double reheat	2,950,000 lb/h steam at 5,000 psig & 1200°F	1
2	Primary Air Fan	Axial	445,325 lb/h, 100,209 acfm, 35" wg, 850 hp	2
3	FD Fan	Cent.	1,449,670 lb/h, 326,213 acfm, 10" wg, 675 hp	2
4	ID Fan	Cent.	2,108,200 lb/h, 683,563 acfm, 110" wg 13,500 hp	2
5	Seal Air Blower	3-stage recip	1300 acfm/350 psig	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Electrostatic Precipitator	Rigid frame, single-stage	681,817 acfm, total +99% removal efficiency	2

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,154,800 acfm	1
2	Recirculation Pump	Horizontal centrifugal	31,500 gpm	4
3	Bleed Pump	Horizontal centrifugal	650 gpm	2
4	Oxidation Air Blower	Centrifugal	5,600 scfm	1
5	Agitators	Side entering	25 hp motor	6
6	Formic Acid Storage Tank	Vertical, diked	1,000 gal	1
7	Formic Acid Pumps	Metering	0.1 gpm	2
8	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
9	Gypsum Stacking Area		42 acres	1
10	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
11	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
12	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

ACCOUNT 5C CO_2 REMOVAL AND COMPRESSION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber	Packed bed 2" rings Three 20-foot stages	30 psig / 300°F	4
2	Stripper	Tray tower	50 psig / 300°F	4
3	Reflux Drum	Horizontal Cooling water	50 psig / 250°F	4
4	Reboiler	Horizontal shell 50 psig steam	75 psig / 350°F	4
5	Cartridge Filter	Horizontal	100 psig / 200°F	4
6	Carbon Filter	Horizontal	100 psig / 200°F	4
7	Rich Amine Pump	Centrifugal	6,200 gpm @ 250 ft	4
8	Lean/Rich Amine Heat Exchanger	Horizontal shell	100 psig / 280°F	4
9	Lean Amine Pump	Centrifugal	6,200 gpm @ 250 ft	4
10	CO_2 Compressor and Auxiliaries	Centrifugal Multi-staged	25 psia / 1300 psia	1
11	Final CO_2 Cooler	Shell and tube	56.26 10^6 Btu/h	1
12	Dehydration Package	Triethylene glycol	1300 psia	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Not Applicable

ACCOUNT 7 WASTE HEAT BOILER, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Qty.
1	Stack	Reinf. concrete, two FRP flues	60 ft/sec exit velocity 480 ft high x 16 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty.
1	450 MW Turbine Generator	TC2F26	5000 psig/1200°F/ 1200°F/1200°F	1
2	Bearing Lube Oil Coolers	Shell and tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell and tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid state brushless	-	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Cooling Tower	Mech draft	160,000 gpm 95°F to 75°F	1
2	Circ. W. Pumps	Vert. wet pit	80,000 gpm @ 80 ft	2

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A BOTTOM ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Economizer Hopper (part of Boiler scope of supply)			4
2	Bottom Ash Hopper (part of Boiler scope of supply)			2
3	Clinker Grinder		5 tph	2
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)			6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank		40,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	1,000 gpm	2
8	Ash Seal Water Pumps	Vertical, wet pit	1,000 gpm	2

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	ESP Hoppers (part of ESP scope of supply)			24
2	Air Heater Hopper (part of boiler scope of supply)			10
3	Air Blower		1,800 cfm	2
4	Fly Ash Silo	Reinf. concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

5.2.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the ultra-supercritical pulverized coal power plant with CO_2 removal, case 7B, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 7B represents a plant with a net output of 367.4 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 5-8. A detailed estimate for case 7B is included in Appendix A.

Table 5-8
CASE 7B SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	PC Boiler and Accessories	126,040
5	Flue Gas Cleanup	60,920
5B	CO_2 Removal and Compression	115,190
6	Combustion Turbine and Accessories	N/A
7	Ducting and Stack	18,500
8&9	Steam T-G Plant, including Cooling Water System	103,220
11	Accessory Electric Plant	31,970
	Balance of Plant	125,990
	SUBTOTAL	581,830
	Engineering, Construction Management Home Office and Fee	34,910
	Process Contingency	6,220
	Project Contingency	91,040
	TOTAL PLANT COST (TPC)	$714,000
	TPC $/kW	1,943

The production costs for case 7B consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal) and Fuel costs. The costs were determined on a first-year basis that includes evaluation at a 65 percent equivalent plant operating capacity factor. The results are summarized in Table 5-9 and supporting detail is contained in Appendix A.

Table 5-9
CASE 7B ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	5,272	0.25
Maintenance	9,482	0.45
Administrative & Support Labor	2,266	0.11
Consumables	16,648	0.80
By-Product Credits	N/A	N/A
Fuel	28,534	1.36
TOTAL PRODUCTION COST	62,203	2.97

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 7B. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per tonne. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI is included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 5-10.

Table 5-10
CASE 7B LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	2.97
Annual Carrying Charge (¢/kWh)	5.27
Levelized Busbar Cost of Power Charge (¢/kWh)	8.24
Levelized Cost per tonne of CO_2 Removed ($/tonne of CO_2)	90.4

5.3 CASE 7C – SUPERCRITICAL STEAM PLANT WITHOUT CO_2 REMOVAL

5.3.1 Introduction

Case 7C is a coal-fired supercritical steam plant. For this case, there is no provision for CO_2 removal. The plant design approach is market-based and the configuration reflects current information and design preferences, the availability of a newer generation steam turbine, and the relative latitude of a greenfield site.

The coal-fired boiler is staged for low NOx formation. The boiler is also equipped with an SCR. Wet limestone forced oxidation FGD is used to limit SO_2 emissions. A once-through steam generator is used to power a double-reheat supercritical steam turbine with a net power output of 491 MWe. The steam turbine conditions correspond to 24.2 MPa/565.6°C(3500 psig/1050°F) throttle with 565.6°C(1050°F)at both reheats. Net plant power, after consideration of the auxiliary power load, is 462 MWe. The plant operates with an estimated HHV efficiency of 40.5 percent with a corresponding heat rate of 8,882 kJ/kWh (8,421 Btu/kWh).

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections are:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Performance Cost, and Economics

The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost.

5.3.2 Thermal Plant Performance

Table 5-11 shows a detailed breakdown of the estimated system performance for this conventional coal-fired steam turbine power plant. Plant performance is based on the use of Illinois No. 6 coal as fuel and reflects current state-of-the art turbine adiabatic efficiency levels, boiler performance, and wet limestone FGD system capabilities.

Gross power output (prior to the generator terminals) for the steam turbine is estimated to be 498 MWe. Plant auxiliary power is estimated to be 29 MWe. Net plant power output, which takes generator losses and auxiliary power into account, is 462 MWe. This plant power output results in a net system thermal efficiency of 40.5 percent (HHV) with a corresponding heat rate of 8,882 kJ/kWh (8,421 Btu/kWh) (HHV).

A heat and material balance diagram for this convention coal-fired steam plant is shown in Figure 5-3. The steam turbine power cycle is shown at 100 percent of design load. The supercritical Rankine cycle used for this case is based on a 24.2 MPa/565.6°C/565.6°C/565.6°C (3500 psig/1050°F/1050°F/1050°F) double-reheat configuration. Condensate is heated in the low-pressure feedwater heaters. Boiler feedwater is heated in high-pressure feedwater heaters. Steam generation, superheat, and reheat are accomplished in the boiler house. Also shown in the diagram is the basic equipment of the FGD system.

The heat and material balance in Figure 5-3 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Table 5-11
CASE 7C – SUPERCRITICAL PC PLANT WITHOUT CO_2 REMOVAL
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	24.1 (3,500)
Throttle Temperature, °C (°F)	565.6 (1,050)
Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
2nd Reheat Outlet Temperature, °C (°F)	565.6 (1,050)
GROSS POWER SUMMARY, kWe	
Steam Turbine Power	498,319
Generator Loss	(7,211)
Gross Plant Power	491,108
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	390
Limestone Handling & Reagent Preparation	920
Pulverizers	1,860
Ash Handling	1,670
Primary Air Fans	1,220
Forced Draft Fans	970
Induced Draft Fans	5,050
SCR	100
Seal Air Blowers	50
Precipitators	1,000
FGD Pumps and Agitators	3,450
Condensate Pumps	590
Boiler Feed Water Booster Pumps	2,670
High Pressure Boiler Feed Pump	(Note 1)
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	3,540
Cooling Tower Fans	2,030
Transformer Loss	1,140
Total Auxiliary Power Requirement	29,050
NET PLANT POWER, kWe	462,058
PLANT EFFICIENCY	
Net Efficiency, % HHV	40.5%
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	8,882 (8,421)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	1,914 (1,815)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 3)	151,295 (333,542)
Sorbent, kg/h (lb/h)	15,535 (34,248)

Note 1 – Boiler feed pumps are turbine driven
Note 2-- Includes plant control systems, lighting, HVAC, etc.
Note 3 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

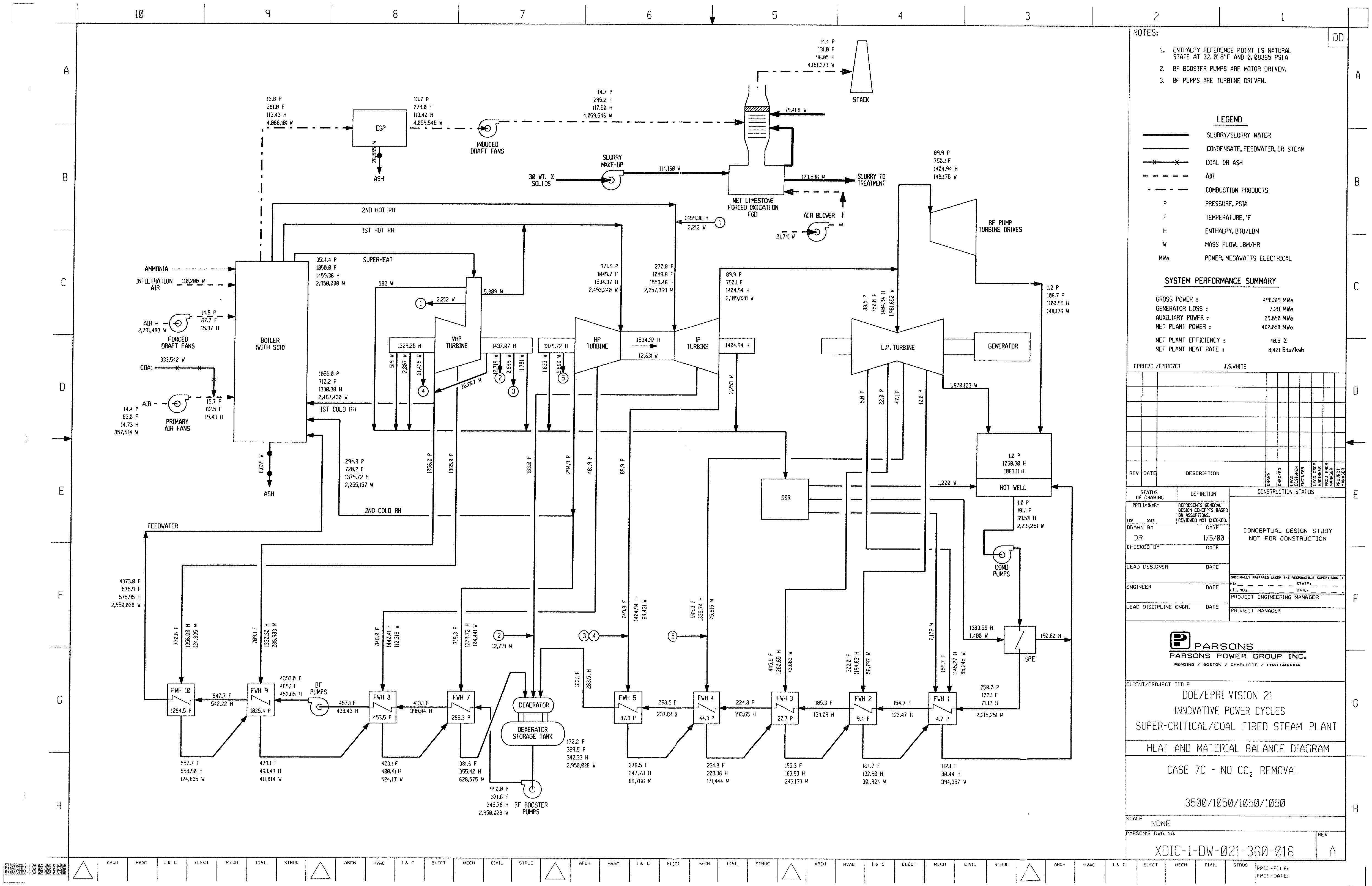

Figure 5-3
Heat and Material Balance Diagram – Case 7C – Without CO_2 Removal – Supercritical/Coal-Fired Steam Plant

5.3.3 Power Plant Emissions

This supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the first decade of the next century. A summary of the plant emissions is presented in Table 5-12.

Table 5-12
CASE 7C AIRBORNE EMISSIONS
SUPERCRITICAL PC PLANT WITH FGD AND NO CO_2 REMOVAL

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	0.037 (0.086)	861.8 (950)	1,128 (1,243)	0.46 (1.01)
NOx	0.068 (0.157)	1583 (1,745)	2,070 (2,282)	0.84 (1.85)
Particulates	0.004 (0.01)	99.8 (110)	129.7 (143)	0.05 (0.12)
CO_2	87.3 (203)	2,037,020 (2,245,430)	2,663,973 (2,936,330)	774 (1,707)

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 98 percent.

The minimization of NOx production and subsequent emission is achieved by a combination of low-NOx burners, overfire air staging, and selective catalytic reduction (SCR). The low-NOx burners utilize zoning and staging of combustion. Overfire air staging is employed in the design of this boiler. SCR utilizes the injection of ammonia and a catalyst to reduce the NOx emissions.

Particulate discharge to the atmosphere is reduced by the use of a modern fabric filter, which provides a particulate removal rate of 99.9 percent.

5.3.4 System Description

This greenfield power plant is a 462 MW coal-fired supercritical steam plant with FGD. The major subsystems of the power plant are:

- Coal Handling
- Coal Combustion System
- Ash Handling System
- Flue Gas Desulfurization
- Steam Turbine Generator

- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief description of these individual power plant subsystems. The equipment list, which follows this section, is based on the system descriptions provided here. The equipment list, in turn, was used to generate plant cost.

5.3.4.1 Coal Handling

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The 15.24 cm (6") x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 90.7-tonne (100-ton) rail cars. Each unit train consists of 100, 90.7-tonne (100-ton) rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 15.24 cm (6") x 0 coal from the feeder is discharged onto a belt conveyor and then transferred to a second conveyor that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 7.62 cm (3") x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 2.54 cm (1") x 0. The coal is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of six silos.

The crushed coal is fed through pairs (six in parallel) of weight feeders and mills (pulverizers). The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls.

5.3.4.2 Coal Combustion System

The primary components of the pulverized-coal combustion system are:

- Air Handling and Preheat
- Coal Burners
- Steam Generation and Reheat
- NOx Control
- Soot and Ash Removal

Each of these is described below.

Air Handling and Preheat

Air from the FD fans is heated in two vertical Ljungstrom regenerative type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the PA fans. This air is heated in Ljungstrom type air preheaters and is used as combustion air to the pulverizers. A portion of the air from the PA fans is routed around the air preheaters and is used as tempering air for the pulverizers. Preheated air and tempering air are mixed at each pulverizer to obtain the desired pulverizer fuel-air mixture outlet temperature.

The pulverized coal and air mixture flows to the coal nozzles at the various elevations of the wall-fired furnace. The hot combustion products rise to the top of the boiler and pass horizontally through the secondary superheater and reheater in succession. The gases then turn downward, passing in sequence through the primary superheater, economizer, and air preheater. The gases exit the air preheater at this point and flow to the ESP.

Coal Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in six elevations, divided between the front and rear walls of the furnace. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, at least one elevation of overfire air nozzles is provided to introduce additional air to cool the rising combustion products to inhibit NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition and flame stabilization at startup and low loads.

Steam Generation and Reheat

The steam generator in this reference supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit. It is assumed for the purposes of this study that the power plant is designed to be operated as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

Feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the lower and then the upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater. The fluid is mixed in cross-tie headers at various locations throughout this path.

The steam then exits the steam generator enroute to the HP turbine. Returning cold reheat steam passes through the reheater and then returns to either the HP or IP turbine.

NOx Control

The plant will be designed to achieve 0.067 kg/GJ (0.157 lb/10^6 Btu) (0.84 kg/MWh (1.85 lb/MWh)) NOx emissions. Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. The low-NOx burners and overfire air reduce the emissions by 65 percent as compared to a boiler installed without low-NOx burners.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems – reactor vessel, ammonia storage and injection, and gas flow control. The SCR system will be designed to remove 63 percent of the incoming NOx. This along with the low-NOx burners will achieve the emission limit of 0.067 kg/GJ (0.158 lb/10^6 Btu).

Selective noncatalytic reduction (SNCR) was and could be considered for this application. However, with the installation of the low-NOx burners, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions of 0.067 kg/GJ (0.157 lb/10^6 Btu) difficult. SNCR works better in applications that contain medium to high quantities of NOx and removal efficiencies in the range of 40 to 60 percent. SCR, because of the catalyst used in the reaction, can achieve higher efficiencies with lower concentrations of NOx.

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NOx in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consist of the unloading facilities, bulk storage tank, transfer pumps, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass as well as the SCR reactor bypass duct and dampers are also included.

Soot and Ash Removal

The soot-blowing system utilizes an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Electric motors drive the soot blowers through their cycles. The soot-blowing medium is steam.

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 22.9-cm-thick (9-inch-thick) refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to the ash pond. Particulate removal is achieved with an ESP.

5.3.4.3 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

Fly ash collected in the ESP and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is discharged via a hydro-ejector and ash discharge piping to the ash pond.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) are conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

5.3.4.4 Flue Gas Desulfurization

For purposes of this discussion, the flue gas desulfurization system will be broken down into three subgroups:

- Limestone Handling and Reagent Preparation System
- Flue Gas Desulfurization System
- Byproduct Dewatering

Each of these three subtopics is presented below.

Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. The scope of the system is from the storage pile up to the limestone feed system. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent guarantee point (30 days). Truck roadways, turnarounds, and unloading hoppers are included in this reference plant design.

For the purposes of this conceptual design, limestone will be delivered to the plant by 22.7-tonne (25-ton) trucks. The limestone is unloaded onto a storage pile located above vibrating feeders. The limestone is fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create a limestone slurry which is then discharged into the mill slurry tank. Mill recycle pumps, two for the tank, pump the limestone water slurry to an assembly of hydroclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydroclone underflow is directed back to the mill for further grinding. The hydroclone overflow is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

Flue Gas Desulfurization System

The function of the FGD system is to scrub the boiler exhaust gases to remove 98 percent of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the ID fans to the stack inlet. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

The flue gas exiting the air preheater section of the boiler passes through an ESP, then through the ID fans and into the one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through a tray, which provides enhanced contact between gas and reagent. Multiple sprays above the tray maintain a consistent reagent concentration in the tray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. The moisture separators will consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed and dried flue gas exits at the top of the absorber vessel and is routed to the plant stack. The FGD system for this plant is designed to continuously remove 98 percent of the SO_2.

Formic acid is used as a buffer to enhance the SO_2 removal characteristics of the FGD system. The system will include truck unloading, storage, and transfer equipment.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfate, contained in the slurry, to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps transfer the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via the bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The spent reagent is routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack. The system is designed to support operation on a 20-year life cycle.

The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis, as byproducts from the SO_2 absorption reaction process. Maintenance of the quality of the recirculating reagent requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off spent reagent and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The gypsum slurry, at approximately 15 percent solids, is pumped to a gypsum stacking area. A starter dike is constructed to form a settling pond so that the 15 percent solid gypsum slurry is pumped to the sedimentation pond, where the gypsum particles settle and the excess water is decanted and recirculated back to the plant through the filtrate system. A gypsum stacking system allows for the possibility of a zero discharge system. The stacking area consists of approximately 17 ha (42 acres), enough storage for 20 years of operation. The gypsum stack is rectangular in plan shape, and is divided into two sections. This allows one section to drain while the other section is in use. There is a surge pond around the perimeter of the stacking area, which accumulates excess water for recirculation back to the plant. The stacking area includes all necessary geotechnical liners and construction to protect the environment.

5.3.4.5 Steam Turbine Generator

The turbine consists of a VHP section, HP section, IP section, and two double-flow LP sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 24.1 MPa/565.6°C (3500 psig/1050°F). The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The first reheat steam flows through the reheat stop valves and intercept valves and enters the HP section at 6.6 MPa/565.6°C (955 psig/1050°F). The second reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 1.9 MPa/565.6°C (270 psig/1050°F). After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam is split into four paths which flow through LP sections exhausting downward into the condenser.

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

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

The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. Water temperature is controlled by regulating heat exchanger bypass water flow. Stator cooling water flow is controlled by regulating stator inlet pressure.

The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. Heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Stator cooling water flows through these coils. Gas is prevented from escaping at the rotor shafts using a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

5.3.4.6 Condensate and Feedwater Systems

The function of the condensate system is to pump water from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The function of the feedwater system is to pump feedwater from the deaerator storage tank to the boiler economizer. One turbine-driven boiler feed pump is provided to pump feedwater through the HP feedwater heaters. The pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each VHP and HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

5.3.4.7 Balance of Plant

The balance of plant items discussed in this section include:

- Steam Systems
- Extraction Steam
- Circulating Water System
- Ducting and Stack
- Waste Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

These items are discussed in more detail below.

Steam Systems

The function of the main steam system is to convey supercritical steam from the boiler house to the very-high-pressure turbine stop valves. The function of the reheat system is to convey steam from the VHP and HP turbine exhaust to the reheaters and from the reheater outlet to the turbine reheat stop valves.

Main supercritical steam at approximately 25.2 MPa/565.6°C (3650 psig/1050°F) exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the VHP turbine. A branch line off the main steam line feeds the two boiler feed pump turbines during unit operation up to 60 percent load.

Cold reheat steam at approximately 7.2 MPa/371°C (1050 psig/700°F) exits the VHP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the reheater. Hot reheat steam at approximately 6.7 MPa/565.6°C (972 psig/1050°F) exits the reheater through a motor-operated gate valve and is routed to the HP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 9.

Cold reheat steam at approximately 2 MPa/382°C (290 psig/720°F) exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the reheater. Hot reheat steam at approximately 1.9 MPa/565.6°C (270 psig/1050°F) exits the reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From VHP turbine extraction to heater 10
- From VHP turbine exhaust (1^{st} cold reheat) to heater 9
- From HP turbine extraction to heater 8
- From HP turbine exhaust (2^{nd} cold reheat) to heater 7
- From IP turbine extraction to the deaerator
- From IP turbine exhaust (cross-over) to heater 5
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disk non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

Circulating Water System

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

Each pump has a motor-operated discharge gate valve. A motor-operated crossover gate valve and reversing valves permit each pump to supply both sides of the condenser when the other pump is shut down. The pump discharge valves are controlled manually, but will automatically close when its respective pump is tripped.

Ducting and Stack

One stack is provided with a single FRP liner. The stack is constructed of reinforced concrete, with an outside diameter at the base of 21.3 meters (70 feet). The stack is 146.3 meters (480 feet) high for adequate particulate dispersion. The stack has one 5.9-meters-diameter (19.5-foot-diameter) FRP stack liner.

Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 45.4-tonne (50-ton) lime silo, a 0-453.6 kg/h (0-1000 lb/h) dry lime feeder, a 18.9-m^3 (5,000-gallon) lime slurry tank, slurry tank mixer, and 0.09 m^3/min (25 gpm) lime slurry feed pumps.

The oxidation system consists of a 1.4 scm/min (50 scfm) air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 757-m^3 (200,000-gallon) storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Accessory Electric Plant

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

Instrumentation and Control

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

Buildings and Structures

A soil-bearing load of 24,413 kg/m^2 (5,000 lb/ft^2) is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building
- Coal crusher building
- River water intake structure
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

5.3.5 Case 7C - Major Equipment List

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter)   Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Ton, multiply by 0.9072 = tonne (metric ton)

Gallon, gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm. multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832 x 10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9 $x10^{-3}$ = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

Acre, multiply by 0.4047 = ha (hectare)

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6" x 0 - 3" x 0	1
12	Crusher	Impactor reduction	3" x 0 - 1" x 0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	600 ton	6

ACCOUNT 1B LIMESTONE RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibrator	115 tph	2
3	Conveyor 1	30" belt	115 tph	1
4	Conveyor 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	400 tons	1

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A COAL PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Feeder	Gravimetric	40 tph	6
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		20 tph	1
2	Weigh Feeder	Gravimetric	20 tph	1
3	Limestone Ball Mill	Rotary	20 tph	1
4	Mill Slurry Tank with Agitator		10,000 gal	1
5	Mill Recycle Pumps	Horizontal centrifugal	600 gpm	2
6	Hydroclones	Radial assembly		1
7	Distribution Box	Three-way		1
8	Reagent Storage Tank with Agitator	Field erected	200,000 gal	1
9	Reagent Distribution Pumps	Horizontal centrifugal	300 gpm	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Field fab.	200,000 gal.	1
2	Surface Condenser	Two shell, transverse tubes	2.21 x 10^6 lb/h 2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vert. canned	2,250 gpm/800 ft	3
5	LP Feedwater Heater	Horiz. U tube	2,215,251 lb/h 102°F to 160°F	1
6	LP Feedwater Heater	Horiz. U tube	2,215,251 lb/h 150°F to 300°F	1
7	LP Feedwater Heater 3	Horiz. U tube	2,215,251 lb/h 179°F to 450°F	1
8	LP Feedwater Heater 4	Horiz. U tube	2,215,251 b/h 225°F to 590°F	1
9	LP Feedwater Heater 5	Horiz U tube	2,215,251 lb/h 277°F to 750°F	1
10	Deaerator and Storage Tank	Horiz. spray type	2,950,000 lb/h 300°F to 700°F	1
11	Boiler Feed Water Booster Pump	Horiz. split	6800 gpm @ 2,400 ft	2
12	HP Feedwater Heater 7	Horiz. U tube	2,950,000 lb/h 370°F to 720°F	1
13	HP Feedwater Heater 8	Horiz. U tube	2,950,000 lb/h 410°F to 850°F	1
14	Boiler Feed Pump/ Turbine Drive	Barrel type, multi-staged, centr.	6,800 gpm @ 11,500 ft	2
15	Startup Boiler Feed Pump	Barrel type, multi-staged centr.	2,500 gpm @ 11,500 ft	2
16	HP Feedwater Heater 9	Horiz. U tube	2,950,000 lb/h 470°F to 710°F	1
17	HP Feedwater Heater 10	Horiz. U tube	2,950,000 lb/h 550°F to 810°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	S.S., double acting	100 psig, 800 scfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	S.S., double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell and tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	185 ft, 600 gpm	2
11	Fire Service Booster Pump	Two-stage cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water Pumps	S.S., single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	S.S., single suction	200 ft, 200 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System	-	10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Once-Through Steam Generator with Air Heater. SCR Before Air Heater Surface.	Universal pressure, wall-fired, double reheat	2,950,000 lb/h steam at 3500 psig and 1050°F	1
2	Primary Air Fan	Axial	428,757 lb/h, 96,482 acfm, 35" wg, 790 hp	2
3	FD Fan	Cent.	1,395,740 lb/h, 313,330 acfm, 10" wg, 630 hp	2
4	ID Fan	Cent.	2,029,770 lb/h, 658,134 acfm, 26" wg 3,400 hp	2
5	Seal Air Blower	3-stage recip	1300 acfm/350 psig	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Electrostatic Precipitator	Rigid frame, single-stage	656,500 acfm, total +99% removal efficiency	2

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,259,900 acfm	1
2	Recirculation Pump	Horizontal centrifugal	31,500 gpm	4
3	Bleed Pump	Horizontal centrifugal	650 gpm	2
4	Oxidation Air Blower	Centrifugal	5,600 scfm	1
5	Agitators	Side entering	25 hp motor	6
6	Formic Acid Storage Tank	Vertical, diked	1,000 gal	1
7	Formic Acid Pumps	Metering	0.1 gpm	2
8	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
9	Gypsum Stacking Area		42 acres	1
10	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
11	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
12	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Not Applicable

ACCOUNT 7 WASTE HEAT BOILER, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Qty.
1	Stack	Reinf. concrete, two FRP flues	60 ft/sec exit velocity 480 ft high x 15 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty.
1	500 MW Turbine Generator	TC2F40	3500 psig/1050°F/ 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Shell and tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell and tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid state brushless	-	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Cooling Tower	Mech draft	160,000 gpm 95°F to 75°F	1
2	Circ. W. Pumps	Vert. wet pit	80,000 gpm @ 80 ft	2

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A BOTTOM ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Economizer Hopper (part of boiler scope of supply)			4
2	Bottom Ash Hopper (part of boiler scope of supply)			2
3	Clinker Grinder		5 tph	2
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)			6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank		40,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	1,000 gpm	2
8	Ash Seal Water Pumps	Vertical, wet pit	1,000 gpm	2

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	ESP Hoppers (part of ESP scope of supply)			24
2	Air Heater Hopper (part of Boiler scope of supply)			10
3	Air Blower		1,800 cfm	2
4	Fly Ash Silo	Reinf. concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

5.3.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the supercritical pulverized coal power plant without CO_2 removal, case 7C, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 7C represents a plant with a net output of 462.1 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 5-13. A detailed estimate for case 7C is included in Appendix A.

Table 5-13
CASE 7C SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	PC Boiler and Accessories	109,560
5	Flue Gas Cleanup	61,490
5B	CO_2 Removal and Compression	N/A
6	Combustion Turbine and Accessories	N/A
7	Ducting and Stack	20,540
8&9	Steam T-G Plant, including Cooling Water System	92,470
11	Accessory Electric Plant	24,150
	Balance of Plant	125,840
	SUBTOTAL	434,050
	Engineering, Construction Management Home Office and Fee	26,040
	Process Contingency	N/A
	Project Contingency	67,990
	TOTAL PLANT COST (TPC)	$528,080
	TPC $/kW	1,143

The production costs for case 7C consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal) and Fuel costs. The costs were determined on a first-year basis that includes evaluation at a 65 percent equivalent plant operating capacity factor. The results are summarized in Table 5-14 and supporting detail is contained in Appendix A.

Table 5-14
CASE 7C ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	4,815	0.18
Maintenance	6,588	0.25
Administrative & Support Labor	1,863	0.07
Consumables	12,945	0.49
By-Product Credits	N/A	N/A
Fuel	27,472	1.04
TOTAL PRODUCTION COST	53,683	2.04

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 7C. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per tonne. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI is included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 5-15.

Table 5-15
CASE 7C LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	2.04
Annual Carrying Charge (¢/kWh)	3.11
Levelized Busbar Cost of Power Charge (¢/kWh)	5.15
Levelized Cost per tonne of CO_2 Removed ($/tonne of CO_2)	N/A (N/A)

5.4 CASE 7D -- CONVENTIONAL COAL-FIRED ULTRA-SUPERCRITICAL STEAM PLANT

5.4.1 Introduction

Case 7D is a conventional coal-fired ultra-supercritical steam plant. The plant design approach is market-based and the configuration reflects current information and design preferences, the availability of a newer generation steam turbine, and the relative latitude of a greenfield site.

The coal-fired boiler is staged for low NOx formation. The boiler is also equipped with an SCR. Wet limestone forced oxidation FGD is used to limit SO_2 emissions. A once-through steam generator is used to power a double-reheat ultra-supercritical steam turbine with a net power output of 536 MWe. The steam turbine conditions correspond to 34.5 MPa/649°C (5000 psig/1200°F) throttle with 649°C (1200°F) at both reheats. Net plant power, after consideration of the auxiliary power load, is 506 MWe. The plant operates with an estimated HHV efficiency of 42.7 percent with a corresponding heat rate of 8,422 kJ/kWh (7,984 Btu/kWh).

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The individual sections are:

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Equipment List
- Capital Cost, Production Cost, and Economics

The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost.

5.4.2 Thermal Plant Performance

Table 5-16 shows a detailed breakdown of the estimated system performance for this conventional coal-fired steam turbine power plant. Plant performance is based on the use of Illinois No. 6 coal as fuel and reflects current state-of-the art turbine adiabatic efficiency levels, boiler performance, and wet limestone FGD system capabilities.

Gross power output (prior to the generator terminals) for the steam turbine is estimated to be 544 MWe. Plant auxiliary power is estimated to be 29.7 MWe. Net plant power output, which takes generator losses and auxiliary power into account, is 506 MWe. This plant power output results in a net system thermal efficiency of 42.7 percent (HHV) with a corresponding heat rate of 8,422 kJ/kWh (7,984 Btu/kWh) (HHV).

A heat and material balance diagram for this convention coal-fired steam plant is shown in Figure 5-4. The steam turbine power cycle is shown at 100 percent of design load. The ultra-supercritical Rankine cycle used for this case is based on a 34.5 MPa/649°C/649°C/649°C (5000 psig/1200°F/1200°F/1200°F) double-reheat configuration. Condensate is heated in the low-pressure feedwater heaters. Boiler feedwater is heated in the high-pressure feedwater heaters. Steam generation, superheat, and reheat are accomplished in the boiler house. Also shown in the diagram is the basic equipment of the FGD system.

The heat and material balance in Figure 5-4 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Table 5-16
CASE 7D – ULTRA-SUPERCRITICAL PC PLANT WITH FGD AND WITHOUT CO_2 REMOVAL
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	34.5 (5,000)
Throttle Temperature, °C (°F)	649 (1,200)
Reheat Outlet Temperature, °C (°F)	649 (1,200)
2nd Reheat Outlet Temperature, °C (°F)	649 (1,200)
GROSS POWER SUMMARY, kWe	
Steam Turbine Power	543,919
Generator Loss	(7,949)
Gross Plant Power	535,970
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	400
Limestone Handling & Reagent Preparation	960
Pulverizers	1,930
Ash Handling	1,730
Primary Air Fans	1,230
Forced Draft Fans	970
Induced Draft Fans	5,060
SCR	100
Seal Air Blowers	50
Precipitators	1,040
FGD Pumps and Agitators	3,580
Condensate Pumps	550
Boiler Feed Water Booster Pumps	2,930
High Pressure Boiler Feed Pump	(Note 1)
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	3,570
Cooling Tower Fans	2,020
Transformer Loss	1,240
Total Auxiliary Power Requirement	29,760
NET PLANT POWER, kWe	506,210
PLANT EFFICIENCY	
Net Efficiency, % HHV	42.7%
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	8,422 (7,984)
CONDENSER COOLING DUTY, 10^6 Btu/h	1,867 (1,770)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 3)	157,141 (346,430)
Sorbent, kg/h (lb/h)	16,135 (35,571)

Note 1 – Boiler feed pumps are turbine driven
Note 2 - Includes plant control systems, lighting, HVAC, etc.
Note 3 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

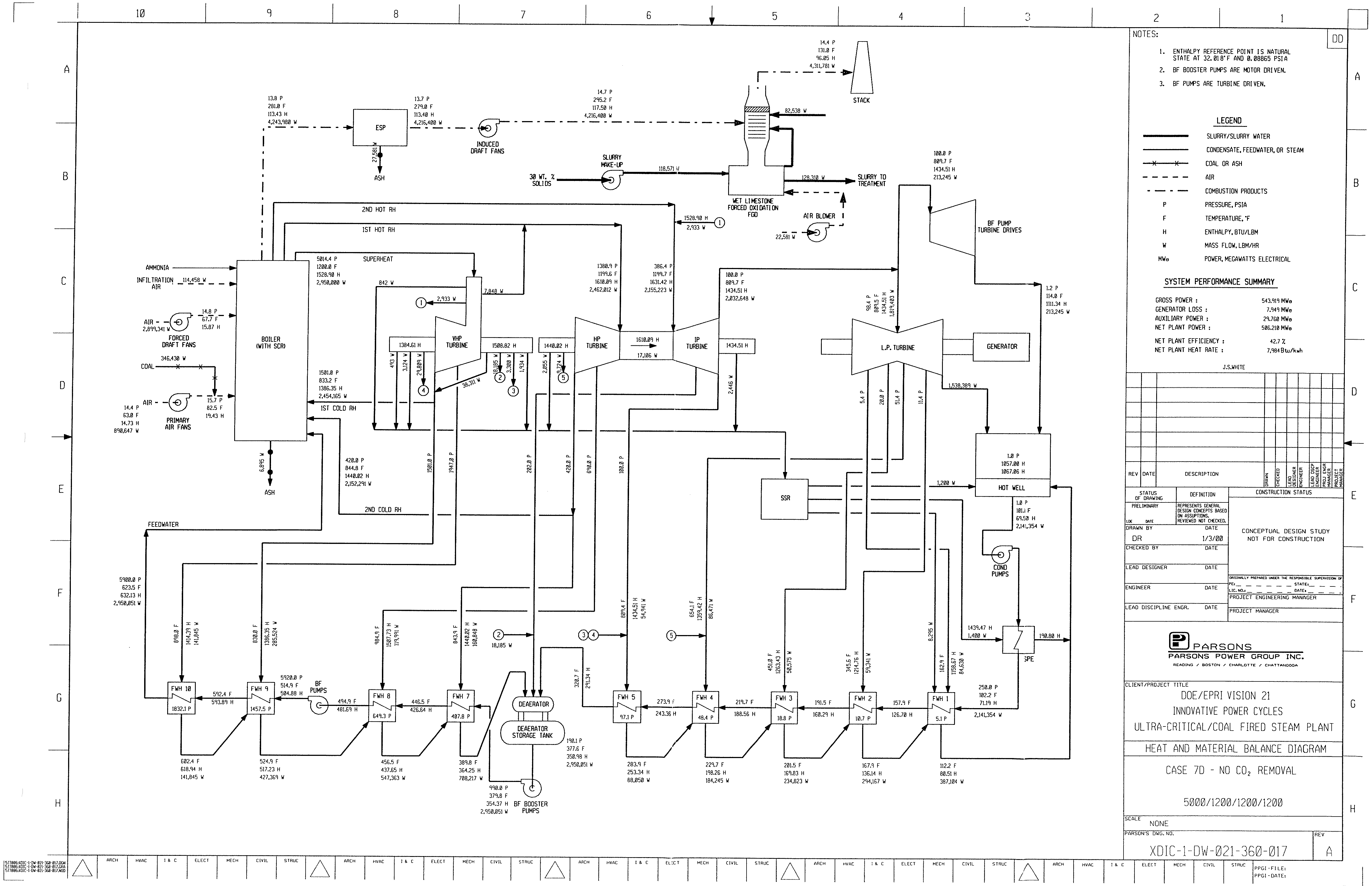

Figure 5-4
Heat and Material Balance Diagram – Case 7D – Without CO_2 Removal – Ultra-Supercritical/Coal-Fired Steam Plant

5.4.3 Power Plant Emissions

This ultra-supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the first decade of the next century. A summary of the plant emissions is presented in Table 5-17.

Table 5-17
CASE 7D AIRBORNE EMISSIONS
ULTRA-SUPERCRITICAL PC PLANT WITH FGD AND WITHOUT CO_2 REMOVAL

	Values at Design Condition (65% and 85% Capacity Factor)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	0.037 (0.086)	893.6 (985)	1,169 (1,289)	0.43 (0.94)
NOx	0.068 (0.157)	1,642 (1,810)	2,147 (2,367)	0.67 (1.47)
Particulates	0.004 (0.01)	103.4 (114)	134 (148)	0.029 (0.065)
CO_2	87.3 (203)	2,115,690 (2,332,110)	2,766,679 (3,049,690)	734 (1,619)

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 98 percent.

The minimization of NOx production and subsequent emission is achieved by a combination of low-NOx burners, overfire air staging, and selective catalytic reduction (SCR). The low-NOx burners utilize zoning and staging of combustion. Overfire air staging is employed in the design of this boiler. SCR utilizes the injection of ammonia and a catalyst to reduce the NOx emissions.

Particulate discharge to the atmosphere is reduced by the use of a modern fabric filter, which provides a particulate removal rate of 99.9 percent.

5.4.4 System Description

This greenfield power plant is a 506 MW coal-fired ultra-supercritical steam plant with FGD. The major subsystems of the power plant are:

- Coal Handling
- Coal Combustion System
- Ash Handling System
- Flue Gas Desulfurization
- Steam Turbine Generator

- Condensate and Feedwater Systems
- Balance of Plant

This section provides a brief description of these individual power plant subsystems. The equipment list, which follows this section, is based on the system descriptions provided here. The equipment list, in turn, was used to generate plant cost.

5.4.4.1 Coal Handling

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The 15.24 cm (6") x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 90.7-tonne (100-ton) rail cars. Each unit train consists of 100, 90.7-tonne (100-ton) rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 15.24 cm (6") x 0 coal from the feeder is discharged onto a belt conveyor and then transferred to a second conveyor that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the surge bin located in the crusher tower. The coal is reduced in size to 7.62 cm (3") x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 2.54 cm (1") x 0. The coal is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the six silos.

The crushed coal is fed through pairs (six in parallel) of weight feeders and mills (pulverizers). The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls.

5.4.4.2 Coal Combustion System

The primary components of the pulverized-coal combustion system are:

- Air Handling and Preheat
- Coal Burners
- Steam Generation and Reheat
- NOx Control
- Soot and Ash Removal

Each of these is described below.

Air Handling and Preheat

Air from the FD fans is heated in two vertical Ljungstrom regenerative type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the PA fans. This air is heated in Ljungstrom type air preheaters and is used as combustion air to the pulverizers. A portion of the air from the PA fans is routed around the air preheaters and is used as tempering air for the pulverizers. Preheated air and tempering air are mixed at each pulverizer to obtain the desired pulverizer fuel-air mixture outlet temperature.

The pulverized coal and air mixture flows to the coal nozzles at the various elevations of the wall-fired furnace. The hot combustion products rise to the top of the boiler and pass horizontally through the secondary superheater and reheater in succession. The gases then turn downward, passing in sequence through the primary superheater, economizer, and air preheater. The gases exit the air preheater at this point and flow to the ESP.

Coal Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in six elevations, divided between the front and rear walls of the furnace. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, at least one elevation of overfire air nozzles is provided to introduce additional air to cool the rising combustion products to inhibit NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition and flame stabilization at startup and low loads.

Steam Generation and Reheat

The steam generator in this reference ultra-supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit. It is assumed for the purposes of this study that the power plant is designed to be operated as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

Feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the lower and then the upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater. The fluid is mixed in cross-tie headers at various locations throughout this path.

The steam then exits the steam generator enroute to the HP turbine. Returning cold reheat steam passes through the reheater and then returns to either the HP or IP turbine.

NOx Control

The plant will be designed to achieve 0.067 kg/GJ (0.157 lb/10^6 Btu) (0.84 kg/MWh (1.85 lb/MWh)) NOx emissions. Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. The low-NOx burners and overfire air reduce the emissions by 65 percent as compared to a boiler installed without low-NOx burners.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems – reactor vessel, ammonia storage and injection, and gas flow control. The SCR system will be designed to remove 63 percent of the incoming NOx. This along with the low-NOx burners will achieve the emission limit of 0.067 kg/GJ (0.158 lb/10^6 Btu).

Selective noncatalytic reduction (SNCR) was and could be considered for this application. However, with the installation of the low-NOx burners, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions of 0.067 kg/GJ (0.157 lb/10^6 Btu) difficult. SNCR works better in applications that contain medium to high quantities of NOx and removal efficiencies in the range of 40 to 60 percent. SCR, because of the catalyst used in the reaction, can achieve higher efficiencies with lower concentrations of NOx.

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NOx in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consist of the unloading facilities, bulk storage tank, transfer pumps, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass as well as the SCR reactor bypass duct and dampers are also included.

Soot and Ash Removal

The soot-blowing system utilizes an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Electric motors drive the soot blowers through their cycles. The soot-blowing medium is steam.

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 22.9-cm-thick (9-inch-thick) refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to the ash pond. Particulate removal is achieved with an ESP.

5.4.4.3 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the ESP and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is discharged via a hydro-ejector and ash discharge piping to the ash pond.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) are conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

5.4.4.4 Flue Gas Desulfurization

For purposes of this discussion, the flue gas desulfurization system will be broken down into three subgroups:

- Limestone Handling and Reagent Preparation System
- Flue Gas Desulfurization System
- Byproduct Dewatering

Each of these three subtopics is presented below.

Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. The scope of the system is from the storage pile up to the limestone feed system. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent guarantee point (30 days). Truck roadways, turnarounds, and unloading hoppers are included in this reference plant design.

For the purposes of this conceptual design, limestone will be delivered to the plant by 22.7-tonne (25-ton) trucks. The limestone is unloaded onto a storage pile located above vibrating feeders. The limestone is fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create a limestone slurry. The reduced limestone slurry is then discharged into the mill slurry tank. Mill recycle pumps, two for the tank, pump the limestone water slurry to an assembly of hydroclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydroclone underflow is directed back to the mill for further grinding. The hydroclone overflow is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

Flue Gas Desulfurization System

The function of the FGD system is to scrub the boiler exhaust gases to remove 98 percent of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the ID fans to the stack inlet. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

The flue gas exiting the air preheater section of the boiler passes through an ESP, then through the ID fans and into the one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through a tray, which provides enhanced contact between gas and reagent. Multiple sprays above the tray maintain a consistent reagent concentration in the tray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. The moisture separators will consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed and dried flue gas exits at the top of the absorber vessel and is routed to the plant stack. The FGD system for this plant is designed to continuously remove 98 percent of the SO_2.

Formic acid is used as a buffer to enhance the SO_2 removal characteristics of the FGD system. The system will include truck unloading, storage, and transfer equipment.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfate, contained in the slurry, to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via the bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The spent reagent is routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack. The system is designed to support operation on a 20-year life cycle.

The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis, as byproducts from the SO_2 absorption reactions process. Maintenance of the quality of the recirculating reagent requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off spent reagent and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The gypsum slurry, at approximately 15 percent solids, is pumped to a gypsum stacking area. A starter dike is constructed to form a settling pond so that the 15 percent solid gypsum slurry is pumped to the sedimentation pond, where the gypsum particles settle and the excess water is decanted and recirculated back to the plant through the filtrate system. A gypsum stacking system allows for the possibility of a zero discharge system. The stacking area consists of approximately 17 ha (42 acres), enough storage for 20 years of operation. The gypsum stack is rectangular in plan shape, and is divided into two sections. This allows one section to drain while the other section is in use. There is a surge pond around the perimeter of the stacking area, which accumulates excess water for recirculation back to the plant. The stacking area includes all necessary geotechnical liners and construction to protect the environment.

5.4.4.5 Steam Turbine Generator

The turbine consists of a VHP section, HP section, IP section, and two double-flow LP sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 34.5 MPa/649°C (5000 psig/1200°F). The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The first reheat steam flows through the reheat stop valves and intercept valves and enters the HP section at 9.5 MPa/649°C (1380 psig/1200°F). The second reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 2.6 MPa/649°C (370 psig/1200°F). After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam is split into four paths which flow through the LP sections exhausting downward into the condenser.

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

95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

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

The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. Water temperature is controlled by regulating heat exchanger bypass water flow. Stator cooling water flow is controlled by regulating stator inlet pressure.

The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Stator cooling water flows through these coils. Gas is prevented from escaping at the rotor shafts using a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

5.4.4.6 Condensate and Feedwater Systems

The function of the condensate system is to pump water from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The function of the feedwater system is to pump feedwater from the deaerator storage tank to the boiler economizer. One turbine-driven boiler feed pump is provided to pump feedwater through the HP feedwater heaters. The pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

5.4.4.7 Balance of Plant

The balance of plant items discussed in this section include:

- Steam Systems
- Extraction Steam
- Circulating Water System
- Ducting and Stack
- Waste Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

These items are discussed in more detail below.

Steam Systems

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

Main steam at approximately 34.5 MPa/649°C (5000 psig/1200°F) exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the VHP turbine. A branch line off the main steam line feeds the two boiler feed pump turbines during unit operation up to 60 percent load.

First reheat steam at approximately 10.3 MPa/445°C (1500 psig/833°F) exits the VHP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam at approximately 9.5 MPa/649°C (1380 psig/1200°F) exits the boiler reheater through a motor-operated gate valve and is routed to reheater. A branch connection from the cold reheat piping supplies steam to feedwater heater 9.

Second reheat steam at approximately 2.9 MPa/452°C (420 psig/845°F) exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam at approximately 2.6 MPa/649°C (372 psig/1200°F) exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From VHP turbine extraction to heater 10
- From VHP turbine exhaust (1st cold reheat) to heater 9
- From HP turbine extraction to heater 8
- From HP turbine exhaust (2nd cold reheat) to heater 7
- From IP turbine extraction to the deaerator
- From IP turbine exhaust (cross-over) to heater 5
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disk non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

Circulating Water System

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

Each pump has a motor-operated discharge gate valve. A motor-operated crossover gate valve and reversing valves permit each pump to supply both sides of the condenser when the other pump is shut down. The pump discharge valves are controlled manually, but will automatically close when its respective pump is tripped.

Ducting and Stack

One stack is provided with a single FRP liner. The stack is constructed of reinforced concrete, with an outside diameter at the base of 21.3 meters (70 feet). The stack is 146.3 meters (480 feet) high for adequate particulate dispersion. The stack has one 8.8-meter-diameter (19.5-foot-diameter) FRP stack liner.

Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 45.4-tonne (50-ton) lime silo, a 0-453.6 kg/h (0-1000 lb/h) dry lime feeder, a 18.9-m^3 (5,000-gallon) lime slurry tank, slurry tank mixer, and 0.09 m^3/min (25 gpm) lime slurry feed pumps.

The oxidation system consists of a 1.4 scm/min (50 scfm) air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 757-m^3 (200,000-gallon) storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Accessory Electric Plant

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

Instrumentation and Control

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

Buildings and Structures

A soil-bearing load of 24,413 kg/m^2 (5,000 lb/ft^2) is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building
- Coal crusher building
- River water intake structure
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

5.4.5 Case 7D - Major Equipment List

This equipment list is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Inch, in. multiply by 2.54 = cm (centimeter) Foot, ft. multiply by 0.3048 = m (meter)

Mile, multiply by 1.6093 = km (kilometer)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Ton, multiply by 0.9072 = tonne (metric ton) tph = tons per hour

Gallon, gal. multiply by 3.785 $x10^{-3}$ = m^3 (cubic meters)

Gallons per minute, gpm. multiply by $3.785x10^{-3}$ = m^3/min (cubic meters/minute)

Cubic feet, cf. multiply by 2.832 $x10^{-2}$ = m^3 (cubic meters)

Cubic feet per minute, cfm. multiply by 2.832 x 10^{-2} = m^3/min (cubic meters per minute)

Inches H_2O pressure, in. WG multiply by 2.49 = mbar (millibar)

Inches Mercury absolute, in.Hga multiply by 33.86 = mbara (millibar absolute)

P Absolute Pressure, PSIA multiply P by 6.9 $x10^{-3}$ = MPa (Mega Pascals absolute)

For Gauge Pressure, PSIG add 14.7 to convert to PSIA and then proceed as above to convert to MPa

°F Temperature, (F minus 32) divided by 1.8 = °C (Centigrade)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

H Enthalpy btu/lb, multiply H by 2.3256 = kJ/kg (kilojoules/kilogram)

Heat rate, multiply btu/kWh by 1.0548 = kJ/kWh (kilojoules/kilowatt-hour)

Horsepower (U.S.), hp multiply by 1.014 = hp metric

Acre, multiply by 0.4047 = ha (hectare)

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6" x 0 - 3" x 0	1
12	Crusher	Impactor reduction	3" x 0 - 1" x 0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	600 ton	6

ACCOUNT 1B LIMESTONE RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibrator	115 tph	2
3	Conveyor 1	30" belt	115 tph	1
4	Conveyor 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	400 tons	1

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A COAL PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Feeder	Gravimetric	40 tph	6
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		20 tph	1
2	Weigh Feeder	Gravimetric	20 tph	1
3	Limestone Ball Mill	Rotary	20 tph	1
4	Mill Slurry Tank with Agitator		10,000 gal	1
5	Mill Recycle Pumps	Horizontal centrifugal	600 gpm	2
6	Hydroclones	Radial assembly		1
7	Distribution Box	Three-way		1
8	Reagent Storage Tank with Agitator	Field erected	200,000 gal	1
9	Reagent Distribution Pumps	Horizontal centrifugal	300 gpm	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Field fab.	200,000 gal.	1
2	Surface Condenser	Two shell, transverse tubes	2.14 x 10^6 lb/h 2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vert. canned	2,410 gpm/800 ft	3
5	LP Feedwater Heater	Horiz. U tube	2,141,400 lb/h 102°F to 160°F	1
6	LP Feedwater Heater	Horiz. U tube	2,141,400 lb/h 150°F to 350°F	1
7	LP Feedwater Heater 3	Horiz. U tube	2,141,400 lb/h 190°F to 450°F	1
8	LP Feedwater Heater 4	Horiz. U tube	2,141,400 lb/h 219°F to 650°F	1
9	LP Feedwater Heater 5	Horiz U tube	2,141,400 lb/h 277°F to 750°F	1
10	Deaerator and Storage Tank	Horiz. spray type	2,950,000 lb/h 300°F to 700°F	1
11	Boiler Feed Water Booster Pump	Horiz. split	6800 gpm @ 2,400 ft	2
12	HP Feedwater Heater 7	Horiz. U tube	2,950,000 lb/h 370°F to 840°F	1
13	HP Feedwater Heater 8	Horiz. U tube	2,950,000 lb/h 450°F to 980°F	1
14	Boiler Feed Pump/ Turbine Drive	Barrel type, multi-staged, centr.	6,800 gpm @ 15,500 ft	2
15	Startup Boiler Feed Pump	Barrel type, multi-staged centr.	2,500 gpm @ 15,500 ft	2
16	HP Feedwater Heater 9	Horiz. U tube	2,950,000 lb/h 510°F to 830°F	1
17	HP Feedwater Heater 10	Horiz. U tube	2,950,000 lb/h 550°F to 870°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	S.S., double acting	100 psig, 800 scfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	S.S., double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell and tube	50% cap each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	185 ft, 600 gpm	2
11	Fire Service Booster Pump	Two-stage cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water Pumps	S.S., single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	S.S., single suction	200 ft, 200 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System	-	10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Once-Through Steam Generator with Air Heater. SCR Before Air Heater Surface.	Universal pressure, wall-fired, double reheat	2,950,000 lb/h steam at 5000 psig & 1200°F	1
2	Primary Air Fan	Axial	445,325 lb/h 100,209 acfm, 35" wg, 850 hp	2
3	FD Fan	Cent.	1,449,670 lb/h, 326,213 acfm, 10" wg, 675 hp	2
4	ID Fan	Cent.	2,108,200 lb/h, 683,563 acfm, 26" wg 3,500 hp	2
5	Seal Air Blower	Three-stage recip.	1300 acfm/350 psig	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Electrostatic Precipitator	Rigid frame, single-stage	681,817 acfm, total +99% removal efficiency	2

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,308,800 acfm	1
2	Recirculation Pump	Horizontal centrifugal	31,500 gpm	4
3	Bleed Pump	Horizontal centrifugal	650 gpm	2
4	Oxidation Air Blower	Centrifugal	5,600 scfm	1
5	Agitators	Side entering	25 hp motor	6
6	Formic Acid Storage Tank	Vertical, diked	1,000 gal	1
7	Formic Acid Pumps	Metering	0.1 gpm	2
8	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
9	Gypsum Stacking Area		42 acres	1
10	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
11	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
12	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

ACCONT 6 COMBUSTION TURBINE AND AUXILIARIES

Not Applicable

ACCOUNT 7 WASTE HEAT BOILER, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Qty.
1	Stack	Reinf. concrete, two FRP flues	60 ft/sec exit velocity 480 ft high x 16 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty.
1	540 MW Turbine Generator	TC2F40	5000 psig/1200°F/ 1200°F/1200°F	1
72	Bearing Lube Oil Coolers	Shell and tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell and tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid state brushless	-	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Cooling Tower	Mech draft	160,000 gpm 95°F to 75°F	1
2	Circ. W. Pumps	Vert. wet pit	80,000 gpm @ 80 ft	2

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A BOTTOM ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Economizer Hopper (part of Boiler scope of supply)			4
2	Bottom Ash Hopper (part of Boiler scope of supply)			2
3	Clinker Grinder		5 tph	2
4	Pyrites Hopper (part of Pulverizer scope of supply included with Boiler)			6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank		40,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	1,000 gpm	2
8	Ash Seal Water Pumps	Vertical, wet pit	1,000 gpm	2

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	ESP Hoppers (part of ESP scope of supply)			24
2	Air Heater Hopper (part of Boiler scope of supply)			10
3	Air Blower		1,800 cfm	2
4	Fly Ash Silo	Reinf. concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

5.4.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the ultra-supercritical pulverized coal power plant without CO_2 removal, case 7D, were developed consistent with the approach and basis identified in the first section of Appendix A. The capital cost estimate is expressed in December 1999 dollars. The production cost and expenses were developed on a first-year basis with a January 2000 plant in-service date. Figure-of-merit results of the economic analysis are the Levelized Busbar Cost of Electricity, expressed in cents per kilowatt-hour and the Levelized Cost per tonne of CO_2 Removed.

The capital cost for case 7D represents a plant with a net output of 506.2 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 5-18. A detailed estimate for case 7D is included in Appendix A.

Table 5-18
CASE 7D SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	PC Boiler and Accessories	126,440
5	Flue Gas Cleanup	61,800
5B	CO_2 Removal and Compression	N/A
6	Combustion Turbine and Accessories	N/A
7	Ducting and Stack	21,100
8&9	Steam T-G Plant, including Cooling Water System	119,640
11	Accessory Electric Plant	24,900
	Balance of Plant	130,320
	SUBTOTAL	484,200
	Engineering, Construction Management Home Office and Fee	29,050
	Process Contingency	
	Project Contingency	74,650
	TOTAL PLANT COST (TPC)	$587,900
	TPC $/kW	1,161

The production costs for case 7D consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal) and Fuel costs. The costs were determined on a first-year basis that includes evaluation at a 65 percent equivalent plant operating capacity factor. The results are summarized in Table 5-19 and supporting detail is contained in Appendix A.

Table 5-19
CASE 7D ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	4,815	0.17
Maintenance	7,263	0.25
Administrative & Support Labor	1,930	0.07
Consumables	13,547	0.47
By-Product Credits	N/A	N/A
Fuel	28,536	0.99
TOTAL PRODUCTION COST	56,091	1.95

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 7D. This analysis was performed on a levelized, over book life, constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Two figure-of-merit values were determined; Busbar Cost of Power, expressed in cents per kilowatt-hour, and the Levelized Cost per tonne of CO_2 Removed, expressed in dollars per tonne. The Total Capital Requirement component of the figure-of-merit was determined on the basis of a factor produced by the EPRI model ECONCC. The economic inputs and basis provided by EPRI is included in Appendix A along with a case summary that includes line items of the economic results. Summary economic results are provided in Table 5-20.

Table 5-20
Case 7D Levelized Economic Result Summary

Component (unit)	Value
Production Cost (¢/kWh)	1.95
Annual Carrying Charge (¢/kWh)	3.15
Levelized Busbar Cost of Power Charge (¢/kWh)	5.10
Levelized Cost per tonneof CO_2 Removed ($/tonne of CO_2)	N/A

5.5 CASE 7E -- ADVANCED COAL-FIRED ULTRA-SUPERCRITICAL STEAM PLANT

5.5.1 Introduction

Case 7E is an advanced coal-fired ultra-supercritical steam plant featuring European steam conditions. It is a "side" case that was completed for purposes of comparison for other cases. It has not costed, and no equipment list or system description is given. It is a "performance" case only.

The coal-fired boiler is staged for low NOx formation. The boiler is also equipped with an SCR. Wet limestone forced oxidation FGD is used to limit SO_2 emissions. A once-through steam generator is used to power a double-reheat ultra-supercritical steam turbine with a net power output of 527 MWe. The steam turbine conditions correspond to 37.5 MPa/ 699°C (5440 psig/1290°F) throttle with 699°C (1290°F) first reheat and 721°C (1330°F) for the second reheat. Net plant power, after consideration of the auxiliary power load, is 498 MWe. The plant operates with an estimated HHV efficiency of 44 percent with a corresponding heat rate of 8,179 kJ/kWh (7,754 Btu/kWh).

5.5.2 Thermal Plant Performance

Table 5-21 shows a detailed breakdown of the estimated system performance for this conventional coal-fired steam turbine power plant. Plant performance is based on the use of Illinois No. 6 coal as fuel and reflects current state-of-the art turbine adiabatic efficiency levels, boiler performance, and wet limestone FGD system capabilities.

Gross power output (prior to the generator terminals) for the steam turbine is estimated to be 534 MWe. Plant auxiliary power is estimated to be 28.6 MWe. Net plant power output, which considers generator losses and auxiliary power, is 498 MWe. This plant power output results in a net system thermal efficiency of 44 percent (HHV) with a corresponding heat rate of 8,179 kJ/kWh (7,754 Btu/kWh) (HHV).

A heat and material balance diagram for this conventional coal-fired steam plant is shown in Figure 5-5. The steam turbine power cycle is shown at 100 percent of design load. The ultra-supercritical Rankine cycle used for this case is based on a 37.5 MPa/699°C/699°C/721°C (5440 psig/1290°F/1290°F/1330°F) double-reheat configuration. Condensate is heated in the low-pressure feedwater heaters. Boiler feedwater is heated in the high-pressure feedwater heaters. Steam generation, superheat, and reheat are accomplished in the boiler house. Also shown in the diagram is the basic equipment of the FGD system.

The heat and material balance in Figure 5-5 is shown in U.S. standard units. The following factors can be used for conversion to SI units.

P Absolute Pressure, PSIA multiply P by 6.9 x10^{-3}	= MPa (Mega Pascals)
°F Temperature, (F minus 32) divided by 1.8	= °C (Centigrade)
H Enthalpy btu/lb, multiply H by 2.3256	= kJ/kg (kilojoules/kilogram)
W Total plant flow lbs/hr, multiply W by 0.4536	= kg/hr (kilograms/hour)
Heat rate, multiply btu/kWh by 1.0548	= kJ/kWh (kilojoules/kilowatt-hour)

Table 5-21
CASE 7E – ULTRA-SUPERCRITICAL PC PLANT
ADVANCED 700°C EUROPEAN CONDITIONS
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	37.5 (5,440)
Throttle Temperature, °C (°F)	699 (1,290)
Reheat Outlet Temperature, °C (°F)	699 (1,290)
2nd Reheat Outlet Temperature, °C (°F)	721 (1,330)
GROSS POWER SUMMARY, kWe	
Steam Turbine Power	534,794
Generator Loss	(7,799)
Gross Plant Power	526,995
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	380
Limestone Handling & Reagent Preparation	920
Pulverizers	1,850
Ash Handling	1,650
Primary Air Fans	1,220
Forced Draft Fans	980
Induced Draft Fans	5,020
SCR	100
Seal Air Blowers	50
Precipitators	990
FGD Pumps and Agitators	3,420
Condensate Pumps	530
Boiler Feed Water Booster Pumps	2,710
High Pressure Boiler Feed Pump	(Note 1)
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	3,290
Cooling Tower Fans	1,860
Transformer Loss	1,220
Total Auxiliary Power Requirement	28,590
NET PLANT POWER, kWe	498,405
PLANT EFFICIENCY	
Net Efficiency, % HHV	44.0%
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	8,179 (7,754)
CONDENSER COOLING DUTY, 10^6 Btu/h	1,719 (1,630)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 3)	150,265
Sorbent, kg/h (lb/h)	(331,271)
	15,429 (34,015)

Note 1 – Boiler feed pumps are turbine driven
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

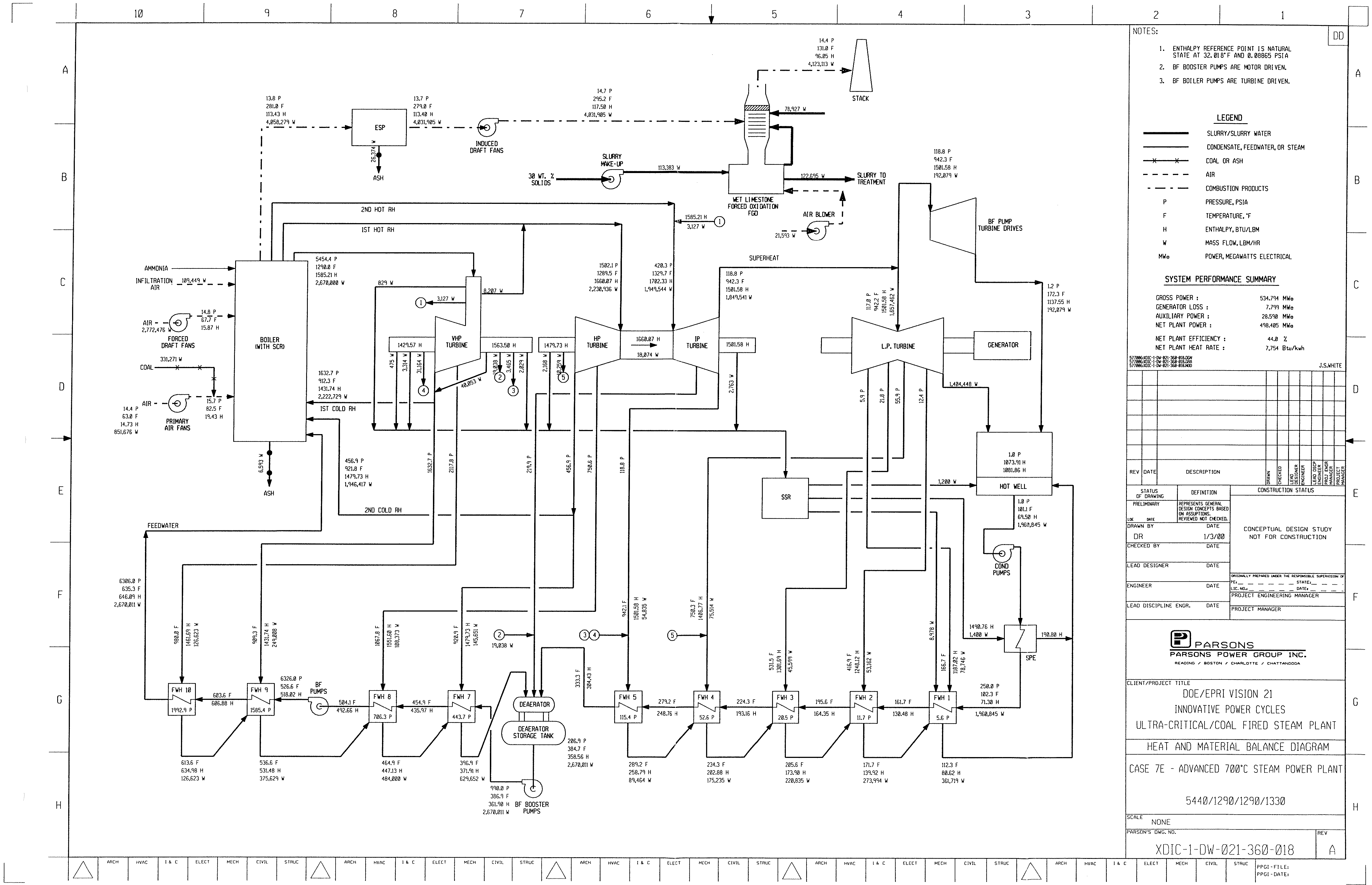

Figure 5-5
Heat and Material Balance Diagram – Case 7E – Advanced 700°C Steam Power Plant – Ultra-Supercritical/Coal-Fired Steam Plant

5.5.3 Power Plant Emissions

This advanced ultra-supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the first decade of the next century. A summary of the plant emissions is presented in Table 5-22.

Table 5-22
CASE 7E AIRBORNE EMISSIONS
ADVANCED ULTRA-SUPERCRITICAL PC PLANT WITH FGD AND WITHOUT CO_2 REMOVAL

	VALUES AT DESIGN CONDITION (65% AND 85% CAPACITY FACTOR)			
	kg/GJ (HHV) (lb/10^6 Btu (HHV))	Tonnes/year 65% (Tons/year 65%)	Tonnes/year 85% (Tons/year 85%)	kg/MWh (lb/MWh)
SO_2	0.037 (0.086)	854.5 (942)	1,116 (1,230)	0.32 (0.70)
NOx	0.068 (0.157)	1,569 (1,730)	2,050 (2,260)	0.56 (1.23)
Particulates	0.004 (0.01)	98.9 (109)	127.9 (141)	0.034 (0.076)
CO_2	87.3 (203)	2,023,110 (2,230,060)	2,645,613 (2,916,240)	746 (1,645)

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 98 percent.

The minimization of NOx production and subsequent emission is achieved by a combination of low-NOx burners, overfire air staging, and selective catalytic reduction (SCR). The low-NOx burners utilize zoning and staging of combustion. Overfire air staging is employed in the design of this boiler. SCR utilizes the injection of ammonia and a catalyst to reduce the NOx emissions.

Particulate discharge to the atmosphere is reduced by the use of a modern fabric filter, which provides a particulate removal rate of 99.9 percent.

The higher European target 700°C steam temperature in Case 7E offers an increase in net plant efficiency to 44.0% HHV basis over the 42.7% for Case 7D with a steam temperature of 649°C. However the cost of materials for this advanced steam temperature are not yet defined.

A
SUPPORTING DATA FOR THE ECONOMIC ANALYSIS

This appendix contains raw data and other supporting material that was used in forming the economic analysis presented in the main body of this report. The first section contains information on the basis used to perform the economic analysis developed for each technology configuration. The second and third sections contain data submitted by the Electric Power Research Institute (EPRI) that was used in the economic analysis. The later sections contain capital investment and revenue requirement summaries and Total Plant Cost Summaries for each power plant evaluated. These raw data are meant to support the analysis results found in the main body of the report.

A.1 Capital Cost Estimate, Production Cost/Expense Estimate, and Economic Basis

Capital cost estimates were developed for the NGCC, PC, IGCC, and NG-CHAT power plants based on a combination of adjusted vendor-furnished cost data and Parsons cost estimating database. The capital costs at the Total Plant Cost (TPC) level include equipment, materials, labor, indirect construction costs, engineering, and contingencies. Production, operation and maintenance, including any fuel, cost values were determined on a first-year basis and subsequently levelized over the 20-year plant book life to form a part of the economic analysis. Quantities for major consumables such as fuel, sorbent, and ash were taken from technology-specific heat and material balance diagrams developed for each plant application. Annual costs were determined on the basis of EPRI-furnished unit costs. Other consumables were evaluated on the basis of the quantity required using reference data. Operating labor cost was determined on the basis of the number of operators, operating jobs (O.J.), and the average wage rate. Maintenance costs were evaluated on the basis of requirements for each major plant section. The operating and maintenance costs were then converted to unit values of $/kW-year or ¢/kWh.

Each major system capital cost was based on a reference bottoms-up estimate and subsequently adjusted for the case specific requirements.

The estimate boundary limit is defined as the total plant facility within the "fence line," including coal receiving and water supply system, but terminating at the high-voltage side of the main power transformers. Site is characterized to be located in an East West region of the United States. Although not specifically sited within this region, it is based on a relative equipment/materials/labor cost factor of 1.0. Specific regional locations would result in adjustments to these cost factors. The reference labor cost to install the equipment and materials was estimated on the basis of labor man-hours. The approach to labor costing was a multiple contract labor basis with the labor cost including direct and indirect labor costs plus fringe benefits and allocations for contractor expenses and markup. This approach was supplemented in limited cases with equipment labor relationship data to determine the labor cost.

An indirect labor cost estimated at 7 percent of direct labor was included to provide the cost of construction services and facilities not provided by the individual contractors. The indirect cost represents the estimate for miscellaneous temporary facilities such as construction road and parking area construction and maintenance, installation of construction power; installation of construction water supply and general sanitary facilities, and general and miscellaneous labor services such as jobsite cleanup and construction of general safety and access items.

The TPC level of the estimate consists of the bare erected cost plus engineering and contingencies. The engineering costs represent the cost of architect/engineer (A/E) services for home office engineering, design, drafting, and project construction management services. The cost was determined at a nominal rate of 6 percent applied to the bare erected cost on an individual account basis. Any cost for engineering services provided by the equipment manufacturers and vendors is included directly in the equipment costs.

Consistent with conventional power plant practices, project contingencies were added to the TPC accounts to cover project uncertainty and the cost of any additional equipment that could result from a detailed design. The contingencies represent costs that are expected to occur. Each TPC cost account is evaluated against the level of estimate detail and field experience to define project contingency. As a result, nominal contingency values of 5 to 30 percent were applied to arrive at the TPC values. The cumulative impact of this contingency approach is a composite result of approximately 15 percent. Process contingency was also considered for systems and equipment not considered commercially mature, and is intended to cover the uncertainty in the cost estimate, namely the CO_2 removal systems and the “H” combustion turbine at a rate of 10 percent. Total plant costs, or “Overnight Construction Costs” values, are expressed in December 1999 dollars.

The operating and maintenance expenses and consumable costs were developed on a quantitative basis and are shown as production costs. Operating labor cost was determined on the basis of the number of operator jobs (O.J.) required. The average labor rate to determine annual cost was $30.20/hour, with a labor burden of 30 percent. The labor administration and overhead charge cost was assessed at a rate of 25 percent of operation and maintenance labor. Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. The exception was maintenance cost for the combustion turbine, which is a function of operating hours. Cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours. Each of these expenses and costs is determined on a first-year basis, assuming a 65 percent annual plant capacity factor.

Byproduct credits were considered for sulfur-cake production, which is a marketable commodity. However, market demand and price for such a product are site specific, and therefore difficult to define for a generic application. It is assumed that a local demand exists for sulfur-cake. A sulfur-cake market price of $47.10/tonne ($42.73/ton) is assumed.

A.2 ECONOMIC BASIS PROVIDED BY EPRI

Table A-1
AG FINANCIAL PARAMETERS, 1997

			Current Dollars	**Constant Dollars**	
	Percent of Total	**Cost, %**	**Percent Return, %**	**Percent Cost, %**	**Percent Return, %**
Debt	45	9	4.05	5.83	2.62
Preferred Stock	10	8.5	0.85	5.34	0.53
Common Stock	45	12	5.40	8.74	3.93
Total Annual Return	100		10.30		7.09
Inflation Rate, %		3.0			
Federal Tax, %		34.0			
State Tax, %		4.15			
Federal & State Tax, %		38.0			
Discount Rates					
After Tax			8.76		6.09
Before Tax			10.3		7.09

The 'Summary of Operating and Maintenance Cost Data for TAG, 1998' is shown using U.S. standard units. The following factors can be used for conversion to SI units.

Foot, ft. multiply by 0.3048 = m (meter)

Pound, lb. multiply by 0.4536 = kg (kilogram)

Short ton or ton, st or t = 2000 lbs multiply by 0.9072 = tonne (metric ton)

Long ton = 2240 lbs multiply by 0.9842 = tonne (metric ton)

Gallon,gal. multiply by 3.785 x10^{-3} = m^3 (cubic meters)

Cubic feet, cf. multiply by 2.832 x10^{-2} = m^3 (cubic meters)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

Heat rate, multiply btu/kWh by 1.0458 = kJ/kWh (kilojoules/kilowatt-hour)

Acre multiply by 0.4047 = ha (hectare)

Summary of Operating and Maintenance Cost Data for TAG, 1998

Region	NE	SE	1998 E/W	SC	W	1998 Average
Land, $/acre						
Urban	8500.00	8500.00	8500.00	8500.00	8500.00	8500.00
Rural	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00
Nonproductive	450.00	450.00	450.00	450.00	450.00	450.00
FGD reagents, $/ton						
Lime						
Pebble Lime	70.00	70.00	66.00	66.00	72.00	68.80
Magnesium enhanced lime	74.00	74.00	70.00	70.00	75.00	72.60
Limestone	13.10	11.30	12.30	14.10	14.90	13.14
Soda ash	180.00	180.00	161.00	164.00	117.00	160.40
Nahcolite						
Trona	180.00	185.00	170.00	140.00	80.00	151.00
Sodium Bicarbonate	297.00	299.00	278.00	339.00	277.00	298.00
Magnesia	257.00	257.00	247.00	247.00	222.00	246.00
Organic acids						
Adipic Acid	1560.00	1410.00	1470.00	1440.00	1540.00	1484.00
Formic Acid	1075.00	925.00	985.00	955.00	1055.00	999.00
Dibasic Acid	770.00	470.00	590.00	530.00	730.00	618.00
Sorbent-Dolomite of PFBCs, $/ton	14.10	12.30	12.30	14.10	14.90	13.54
NOx control						
SCR catalyst , $/ft^3						
Catalyst Cost	363.00	360.00	368.00	354.00	362.00	361.40
Catalyst Disposal	11.00	11.00	9.00	10.00	10.00	10.20
Ammonia, $/st						
Anhydrous	280.00	256.40	320.00	245.72	338.00	288.02
Aqueous	345.00	350.78	348.00	430.65	581.70	411.23
SNCR urea, $/ton	225.00	190.00	230.00	185.00	230.00	212.00
Water and wastewater						
Raw water, $/ 1000 gal	0.80	0.65	0.40	2.10	0.65	0.92
Demineralized water, $/ 1000 gal	3.10	2.95	2.70	4.40	2.95	3.22
Cooling sysem chemicals, $/ton	415.00	415.00	415.00	415.00	415.00	415.00
Wastewater treatment chemicals, $/ 1000 gal water	0.07	0.07	0.07	0.07	0.00	0.06
Disposal Costs, $/ton						
Flyash/FGD solids disposal	16.00	16.00	16.00	16.00	16.00	16.00
FGD sysem, gypsum stacking	6.40	6.40	6.40	6.40	6.40	6.40
Flyash with nahcolite disposal	20.50	20.50	20.50	20.50	20.50	20.50
PC plant bottom ash/gasification system slag disposal	16.00	16.00	16.00	16.00	16.00	16.00
Byproduct credits						
FGD system sulfur, $/long ton	64.00	64.00	47.00	47.00	37.00	51.80
FGD system, sufuric acid, $/st	65.00	65.00	70.00	70.00	70.00	68.00
FGD systm gypsum, $/ton	2.00	2.00	2.00	2.00	2.00	2.00
Ammonium sulfate, $/ton	95.00	126.00	110.00	120.00	115.00	113.20
Steam, $/1000lbs-hour	3.05	3.05	3.05	3.05	3.05	3.05

A.3 CAPITAL INVESTMENT AND REQUIREMENT AND TOTAL PLANT COST SUMMARIES

This section contains summary sheets describing capital investment and revenue requirements for each power plant configuration evaluated. Also shown are total plant cost summaries.

The summary sheets are shown using U.S. standard units. The following factors can be used for conversion to SI units.

Short ton or ton, st or t = 2000 lbs multiply by 0.9072 = tonne (metric ton)

Million btu, Mbtu multiply by 1.0548 = GJ (Gigajoules)

(Natural gas at $2.70/Mbtu HHV basis = $2.56/GJ

Coal at $1.24/Mbtu HHV basis = $1.176/GJ)

Heat rate, multiply btu/kWh by 1.0458 = kJ/kWh (kilojoules/kilowatt-hour)

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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