Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal

Technical Report

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REPORT SUMMARY

This interim report presents updated results of an ongoing study on 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. 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 the global climate is a key issue for the future of power generation worldwide. In December 2000, EPRI and the U.S Department of Energy (DOE) issued a report (EPRI report 1000316) that showed the added cost of CO_2 removal from an IGCC plant was only ~40% of that from a PC plant. If CO_2 removal was required, an IGCC plant's COE was about 75% of that for a PC plant. With coal at \$1.18/GJ, the breakeven natural gas cost was \$3.8/GJ for IGCC, but \$6/GJ for PC plants.

Objectives

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

Approach

EPRI and U.S DOE have continued to fund the contractor to evaluate innovative fossil fuel plants incorporating CO_2 removal. The cases included in the previous report (1000316) were updated to reflect more recent design information. In addition, new cases were studied, including a natural-gas-fired advanced cycle incorporating a solid oxide fuel cell (SOFC) followed by a cascaded humidified air turbine (CHAT) and an IGCC fed with a slurry of coal in CO_2.

Results

Results in this summary are for cases using 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 (CF) of 80%was used for COE.

The IGCC case with CO_2 removal has been updated to include a water wash to remove chlorides prior to the shift reactor. This resulted in a slight loss in efficiency; however, moving to a single

air separation unit (ASU) and using two instead of three gasification trains reduced the capital cost.

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 $3.4/GJ ($3.64/Mbtu). Above that price, IGCC plants with CO_2 removal would have a lower COE than NGCC plants. IGCC plants also would have a COE 18$/MWh (~25%) lower than PC plants if both were designed for CO_2 removal. The cost of CO_2 emissions avoided with IGCC ($19.5/metric ton) was markedly less than with NGCC ($60.4/metric ton) or ultra-supercritical PC Plants ($42.4/metric ton). These updated results support previous report conclusions and also show that adjustments normalizing CO_2 removal cases to the same emissions of CO_2/kWh, the same plant size, or larger plant sizes do not alter these main conclusions.

The natural-gas-fired SOFC/CHAT advanced cycle had a high efficiency of 59.7% HHV basis; however, with CO_2 removal added, it reduced to 41.6%. This was lower than NGCC with CO_2 removal at 43.4%. Further study of this cycle was, therefore, deferred.

Although coal in CO_2 slurry increases the gasifier efficiency, the higher CO-content syngas required additional steam for the shift reaction, and this reduced overall plant efficiency below that for the coal in a water slurry base case. Further cost analysis was, therefore, not completed.

EPRI Perspective

If CO_2 removal is required, IGCC remains the coal technology most competitive with NGCC. If costs for CO_2 transportation and sequestration are included, costs of CO_2 avoided will increase (more for coal plants than for NGCC) and the breakeven costs of natural gas also would be a little higher than those cited in this report summary. The cases documented in this report are anticipated to be the next generation of fossil fuel technologies. Due to increased attention on the global climate issue, EPRI is conducting additional studies on costs of CO_2 removal from current state-of-the-art fossil fuel technologies.

Keywords

CO_2 removal
Sequestration
Economic evaluation
Pulverized coal plants
GCC power plants

EPRI NOTES ON UPDATED ESTIMATES FOR FOSSIL FUEL POWER PLANTS WITH CO_2 REMOVAL

In this updated report the NGCC and PC cases are essentially unchanged from those reported in the previous Report #1000316 published in December 2000. However a new IGCC case with CO_2 removal has been added, Case 3E, with several improvements over the Case 3A reported previously in # 1000316. In Case 3E water scrubbing of the syngas has been added ahead of the shift reactor to remove chlorides. This slightly reduced the overall efficiency since some moisture was removed from the syngas by water scrubbing so that additional steam was required to obtain the necessary degree of shift reaction. Since single train Air Separation Units (ASUs) are in commercial use up to 3250 tonnes/day of oxygen, the previous cases 3A and 3B, which had included two 50% ASU trains, and all the IGCC cases, have been modified to single train ASU designs. The previous Case 3A had also conservatively used three 33% gasification trains and on further analysis it was decided that two 50% trains were sufficient for the new Case 3E. The net effect of these changes has been to reduce the capital costs and to slightly lower the estimated COE's for the IGCC cases both with and without CO_2 removal over those previously reported in #1000316.

The power plant designs evaluated in this study are for technologies representative of the next generation of commercially available technology. The Ultra Supercritical PC plant is a double reheat steam cycle with steam temperatures of 650°C (compared to the current state of the art at 600-620°C). H type gas turbines were used for the NGCC and IGCC cases. The first of the NGCC H plants is due to be commissioned at the end of 2002-3. H gas turbines for the IGCC application will probably become available after the NGCC performance experience has been verified. The IGCC cases with CO_2 removal assumed gasification pressures of 56 barg (800 psig) for the Global E Gas gasifiers. Global has a design for this application that features a tall cylindrical design however this has not yet been commercially proven. In view of the growing attention being accorded to the global climate issue, and because of some uncertainty in the timing of the availability of the higher pressure E Gas gasifiers and the H gas turbine, IGCC cases using currently commercially available FA gas turbines and currently offered gasifier designs at 30 barg (450 psig) pressure will be added to the project's scope of work. IGCC cases with FA gas turbines are also being studied on other EPRI projects using the Texaco and Shell gasification technologies. For cases involving CO_2 removal there appears to be an advantage to using higher-pressure systems. Texaco already has commercial gasifiers operating at 70 barg (1000 psig) pressure that appear well suited to IGCC applications incorporating CO_2 removal.

Earlier work by EPRI with Arthur D. Little had shown that coal in CO_2 slurries could be made that were pumpable at concentrations of up to 88% as received coal. ("Investigation of Low-Rank-Coal-Liquid Carbon Dioxide Slurries", EPRI Report AP-4849 Arthur D. Little October 1986). The use of coal in CO_2 slurries was included in some EPRI/Texaco sponsored IGCC case studies for the use of low rank coals in the Texaco process (“ Use of Lignite in Texaco Gasification-Based-Combined-Cycle Power Plants” EPRI Report AP 4509 Energy Conversion Systems Inc, April 1986). The use of coal in CO_2 slurries was identified as one of several options for improving the performance of Texaco IGCC plants using low rank coals as compared to the conventional feeding as a 50% coal in water slurry. No further testing of this concept was pursued at that time. However, when IGCC plants were considered in the context of CO_2 removal this concept was thought to merit further investigation since liquid CO_2 would have to be produced in any case. The cases reported in this updated Parsons report used Illinois #6 bituminous coal however it was found that the high CO content of the syngas meant that additional steam had to be taken from the steam cycle to conduct the necessary shift conversion. This decreased the overall plant efficiency below that for conventional coal/water slurry feed and it was therefore judged that completing the cost evaluation could not be justified. However it may still be a viable option for low rank coals where the high equilibrium moisture content produces coal/water slurries of low energy content requiring very high oxygen consumption.

An advanced natural gas fired combined cycle was also evaluated and is included in this report. It features a solid oxide fuel cell (SOFC) followed by a cascaded humidified air turbine (CHAT). This cycle was expected to have a high efficiency and it was evaluated to have an efficiency of 59.7% HHV basis without CO_2 removal. However, when post combustion removal of CO_2 from the gas turbine flue gas with MEA solvent was added the efficiency dropped to 41.6% HHV basis. Because of the high steam demand for MEA solvent regeneration in this latter scheme additional natural gas had to be used to raise additional steam and fulfill the total steam requirements. The efficiency for the NGCC with H gas turbine and post combustion CO_2 removal with MEA at 43.3% HHV basis was higher that this advanced cycle. It was therefore decided that further full cost evaluation of the advanced SOFC/CHAT cycle could not be justified.

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EXECUTIVE SUMMARY

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 52 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 fossil 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 due to 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. However, 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 and large flue gas volumes yield large and costly removal equipment. In contrast, *advanced* coal-based technologies, such as *gasification* – because they can produce concentrated streams of CO_2 at high pressure – offer convenient opportunities that may be exploited for lower-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 combustion. The high pressure of the synthesis gas stream, as well as the absence of diluent N_2, yields high CO_2 partial pressures. This, in turn, results in a relatively cheaper separation due to increased driving force and smaller equipment due to lower gas volume. 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, a number of gas- and coal-fired base cases were identified. These cases include:

- **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 (Class H Gas Turbine)
  <u>Case 3B</u> – Base Case IGCC Plant without CO_2 Removal (Class H Gas Turbine)
  <u>Case 3C</u> – 80 Percent CGE IGCC with CO_2 Removal (Class H Gas Turbine)
  <u>Case 3D</u> – 80 Percent CGE IGCC without CO_2 Removal (Class H Gas Turbine)
  <u>Case 3E</u> – Sensitivity of Case 3A (Added Water Scrubber)

- **Conventional Coal-Fired Configurations**
  <u>Case 7A</u> – Conventional Supercritical (SC) Pulverized Coal with CO_2 Removal
  <u>Case 7B</u> – Ultra-Supercritical (USC) Pulverized Coal with CO_2 Removal
  <u>Case 7C</u> – Conventional SC Pulverized Coal without CO_2 Removal
  <u>Case 7D</u> – USC Pulverized Coal without CO_2 Removal
  <u>Case 7E</u> – Advanced USC Pulverized Coal without CO_2 Removal
  <u>Case 7F</u> – Sensitivity of Case 7A (Power Increased to Match Case 3E)
  <u>Case 7G</u> – Sensitivity of Case 7B (Power Increased to Match Case 3E)

- **CO_2 Slurry Gasification Configurations**
  <u>Case 8A</u> – Gasification with CO_2 – Direct Water Quench Option
  <u>Case 8B</u> – Gasification with CO_2 – Raw Gas Cooler Option

- **Additional Coal-Fired Configurations**
  <u>Case 9A</u> – Base Case IGCC Plant without CO_2 Removal (Class F Gas Turbine)
  <u>Case 9B</u> – Base Case IGCC Plant with CO_2 Removal (Class F Gas Turbine)

The Interim Report, “Natural Gas and Coal Baseline Plants, Interim Report – October 2000,” which was subsequently released by DOE and EPRI under the title “Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal,” contains the results of the initial study effort. This second Interim Report documents nine cases that have been completed or updated since the release of that volume: Cases 2A, 2B, 3C, 3D, 3E, 7F, 7G, 8A, 8B, 9A and 9B. Technical descriptions, performance results, and equipment lists are presented for each of those cases, as necessary. 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.

Summary of Key Results

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

In the NGCC and PC cases with carbon sequestration (1A, 1B, 7A, 7B, 7F, and 7G), 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 ES-1
Key Results of Parsons Studies without CO_2 Removal

Case Number	**1D**	**2B**	**3B**	**7C**	**7D**
Description	NGCC – H	NGCC – SOFC	IGCC – H	SC PC	USC PC
Net MW Output	384.4	556.5	424.5	462.1	506.2
Net Plant Efficiency	53.6%	59.7%	43.1%	40.5%	42.7%
TPC $/kW	496	623	1,111	1,143	1,161
LCOE mills/kWh at 65% Capacity Factor 80% Capacity Factor	 33.5 30.7	 32.9 29.8	 47.7 41.0	 51.5 44.8	 51.0 44.1
kgCO_2/kWh (lbCO_2/kWh)	0.342 (0.753)	0.302 (0.667)	0.719 (1.586)	0.776 (1.711)	0.736 (1.622)

Table ES-2
Key Results of Parsons Studies Incorporating 90% CO_2 Removal

Case Number	**1B**	**2A**	**3E**	**7A**	**7B**
Description	NGCC – H	NGCC – SOFC	IGCC – H	SC PC	USC PC
Net MW Output	310.8	517.4	386.8	329.5	367.4
Net Plant Efficiency	43.3%	41.6%	35.4%	28.9%	31.0%
TPC \$/kW	943	N/A	1,510	1,980	1,943
LCOE mills/kWh at 65% Capacity Factor 80% Capacity Factor	 54.1 48.8	 N/A N/A	 62.6 53.6	 85.6 73.9	 82.4 71.0
$kgCO_2$/kWh ($lbCO_2$/kWh)	0.042 (0.093)	0.043 (0.096)	0.077 (0.169)	0.108 (0.239)	0.101 (0.222)

Notes: TPC on December 1999 dollar basis; LCOE on constant dollar basis

In order to ensure that corrosion does not occur downstream of the gasifier in case 3A, a water scrubber was added and new performance calculated. The result is case 3E, which, due to increased steam injection requirements as a result of syngas water loss in the scrubber, is somewhat less efficient. Case 3E, then, replaces case 3A as the representative IGCC plant configuration with CO_2 removal in this study.

As can be seen in Table ES-1 and Table ES-2, the configurations with CO_2 removal each decrease plant CO_2 emissions by 90 percent, and have lower net plant power output and increased heat rates as compared to their corresponding case with no CO_2 removal. 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 ES-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, generated with the H-based NGCC case 1D. Case 2A, which includes 90 percent CO_2 removal, produces 517 MWe at a net plant efficiency of 41.6 percent HHV. This configuration, like that of case 2B, shows a 1.7 point decrease in net plant efficiency when compared to the H-based NGCC with CO_2 removal, case 1B.

Cost of CO_2 Avoided

It is usually considered appropriate in global climate-related studies to express the CO_2 mitigation costs as $/tonne of CO_2 avoided. 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:

$$MC = \frac{COE_{withremoval} - COE_{reference}}{E_{reference} - E_{withremoval}}$$

The costs of CO_2 avoided for the main comparison case sets are shown in Table ES-3 for the NGCC, IGCC, SC PC, and USC PC technologies.

Table ES-3
COSTS OF CO_2 AVOIDED FOR NGCC, IGCC, AND PC

Technology	NGCC H Cases 1B vs. 1D	IGCC H Cases 3E vs. 3B	SC PC Cases 7A vs. 7C	USC PC Cases 7B vs. 7D
$/tonne ($/ton) CO_2 Avoided at 65% CF	68.8 (75.8)	23.2 (25.6)	51.0 (56.2)	49.5 (54.6)
$/tonne ($/ton) CO_2 Avoided at 80% CF	60.4 (66.6)	19.5 (21.5)	43.6 (48.1)	42.4 (46.7)

Notes: Calculation must be done in metric units, then converted to English units to match table results.
Cases 1D, 3B, 7C, and 7D are without CO_2 removal
Cases 1B, 3E, 7A, and 7B are with CO_2 removal

Allowable Capital Cost for Coal Technologies for Breakeven with NGCC

One way of analyzing the 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 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 percent capacity factor (CF) in previous studies for the U.S. DOE; however, EPRI typically uses a higher CF of 80 percent for base load plants. The effect of using the higher CF is to improve the competitiveness of the coal technologies so that they break even with NGCC at lower natural gas prices. The calculated allowable Total Plant Cost (TPC) costs for breakeven LCOE with and without CO_2 removal are shown in Table ES-1 for the IGCC and PC technologies evaluated at 80 percent CF using the case 1B costs for NGCC with H frame gas turbines. Table ES-2 shows the same cases evaluated at 65 percent CF.

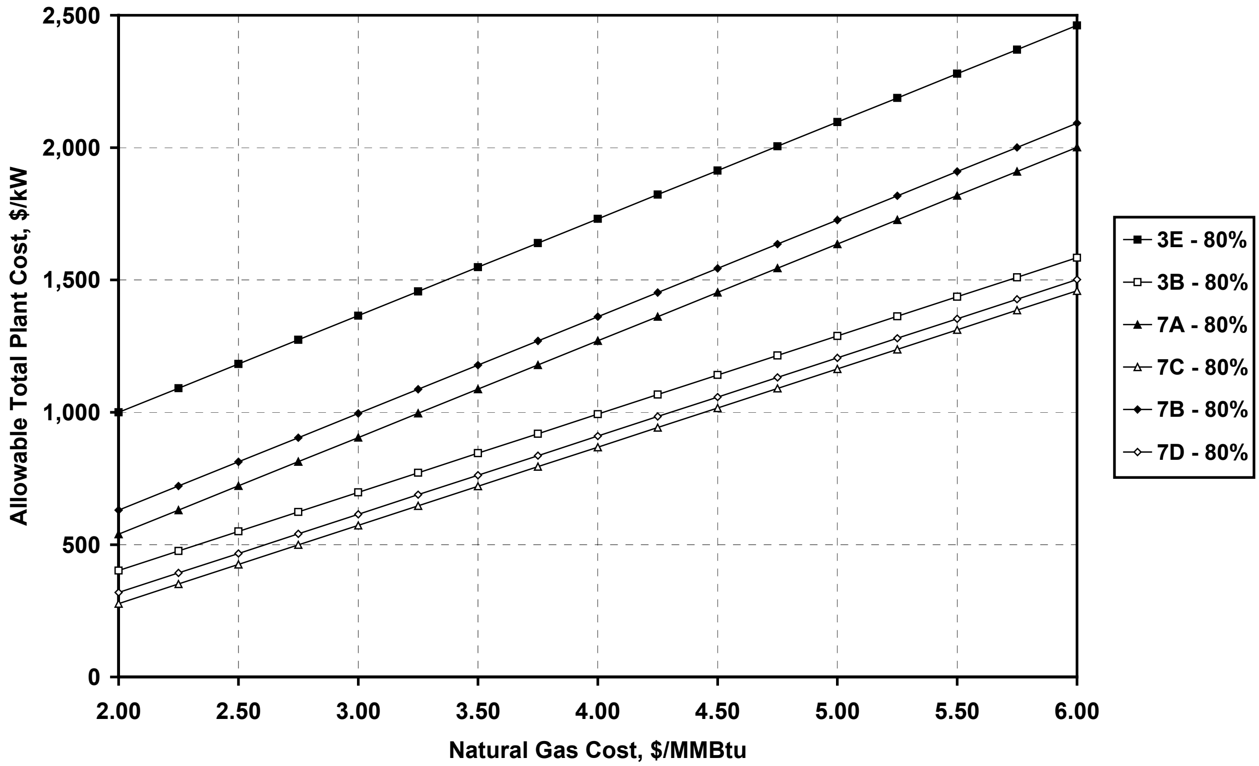

Figure ES-1
Approximate Allowable Capital Costs for Breakeven COE
(Based on Class H NGCC and 80% Capacity Factor)

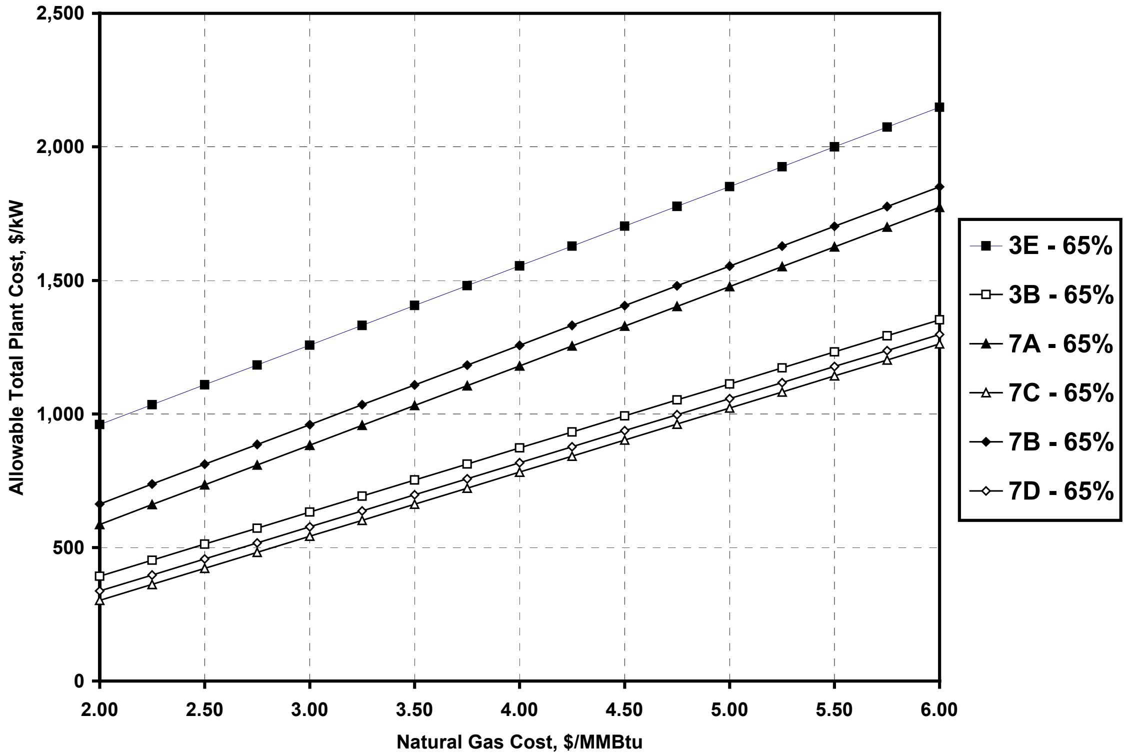

Figure ES-2
Approximate Allowable Capital Costs for Breakeven COE
(Based on Class H NGCC AND 65% Capacity Factor)

From the upper curves in Figure ES-1 and Figure ES-2, for cases with CO_2 removal, the IGCC case (with a TPC of $1,510/kW) shows a breakeven cost of natural gas of $3.65/GJ ($3.85/MMBtu) when evaluated at a 65 percent CF and $3.22/GJ ($3.40/MMBtu) at 80 percent CF. For the two PC cases with TPCs of $1,980 and $1,943/kW, the corresponding natural gas costs are $6.34 and $5.98/GJ ($6.69 and $6.31/MMBtu) when evaluated at the 65 percent CF and $5.63 and $5.30/GJ ($5.94 and $5.59/MMBtu) at the 80 percent CF.

The IGCC and PC cases without CO_2 removal are also shown in the lower curves of Figure ES-1 and Figure ES-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 with natural gas at $4.16/GJ ($4.39/MMBtu) versus $4.69/GJ ($4.95/MMBtu) and $4.59/GJ ($4.84/MMBtu) for the SC and USC cases, respectively, when evaluated at 80 percent 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 at ~16 to 18 mills/kWh higher than for the IGCC plant. The breakeven cost with natural gas for the IGCC at $3.22/GJ ($3.40/MMBtu) is about $2.08 to $2.41/GJ ($2.19 to $2.54/MMBtu) lower than for the PC plants.

Adjustment to Same CO_2 Emissions/kWh

The cases with CO_2 removal were all designed at 90 percent 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 0.039 kg/kWh (0.088 lb/kWh) versus 0.077 kg/kWh (0.170 lb/kWh) for IGCC and 0.106 and 0.098 kg/kWh (0.233 and 0.216 lb/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 for the coal technologies.

To achieve the same emissions as the IGCC case, the NGCC needs to remove only 82 percent 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 percent of the CO_2 with further increases in net plant output and reduction of LCOE.

The key plant characteristics of the NGCC 90 percent, 82 percent, and 73 percent removal cases are shown in Table ES-4. Case 1B was explicitly calculated, while cases 1E and 1F were estimated by scaling from case 1E. The revised breakeven natural gas costs for the coal technologies based on these three NGCC H cases are shown in Table ES-5.

When evaluated at the same CO_2 emissions per kWh, the breakeven cost of natural gas to compete with IGCC rises from $3.22/GJ to $3.45/GJ ($3.40/MMBtu to $3.64/MMBtu); for SC PC and USC PC, the breakeven cost rises from $5.60/GJ and $5.08/GJ ($5.91/MMBtu and $5.36/MMBtu) to $6.16/GJ and $5.63/GJ ($6.50/MMBtu and $5.94/MMBtu), respectively. This larger increase for the PC plants is a result of the higher residual CO_2 emissions (0.106 kg/kWh [0.233 lb/kWh] and 0.098 kg/kWh [0.216 lb/kWh]) than for the IGCC plants (0.077 kg/kWh [0.170 lb/kWh]).

Table ES-4
Key Results of NGCC – H Cases with 82% and 73% CO_2 Removal

Case Number	**1B**	**1E**	**1F**
Description	NGCC – H	NGCC – H	NGCC - H
% CO_2 Removal	90	82	73
Net MW Output	310.8	317.4	324.7
Net Plant Efficiency (HHV Basis)	43.3%	44.3%	45.2%
Heat Rate kJ/kWh (Btu/kWh) (HHV Basis)	8,311 (7,879)	8,134 (7,711)	7,955 (7,542)
TPC $/kW	943	903	866
LCOE mills/kWh at 80% CF	48.8	47.03	45.28
kgCO_2/kWh (lbCO_2/kWh)	0.042 (0.093)	0.073 (0.161)	0.108 (0.238)

Table ES-5
REVISED BREAKEVEN NATURAL GAS COSTS FOR COAL TECHNOLOGIES EVALUATED AT THE SAME CO_2 EMISSIONS PER KWH

Case Number	**3E**	**7A**	**7B**
Description	IGCC H	SC PC	USC PC
% CO_2 Removal	90	90	90
kgCO_2/kWh	0.077	0.108	0.101
lbCO_2/kWh	0.169	0.239	0.222
Breakeven Cost of Natural Gas $/GJ ($/MMBtu) @ 80%CF			
90% removal from NGCC	3.22 (3.40)	5.60 (5.91)	5.08 (5.36)
82% removal from NGCC	3.45 (3.64)	5.88 (6.20)	5.35 (5.64)
73% removal from NGCC	3.68 (3.88)	6.16 (6.50)	5.63 (5.94)

Comparison of Comparable IGCC and PC Plant Sizes

It is useful to compare IGCC with PC plants of similar size in order to see which may offer an advantage over NGCC when CO_2 removal technologies are applied. For the IGCC case with CO_2 removal, the coal feed was increased above that of the base case such that the gas turbine was fully loaded. Net plant power output was reduced from the base case value of 424.5 MW without CO_2 removal to 386.8 MW with CO_2 removal. This plant power loss was incurred due to inclusion of the CO_2 removal equipment and is unavoidable. The only way to match net plant power output would be through supplemental firing with energy input to the steam turbine. This was not pursued because it would decrease net plant efficiency.

For the original PC cases (cases 7A and 7B), the coal feed rate was kept the same for both the base cases and cases with CO_2 removal. Because of this a significant drop in net plant power output was realized when CO_2 removal was added: 462 to 329.5 MW for SC PC and 506.2 to 367.4 MW for USC PC. For comparison sake, coal feed rates were modified in cases 7F (SC PC) and 7G (USC PC) such that nominal net plant power outputs matched that of case 3E. This approach would improve the PC coal-fired cases since the plants with CO_2 removal would achieve some capital cost advantages due to the larger scale. The key characteristics of the PC plants adjusted in this manner are shown in Table ES-6.

Table ES-6
IGCC PLANTS COMPARED WITH PULVERIZED COAL PLANTS OF EQUAL SIZE

Case Number	3E	7F	7G
Description	IGCC	SC PC	USC PC
Net MW Output	386.8	379.5	384.6
TPC $/kW	1,510	1,902	1,915
LCOE mills/kWh 65% Capacity Factor 80% Capacity Factor	 62.6 53.6	 82.8 71.6	 81.4 70.2
Breakeven Cost of Natural Gas at 80% CF $/GJ ($/MMBtu) HHV	3.22 (3.40)	5.49 (5.79)	5.01 (5.29)

Table ES-6 shows that IGCC has COE benefits over PC plants of the same size. The PC LCOE at 66.1 to 67.3 mills/kWh is significantly more than the IGCC at 53.6 mills/kWh at 80 percent CF. The breakeven cost of natural gas for the PC cases at $5.01 to $5.49/GJ ($5.29 to $5.79/MMBtu) is also still much higher than that for the IGCC case at $3.22/GJ ($3.40/MMBtu) at 80 percent CF.

Many of the ultra-supercritical PC plants currently entering service in Japan are about 800 to 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, the outcome would not be affected. The preliminary TPC estimate of 807 MW net output was ~$1,700/kW for the SC PC and ~$1,440/kW for the two-train IGCC.

At this TPC differential and with the other performance characteristics (heat rate, operating costs) similar to the 400 to 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.

Additional IGCC Cases

Three additional coal-fired IGCC cases were studied, two of which involve feeding a CO_2/coal slurry to an E-Gas™ gasifier rather than the conventional water/coal slurry. The other case is a single-train IGCC based on estimates of future expected 7FA+ gas turbine performance. It is anticipated that the power output of this gas turbine may be increased from 197 MWe currently to approximately 210 MWe. The results of these cases are shown in Table ES-7. At this time the cost estimation has not been completed for these cases, so cost comparisons to the previously completed work are not possible at this time.

Table ES-7
ADDITIONAL IGCC CASE DATA

Case Number	8A	8B	9A
Slurry Type	CO_2/Coal	CO_2/Coal	Water/Coal
ASU Integration	0%	0%	50% (H/P)
Syngas Diluent	Steam	Steam	N_2 / Water
Gas Turbine	H	H	7FA+
CO_2 Removal?	Yes	Yes	No
Net MW Output	365.1	381.1	583.6
Net Plant Efficiency (HHV Basis)	35.2%	36.8%	39.6%
TPC $/kW	N/A	N/A	N/A

CO_2 Slurry Cases

Cases 8A and 8B were performed in order to determine the effect of using a supercritical CO_2 and coal slurry on plant cost and performance when 90 percent CO_2 removal is required.

To this end, a high-pressure E-Gas™ gasifier was chosen as the basis for this IGCC configuration. Supercritical CO_2 is used to slurry the coal, rather than the more traditional water-based slurry approach. Raw fuel gas exiting the gasifier is cooled either by direct water quench (8A) or by raw gas cooler (8B). Particulate matter is then removed from the cool raw fuel gas stream in a metallic candle filter. The particulate-free fuel gas stream is then 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 the use of a double-stage Selexol unit. CO_2 is then dried and compressed to supercritical conditions for pipeline transport. A portion of the CO_2 is routed to the coal handling and feed preparation section for slurry preparation. Clean fuel gas from the Selexol unit, now rich in H_2, is fired in the combustion turbine for power generation. Waste heat is recovered from this process and is used to raise steam that is fed to a steam turbine.

It was the preliminary judgment of the project team that this configuration may make sense only when CO_2 removal is required; therefore, a "power-only" case was not performed. Table ES- contains performance data for cases 8A and 8B. Due to the small changes in performance for Cases 8A (-0.2%) and 8B (1.4%) compared to case 3E, and the anticipated increase in capital and operating costs of these plants, detailed cost estimates were not performed.

7FA Gas Turbine-Based IGCC

It is anticipated that, in the future, the GE 7FA+ gas turbine may be uprated to approximately 210 MWe. With that goal in mind, case 9A was performed.

Case 9A consists of an elevated-pressure air separation unit (ASU), which receives 50 percent of its air requirement from the 7FA gas turbine, and produces 95 mole% oxygen for gasification and nitrogen for syngas dilution. The conventional-pressure E-Gas™ gasifier is fed a slurry of water and coal and produces raw fuel gas that is fed to a fire-tube boiler for high-pressure steam generation. The raw gas is cooled, sent to a water scrubber, and through a COS hydrolysis unit prior to being cooled to approximately 37.8°C (100°F) for feed to acid gas removal. A Claus plant and tail gas treatment unit are used to generate elemental sulfur and a tail gas, which is incinerated. The clean syngas is passed through a humidification tower and reheated prior to being sent to the gas turbine combustor, where it is diluted further with nitrogen for NOx control. Gas turbine exhaust is sent to a heat recovery steam generator (HRSG) for further steam generation. Other low-level heat recovery is used to increase the thermal performance of the cycle.

This case is comparable to case 3B, though with a smaller gas turbine. A case is to be run with CO_2 removal, though it was not complete at the time of publication. Table ES-7 contains performance data for this case.

LIST OF ACRONYMS AND ABBREVIATIONS

A/E	Architect/engineer
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
CF	Capacity factor
CO_2	Carbon dioxide
COE	Cost of electricity
COS	Carbonyl sulfide
CRT	Cathode ray tube
CS	Carbon steel
CT	Combustion turbine
CWT	Cold water temperature
dB	Decibel
DCS	Distributed control system
DLN	Dry low NOx
DOE	Department of Energy
E-Gas™	Global Energy gasifier technology
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
gpm	Gallons per minute
GT	Gas turbine
h	Hour

H_2	Hydrogen
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 (absolute pressure)
IGCC`	Integrated gasification combined cycle
IP	Intermediate pressure
ISO	International Standards Organization
kV	Kilovolt
kWe	Kilowatts electric
kWh	Kilowatt-hour
lb	Pound
LCOE	Levelized cost of electricity
LHV	Lower heating value
LP	Low pressure
MC	Mitigation cost
MCR	Maximum coal burning rate
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MHz	Megahertz
MMBtu	Million British thermal units (shown as 10^6 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
SC	Supercritical
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SOFC	Solid oxide fuel cell
SS	Stainless steel
TAG	Technical Assessment Guide
TGTU	Tail gas treating unit
TPC	Total plant capital (cost)
tpd	Tons per day
tph	Tons per hour
USC	Ultra-supercritical
WB	Wet bulb
wt%	Weight percent

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1
INTRODUCTION

In October 2000 Parsons created an Interim Report, "Natural Gas and Coal Baseline Plants, Interim Report – October 2000," based on the study work completed to that point. This report, to be referred to herein as Interim Report, October 2000, or the original Interim Report, was subsequently released by both the United States Department of Energy's National Energy Technology Laboratory and the Electric Power Research Institute, who co-funded the work, under the title "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal." This Interim Report represents the work completed since that release and follows a similar format.

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 competitiveness with NGCCs is through the use of advanced coal-fired power plants that utilize advanced 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. In addition, some advanced systems and sensitivity analyses are reported. 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 is 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 H class. Five advanced technology cases were identified – four coal-based and one natural-gas-based. Each cycle incorporated a process to limit CO_2 emissions by 90 percent. Once identified, a heat and material balance will be used to estimate system performance. The results of the system performance estimate, and the heat and material balance, will then be 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 cycles (IGCC) utilizing H class turbine technology. Both cases utilize entrained-bed gasification technology currently in commercial demonstration under DOE's Clean Coal Technology 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 with no 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 with no 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**

  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 – 80 Percent CGE IGCC with CO_2 Removal

Case 3D – 80 Percent CGE IGCC without CO_2 Removal

Case 3E – Sensitivity of Case 3A with Water Scrubber
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

  Case 7F – Sensitivity of Case 7A with Power Output to Match Case 3E

  Case 7G – Sensitivity of Case 7B with Power Output to Match Case 3E

- **CO_2 Slurry Gasification Configurations**

  Case 8A – Gasification with CO_2 – Direct Water Quench Option

  Case 8B – Gasification with CO_2 – Raw Gas Cooler Option

- **Additional Coal-Fired Configurations**

  Case 9A – Base Case IGCC Plant without CO_2 Removal (Class F Gas Turbine)

  Case 9B – Base Case IGCC Plant with CO_2 Removal (Class F Gas Turbine)

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 (2A and 2B), the set of advanced coal-fired base cases (3A, 3B, and 3E), all of the conventional coal-fired cases (7A through 7D), the CO_2 slurry gasification cases (8A and 8B), and conventional coal-fired base cases (9A and 9B). Thermal performance and heat and mass balances are provided for the sensitivity cases (3C, 3D, 7E, 7F, and 7G). 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 is to evaluate several 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 H class or conventional coal-fired plants. The inputs to the coal-fired power plants will be coal, air, and water. The outputs will be electricity, slag, sulfur, and pressurized high purity CO_2. The plants will be 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 will be collected in a form suitable for reuse or sequestration. For example, solid wastes will be acceptable for recycling into building and construction uses, and sulfur will be recycled to the chemical industry. CO_2 will be 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 dry bulb temperature for mechanical design is –6.7°C (20°F).

Table 1-1
SITE CHARACTERISTICS

Topography	Level
Elevation	152.4 m (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

- Illinois No. 6 coal — 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 2A, 2B, 3C, 3D, 7E, 8A, and 8B are performance cases only.

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 (Btu/lb)	11,666	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

1.3 Case Descriptions

The following power system configurations will be evaluated. Performance results for cases 2A and 2B, 3C through 3E, 7F and 7G, 8A and 8B, and 9A and 9B are presented in this Interim Report. The remaining cases were documented in the Interim Report published in October 2000.

- **Natural Gas Base Configurations:**

  Case 1A – Two-train GE 7FA natural gas combined cycles, each with its own heat recovery steam generator (HRSG) and a single steam turbine, with CO_2 removal.

  Case 1B – Single-train GE H class natural gas combined cycle with a single HRSG and steam turbine, with CO_2 removal.

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

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

Case 2A – 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.

Case 2B – As case 2A but without 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 carbonyl sulfide (COS) hydrolysis), gas cooling with heat recovery including raising hot water for gas saturation, two-stage Selexol for hydrogen disulfide (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 to 15.27 MPa (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 (without CO_2 removal) but with E-Gas™ gasifier with cold gas efficiency (CGE) at 80 percent (HHV basis).

Case 3D – As case 3A (with CO_2 removal) but with E-Gas™ gasifier at 80 percent CGE (HHV basis) and 5.6 MPa (800 psig).

Case 3E – As case 3A (with CO_2 removal) but with an added water scrubber for particulate removal prior to the water-gas shift reactors.

Case 4 – Gasification island as in case 3D (with CO_2 removal) 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 24.1 MPa/ 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, and selective catalytic reduction (SCR) with MEA absorption for NOx and CO_2 removal.

Case 7B – As case 7A but with steam conditions 34.5 MPa/649°C/649°C/649°C (5000 psig/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 7D but with steam conditions 37.6 MPa/700°C/700°C/720°C (5440 psig/1290°F/1290°F/1330°F.

Case 7F – As case 7A but with power output to match case 3E.

Case 7G – As case 7B but with power output to match case 3E.

- **CO_2 Slurry Gasification Configurations:**

  Case 8A – High-pressure, supercritical CO_2 coal slurry-fed E-Gas™ IGCC. Steam conditions 12.4 MPa/566°C/566°C (1800 psig/1000°F/1000°F), i.e., single reheat. Low pressure air separation unit (ASU), E-Gas™ gasifier, direct water quench, particulate removal by candle 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 and partial recycle for coal slurrying, 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 to 15.27 MPa (2200 psig).

  Case 8B – As case 8A but with a raw gas cooler instead of direct water quench.

- **GE 7FA Gas Turbine-Based IGCC Configurations:**

  Case 9A – 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 (7F) to reduce gas to 5.59 GJ/scm (150 Btu/scf) LHV basis.

  Case 9B – 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 carbonyl sulfide (COS) hydrolysis), gas cooling with heat recovery including raising hot water for gas saturation, two-stage Selexol for hydrogen disulfide (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 to 5.59 GJ/scm (2200 psig).

2
NATURAL GAS COMBINED CYCLES (NGCC) – TECHNICAL DESCRIPTIONS

Section 2 is included in the original Interim Report, which was issued as a draft in October 2000.

3
ADVANCED NGCC – TECHNICAL DESCRIPTIONS

Two “advanced” natural-gas-fired combined cycle power plants were identified for this study. The designs are market-based and consist of a solid oxide fuel cell coupled with a cascaded humidified advanced turbine cycle. Plant performance was estimated and heat and material balance diagrams developed. Equipment lists were generated based on the estimated plant performance. Plant descriptions are also included.

The two cases identified are:

- Case 2A – Advanced NGCC with CO_2 Removal and Recovery
- Case 2B – Advanced NGCC without CO_2 Removal and Recovery

Case 2A utilizes a MEA-based solvent in a traditional absorber-stripper unit to remove CO_2 from the flue gas exiting the plant. CO_2 removed with the MEA unit is compressed to 8.38MPa (1200 psig) in a multi-stage, intercooled compressor. Case 2A was not analyzed from a cost perspective. Due to shortcomings inherent in the CO_2 removal methodology, the authors believe that the configuration did not warrant further pursuit outside thermal performance evaluation. These shortcomings consisted of irrecoverable losses due to the addition of heat exchange surface, the combustion of natural gas purely for use in generating steam for the regeneration of the CO_2 recovery solvent, and the tremendous steam requirement for the regeneration of the CO_2 recovery solvent. A more refined approach for CO_2 removal is required in order to proceed further. This is outside the scope and budget of this study and therefore will not be addressed further here.

There is no provision for CO_2 removal with case 2B. An economic analysis for case 2B is provided.

3.1 Case 2A – Advanced NGCC with CO_2 Removal

3.1.1 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. CO_2 is removed from the flue gas exiting the plant with a MEA-based solvent in a traditional absorber-stripper unit. The CO_2 is compressed to 8.38MPa (1200 psig) in a multi-stage, intercooled compressor. This market-based configuration has been labeled case 2A. The balanced shaft of the CHAT cycle, which mechanically couples the high-pressure expander and process air compressors, is based on industrial-type turbo machinery. The mechanical output of the expander is balanced to produce just enough work to power the compressors. 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 43,950 kWe. This results in a net plant power output of 517 MWe. Net plant efficiency is estimated at 41.6 percent, HHV, with a corresponding heat rate of 8,658 kJ/kWh (8,208 Btu/kWh).

The following sections provide a more detailed discussion of plant performance and description. The individual sections are:

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

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.

The power plant configuration presented here was not analyzed from a cost perspective. The authors believed that the configuration did not warrant further pursuit outside thermal performance evaluation. The main reason for this belief was that this power plant configuration utilizes supplemental firing of natural gas in the heat recovery unit to generate steam for the MEA stripper. The authors thought that this was an abject "waste" of natural gas and represented an unrefined approach to SOFC-based CHAT with CO_2 removal. An alternative configuration, described at the end of this section, was investigated without success. Therefore, the authors decided to drop pursuit of this configuration until a more sophisticated approach could be formulated.

3.1.2 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 low-pressure (LP) expander, develops 356 MWe (363.9 MWe before generator losses), while the solid oxide fuel cell generates an estimated 204 MWe. The estimated auxiliary power load is 43.95 MWe, resulting in a net plant power output of 517 MWe. This power is generated with an expected HHV efficiency of 41.6 percent, with a corresponding heat rate of 8,658 kJ/kWh (8,208 Btu/kWh). The high auxiliary power load and low net plant thermal efficiency are due entirely to the CO_2 removal requirement and are not a reflection of either CHAT or SOFC technology as traditionally presented.

Figure 3-1 is a heat and material balance diagram for the 100 percent load condition. The schematic shows all three compressors rotating on a single shaft with the balanced-shaft turbine (or high-pressure [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 support the firing of natural gas in the balanced turbine combustor. In turn, the flue gas exiting the balanced shaft turbine supports firing additional natural gas in the power turbine. A heat recovery unit (HRU) is used to manage and effectively recover any waste heat.

Table 3-1
CASE 2A – SOFC/CHAT CYCLE WITH 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
Low-Pressure Boiler Feed Pump	210
Saturated Water Pump	250
Miscellaneous Balance of Plant (Note 1)	1,000
Expander Auxiliaries	300
Waste Water Treatment	1,210
Circulating Water Pumps	2,500
Cooling Tower Fans	1,410
Flue Gas Blower	11,740
MEA CO_2 Removal	1,750
CO_2 Compressor and Drying (Note 2)	19,840
Transformer Loss	1,760
Total Auxiliary Power Requirement	43,950
NET PLANT POWER, kWe	517,364
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	46.1
Net Heat Rate, kJ/kWh (Btu/kWh) (LHV)	7,802 (7,397)
Net Efficiency, % HHV	41.6
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	8,658 (8,208)
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	989 (938)
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 3)	88,265 (194,588)

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

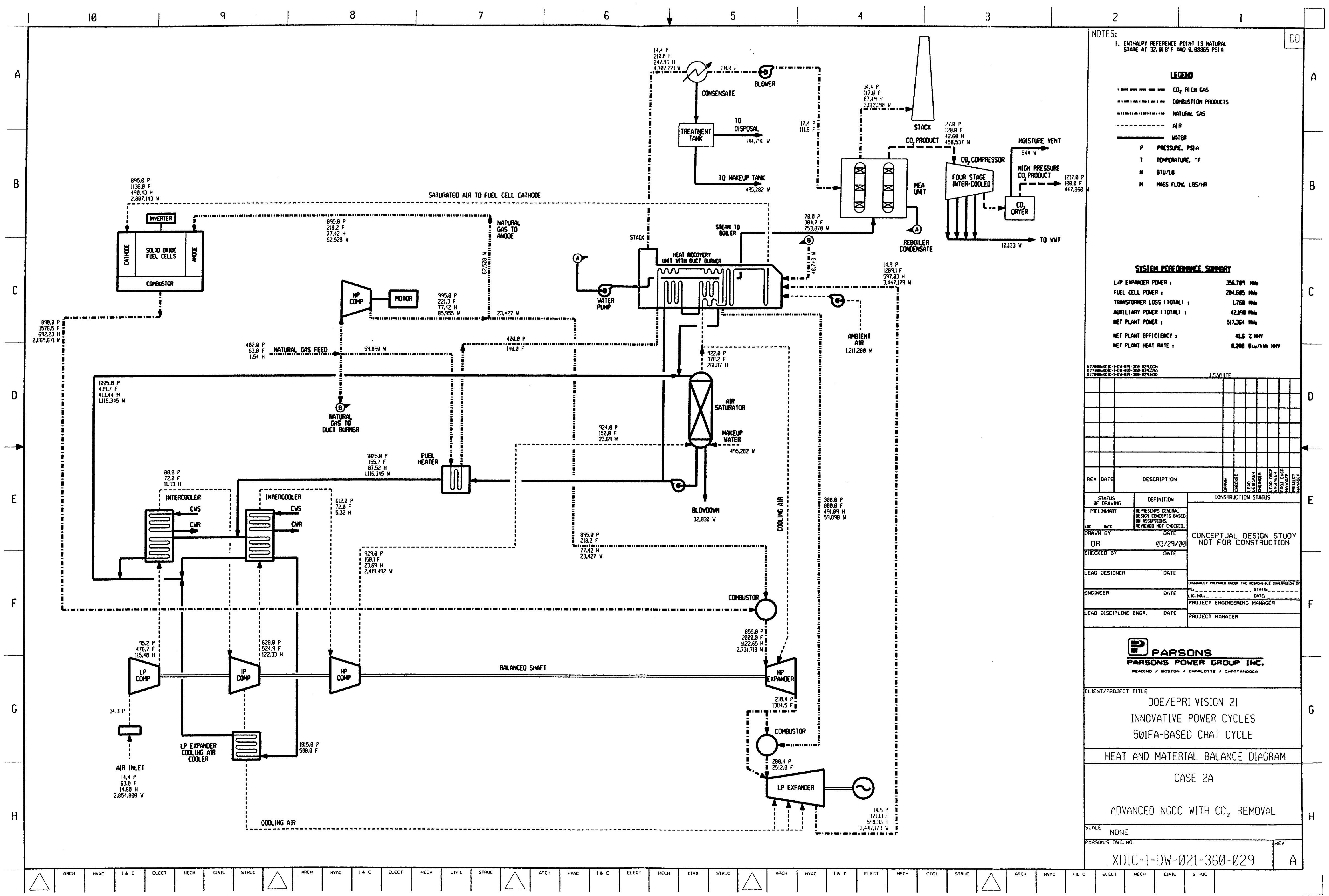

Figure 3-1
Heat and Material Balance Diagram – Case 2A – Advanced NGCC with CO_2 Removal

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3.1.3 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 bases: (1) pounds per million Btu of HHV thermal input, (2) tons per year for a 65 percent capacity factor, (3) tons per year for an 85 percent capacity factor, and (4) pounds per hour of MWe power output.

Table 3-2
CASE 2A AIRBORNE EMISSIONS
501FA-BASED CHAT CYCLE 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)	302.4 (333)	395 (435)	0.104 (0.23)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	4.7 (11)	124,282 (136,872)	162,517 (178,980)	42.2 (93)

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 by the high moisture level in the airflow to the HP and LP combustors. The CHAT cycle characteristically produces very low NOx levels due to the high moisture level acting as a diluent to the O_2 and fuel, and reducing the adiabatic flame temperature. This phenomenon should limit NOx emissions to 9 ppm adjusted to 15 percent O_2 content in the flue gas.

3.1.4 System Description

Ambient air is compressed to 0.66MPa (95.2 psia) in the low-pressure compressor. The air stream is indirectly cooled to 22°C (72°F), first by exchange with process water from the saturator and then with plant cooling water. The air is further compressed to 4.33 MPa (628 psia) in the intermediate-pressure (IP) compressor. An inter-stage bleed provides turbine-cooling air to the power expander. Turbine-cooling air is cooled indirectly via exchange with process water from the saturator before being routed to the expander. Main air flowing from the IP compressor is indirectly cooled to 22°C (72°F), first by exchange with process water for the saturator and then with plant cooling water. The cool main air stream is then compressed to 6.41MPa (929 psia).

The high-pressure air stream, with a moisture content of 0.09 percent H_2O, is directed to the bottom of the air saturation column. In the column, high-pressure air will be directly contacted with warm water flowing down the column counter-current to the air stream. Contact with the warm water heats and humidifies the high-pressure air stream. Tower packing, rings, or trays will be used to enhance the rate of mass transfer between water and air. Moist air exits the top of the saturator at 6.36MPa (922 psia) and 192.2°C (378°F). The moisture content of the air stream is now 24 percent H_2O. The moist air stream is then heated to 613°C (1136°F) in the heat recovery unit and routed to the fuel cell cathode.

Compressed natural gas at 6.17MPa (895 psia) and 103°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. Cell reactions take place at temperatures above 982°C (1800°F). The saturated air stream and spent fuel stream are then combined and combusted. Flue gas exits the fuel cell at 6.14MPa (890 psia) and 854°C (1570°F).

High-temperature flue gas from the fuel cell combustor supports the combustion of heated natural gas in the balanced expander combustor. Flue gas exiting the combustor enters the balanced expander at 5.9MPa (855 psia) and 1093°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 air compressor units.

Flue gas, at 1.45MPa (210 psia) and 752°C (1385°F), exiting the balance shaft expander supports combustion of more natural gas in the power turbine combustor. The combustion products enter the power expander at 1377°C (2510°F) and 1.38MPa (200 psia) and exit at 656°C (1213°F) and 0.1MPa (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.

In the heat recovery unit, waste heat in the flue gas is recovered by heating natural gas, heating humidified air, and generating low-pressure steam. Due to the amount of low-pressure steam required for the MEA stripper reboiler, thermal energy available in the advanced cycle exhaust gas in the HRU is inadequate. A forced draft fan supplies additional ambient air to the HRU, where it supports combustion of additional natural gas to supplement the HRU steam production..

Flue gas exiting the HRU is cooled to 43°C (110°F). This causes a large percentage of the water present in the flue gas to condense. This water is recovered and routed to the humidification tower as make-up. Cooled, dry flue gas exits the flue gas cooler and is slightly compressed to 0.12MPa (17.4 psia) in the flue gas blower prior to being routed to the MEA stripper unit.

CO_2 is removed from the flue gas stream in a conventional absorber-stripper unit through direct contact with MEA-based solvent. CO_2 is removed in the absorber. Flue gas exiting the absorber exits the plant through the chimney stack. CO_2, absorbed in the MEA solvent, leaves the absorber in liquid form. CO_2 is liberated as a gas from the liquid solvent in the stripper through the application of heat. Heat is released in the stripper reboiler by condensing low-pressure steam.

Product CO_2 from the MEA stripper is compressed to 8.27MPa (1200 psig) in a four-stage inter-cooled compressor. Condensate removed from the compressed CO_2 is routed to waste water treatment. Any moisture still present in the high-pressure CO_2 product stream is removed via molecular sieves in the CO_2 dryer.

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 of Schedule 40 carbon steel pipe, 40.6 centimeters (16 inches) nominal outside diameter (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 switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, wire, and cable. It also includes the main power transformer, 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 manually with operator selection of available modular automation routines.

3.1.5 Case 2A 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.

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	194,590 lb/h @ 600 psig 16 in. OD, Sch. 40	10 miles
2	Gas Metering Station		194,590 lb/h	1
3	Gas Heater	Shell and tube	44 x 10^6 Btu/h 200 psig / 200°F	1
4	Gas Compressor	Axial	2,570 hp 2.5:1 PR	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	40,000 gal	1
2	LP Feed Pumps	Horizontal split case Multi-staged centrifugal	1,590 gal @ 250 psia	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

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

ACCOUNT 4 BOILER AND ACCESSORIES

Not Applicable

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 210 MMBtu/h	4
2	Flue Gas Fan	Centrifugal	1,147,888 lb/h 281,650 acfm 90" WG 3,800 hp	4
3	Absorber	Packed bed 2" rings Three 20 ft 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	5,750 gpm @ 250 ft	4
10	Lean/Rich Amine Heat Exchanger	Horizontal shell	100 psig / 280°F	4
11	Lean Amine Pump	Centrifugal	5,750 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

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 1100 psig / 500°F	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 / 550°F	1
6	Cooling Air Cooler	Shell and tube	41 x 10^6 Btu/h 1020 psig / 500°F	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, 2000°F	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, 2500°F	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 (1 per shaft)	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	2
15	Air to Air Cooler			1

Equipment No.	Description	Type	Design Condition	Qty
16	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
17	Oil Cooler	Finned air cooler with fan		1
18	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
19	Generator Glycol Cooler	Finned air cooler with 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 1050 psig / 500°F	1
2	Duct Burner	Natural-gas-fired	49,000 lb/h gas	1
3	Saturator Water Pump	Centrifugal	2,300 gpm @ 200 ft	1
4	Heat Recovery Unit	Shell and tube	1,978 x 10^6 Btu/h 4,300,000 acfm	1
5	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

3.1.6 Alternative Configuration

As mentioned in the introduction of this section, the power plant configuration presented here was not analyzed from a cost perspective. The authors believed that the supplemental firing of natural gas in the heat recovery unit, to generate steam for the MEA stripper, was a “waste” of natural gas. As such, the power plant configuration represented an unrefined approach to SOFC-based CHAT with CO_2 removal. Due to this belief, an alternative configuration was formulated and evaluated.

The first step taken in developing a new SOFC/CHAT with CO_2 removal power plant configuration centered on removing steam generation from the heat recovery unit. This action immediately created another problem: where to generate the large amounts of low-pressure steam required by the MEA stripper reboiler?

As can be seen in case 2B (discussed in Section 3.2), the SOFC/CHAT cycle is thermally balanced. All of the excess thermal energy contained in the flue gas, above 96°C (205°F), is recovered and used in the cycle. Therefore, in order to generate low-pressure steam, additional natural gas must be fired somewhere within the system in order to provide the energy to generate the steam. Ideally, combustion of this additional natural gas should be integral to the plant’s electrical power output.

The approach chosen for evaluation centered on the utilization of the sensible energy of the SOFC exhaust to raise steam for the CO_2 stripper reboiler, the idea being that “additional” natural gas could be fired in the combustor prior to the balanced shaft turbine. In this manner, the energy from the combustion of the additional natural gas would “directly” contribute to power generation and thus be “integral” to plant performance.

As proposed, this case was unworkable. The approach could generate the required steam for the MEA stripper reboiler and allows for the attainment of the balanced shaft turbine inlet temperature. However, there was not enough oxygen available in the vitiated air to support the combustion levels required in the power turbine. Nevertheless, the idea is good and should be rethought. This, however, is outside the scope and budget of this study. Therefore, the authors decided to drop pursuit of this configuration until a more sophisticated approach could be formulated.

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 market-based 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 (after generator losses). Total plant auxiliary load is estimated at 4,790 kWe. 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
- Cost Estimate

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 3-3 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant. The power turbine, or low-pressure (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).

Table 3-3
CASE 2B – SOFC/CHAT CYCLE WITH NO 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, kJ/kWh (Btu/kWh) (LHV)	5,436 (5,154)
Net Efficiency, % HHV	59.7
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	6,029 (5,716)
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	N/A
CONSUMABLES	
Natural Gas, kg/h (lb/h) (Note 3)	66,155 (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 (21,824Btu/lb).

Figure 3-2 contains a heat and material balance diagram for the 100 percent load condition. The schematic shows all three compressors rotating 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 support the firing of natural gas in the balanced turbine combustor. In turn, the flue gas exiting the balanced shaft turbine supports firing additional natural gas in the power turbine. A heat recovery unit is used to manage and effectively recover any waste heat.

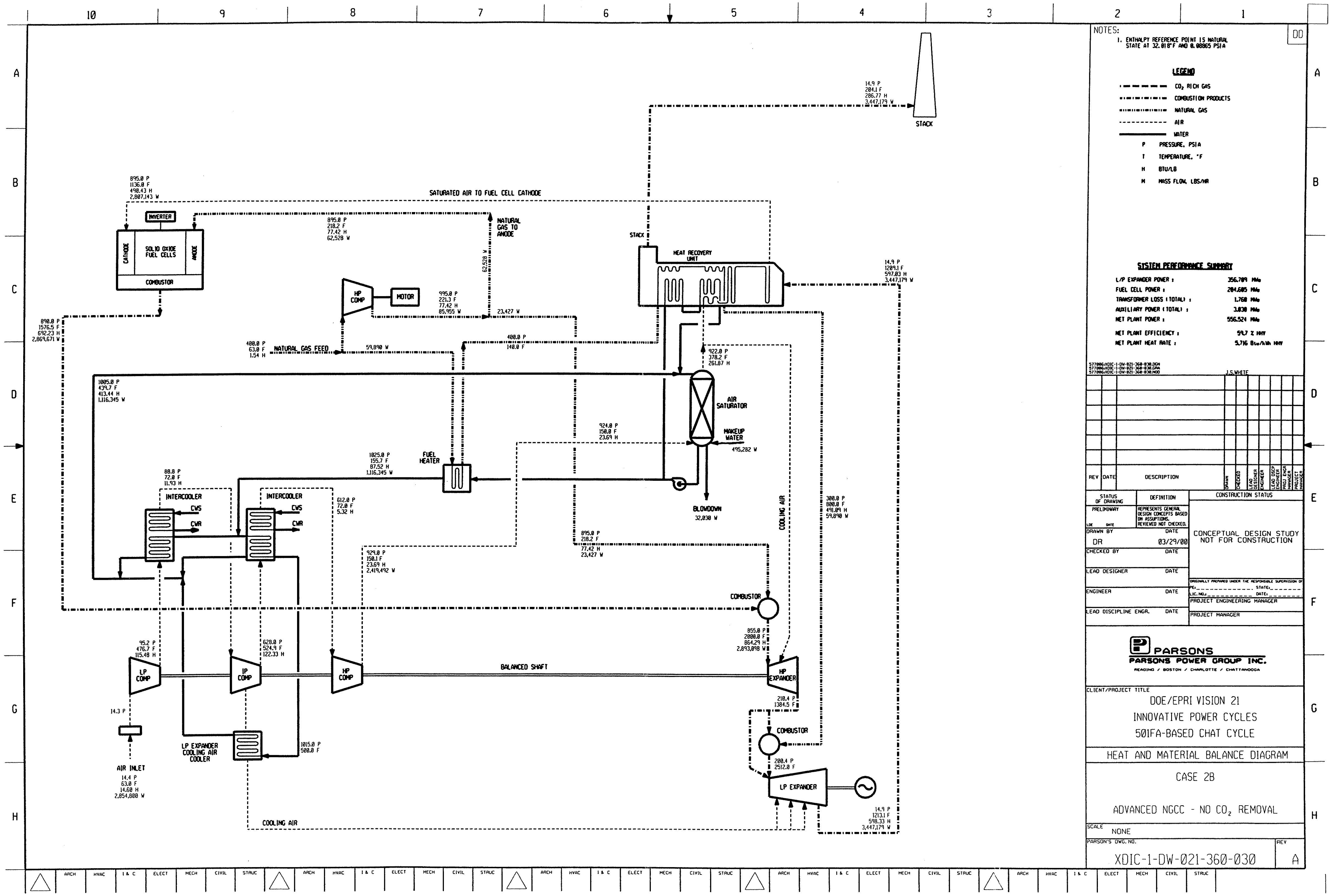

Figure 3-2
Heat and Material Balance Diagram – Case 2B – Advanced NGCC – No CO_2 Removal

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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 3-4. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four bases: (1) pounds per million Btu of HHV thermal input, (2) tons per year for a 65 percent capacity factor, (3) tons per year for an 85 percent capacity factor, and, (4) pounds per hour of MWe power output.

Table 3-4
CASE 2B AIRBORNE EMISSIONS
501FA-BASED CHAT CYCLE WITH 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	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
NOx	<0.012 (< 0.028)	225 (248)	300 (330)	0.07 (0.16)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	50.1 (117)	960,083 (1,057,340)	1,255,490 (1,382,670)	303 (668)

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 high moisture level in the airflow to the HP and LP combustors dilutes the syngas, helping to achieve the low level of NOx production. The CHAT cycle characteristically produces very low NOx levels due to the high moisture level acting as a diluent to the O_2 and fuel, and reducing the adiabatic flame temperature. This phenomenon 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 0.66MPa (95.2 psia) in the low-pressure compressor. The air stream is indirectly cooled to 22°C (72°F), first by exchange with process water from the saturator and then with plant cooling water. The air is further compressed to 4.33MPa (628 psia) in the intermediate-pressure (IP) compressor. An inter-stage bleed provides turbine-cooling air to the power expander. Turbine-cooling air is cooled indirectly via exchange with process water from the saturator before being routed to the expander. Main air flowing from the IP compressor is indirectly cooled to 22°C (72°F), first by exchange with process water for the saturator and then with plant cooling water. The cool main air stream is then compressed to 6.4MPa (929 psia).

The high-pressure air stream, with a moisture content of 0.09 percent H_2O, is directed to the bottom of the air saturation column. In the column, high-pressure air will be directly contacted with warm water flowing down the column counter-currently to the air stream. Contact with the warm water humidifies the high-pressure air stream. Tower packing, rings, or trays will be used to enhance the rate of mass transfer between water and air. Moist air exits the top of the saturator at 6.36MPa (922 psia) and 192°C (378°F). The moisture content of the air stream is now 24 percent H_2O. The moist air stream is then heated to 613°C (1136°F) in the heat recovery unit and routed to the fuel cell cathode.

Compressed natural gas at 6.17MPa (895 psia) and 103°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. Cell reactions take place at temperatures above 982°C (1800°F). The saturated air stream and spent fuel stream are then combined and combusted. Flue gas exits the fuel cell at 6.14MPa (890 psia) and 854°C (1570°F).

High-temperature flue gas from the fuel cell combustor supports the combustion of heated natural gas in the balanced expander combustor. Flue gas exiting the combustor enters the balanced expander at 5.9MPa (855 psia) and 1093°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 air compressor units.

Flue gas, at 1.45MPa (210 psia) and 752°C (1385°F), exiting the balance shaft expander supports combustion of more natural gas in the power turbine combustor. The combustion products enter the power expander at 1377°C (2510°F) and 1.38MPa (200 psia) and exit at 656°C (1213°F) and 0.1MPa (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

3.2.4.1 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 of Schedule 40 carbon steel pipe, 40.6 centimeters (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 switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, wire, and cable. It also includes the main power transformer, 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 manually with operator selection of available modular automation routines.

3.2.5 Case 2B Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 3-2. 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.

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 / 200°F	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	Horizontal, 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 1100 psig / 500°F	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 1130 psig / 550°F	1
6	Cooling Air Cooler	Shell and tube	41 x 10^6 Btu/h 1020 psig / 500°F	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, 2000°F	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, 2500°F	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 (1 per shaft)	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	2
15	Air to Air Cooler			1

Equipment No.	Description	Type	Design Condition	Qty
16	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
17	Oil Cooler	Finned air cooler with fan		1
18	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
19	Generator Glycol Cooler	Finned air cooler with 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 1050 psig / 500°F	1
2	Saturator Water Pump	Centrifugal	2,300 gpm @ 200 ft	1
3	Heat Recovery Unit	Shell and tube	1,978 x 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

3.2.6 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the Natural Gas-CHAT with SOFC power plant without removal, case 2B, was 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 Ton of CO_2 Removed.

The capital cost for case 2B represents a plant with a net output of 556.5 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 3-5. A detailed estimate for case 2B is included in Appendix A.

Table 3-5
Case 2B Summary TPC Cost

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
5	CO_2 Removal and Compression	N/A
6a	CHAT Turbomachinery	84,202
6b	SOFC, Inverters & Accessories	106,543
7	HRSG, Ducting and Stack	22,728
8&9	Steam T-G Plant, including Cooling Water System	N/A
11	Accessory Electric Plant	14,354
	Balance of Plant	24,377
	SUBTOTAL	252,204
	Engineering, Construction Management Home Office and Fee	15,132
	Process Contingency	N/A
	Project Contingency	51,963
	TOTAL PLANT COST (TPC)	$319,299
	TPC $/kW	574

The production costs for case 2B consist of plant Operating Labor, Maintenance (material and labor), an allowance for Administrative & Support Labor, Consumables (including solid waste disposal), and Fuel costs. The cost includes an allowance for fuel cell stack replacement. If the stack replacement were not included, the resulting annual maintenance value would be $4,540 thousand or $3,711 thousand less than the value shown in Table 3-6. This change would result in a COE of 3.29¢/kWh or 0.13 less than if the stack replacement is included.

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 3-6, and supporting detail is contained in Appendix A.

Table 3-6
Case 2B Annual Production Cost

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	1,720	0.05
Maintenance	8,251	0.26
Administrative & Support Labor	1,255	0.04
Consumables	296	0.01
By-Product Credits	N/A	N/A
Fuel	48,905	1.54
TOTAL PRODUCTION COST	60,427	1.91

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 2B. 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 Ton 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 3-7.

Table 3-7
Case 2B Levelized Economic Result Summary
(65% Capacity Factor)

Component (unit)	Value
Production Cost (¢/kWh)	1.91
Annual Carrying Charge (¢/kWh)	1.51
Levelized Busbar Cost of Power Charge (¢/kWh)	3.42
Levelized Cost per Ton of CO_2 Removed ($/ton of CO_2 Removed)	N/A

4

ADVANCED COAL-FIRED CONFIGURATIONS – TECHNICAL DESCRIPTIONS

Five advanced coal-fired combined cycle power plants were evaluated, three of which (cases 3C to 3E) are presented in this section. The sections containing cases 3A and 3B can be found in the original Interim Report, dated October 2000. 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 five 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
- Case 3C – High-Efficiency IGCC Plant with CO_2 Removal and Recovery
- Case 3D – High-Efficiency IGCC Plant without CO_2 Removal
- Case 3E – Sensitivity of Case 3A with Added Water Scrubber

In cases 3A, 3C, and 3E, raw synthesis gas generated with a high-pressure E-Gas™-type gasifier was catalytically water-gas shifted in order to concentrate CO_2. 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. Case 3C is a sensitivity of case 3A with increased gasifier cold gas efficiency, the effect of which is increased gasifier and plant performance. Case 3E is a sensitivity of case 3A that includes a water scrubber after the gasifier and before the shift reactors for particulate removal. There was no provision for CO_2 removal in cases 3B or 3D.

Cases 3C, 3D, and 3E are described in greater detail below. Since the plant descriptions for cases 3C and 3D are largely the same as for cases 3A and 3B, respectively, they are not included in this report. In addition, equipment lists and plant economics for these cases are not included in this report, though the plant thermal performance and heat and mass balance diagrams are. Case 3E, on the other hand, will include a plant description, equipment list, and cost analysis.

4.1 Case 3A – DESTEC IGCC, H Class Turbine with CO_2 Removal

Section 4.1 is included in the original Interim Report, which was issued as a draft in October 2000.

4.2 Case 3B – DESTEC IGCC, H Class Turbine without CO_2 Removal

Section 4.2 is included in the original Interim Report, which was issued as a draft in October 2000. Updated cost estimate sheets included in Appendix A of this volume.

4.3 Case 3C – High-Efficiency E-Gas IGCC, H Class Turbine With CO_2 Removal

4.3.1 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 integrated gasification combined cycle (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. The configuration of this IGCC approach is exactly the same as described in Section 4.1 of the Interim Report, October 2000, for case 3A with the following exception: the cold gas efficiency of the E-Gas gasifier was increased from 77 percent to 80 percent. A cold gas efficiency of 80 percent represents the expected upper-limit of a mature E-Gas technology firing coal.

A detailed discussion of plant performance is given below. There is no new system description because the IGCC configuration for this case is a duplication of that described in the Interim Report, October 2000, for case 3A. However, a complete set of heat and material balances for this case is presented. Only a qualitative description of plant economics is provided. The individual sections include:

- Thermal Plant Performance
- Power Plant Emissions
- Heat and Mass Balance Diagrams
- Qualitative Discussion of Plant Economics

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. A series of heat and material balance diagrams that completely describe the thermodynamics and chemistry of the power plant is provided. These heat and material balances are fully annotated with state point data.

4.3.2 Thermal Plant Performance

The market-based plant described in this section is based on the 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 gasifier used in this evaluation is a high-efficiency E-Gas with a cold gas efficiency of 80 percent. 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 (case 1B is discussed in the Interim Report, October 2000). 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 is possible, while the gas turbine combustor temperature is modified due to the firing of synthesis gas. This can result in as much as a 20 percent increase in net plant power output, though the turbine life may be reduced by this operation. As a result, gross combustion turbine power output has been estimated at 345 MWe – the same as for case 3A – in this IGCC case as compared with 272 MWe estimated for case 1B (or case 1D – also included in the October 2000 Interim Report).

Plant auxiliary power is also summarized in Table 4-1. The total is estimated to be 81.4 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 23 MWe of auxiliary power, accounts for 28 percent of the total auxiliary power load for the entire plant.

The auxiliary power load shown in Table 4-1 is less than the 86.7 MWe required for case 3A, as summarized in Table 4.1-1 of the Interim Report, dated October 2000. The lower auxiliary power load of the case presented here is due to the higher efficiency of coal conversion to synthesis gas (i.e., cold gas efficiency). Less coal is required to generate the necessary fuel gas input to fire the gas turbine. Lower coal input values result in lower parasitic power requirements such as CO_2 compression, air separation unit (ASU) air compression, and gasifier oxidant compression. This is reflected in the lower auxiliary power demand as shown in Table 4-1.

Net plant power output for this IGCC configuration is estimated at 407.5 MWe. This power output is generated with a net plant thermal efficiency of 38.8 percent, HHV, with a corresponding heat rate of 9,279 kJ/kWh (8,797 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.

Table 4-1
CASE 3C – HIGH EFFICIENCY E-GAS 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	141,915
Generator Loss	(7,309)
Turbo-Set Power (Note 1)	479,961
Fuel Gas Expander Power	8,888
Gross Plant Power	488,849
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	350
Coal Milling	800
Coal Slurry Pumps	210
Slag Handling and Dewatering	150
Recycle Gas Blower	330
Air Separation Plant	22,870
Oxygen Boost Compressor	13,340
Selexol Plant	8,210
Claus/TGTU	100
Tail Gas Recycle	970
Humidification Tower Pump	100
Humidifier Makeup Pump	240
Low-Pressure CO_2 Compressor	770
High-Pressure CO_2 Compressor (Note 3)	23,030
Condensate Pumps	380
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	81,380
NET PLANT POWER, kWe	407,469
PLANT EFFICIENCY	
Net Efficiency, % HHV	38.8
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	9,279 (8,797)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	749 (710)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	139,387 (307,290)
Oxygen (95% pure), kg/h (lb/h)	105,712 (233,051)

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure 8.27 MPa (1200 psia)
Note 4 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

However, net plant efficiency as shown in Table 4-1 is greater than that of case 3A. Again, this is due to the greater cold gas efficiency of the gasifier. Less coal is needed to generate the required fuel gas input to the gasifier. This increases the simple cycle efficiency of the gas turbine. At the same time, due to lower coal input to the system, less waste heat is rejected to the steam turbine bottoming cycle. This has a slightly negative effect on the relative efficiency of the power block and simple cycle efficiency of the steam turbine. This loss, however, is relatively much less than the simple cycle efficiency gain of the gas turbine. The result is an improvement in net plant combined cycle efficiency.

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 subcritical 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.

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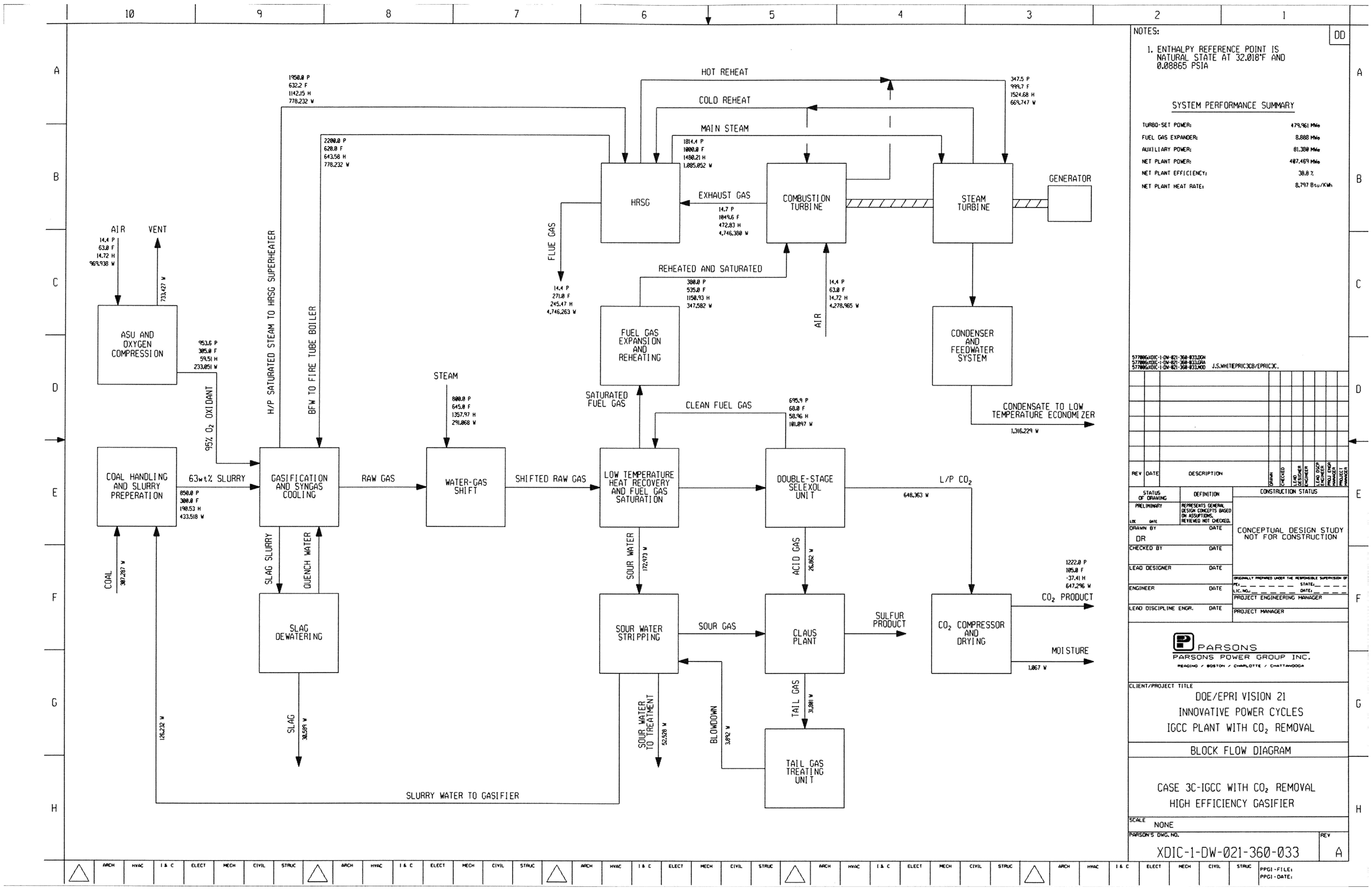

Figure 4-1
Block Flow Diagram – Case 3C – IGCC with CO_2 Removal – High Efficiency Gasifier

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4.3.3 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 high-efficiency 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 bases: (1) kilograms per gigajoule (pounds per million Btu) of HHV thermal input, (2) tonnes per year (tons per year) for a 65 percent capacity factor, (3) tonnes per year (tons per year) for an 85 percent capacity factor, and, (4) kilograms per hour (pounds per hour) of MWe power output.

Table 4-2
CASE 3C AIRBORNE EMISSIONS
H-TYPE HIGH-EFFICIENCY E-GAS 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)	259 (285)	336 (370)	0.113 (0.25)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	8.83 (20.6)	162,444 (178,900)	212,385 (233,900)	70.7 (156)

As shown in Table 4-2, values of SO_2 emissions 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. While these CO_2 levels are greater than those achieved with the same gas turbine fired on natural gas (case 1B or 1D), they are much less than those realized with coal-fired IGCC without CO_2 removal and recovery (case 3B). Also, due to less coal feed and higher net plant efficiency, the CO_2 emitted from this plant is approximately 4 percent less than that of case 3A. Cases 3A, 3B, 1B, and 1D are all described in detail in the October 2000 Interim Report.

4.3.4 Heat and Material Balance Diagrams

This greenfield power plant is a 407 MWe coal-fired IGCC power plant with CO_2 removal through the Selexol absorption process. The gasifier technology choice is a high-efficiency E-Gas, and the combustion turbine choice is based on GE’s H-type advanced turbine system. Due to the similarity between this case and that of 3A, no system description is provided; however, heat and material balances are provided. The reader is urged to review these along with the system description provided for case 3A in the October 2000 Interim Report.

The heat and material balance diagrams presented for this case are:

- Coal Gasification and ASU (Figure 4-2)
- Water-Gas Shift (Figure 4-3)
- Sulfur Recovery (Figure 4-4)
- Combined Cycle Power Generation (Figure 4-5)
- Feedwater System (Figure 4-6)

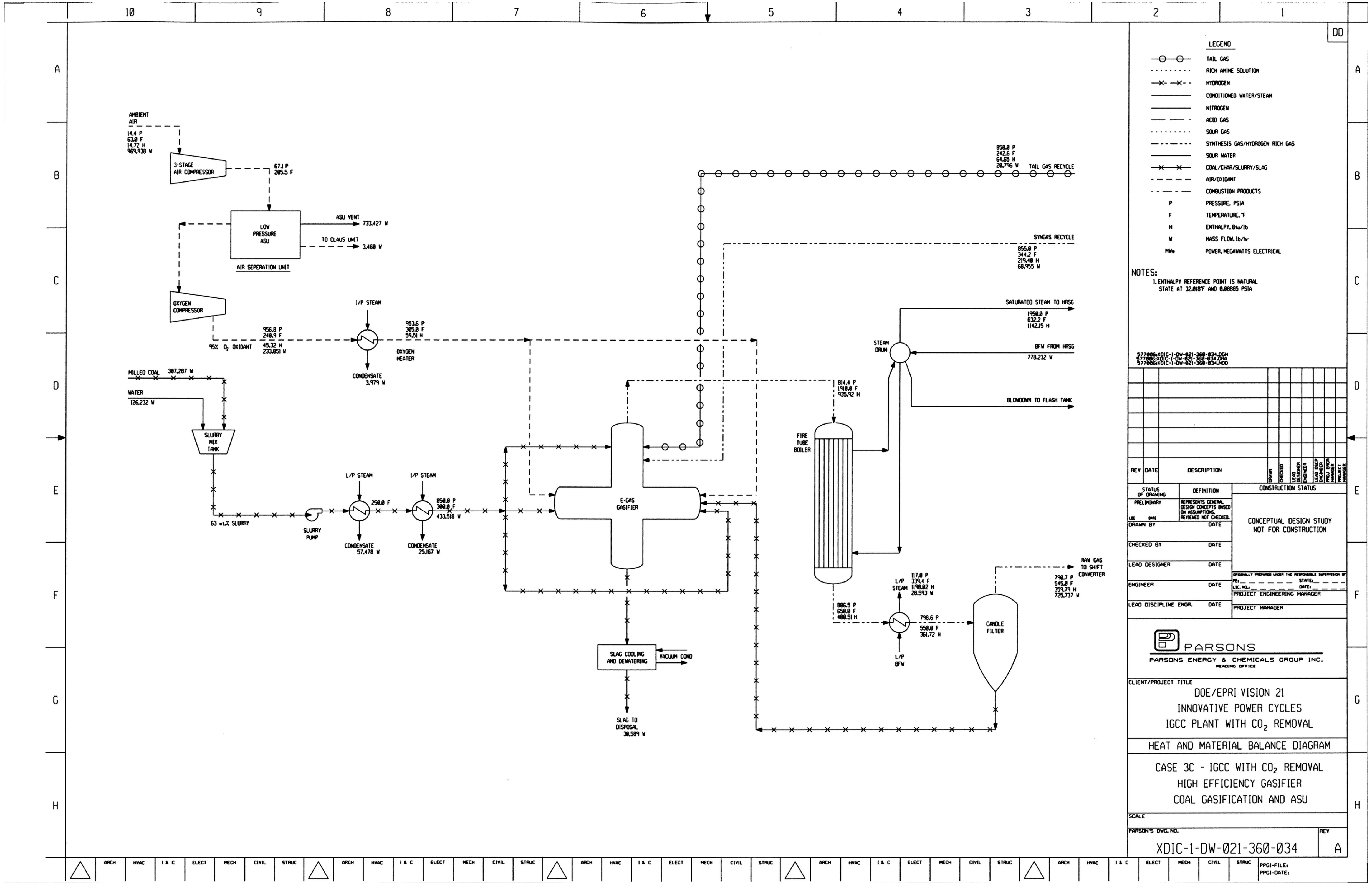

Figure 4-2
Heat and Material Balance Diagram – Case 3C – IGCC with CO_2 Removal – High Efficiency Gasifier – Coal Gasification and ASU

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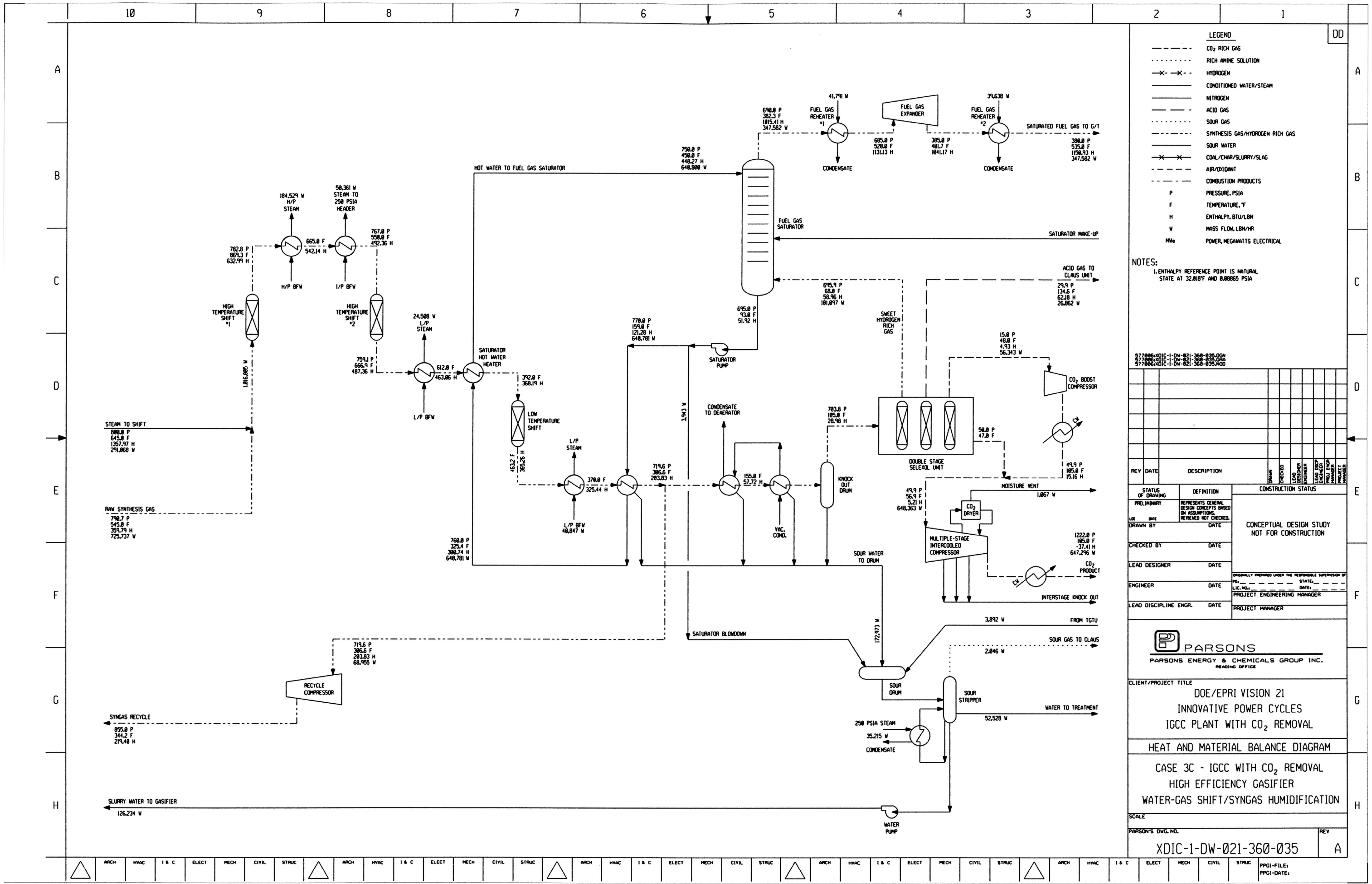

Figure 4-3
Heat and Material Balance Diagram – Case 3C – IGCC with CO_2 Removal – High Efficiency Gasifier – Water-Gas Shift/Syngas Humidification

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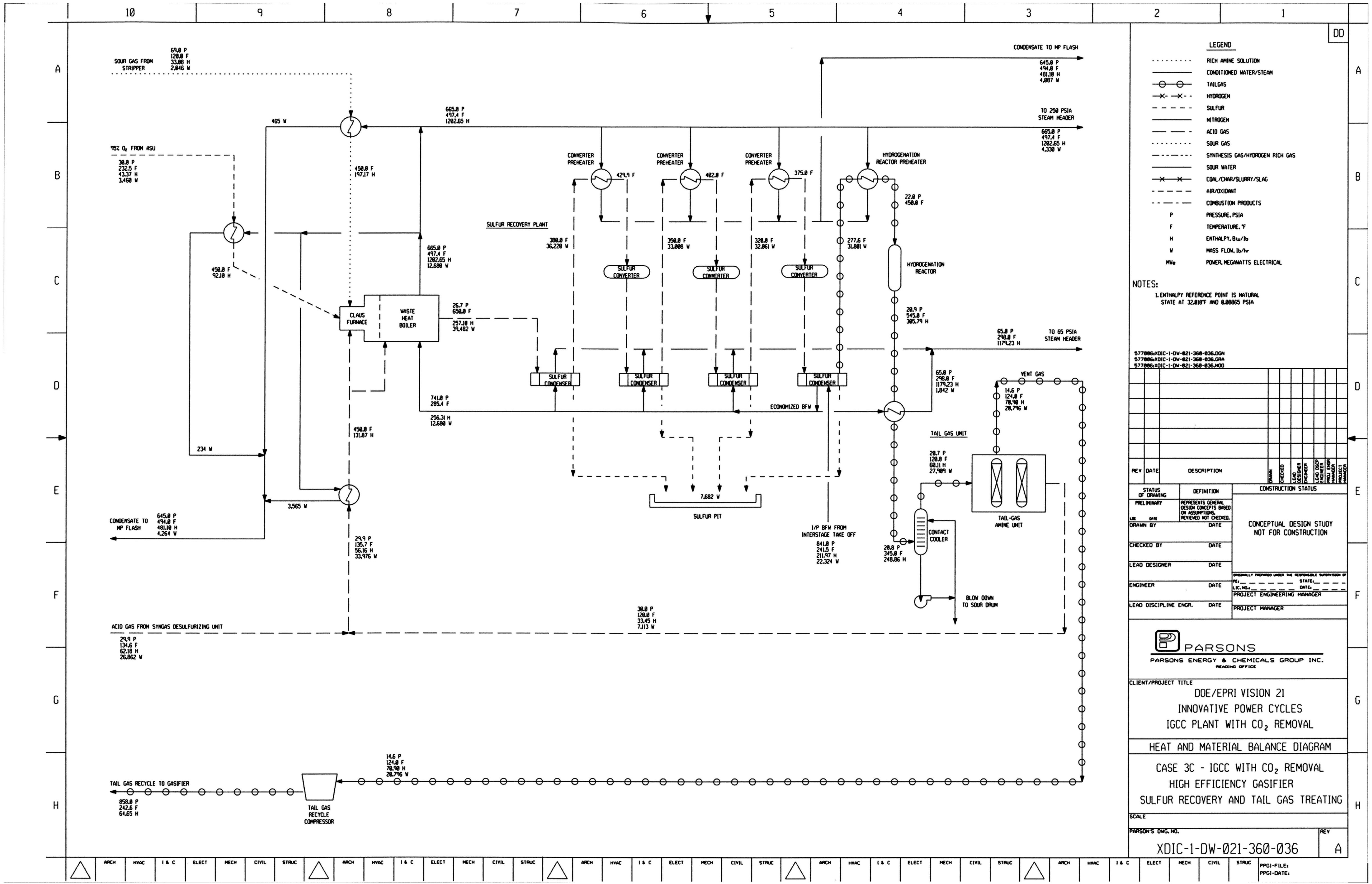

Figure 4-4
Heat and Material Balance Diagram – Case 3C – IGCC with CO_2 Removal – High Efficiency Gasifier – Sulfur Recovery and Tail Gas Treating

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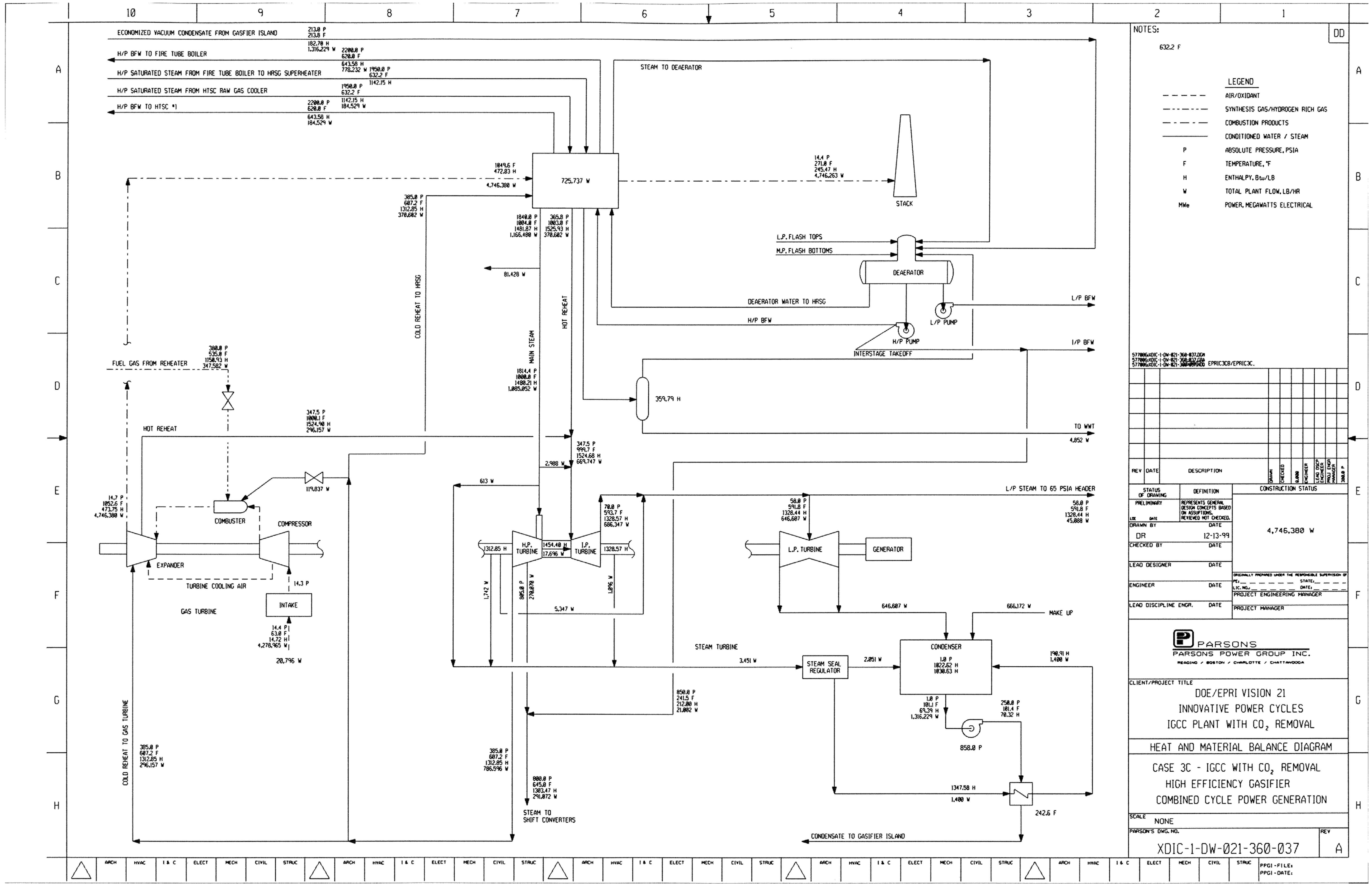

Figure 4-5
Heat and Material Balance Diagram – Case 3C – IGCC with CO_2 Removal – High Efficiency Gasifier – Combined Cycle Power Generation

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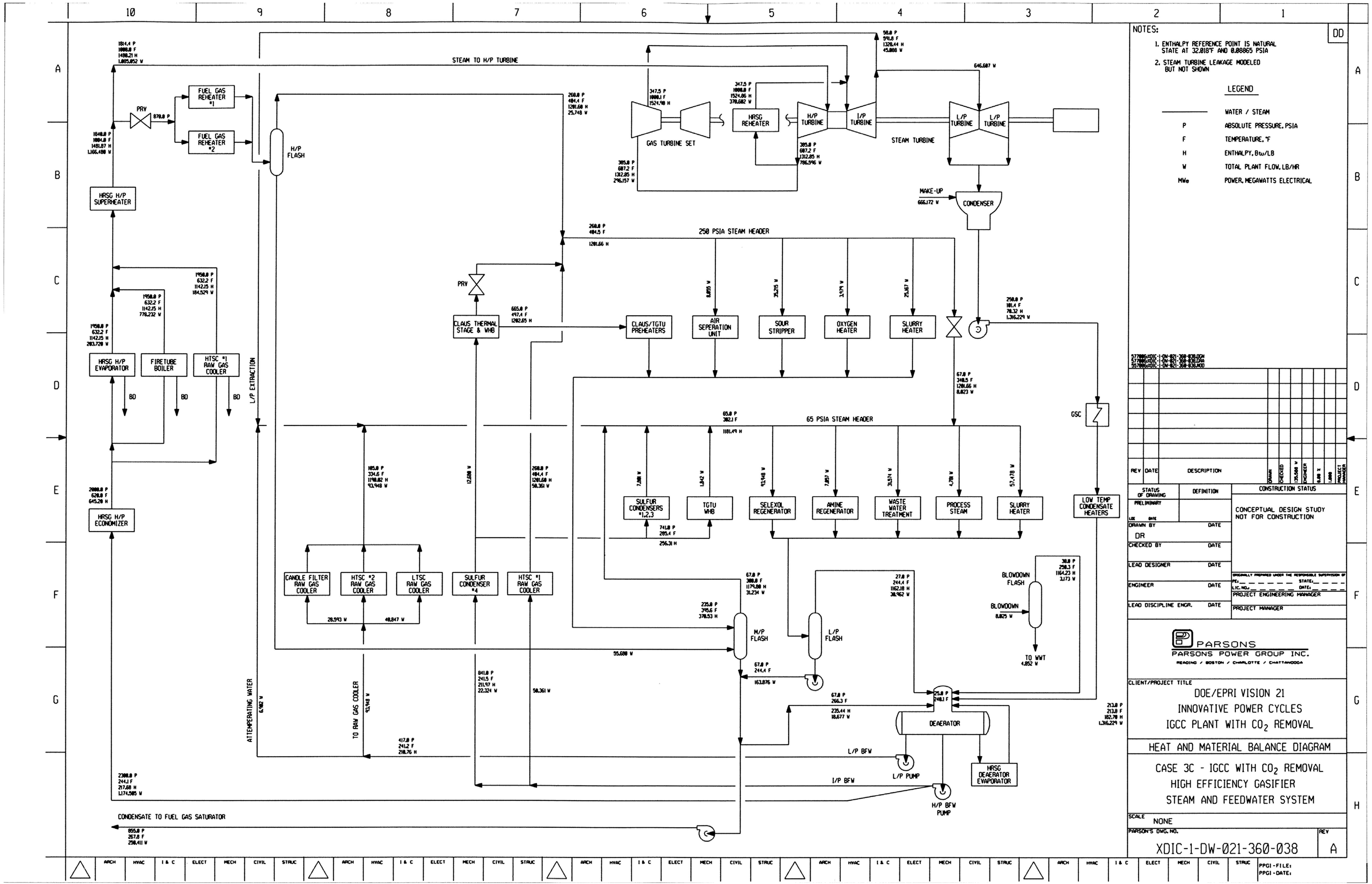

Figure 4-6
Heat and Material Balance Diagram – Case 3C – IGCC with CO_2 Removal – High Efficiency Gasifier – Steam and Feedwater System

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4.4 Case 3D – High-Efficiency E-Gas IGCC, H Class Turbine, No CO_2 Removal

4.4.1 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. The configuration of this IGCC approach is exactly the same as described in Section 4.2 of the October 2000 Interim Report for case 3B, with the following exception: the cold gas efficiency of the E-Gas gasifier was increased from 77 to 80 percent. A cold gas efficiency of 80 percent represents the expected upper-limit of a mature E-Gas technology firing coal.

A detailed discussion of plant performance is given below. There is no system description because, as noted above, the IGCC configuration for this case is a duplication of case 3B. However, a complete set of heat and material balances for this case is presented. Only a qualitative description of plant economics is provided. The individual sections include:

- Thermal Plant Performance
- Power Plant Emissions
- Heat and Mass Balance Diagrams
- Qualitative Discussion of Plant Economics

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. A series of heat and material balance diagrams that completely describe the thermodynamics and chemistry of the power plant are provided. These heat and material balances are fully annotated with state point data.

4.4.2 Thermal Plant Performance

The market-based plant described in this section is based on a high-efficiency E-Gas gasifier IGCC. The gasifier produces fuel gas for a single General Electric H-type ATS gas turbine. The gas turbine is 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 4-3 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 4-3 shows an increase in estimated gas turbine power output compared to the appropriate natural-gas-fired case 1B (or case 1D). Detailed descriptions and results for cases 1B and 1D can be found in the October 2000 Interim Report. This assumption, i.e., increased gas turbine power output, 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 is possible, while the gas turbine combustor temperature is modified due to the firing of synthesis gas. This can result in as much as a 20 percent increase in net plant power output. As a result, gross combustion turbine power output has been estimated at 337.5 MWe – the same as case 3B – in this IGCC case as compared to 272 MWe estimated for case 1B (or case 1D).

The auxiliary power load shown in Table 4-3, 45.8 MWe, is less than the 49.5 MWe required for case 3B as summarized in Table 4.2-1 of the October 2000 Interim Report. The lower auxiliary power load of the case presented here is due to the higher gasifier cold gas efficiency. Less coal is required to generate the necessary fuel gas input to fire the gas turbine. Lower coal input values result in lower parasitic power requirements such as coal handling, ASU air compression, and gasifier oxidant compression. This is reflected in the lower auxiliary power demand as shown in Table 4-3.

Net plant power output for this IGCC configuration is estimated at 425.9 MWe. This power output is generated with a net plant thermal efficiency of 44.9 percent, HHV, with a corresponding heat rate of 8,015 kJ/kWh (7,599 Btu/kWh). These values for net plant thermal efficiency and the corresponding heat rate are improved over that estimated for case 3B. The values for case 3B were 43.1 percent, HHV, and 8,349 kJ/kWh (7,915 Btu/kWh), respectively. This improvement is due entirely to the higher gasifier cold gas efficiency assumed for this case. Less coal is needed to generate the required fuel gas input to the gasifier. This increases the simple cycle efficiency of the gas turbine. At the same time, due to lower coal input to the system, less waste heat is rejected to the steam turbine bottoming cycle. This has a slightly negative effect on the relative efficiency of the power block and simple cycle efficiency of the steam turbine. This loss, however, is relatively much less than the efficiency gain of the gas turbine. The result is an improvement in net plant combined cycle efficiency.

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, which consists of the HRSG and gasifier island waste heat exchangers.

Table 4-3
CASE 3D – HIGH EFFICIENCY E-GAS IGCC POWER CASE
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	337,471
Steam Turbine Power	141,420
Generator Loss	7,183
Gross Plant Power (Note 1)	471,708
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	320
Coal Milling	720
Coal Slurry Pumps	190
Slag Handling and Dewatering	140
Scrubber Pumps	290
Recycle Gas Blower	590
Tail Gas Recycle Blower	1,410
Air Separation Plant	21,010
Oxygen Boost Compressor	10,710
Amine Units	1,350
Claus/TGTU	100
Humidification Tower Pump	100
Humidifier Makeup Pump	60
Condensate Pumps	280
High-Pressure Boiler Feed Pumps	2,910
Miscellaneous Balance of Plant (Note 2)	1,000
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,750
Cooling Tower Fans	1,000
Flash Bottoms Pump	50
Transformer Loss	1,070
Total Auxiliary Power Requirement	45,850
NET PLANT POWER, kWe	425,858
PLANT EFFICIENCY	
Net Efficiency, % HHV	44.9%
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	8,015 (7,599)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	717 (680)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 3)	125,829 (277,400)
Oxygen (95% pure), kg/h (lb/h)	97,138 (214,149)
Water, kg/h (lb/h)	160,535 (353,914)

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).

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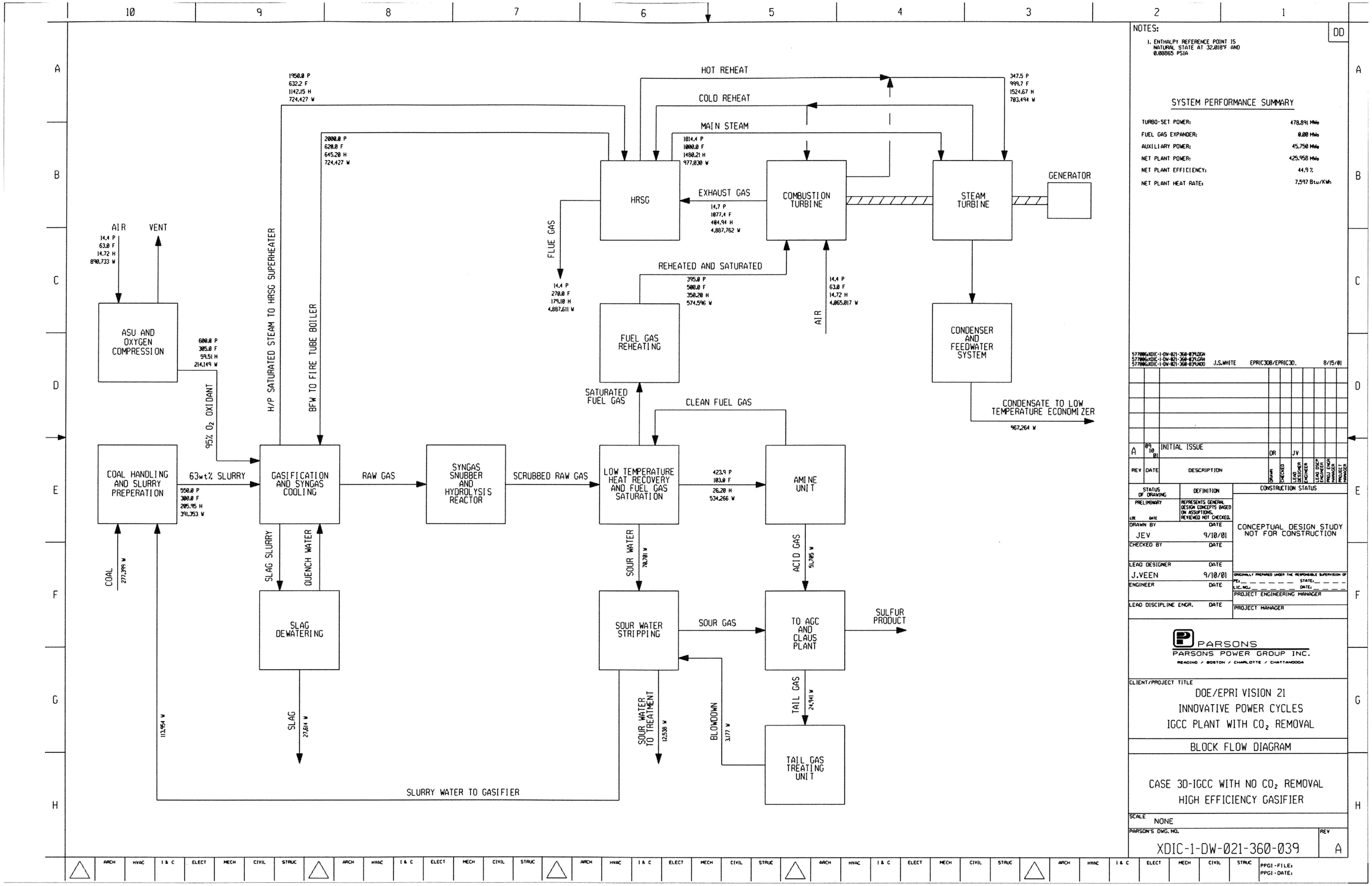

Figure 4-7
Block Flow Diagram – Case 3D – IGCC with No CO_2 Removal – High Efficiency Gasifier

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4.4.3 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, high-efficiency E-Gas gasifier is projected to result in very low levels of SO_2, NOx, and particulate (fly ash) emissions. A summary of the estimated plant emissions for this case is presented in Table 4-4. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four bases: (1) kilograms per gigajoule (pounds per million Btu) of HHV thermal input, (2) tonnes per year (tons per year) for a 65 percent capacity factor, (3) tonnes per year (tons per year) for an 85 percent capacity factor, and, (4) kilograms per hour (pounds per hour) of MWe power output.

Table 4-4
CASE 3D AIRBORNE EMISSIONS
H-TYPE HIGH EFFICIENCY E-GAS IGCC WITH 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	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
NOx	< 0.012 (< 0.028)	259 (285)	336 (370)	0.113 (0.25)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	82.3 (192)	1,668,029 (1,837,000)	2,183,783 (2,405,000)	694 (1,530)

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.

4.4.4 Heat and Material Balance Diagrams

This greenfield power plant is a 425.9 MWe coal-fired IGCC power plant without provision for CO_2 removal. The gasifier technology choice is a high-efficiency E-Gas, and the combustion turbine choice is based on GE's H-type advanced turbine system. Due to the similarity between this case and that of 3B, no system description is provided. However, heat and material balances are provided. The reader is urged to review these along with the system description provided for case 3B.

The heat and material balance diagrams presented for this case are:

- Coal Gasification and ASU (Figure 4-8)
- Raw Gas Cooling/Syngas Humidification (Figure 4-9)
- Sulfur Recovery and Tail Gas Treating (Figure 4-10)
- Combined Cycle Power Generation (Figure 4-11)
- Steam and Feedwater System (Figure 4-12)

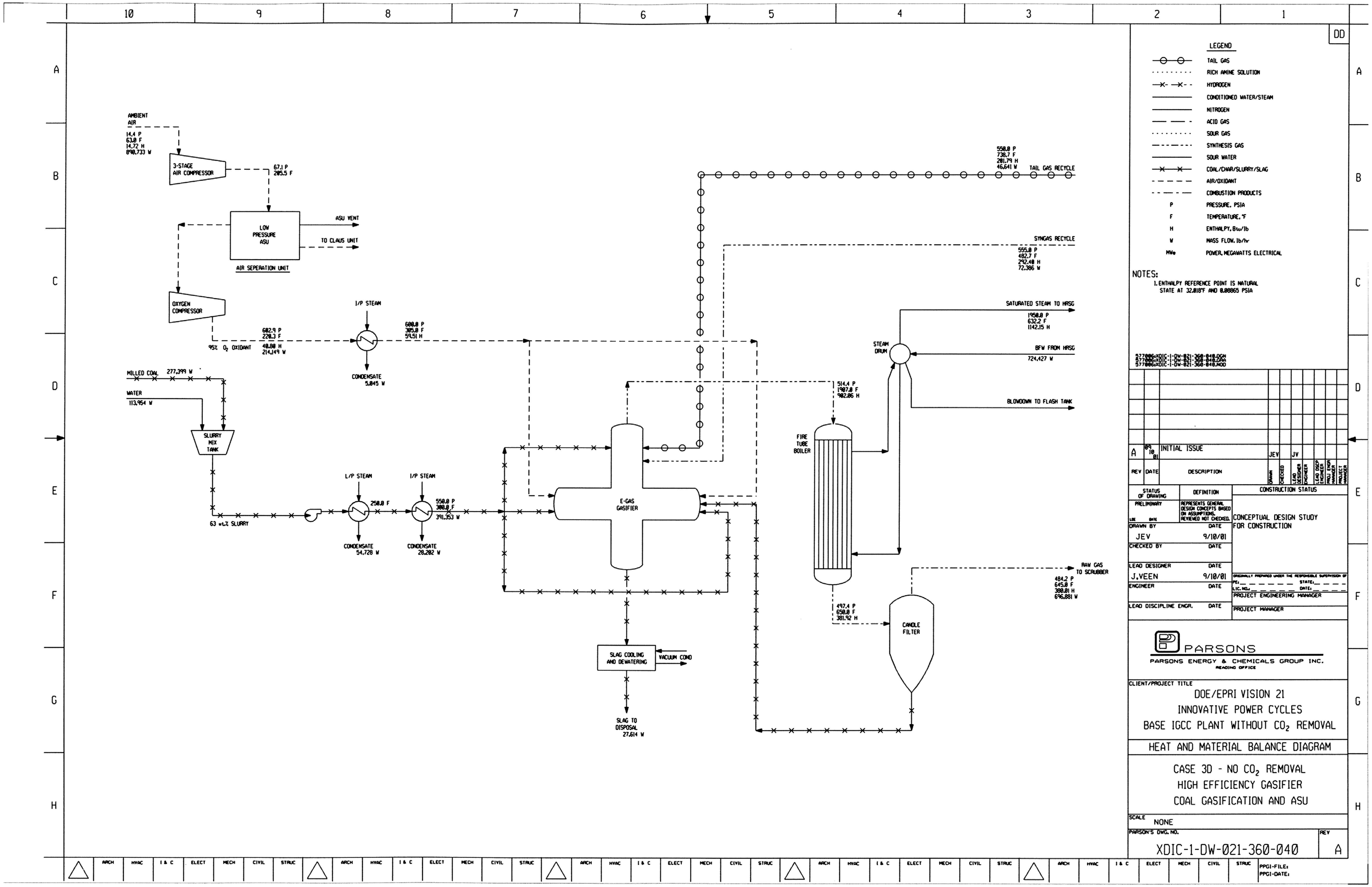

Figure 4-8
Heat and Material Balance Diagram – Case 3D – No CO_2 Removal – High Efficiency Gasifier – Coal Gasification and ASU

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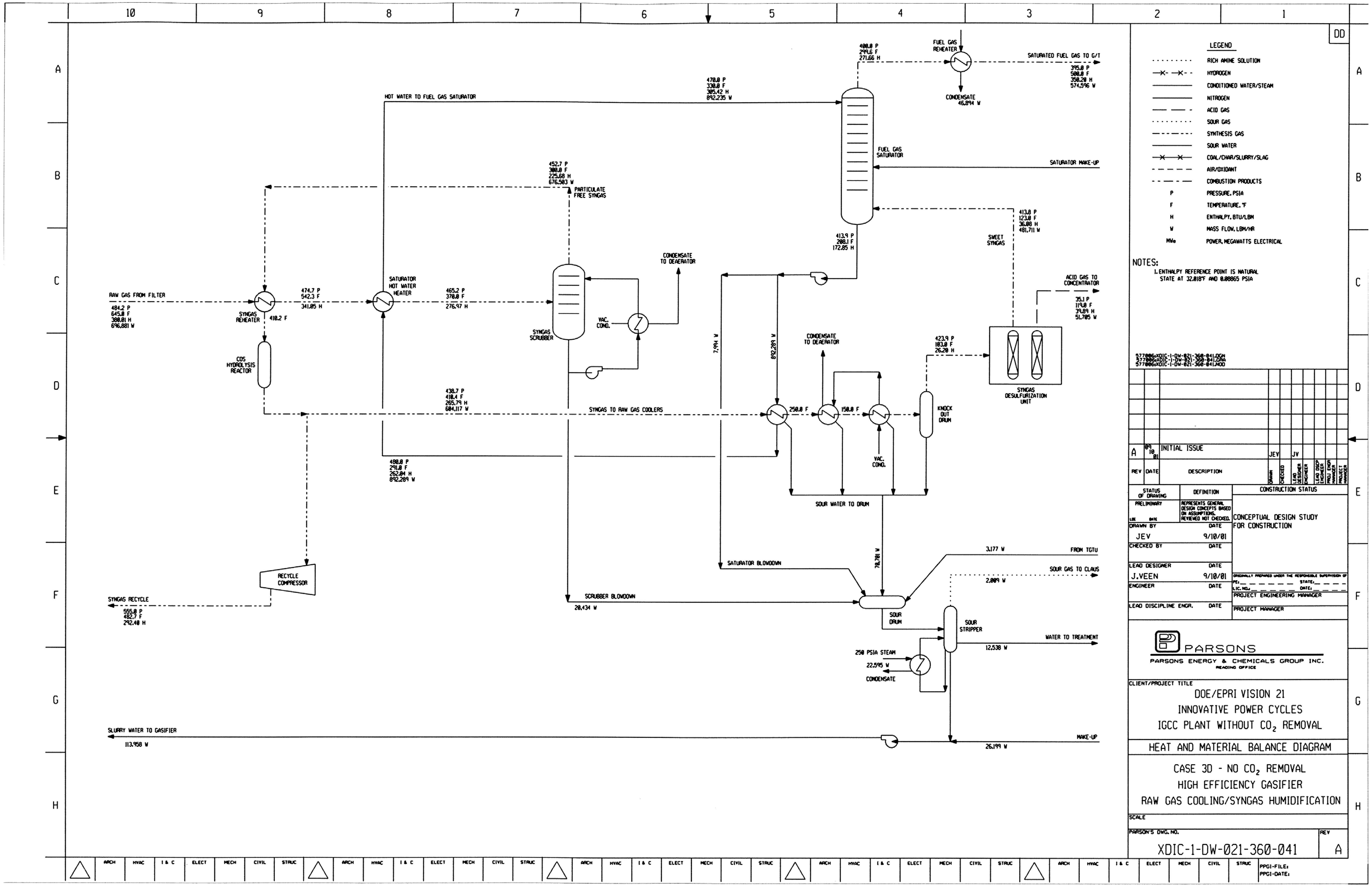

Figure 4-9
Heat and Material Balance Diagram – Case 3D – No CO_2 Removal – High Efficiency Gasifier – Raw Gas Cooling/Syngas Humidification

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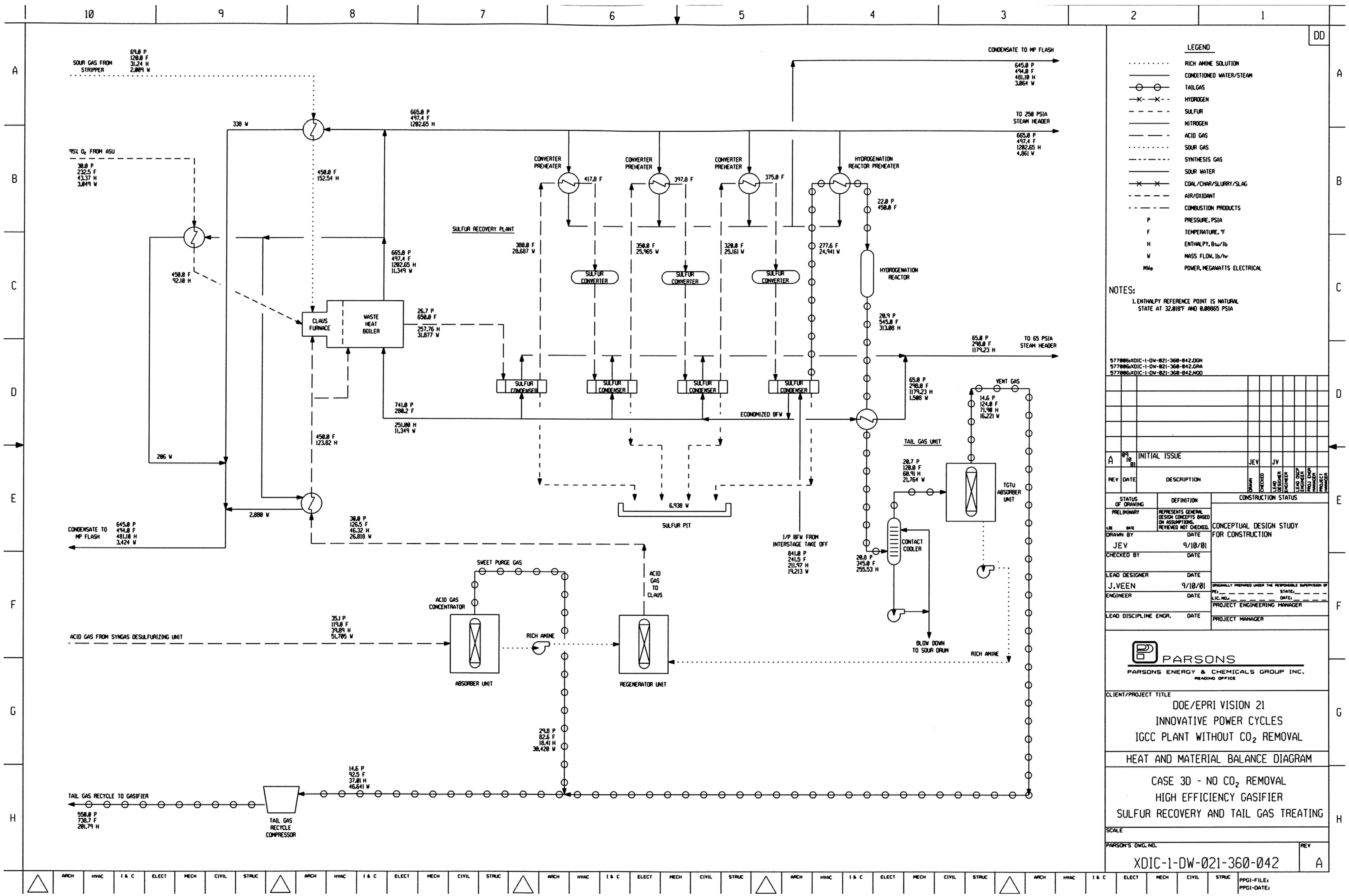

Figure 4-10
Heat and Material Balance Diagram – Case 3D – No CO_2 Removal – High Efficiency Gasifier – Sulfur Recovery and Tail Gas Treating

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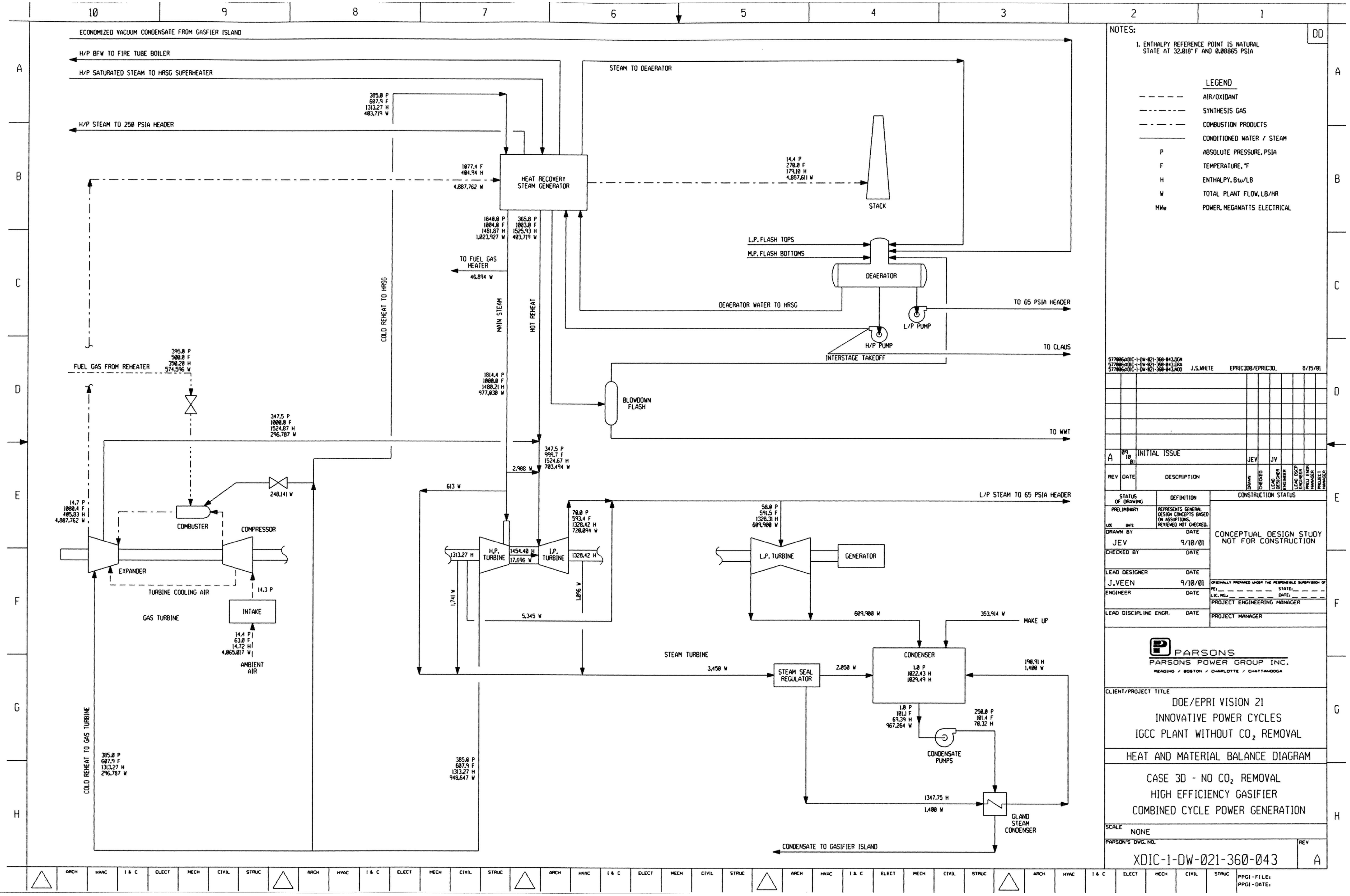

Figure 4-11
Heat and Material Balance Diagram – Case 3D – No CO_2 Removal – High Efficiency Gasifier – Combined Cycle Power Generation

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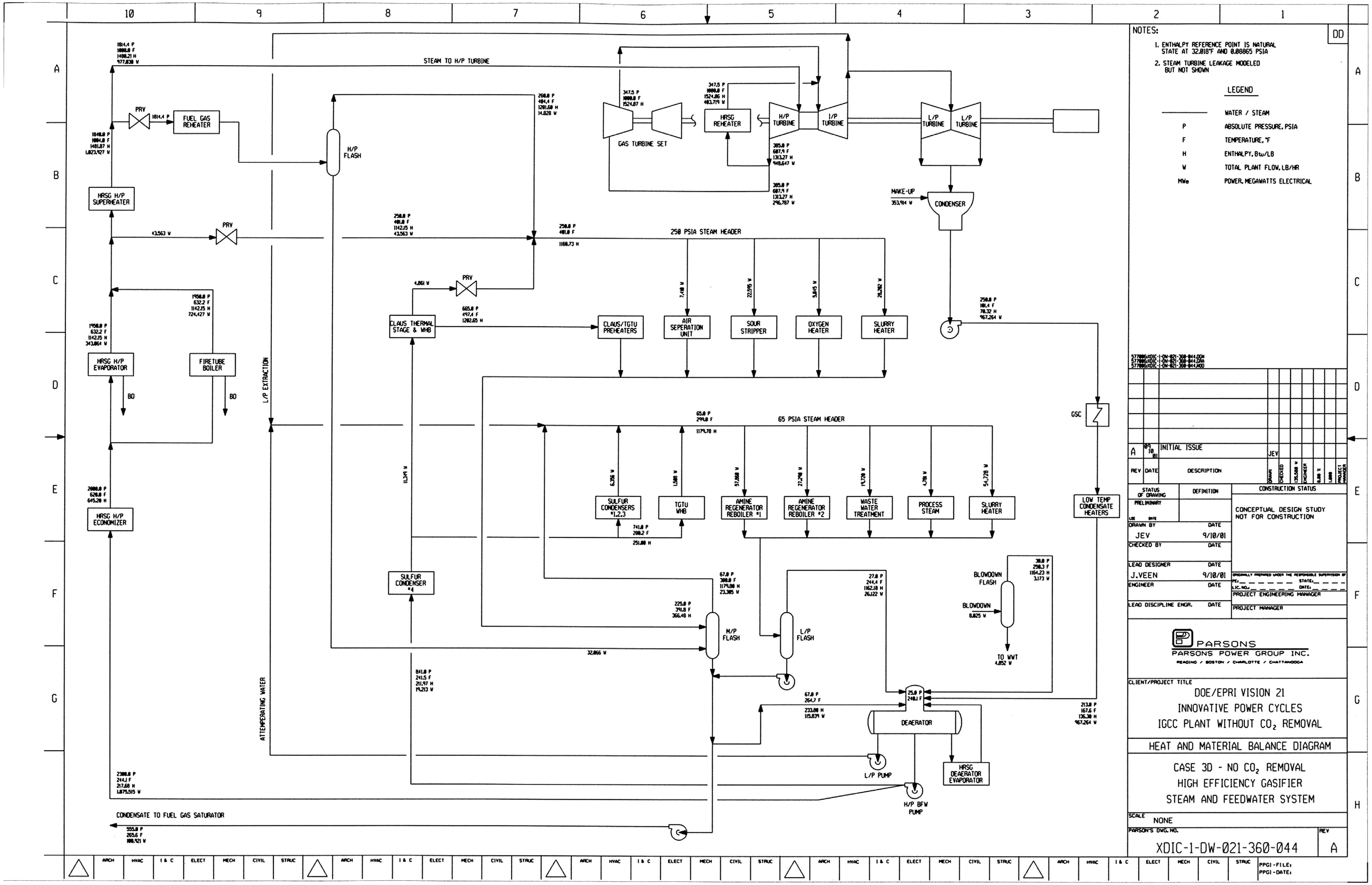

Figure 4-12
Heat and Material Balance Diagram – Case 3D – No CO_2 Removal – High Efficiency Gasifier – Steam and Feedwater System

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4.5 Case 3E – E-Gas IGCC with Water Scrubber, H Class Turbine, and CO_2 Removal

4.5.1 Introduction

This case is a sensitivity case, or alternative option, based on case 3A presented in Section 4.1 of the October 2000 Interim Report. The departure between the two cases centers on the inclusion of a water scrubber prior to the high-temperature shift converter. The water scrubber is used to remove particulates and gaseous chlorides from the raw fuel gas stream. The original case 3A presented in Section 4.1 has no provision for a water scrubber. The case presented in this section uses a water scrubber just prior to the high-temperature shift converter. Use of a water scrubber is a more realistic approach to this type of IGCC configuration and more in line with the best and current approach for this technology.

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 particulates and chlorides 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

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 estimate plant cost.

4.5.2 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 4-5 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 4-5 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 14 percent increase in expander throughput is possible, while maintaining the same firing temperature. This can result in as much as a 20 percent increase in net plant power output, though this operation may result in decreased turbine life. 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 4-5. The total is estimated to be 87.5 MWe – very similar to the original case 3A presented in Section 4.1 of the October 2000 Interim Report. 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 386.7 MWe. This power output is generated with a net plant thermal efficiency of 35.4 percent, HHV, with a corresponding heat rate of 10,166 kJ/kWh (9,638 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.

Net plant power reported above is less than the 403.5 MWe reported for the original case 3A. Also, net plant efficiency for this case is less than the 37 percent HHV reported in Section 4.1 of the October 2000 Interim Report. This difference is due entirely to the inclusion of the water scrubber. Utilizing a water scrubber reduces the moisture content of the raw fuel gas routed to the shift converters. Due to decreased moisture level in the fuel gas, additional IP steam, which would otherwise contribute to steam turbine output power, is required to establish the proper carbon-hydrogen ratio to the shift converter.

Table 4-5
CASE 3E – WATER SCRUBBER OPTION
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	127,207
Generator Loss	(7,088)
Turbo-Set Power (Note 1)	465,474
Fuel Gas Expander Power	8,801
Gross Plant Power	474,275
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	25,560
Oxygen Boost Compressor	14,820
Selexol Plant	8,590
Claus/TGTU	100
Scrubber Pumps	310
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)	24,200
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	1,470
Total Auxiliary Power Requirement	87,490
NET PLANT POWER, kWe	386,785
PLANT EFFICIENCY	
Net Efficiency, % HHV	35.4
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	10,166 (9,638)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	749 (710)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	144,952 (319,560)
Oxygen (95% pure), kg/h (lb/h)	119,285 (262,974)
Water, kg/h (lb/h)	341,143 (752,080)

Note 1 - Single shaft turbo set.
Note 2 - Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure 8.27 MPa (1200 psia)
Note 4 - As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

Figure 4-13 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.

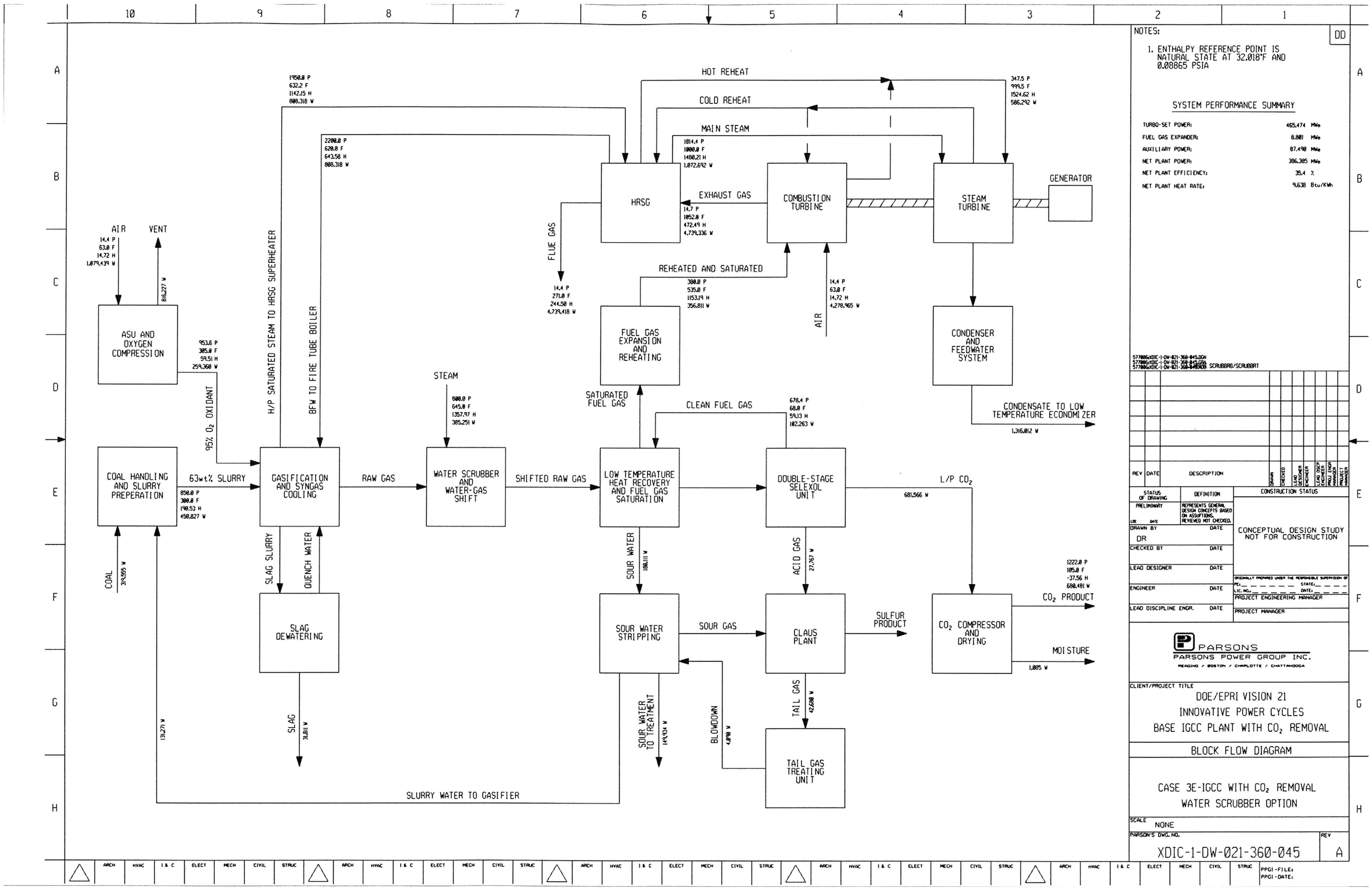

Figure 4-13
Block Flow Diagram – Case 3E – IGCC with CO_2 Removal – Water Scrubber Option

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4.5.3 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 4-6. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four basis: (1) kilograms per gigajoule (pounds per million Btu) of HHV thermal input, (2) tonnes per year (tons per year) for a 65 percent capacity factor, (3) tonnes per year (tons per year) for an 85 percent capacity factor, and, (4) kilograms per hour (pounds per hour) of MWe power output.

Table 4-6
CASE 3E – WATER SCRUBBER OPTION
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)	259 (285)	336 (370)	0.113 (0.25)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	9.17 (21.4)	169,037 (186,160)	221,048 (243,440)	73.5 (162)

As shown in the table, values of SO_2 emission and particulate discharge 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 4-6. 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).

4.5.4 System Description

This greenfield power plant is a 387 MW coal-fired IGCC power plant with CO_2 removal through the Selexol absorption process. 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
- Water Scrubbing / 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.

4.5.4.1 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 over the design load condition for a 16-hour period and long-term operation at the 100 percent of design load point for 90 days or more.

The 6" x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor 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 3" x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 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.

4.5.4.2 Coal-Water Slurry Preparation and Feeding

The slurry preparation and feeding system mills crushed coal and generates a 63 weight percent (dry basis) slurry for the gasifier. Two trains at 75 percent 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°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.

4.5.4.3 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

One train at 100 percent will be used. The train will produce 2,833 tonnes/day (3,120 tons/day) of 95 percent oxygen product (2,706 tonnes/day (2,980 tons/day) on a 100 percent O_2 basis). The train consists of a multi-staged air compressor, an air separation cold box, and an oxygen

compression system. A liquid oxygen storage tank will be maintained in order to ensure reliability. A slipstream of vent nitrogen will be compressed and available for miscellaneous plant requirements.

A simplified schematic of the oxygen plant is shown in Figure 4-14. State point data are also shown. Ambient air at 0.099 MPa (14.4 psia) and 17.2°C (63ºF) is compressed in a three-stage, 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.

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 power plant requires 3,094 tonnes/day (3,410 tons/day) (dry) coal feed. Two gasification trains at 50 percent will be used.

Figure 4-14 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.

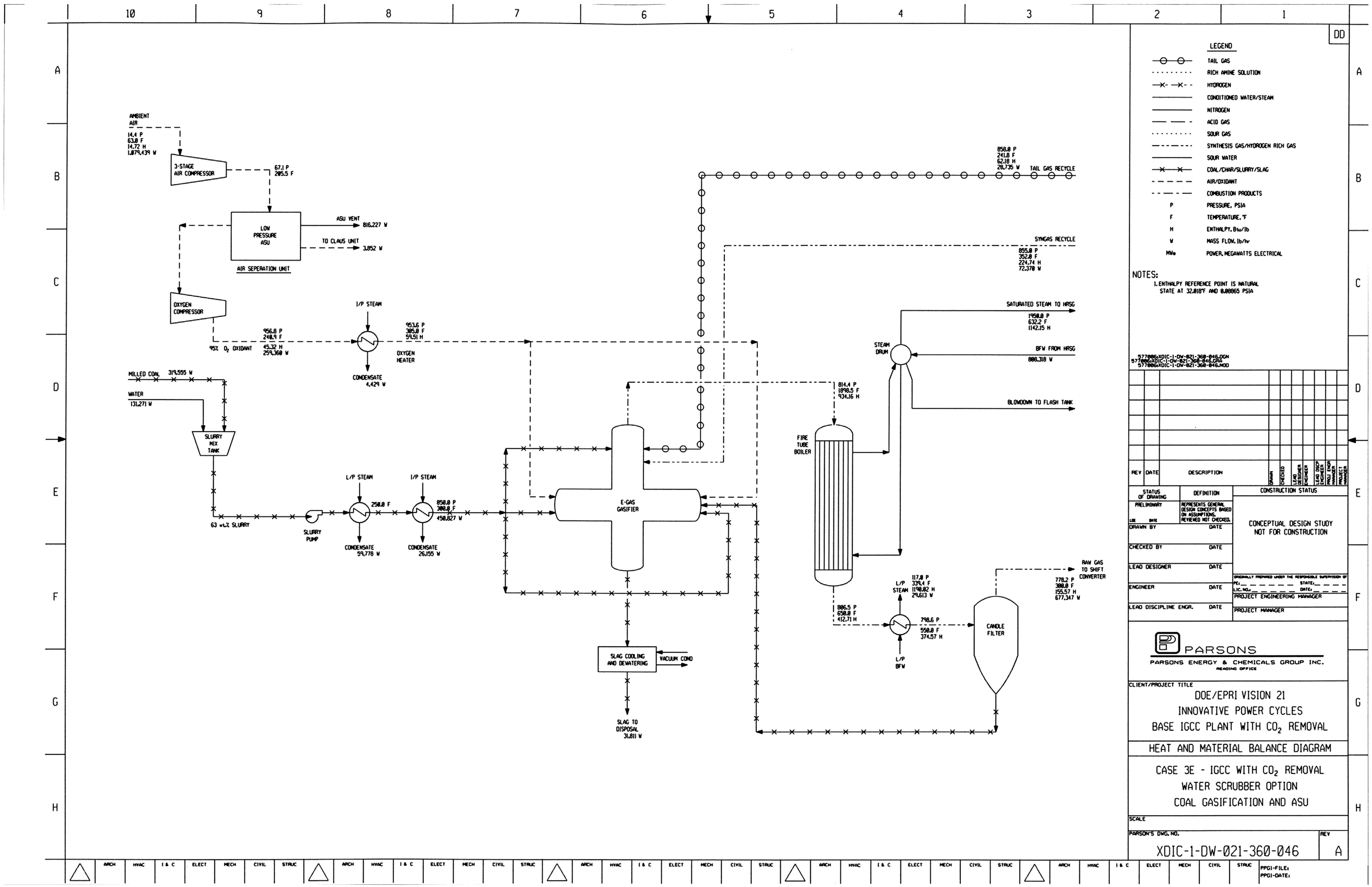

Figure 4-14
Heat and Material Balance Diagram – Case 3E – IGCC with CO_2 Removal – Water Scrubber Option – Coal Gasification and ASU

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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 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 gasifier for reinjection. The gasifier operates with a cold 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 1041°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 366,645 kg/h (808,300 lb/h) of saturated steam at 13.4 MPa (1950 psia) is produced. This steam generation is part of the general heat recovery in the overall gasifier 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, to maintain the desired input temperature to the ceramic candle filter. Raw gas exits this cooler at 288°C (550°F) and generates approximately 13,608 kg/h (30,000 lb/h) 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 comprises 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 (795 psia).

4.5.4.4 Water Scrubbing / 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. The fuel gas stream is cooled further to 254°C (490°F) by generating 9,707 kg/h (21,400 lb/h) of low-pressure steam.

Cooled fuel gas is then routed to the syngas water-scrubbing unit. Here, the fuel gas is directly contacted with cool water in order to reduce the fuel gas temperature and dissolve any gaseous chloride material. A schematic of the syngas scrubber can be found in Figure 4-15. Blowdown from the water scrubber is then treated in the sour water system. Heat is removed from the scrubber system through an indirect heat exchanger used to heat vacuum condensate.

Steam is added to the particulate-free raw fuel gas stream that exits the top of the syngas scrubbing unit, in order to increase the H_2O/CO ratio of the fuel gas stream. The low operating temperature of the syngas scrubber markedly decreases the moisture content of the fuel gas stream. 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 4-15. 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 343°C (650°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-staged shift was utilized in order to maximize CO conversion while maintaining reasonable reactor volumes.

The shifted raw gas temperature exiting the low-temperature shift converter is approximately 238°C (460°F). This stream is cooled to 154°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 drum.

The fuel gas saturator can also be seen in Figure 4-15. 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 4.62 MPa (670 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 2.65 MPa (385 psia) to recover approximately 8.8 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 34°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 buildup of soluble gases, a small blowdown to the sour water drum is taken from the pump discharge.

4.5.4.5 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

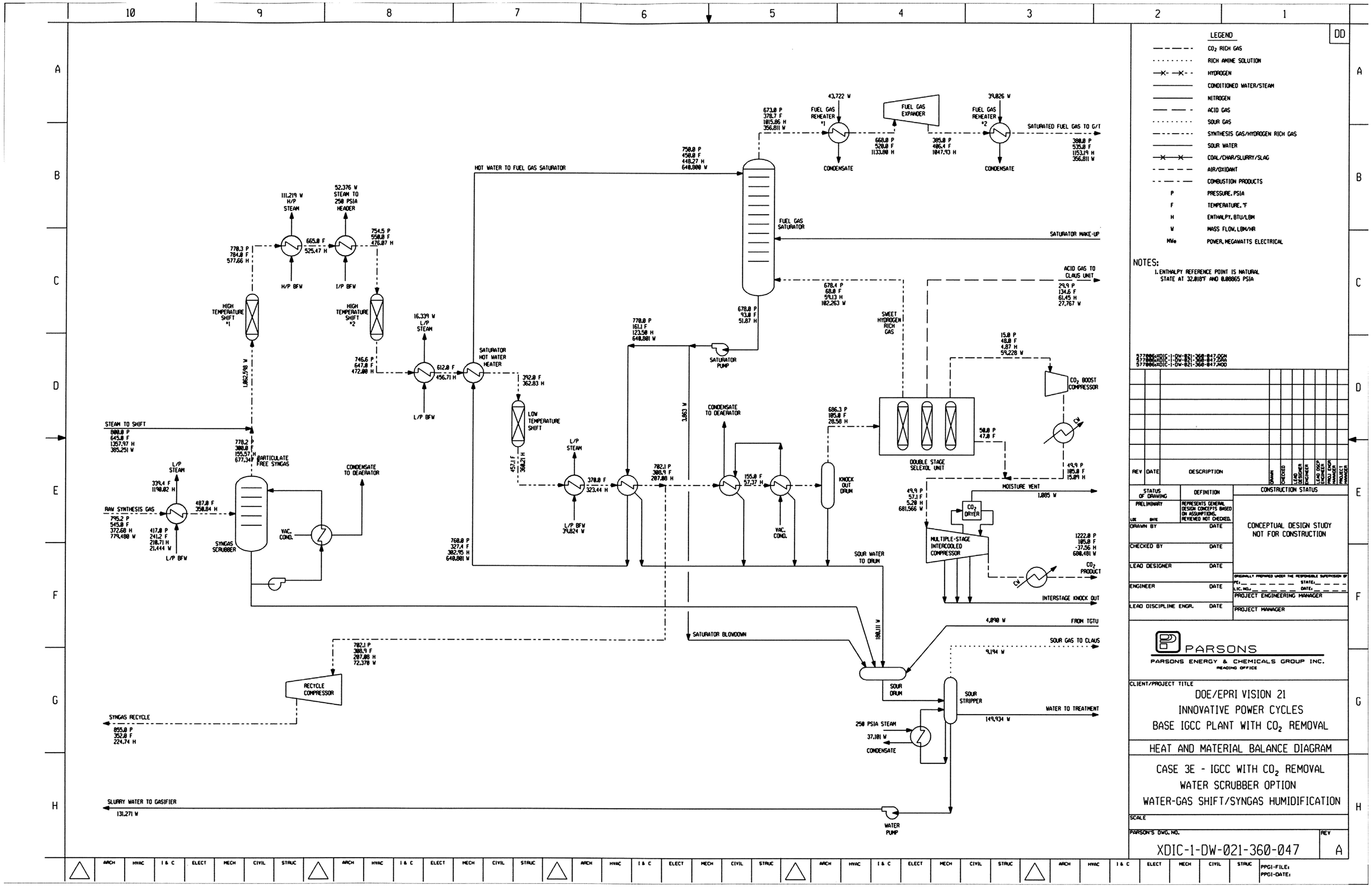

Figure 4-15
Heat and Material Balance Diagram – Case 3E – IGCC with CO_2 Removal – Water Scrubber Option – Water-Gas Shift/Syngas Humidification

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- Claus Plant
- Tail Gas Treating Unit

Heat and mass balance diagrams of these systems can be seen in Figure 4-15 and Figure 4-16.

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 4.73 MPa (686 psia) and 40.6°C (105°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 33 percent H_2S and 59 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 it is flashed off at approximately 0.34 MPa (50 psia), while the remainder is flashed off at atmospheric pressure. The second low-pressure CO_2 stream is "boosted" to 0.34 MPa (50 psia) and 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 stream is then ready for pipeline transportation.

Claus Unit

Acid gas from the first-stage 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 4-16. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. Approximately 3,629 kg/h (8,000 lb/h) 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, 6,441 kg/h (14,200 lb/h) 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 1,270 kg/h (2,800 lb/h) 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. 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 catalytically reduced with H_2 to H_2S, and 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.

4.5.4.6 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 4-17.

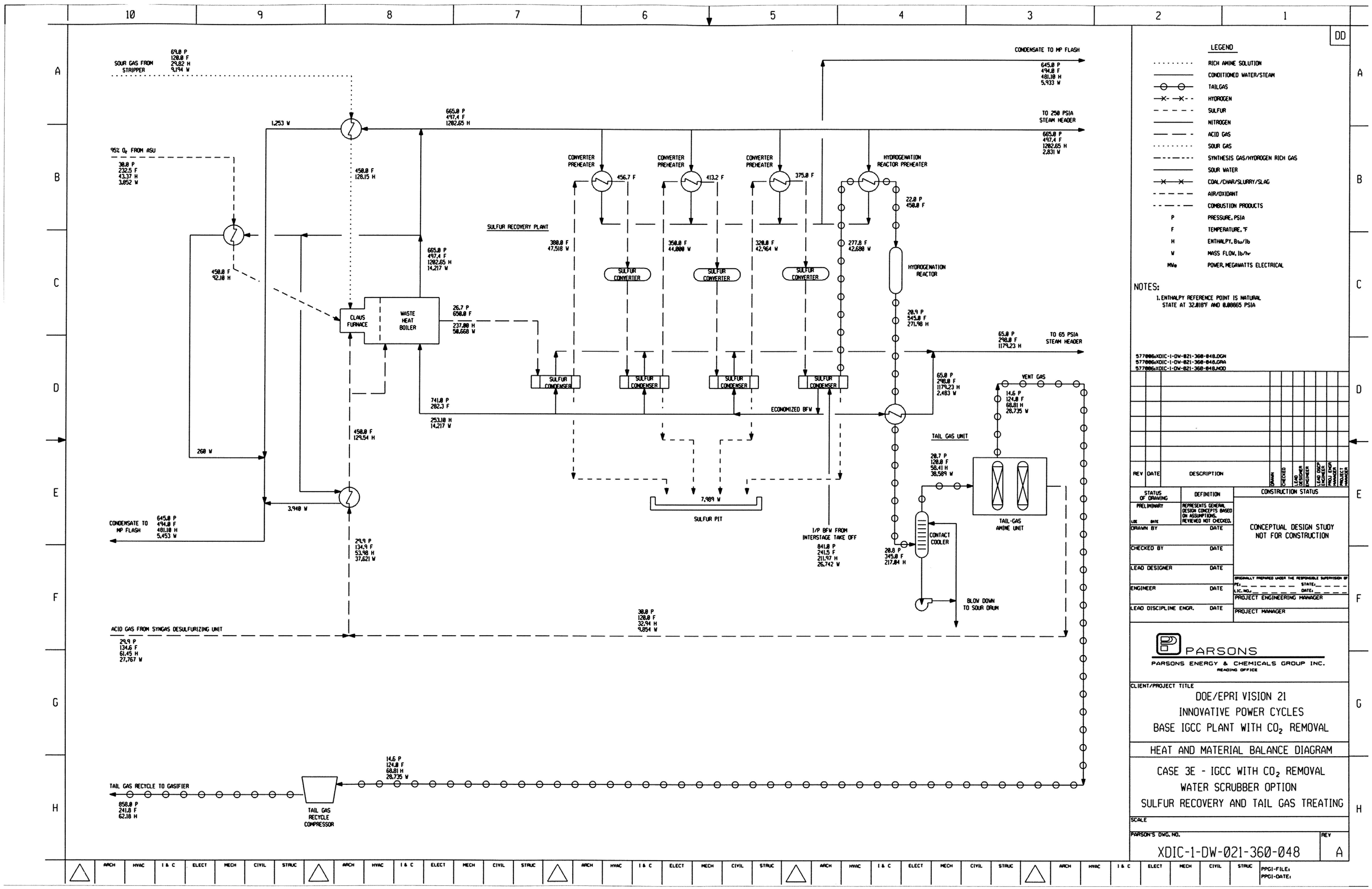

Figure 4-16
Heat and Material Balance Diagram – Case 3E – IGCC with CO_2 Removal – Water Scrubber Option – Sulfur Recovery and Tail Gas Treating

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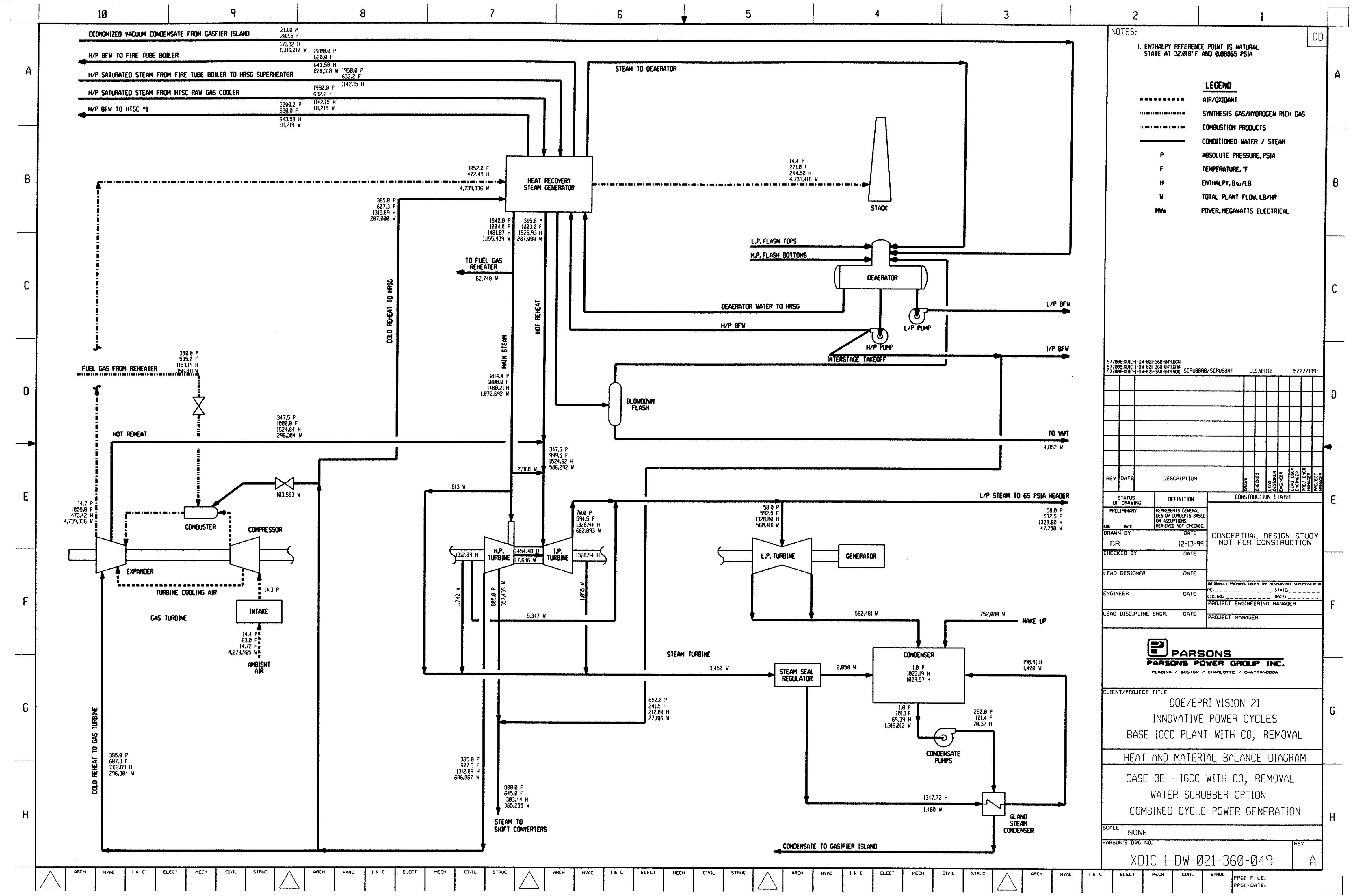

Figure 4-17
Heat and Material Balance Diagram – Case 3E – IGCC with CO_2 Removal – Water Scrubber Option – Combined Cycle Power Generation

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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 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 568°C (1055°F), given the assumed ambient conditions, back-end loss, and HRSG pressure drop. This value, 10°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 4-18. 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, generates steam utilized in the steam turbine to generate electrical power.

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 1.7°C (3°F). The HRSG flue gas exit temperature is assumed to be 133°C (271°F), which should be high enough to avoid sulfur dew-point complications.

The HRSG is configured with a high-pressure (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 527,537 kg/hour (1,163,000 lb/hour) of 15.86 MPa (2300 psia) boiler feed water is heated to 326.7°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, 130,183 kg/hour (287,000 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 state-of-the-art 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 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 182.9 centimeters (72 inches) and a last-stage bucket length of 66 centimeters (26 inches).

Main steam at a rate of 486,713 kg/hour (1,073,000 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 2.39 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 is estimated as 127 MWe. The generator, which is shared with the combustion turbine, is assumed to be a standard hydrogen-cooled machine with static exciter. The net steam turbine contribution to electric power, accounting for generator losses, is estimated around 124.7 MWe.

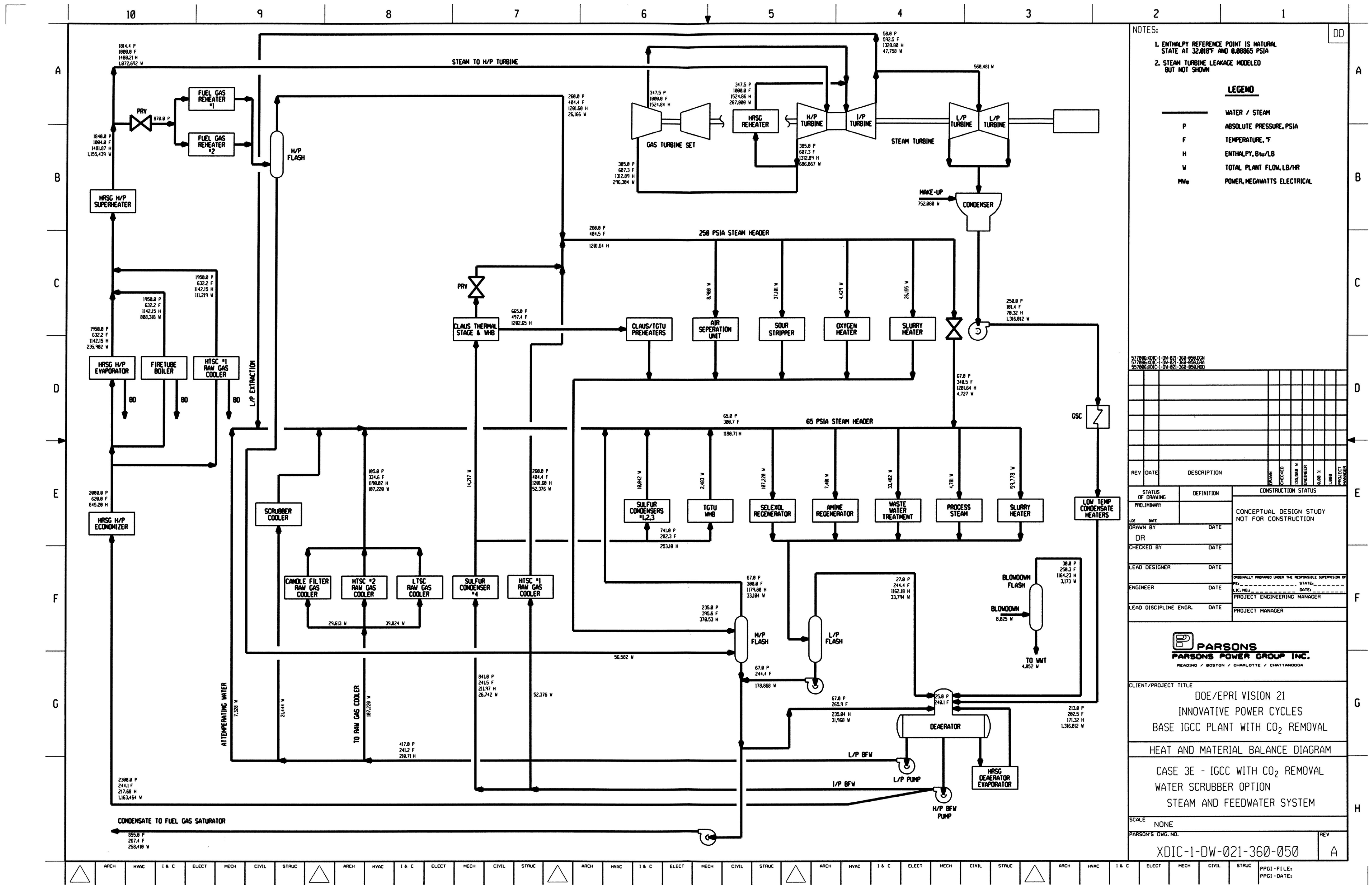

Figure 4-18
Heat and Material Balance Diagram – Case 3E – IGCC with CO_2 Removal – Water Scrubber Option – Steam and Feedwater System

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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.

4.5.4.7 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 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.

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 manually with operator selection of available modular automation routines.

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/hour (0-1000 lb/hour) dry lime feeder, a 18.93 m^3 (5,000-gallon) lime slurry tank, a slurry tank mixer, and 0.09 m^3/min (25 gpm) lime slurry feed pumps.

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.

4.5.5 Case 3E Water Scrubber Option –Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 4-13. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and as input to the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped.

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	270 gpm @ 500 ft	2
5	Slurry Water Storage Tank	Vertical	2,600 gal	1
6	Rod Mill Product Tank	Vertical	52,500 gal	2
7	Slurry Storage Tank with Agitator	Vertical	225,000 gal	2
8	Coal-Slurry Feed Pumps	Positive displacement	1050 gpm @ 2,500 ft	2
9	Low-Temperature Slurry Heater	Shell and tube	30 x 10^6 Btu/h	2
10	High-Temperature Slurry Heater	Shell and tube	10.5 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	Condensate Storage Tank	Vertical, cylindrical, outdoor	200,000 gal	1
2	Condensate Pumps	Vertical canned	2,900 gpm @ 400 ft	2
3	Low Temperature Economizers	Shell and tube	60 x 10^6 Btu/h	2
4	Deaerator	Horizontal spray type	1,500,000 lb/h 205°F to 240°F	1
5	LP Feed Pump	Horizontal centrifugal single stage	300 gpm @ 185 ft	2
6	HP Feed Pump	Barrel type, multi-staged, centrifugal	2,400 gpm @ 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fabricated water tube	400 psig, 650°F 70,000 lb/h	1
2	Service Air Compressors	Recip., single stage, double acting, horizontal	100 psig, 750 cfm	2
3	Inst. Air Dryers	Duplex, regenerative	750 cfm	1
4	Service Water Pumps	Horizontal 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 horizontal centrifugal	250 ft, 1,200 gpm	1
8	Engine-Driven Fire Pump	Vertical 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	1,705 std (dry-coal basis) @ 1000 psia	2
2	Syngas Cooler	Fire-tube with steam drum	270 x 10^6 Btu/h @ 1950 psia, 630°F	2
3	Raw gas Cooler	Shell and tube with L/P steam drum	13 x 10^6 Btu/h @ 120 psia, 340°F	2
3	Low-Temperature Candle Filter	Ceramic	800 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	250,000 scfm, 67 psia discharge pressure	1
2	Cold Box	Vendor supplied	3,200 tpd O_2	1
3	Oxygen Compressor	Centrifugal, multi-stage	50,000 scfm, 950 psig discharge pressure	1
4	Liquid Oxygen Storage Tank	Vertical	60' dia x 80' vertical	1
5	Oxygen Heater	Shell and tube	3.6 x 10^6 Btu/h @ 950 psia and 300°F	1

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	Water Scrubber Tower	Vertical spray tower	700 psia, 300°F	2
2	Water Economizer	Shell and tube	700 psia, 300°F	2
3	Scrubber Water Pumps	Centrifugal	2,100 gpm @ 180 ft	2
4	High-Temperature Shift Reactor 1	Fixed bed	800 psia, 750°F	2
5	High-Temperature Shift Reactor 2	Fixed bed	800 psia, 750°F	2
6	HP Steam Generator	Shell and tube	52.5 x 10^6 Btu/h @ 2800 psia and 700°F	2
7	IP Steam Generator	Shell and tube	30 x 10^6 Btu/h @ 300 psia and 500°F	2
8	LP Steam Generator	Shell and tube	15 x 10^6 Btu/h @ 200 psia and 500°F	2
9	Low-Temperature Shift Reactor	Fixed bed	760 psia, 450°F	2
10	Saturation Water Economizers	Shell and tube	75 x 10^6 Btu/h @ 1000 psia and 500°F	2
11	Raw Gas Coolers	Shell and tube with condensate drain	150 x 10^6 Btu/h	6
12	Raw Gas Knock Out Drum	Vertical with mist eliminator	800 psia, 130°F	2
13	Fuel Gas Saturator	Vertical tray tower	20 stages 750 psia, 450°F	1
14	Saturator Water Pump	Centrifugal	1,500 gpm @ 120 ft	1
15	Fuel Gas Reheater 1	Shell and tube	41 x 10^6 Btu/h @ 690 psia, 550°F	1
16	Fuel Gas Expander	Axial	PR=1.8 @ 685 psia	1
17	Fuel Gas Reheater 2	Shell and tube	39 x 10^6 Btu/h @ 690 psia, 550°F	1

ACCOUNT 5B SULFUR REMOVAL AND RECOVERY

Equipment No.	Description	Type	Design Condition	Qty
1	Double-Stage Selexol Unit	Vendor design	360,000 scfm @ 700 psia	2
2	CO_2 Compressor and Auxiliaries	Centrifugal, multi-staged, intercooled	25 psia / 1300 psia	1
3	Dehydration Package	Triethylene glycol	1300 psia, 100°F	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, multi-staged, intercooled	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

Equipment No.	Description	Type	Design Condition	Qty
6	Oil Cooler	Finned air-cooler with fan		1
7	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
8	Generator Glycol Cooler	Finned air-cooler with 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	1800 psig/1000°F 1,170,000 lb/h	1
2	Stack	Carbon steel plate, type 409 stainless steel liner	213 ft high x 28 ft diameter	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	Vertical 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

4.5.6 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 3E, 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 Ton of CO_2 Removed.

The capital cost for case 3E represents a plant with a net output of 386.8 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 4-7. A detailed estimate for case 3E is included in Appendix A.

Table 4-7
CASE 3E SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	Gasifier, ASU & Accessories	128,620
5A	Gas Cleanup & Piping	73,610
5B	CO_2 Removal and Compression	42,660
6	Combustion Turbine and Accessories	62,160
7	HRSG, Ducting and Stack	20,430
8&9	Steam T-G Plant, including Cooling Water System	33,440
11	Accessory Electric Plant	27,850
	Balance of Plant	80,210
	SUBTOTAL	468,980
	Engineering, Construction Management Home Office and Fee	28,140
	Process Contingency	17,650
	Project Contingency	69,350
	TOTAL PLANT COST (TPC)	$584,110
	TPC $/kW	1,510

The production costs for case 3E 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 4-8, and supporting detail is included in Appendix A.

Table 4-8
CASE 3E ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	5,503	0.25
Maintenance	11,828	0.54
Administrative & Support Labor	2,559	0.12
Consumables	1,927	0.09
By-Product Credits	(972)	-0.04
Fuel	26,321	1.20
TOTAL PRODUCTION COST	47,166	2.14

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 3E. 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 Ton 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 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 4-9.

Table 4-9
CASE 3B LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	2.14
Annual Carrying Charge (¢/kWh)	4.12
Levelized Busbar Cost of Power Charge (¢/kWh)	6.26
Levelized Cost per Ton of CO_2 Removed ($/ton of CO_2 removed)	16.9

5
CONVENTIONAL COAL-FIRED STEAM CYCLES – TECHNICAL DESCRIPTIONS

Seven conventional coal-fired power plant configurations were evaluated. Five, cases 7A through 7E, were presented in Section 5 of the original Interim Report, dated October 2000; two additional plant configurations, cases 7F and 7G, which are sensitivities of cases 7A and 7B, respectively, are presented here. 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. In addition, total plant and operating costs are presented, as well as cost of CO_2 emissions avoided.

The five cases evaluated are:

- Case 7A – Coal-Fired Supercritical Steam Plant with CO_2 Removal
- Case 7B – Coal-Fired Ultra-Supercritical Steam Plant with CO_2 Removal
- Case 7C – Coal-Fired Supercritical Steam Plant
- Case 7D – Coal-Fired Ultra-Supercritical Steam Plant
- Case 7E – Advanced Ultra-Supercritical Coal-Fired Steam Plant
- Case 7F - Coal-Fired Supercritical Steam Plant with CO_2 Removal – Sensitivity Case
- Case 7G – Coal-Fired Ultra-Supercritical Steam Plant with CO_2 Removal – Sensitivity Case

In cases 7A, 7B, 7F, and 7G, 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 two sensitivity cases are described in greater detail below.

5.1 Case 7A – Coal-Fired Supercritical Steam Plant with CO_2 Removal

Section 5.1 is included in the original Interim Report, which was issued as a draft in October 2000.

5.2 Case 7B – Ultra-Supercritical Steam Plant with CO_2 Removal

Section 5.2 is included in the original Interim Report, which was issued as a draft in October 2000.

5.3 Case 7C – Supercritical Steam Plant with No CO_2 Removal

Section 5.3 is included in the original Interim Report, which was issued as a draft in October 2000.

5.4 Case 7D – Conventional Coal-Fired Ultra-Supercritical Steam Plant

Section 5.4 is included in the original Interim Report, which was issued as a draft in October 2000.

5.5 Case 7E – Advanced Coal-Fired Ultra-Supercritical Steam Plant

Section 5.5 is included in the original Interim Report, which was issued as a draft in October 2000.

5.6 Case 7F – Coal-Fired Supercritical Steam Plant with CO_2 Removal – Sensitivity Case

5.6.1 Introduction

Case 7F is a coal-fired supercritical steam plant similar in nature to case 7A with power output increased to match case 3E. It is a sensitivity case that was completed for purposes of comparison for other cases. While a cost estimate is provided, neither an equipment list nor a system description is included. Please refer to the October 2000 Interim Report for this information.

The coal-fired boiler is staged for low NOx formation. The boiler is also equipped with an SCR. Wet limestone forced oxidation flue gas desulfurization (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 463 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 379.5 MWe. The plant operates with an estimated HHV efficiency of 28.8 percent with a corresponding heat rate of 12,512 kJ/kWh (11,862 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.

Descriptions of each of the plant sections are provided in the October 2000 Interim Report and should be used as a reference.

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, located in the October 2000 Interim Report, gives a more detailed account of the individual power plant subsections.

5.6.2 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, and wet limestone FGD system capabilities.

Table 5-1
CASE 7F – SUPERCRITICAL PC PLANT WITH CO_2 REMOVAL
(POWER SET TO MATCH CASE 3E)
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	469,540
Generator Loss	(6,760)
Gross Plant Power	462,780
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	450
Limestone Handling & Reagent Preparation	1,060
Pulverizers	2,150
Ash Handling	1,930
Primary Air Fans	1,420
Forced Draft Fans	1,120
Induced Draft Fans	22,700
SCR	100
Seal Air Blowers	50
Precipitators	1,160
FGD Pumps and Agitators	3,990
Condensate Pumps	360
Boiler Feed Water Booster Pumps	3,510
High-Pressure Boiler Feed Pump	(Note 1)
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	2,230
Cooling Tower Fans	1,270
MEA Unit	2,220
CO_2 Compressor (Note 3)	34,040
Transformer Loss	1,070
Total Auxiliary Power Requirement	83,300
NET PLANT POWER, kWe	379,480
PLANT EFFICIENCY	
Net Efficiency, % HHV	28.8%
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	12,512 (11,862)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	1,160 (1,100)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	175,025 (385,858)
Sorbent, kg/h (lb/h)	17,972 (39,620)

Note 1 – Boiler feed pumps are turbine driven
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 Pressure: 8.3 MPa (1200 psig)
Note 4 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

Gross power output (prior to the generator terminals) for the steam turbine is estimated to be 463 MWe. Plant auxiliary power is estimated to be 83.3 MWe. Net plant power output, which considers generator losses and auxiliary power, is 379.5 MWe. This plant power output results in a net system thermal efficiency of 28.8 percent (HHV) with a corresponding heat rate of 12,512 kJ/kWh (11,862 Btu/kWh) (HHV).

A heat and material balance diagram for this conventional 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 24.1 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 are accomplished in the boiler house. Also shown in the diagram is the basic equipment of the FGD system.

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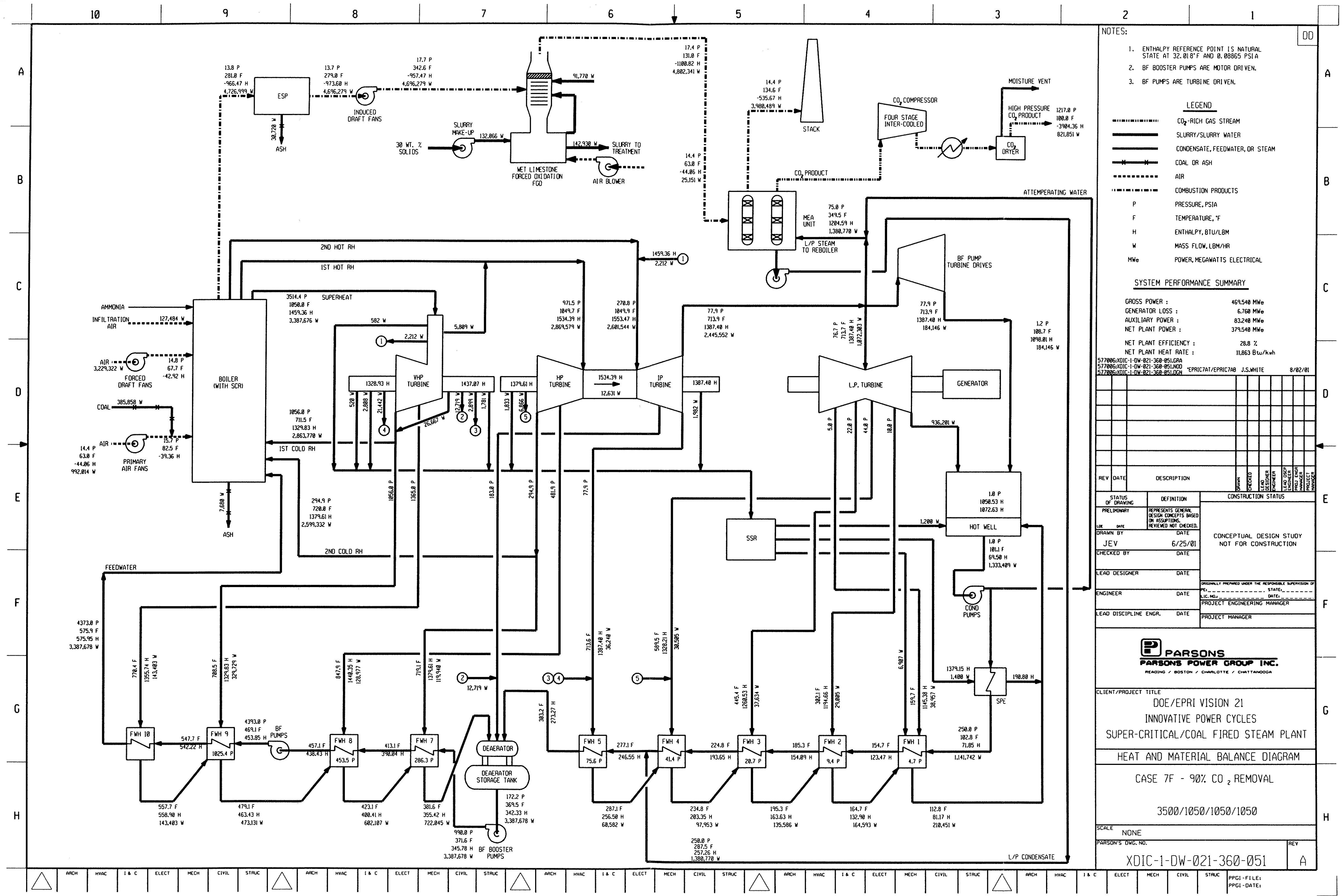

Figure 5-1
Heat and Material Balance Diagram – Case 7F – 90% CO_2 Removal

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5.6.3 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 7F, 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 Ton of CO_2 Removed.

The capital cost for case 7F represents a plant with a net output of 379.5 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 5-2. A detailed estimate for case 7F is included in Appendix A.

Table 5-2
Case 7F Summary TPC Cost

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	PC Boiler and Accessories	112,210
5	Flue Gas Cleanup	65,430
5B	CO_2 Removal and Compression	125,510
-6	Combustion Turbine and Accessories	N/A
7	Ducting and Stack	19,950
8&9	Steam T-G Plant, including Cooling Water System	88,450
11	Accessory Electric Plant	33,760
	Balance of Plant	131,710
	SUBTOTAL	587,020
	Engineering, Construction Management Home Office and Fee	35,220
	Process Contingency	6,800
	Project Contingency	92,850
	TOTAL PLANT COST (TPC)	$721,880
	TPC $/kW	1,900

The production costs for case 7F 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 5-3, and supporting detail is contained in Appendix A.

Table 5-3
CASE 7F ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	5,272	0.24
Maintenance	9,692	0.45
Administrative & Support Labor	2,287	0.11
Consumables	18,419	0.85
By-Product Credits	N/A	N/A
Fuel	31,782	1.47
TOTAL PRODUCTION COST	67,452	3.12

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 7F. 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 Ton 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 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 5-4.

Table 5-4
CASE 7F LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	3.12
Annual Carrying Charge (¢/kWh)	5.16
Levelized Busbar Cost of Power Charge (¢/kWh)	8.29
Levelized Cost per Ton of CO_2 Removed ($/ton of CO_2 Removed)	29

5.7 Case 7G – Coal-Fired Ultra-Supercritical Steam Plant with CO_2 Removal – Sensitivity Case

5.7.1 Introduction

Case 7G is a coal-fired supercritical steam plant similar in nature to case 7B with power output increased to match case 3E. It is a sensitivity case that was completed for purposes of comparison for other cases. While a cost estimate is provided, neither an equipment list nor a system description is included. Please refer to the October 2000 Interim Report for this information.

The coal-fired boiler is staged for low NOx formation. The boiler is also equipped with an SCR. Wet limestone forced oxidation flue gas desulfurization (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 463 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 384.6 MWe. The plant operates with an estimated HHV efficiency of 31.1 percent with a corresponding heat rate of 11,568 kJ/kWh (10,967 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.

Descriptions of each of the plant sections are provided in the October 2000 Interim Report and should be used as a reference.

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, located in the October 2000 Interim Report, gives a more detailed account of the individual power plant subsections.

5.7.2 Thermal Plant Performance

Table 5-5 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.

Table 5-5
CASE 7G – SUPERCRITICAL PC PLANT WITH CO_2 REMOVAL
(POWER SET TO MATCH CASE 3E)
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	469,520
Generator Loss	(6,760)
Gross Plant Power	462,780
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	420
Limestone Handling & Reagent Preparation	1,000
Pulverizers	2,010
Ash Handling	1,810
Primary Air Fans	1,330
Forced Draft Fans	1,050
Induced Draft Fans	21,440
SCR	100
Seal Air Blowers	50
Precipitators	1,080
FGD Pumps and Agitators	3,740
Condensate Pumps	300
Boiler Feed Water Booster Pumps	3,190
High-Pressure Boiler Feed Pump	(Note 1)
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	1,770
Cooling Tower Fans	1,020
MEA Unit	2,220
CO_2 Compressor (Note 3)	32,060
Transformer Loss	1,070
Total Auxiliary Power Requirement	78,180
NET PLANT POWER, kWe	384,580
PLANT EFFICIENCY	
Net Efficiency, % HHV	31.1%
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	11,568 (10,967)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	990 (939)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	163,995 (361,540)
Sorbent, kg/h (lb/h)	16,135 (35,570)

Note 1 – Boiler feed pumps are turbine driven
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 Pressure: 8.3 MPa (1200 psig)
Note 4 – As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

Gross power output (prior to the generator terminals) for the steam turbine is estimated to be 463 MWe. Plant auxiliary power is estimated to be 78 MWe. Net plant power output, which considers generator losses and auxiliary power, is 385 MWe. This plant power output results in a net system thermal efficiency of 31.1 percent (HHV) with a corresponding heat rate of 11,568 kJ/kWh (10,967 Btu/kWh) (HHV).

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 system.

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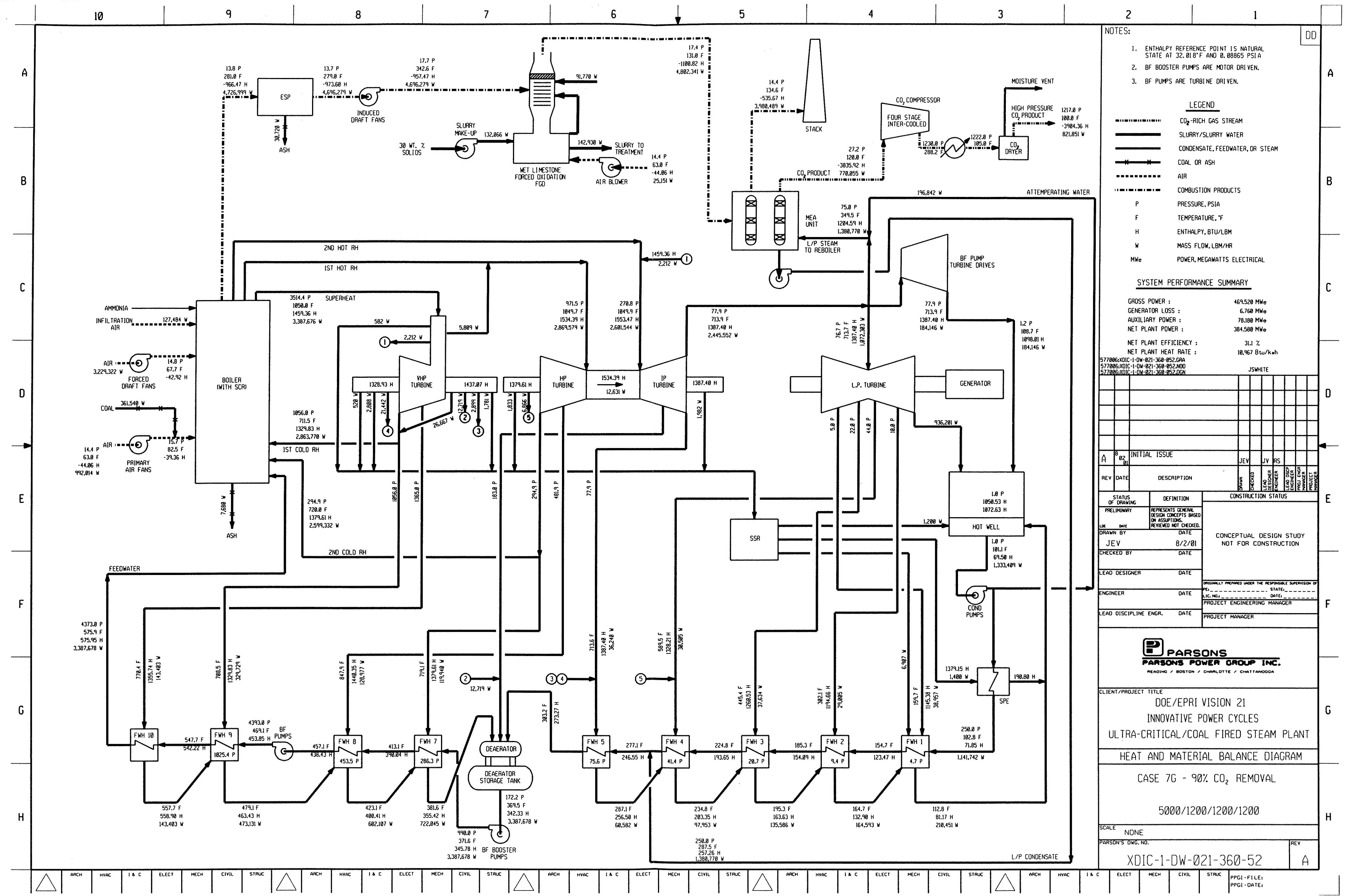

Figure 5-2
Heat and Material Balance Diagram – Case 7G – 90% CO_2 Removal

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5.7.3 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 7G, 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 Ton of CO_2 Removed.

The capital cost for case 7G 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 5-6. A detailed estimate for case 7G is included in Appendix A.

Table 5-6
CASE 7G SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	PC Boiler and Accessories	130,340
5	Flue Gas Cleanup	62,670
5B	CO_2 Removal and Compression	119,170
6	Combustion Turbine and Accessories	N/A
7	Ducting and Stack	19,060
8&9	Steam T-G Plant, including Cooling Water System	106,850
11	Accessory Electric Plant	33,000
	Balance of Plant	129,040
	SUBTOTAL	600,130
	Engineering, Construction Management Home Office and Fee	36,010
	Process Contingency	6,440
	Project Contingency	93,820
	TOTAL PLANT COST (TPC)	$736,390
	TPC $/kW	1,910

The production costs for case 7G 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 5-7, and supporting detail is contained in Appendix A.

Table 5-7
CASE 7G ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	5,272	0.24
Maintenance	9,786	0.45
Administrative & Support Labor	2,297	0.10
Consumables	17,384	0.79
By-Product Credits	N/A	N/A
Fuel	29,779	1.36
TOTAL PRODUCTION COST	64,519	2.95

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 7G. 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 Ton 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 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 5-8.

Table 5-8
CASE 7G LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	2.95
Annual Carrying Charge (¢/kWh)	5.19
Levelized Busbar Cost of Power Charge (¢/kWh)	8.14
Levelized Cost per Ton of CO_2 Removed ($/ton of CO_2 Removed)	30

6
GASIFICATION WITH CO_2 /COAL SLURRY – TECHNICAL DESCRIPTIONS

Two advanced coal-fired combined cycle power plants utilizing supercritical CO_2 to slurry the gasifier coal feed 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. Detailed plant descriptions and qualitative economics are also given for both cases.

The two cases evaluated are:

- Case 8A – Gasification with CO_2 – Direct Water Quench Option
- Case 8B – Gasification with CO_2 – Raw Gas Cooler Option

Each of these cases utilizes supercritical CO_2 to slurry the gasifier coal feed. Both cases also use a high-pressure E-Gas™-type gasifier to produce a high-temperature raw fuel gas stream. The raw fuel gas stream is cooled, shifted, and then processed in a double-stage Selexol unit to remove and concentrate CO_2. The resulting fuel gas is then fired in a H-type gas turbine.

The difference in the two cases listed above is in the treatment of the raw fuel gas stream. The raw fuel gas stream must be cooled prior to entering the shift converters. Option one is to cool the fuel gas stream by direct water injection. The latent heat of evaporation would then be used to cool the fuel gas stream to the desired temperature. The second option is to cool the raw fuel gas stream with a fire-tube boiler heat exchanger. The relative merits of these two cases are described in greater detail below.

6.1 Case 8A – Gasification with CO_2 – Direct Water Quench Option

6.1.1 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 set. 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 and generator connected on a single shaft.

A high-pressure E-Gas™ gasifier was chosen as the basis for this IGCC configuration. Supercritical CO_2 is used to slurry the coal, rather than using the more traditional water-based slurry approach. Raw fuel gas exiting the gasifier is directly cooled through high-pressure water injection. The latent heat of evaporation is utilized in this gas-cooling scheme. Particulate matter is then removed from the cool raw fuel gas stream in a metallic candle filter. The particulate-free fuel gas stream is then 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. A portion of the CO_2 is routed to the coal handling and feed preparation section for slurry preparation. 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 that is fed to a steam turbine.

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

- Thermal Plant Performance
- Power Plant Emissions
- System Description
- Qualitative Discussion of Performance and Cost

The thermal performance section contains a summary of plant performance including a breakdown of individual auxiliary power consumption. 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. No attempt at a refined economic analysis was made. The authors and managers of this study believe that the IGCC approach evaluated here has too many shortcomings to be competitive with conventional IGCC approaches; i.e., coal-water slurry fed gasifiers. Therefore, only a qualitative cost assessment will be provided. This section ends with a short discussion of conclusions generated by the study.

6.1.2 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 set. The resulting power plant thus utilizes a combined cycle for conversion of thermal energy to electric power. Table 6-1 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 6-1 shows an estimated larger-than-expected gas turbine power output compared to that generated with the H-based natural-gas-fired combined cycle. This power output level 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 is possible, while maintaining a similar firing temperature. 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 345 MWe in this IGCC case, as compared to 272 MWe estimated for an H-based natural gas combined cycle.

Plant auxiliary power is also summarized in Table 6-1. The total is estimated to be 79.5 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 almost 30 percent of the total auxiliary power load for the entire plant.

Net plant power output for this IGCC configuration is estimated at 365.1 MWe. This power output is generated with a net plant thermal efficiency of 35.2 percent, HHV, with a corresponding heat rate of 10,217 kJ/kWh (9,686 Btu/kWh). Plant efficiency and heat rate numbers are inferior to those expected for coal-fired IGCC of the H-class technology with CO_2 separation, which are 37.0 percent and 9,726 kJ/kWh (9,221 Btu/kWh), respectively. As discussed above, low system thermal efficiency is primarily due to the increased auxiliary power requirements of the CO_2 removal equipment.

Table 6-1
IGCC WITH CO_2-COAL SLURRY – DIRECT WATER QUENCH OPTION
PLANT PERFORMANCE SUMMARY – 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	12.4 (1,800)
Throttle Temperature, °F	537.8 (1,000)
Reheat Outlet Temperature, °F	537.8 (1,000)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	345,355
Steam Turbine Power	97,408
Generator Loss	(6,641)
Turbo-Set Power (Note 1)	436,122
Fuel Gas Expander Power	8,500
Gross Plant Power	444,622
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	340
Coal Milling	790
Coal Slurry Pumps	220
Slag Handling and Dewatering	160
Recycle Gas Blower	390
Air Separation Plant	21,680
Oxygen Boost Compressor	12,560
Selexol Plant	8,600
Claus/TGTU	100
Tail Gas Recycle	820
Humidification Tower Pump	100
Humidifier Makeup Pump	240
Low-Pressure CO_2 Compressor	810
High-Pressure CO_2 Compressor (Note 3)	24,240
Condensate Pumps	310
High-Pressure Boiler Feed Pump	2,190
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	1,660
Cooling Tower Fans	940
Flash Bottoms Pump	50
Transformer Loss	1,380
Total Auxiliary Power Requirement	79,480
NET PLANT POWER, kWe	365,142
PLANT EFFICIENCY	
Net Efficiency, % HHV	35.2
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	10,217 (9,686)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	493 (467)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	137,518 (303,170)
Oxygen (95% pure), kg/h (lb/h)	101,741 (224,297)
Water, kg/h (lb/h)	375,608 (828,061)

Note 1 - Single shaft turbo set.
Note 2 - Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure 8.3 MPa (1200 psia)
Note 4 - As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

6.1.3 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 6-2. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four bases: (1) kilograms per gigajoule (pounds per million Btu) of HHV thermal input, (2) tonnes per year (tons per year) for a 65 percent capacity factor, (3) tonnes per year (tons per year) for an 85 percent capacity factor, and, (4) kilograms per hour (pounds per hour) of MWe power output.

Table 6-2
IGCC WITH CO_2-COAL SLURRY – DIRECT WATER QUENCH OPTION
AIRBORNE EMISSIONS

	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)	122 (270)	159 (350)	0.113 (0.25)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	10.7 (25)	100,790 (222,200)	131,816 (290,600)	82.1 (181)

As shown in the table, values of SO_2 emission and particulate discharge 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 6-2. These levels are greater than those achieved with the same gas turbine fired on natural gas. However, they are much less than those realized with coal-fired IGCC without CO_2 removal and recovery.

6.1.4 System Description

This greenfield power plant is a 365 MW coal-fired IGCC power plant with CO_2 removal through the Selexol absorption process. 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
- Supercritical CO_2-Coal Slurry Preparation and Feeding
- Coal Gasification and Air Separation Unit
- Water-Gas Shift / Syngas Humidification
- Sulfur Removal and Recovery / CO_2 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.

6.1.4.1 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 over the design load condition for a 16-hour period and long-term operation at the 100 percent of design load point for 90 days or more.

The 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 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 3" x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 1" x 0, and then it is transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to a tripper, which loads the coal into one of three storage silos.

6.1.4.2 Supercritical CO_2-Coal Slurry Preparation and Feeding

CO_2 is removed from the fuel gas stream in a double-staged Selexol unit and compressed to supercritical conditions in a multi-staged intercooled compressor. Supercritical CO_2 at 8.3 MPa (1200 psia) and 40.6°C (105°F) is provided by the CO_2 removal system. For plant startup, liquid CO_2 is stored in a refrigerated storage tank at 21.1°C (70°F). A reciprocating pump with a discharge pressure of 6.9 MPa (1000 psia) is used to remove CO_2 from the storage tank during startup.

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 the pulverized coal hopper. Pulverized coal is removed from the hopper via a transfer screw and enters the slurry tank. Supercritical (or liquid – at startup) CO_2 enters the tank along with the coal. Enough CO_2 is added to produce 85 percent solids in the coal-CO_2 slurry. The slurry tank is agitated and operates at 6.07 MPa (880 psia) and 21.1°C (70°F). The slurry must be kept below 21.7°C (71°F) to avoid flashing. Slurry from the tank is then either fed to the gasifier or routed to an agitated storage tank. Slurry feed to the gasifier is pressurized to 6.14 MPa (890 psia) via the positive displacement feed pumps of the slurry preparation system. The slurry storage tank is sized to hold 8 hours of slurry product.

6.1.4.3 Coal Gasification and Air Separation Unit

This section gives a cursory description of the gasification process and air separation unit (ASU). 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 will be used. Each train will produce 1,208 tonnes/day (1,330 tons/day) of 95 percent oxygen product (1,153 tonnes/day (1,270 tons/day) 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 will be maintained in order to ensure reliability. A slipstream of vent nitrogen will be compressed and available for miscellaneous plant requirements.

A simplified schematic of the oxygen plant is shown in Figure 6-1. State point data are 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.

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 (5.52 MPa (800 psig)). Maximum coal throughput per gasifier is established as 1,135 tonnes/day (1,250 tons/day) dry. This relatively low coal throughput is due to the high operating pressure of the gasifier. This power plant requires 2,942 tonnes/day (3,240 tons/day) (dry) coal feed. Therefore, three gasification trains at 33.3 percent will be used.

Figure 6-1 contains a schematic of the gasifier. Approximately 90 percent of the supercritical CO_2-coal 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 the high-pressure 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 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 gasifier for reinjection. The gasifier operates with a cold gas efficiency of approximately 80 percent.

Raw Gas Cooling

Hot raw gas from the secondary gasification zone exits the gasifier at 5.52 MPa (800 psig) and 1040.6°C (1905°F). This gas stream is directly cooled to 288°C (550°F) through high-pressure water injection. The latent heat of evaporation of the water is used to cool the raw fuel gas stream. Water injection increases the moisture content of the raw fuel gas stream from 7.8 percent to 39 mole percent. This contributes to decreasing the steam injection requirement needed to boost the H_2O/CO ratio prior to the high-temperature shift converter.

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 5.35 MPa (776 psia).

6.1.4.4 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. The moisture content of the fuel gas stream is approximately 50.5 percent following the addition of the steam.

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 6-2. 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 395.6°C (744°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-staged shift was utilized in order to maximize CO conversion while maintaining reasonable reactor volumes.

The shifted raw gas temperature exiting the low-temperature shift converter is approximately 238°C (460°F). This stream is cooled to 160°C (320°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 drum.

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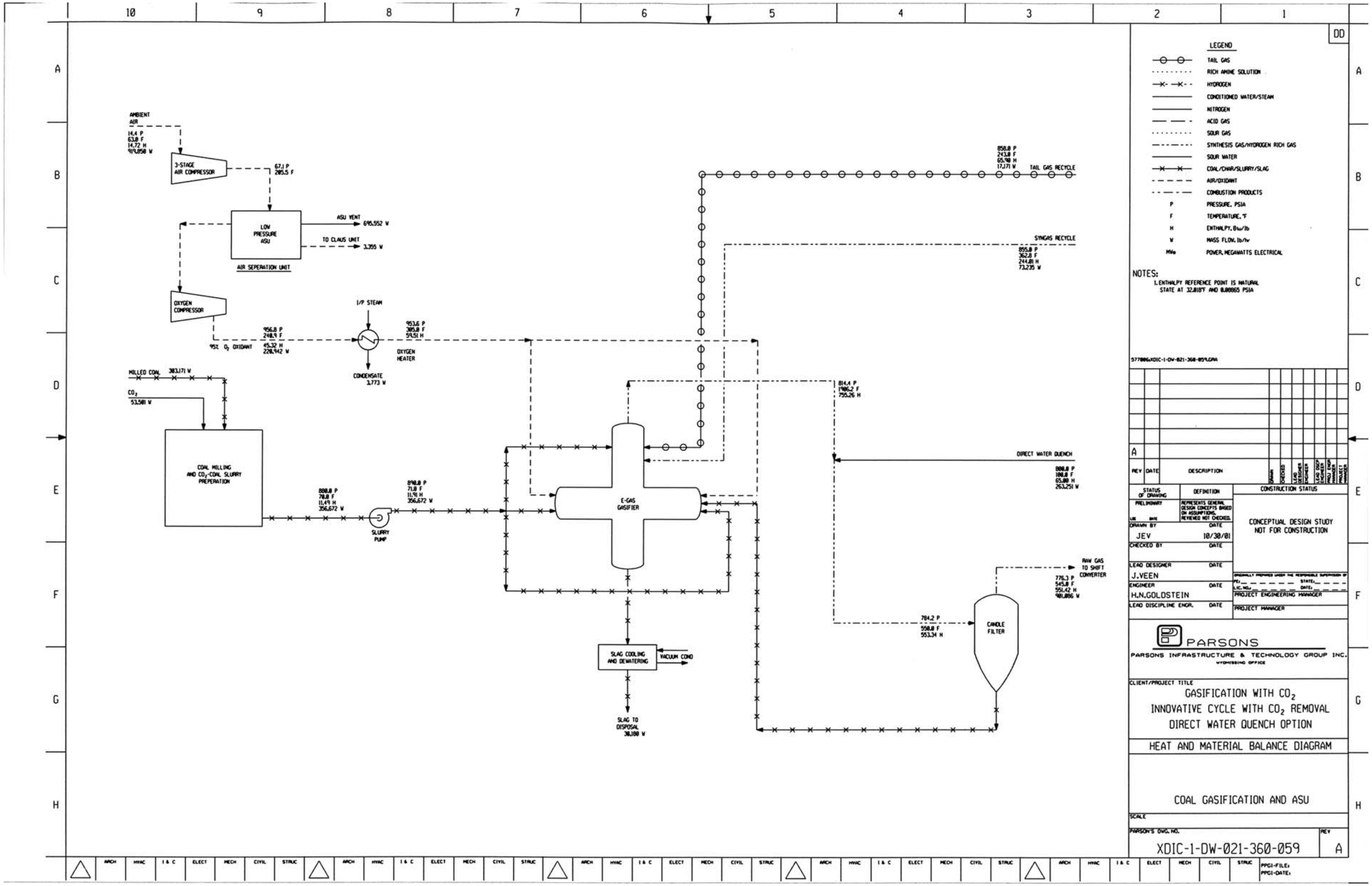

Figure 6-1
Heat and Material Balance Diagram – Case 8A – Coal Gasification and ASU

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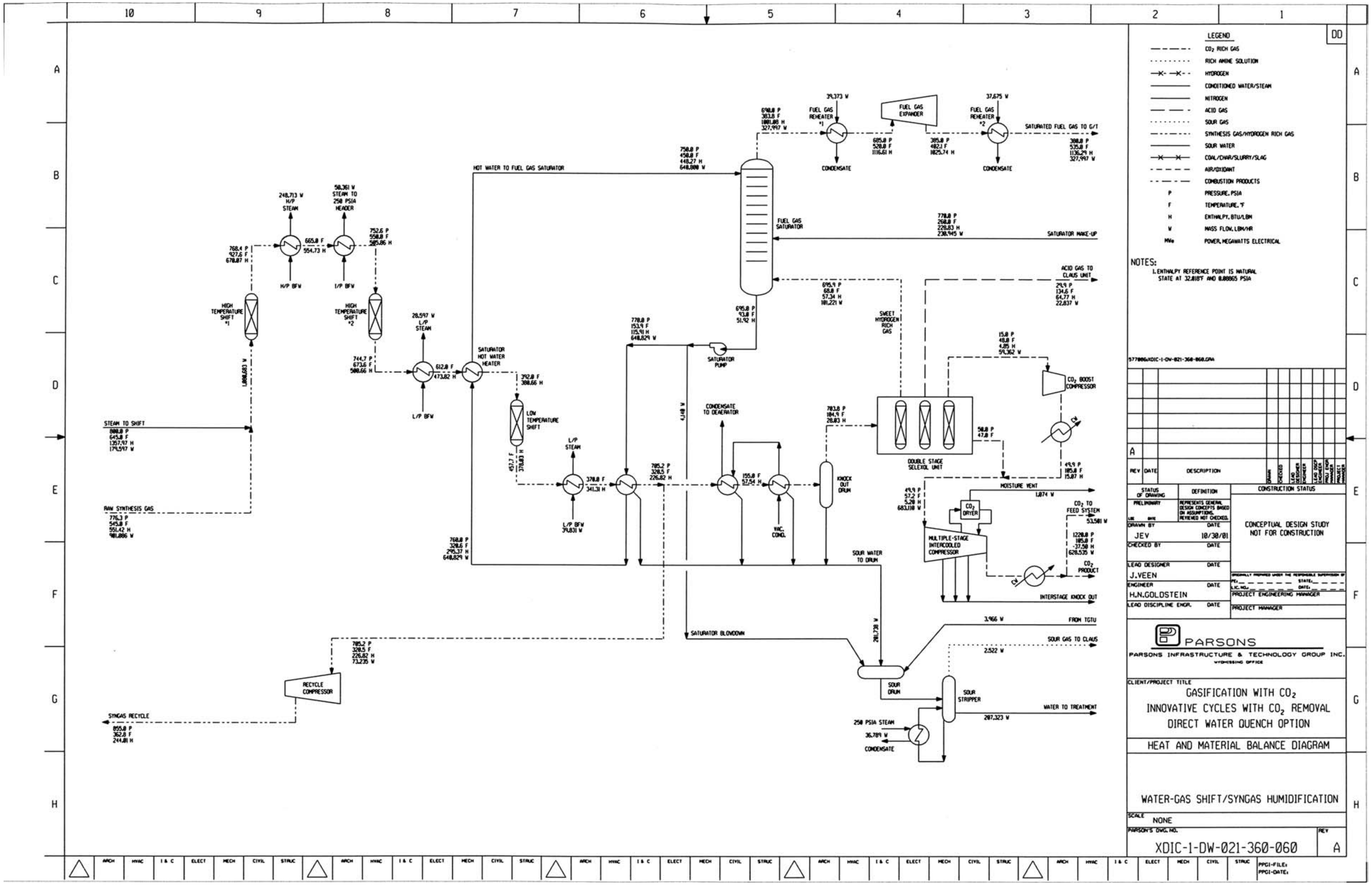

Figure 6-2
Heat and Material Balance Diagram – Case 8A – Water-Gas Shift/Syngas Humidification

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The fuel gas saturator can also be seen in Figure 6-2. 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 4.76 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 2.65 MPa (385 psia) to recover approximately 8.5 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 34°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.

6.1.4.5 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

Heat and mass balance diagrams of these systems can be seen in Figure 6-2 and Figure 6-3. The discussion follows below.

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 4.85 MPa (704 psia) and 40.6°C (105°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 38 percent H_2S and 52 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 exiting 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 0.34 MPa (50 psia), while the remainder is flashed off at atmospheric pressure. The second low-pressure CO_2 stream is "boosted" to 0.34 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. A portion of this CO_2 product stream is returned to the slurry preparation unit.

Claus Unit

Acid gas from the first-stage 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 6-3. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. Approximately 3,438 kg/hour (7,580 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 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 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, 5,670 kg/hour (12,500 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 2,359 kg/hour (5,200 lb/hour) for steam to the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

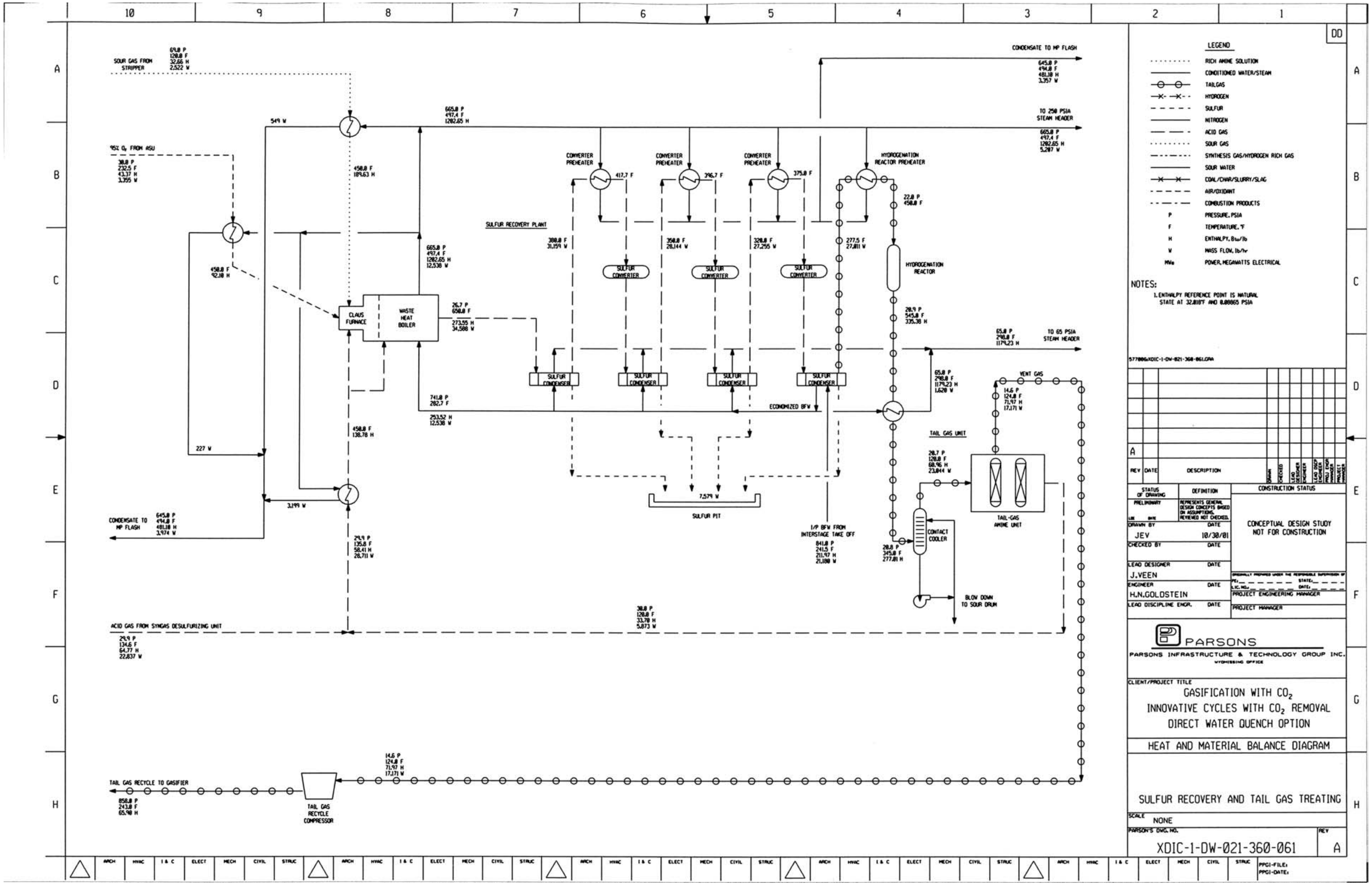

Figure 6-3
Heat and Material Balance Diagram – Case 8A – Sulfur Recovery and Tail Gas Treating

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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 catalytically 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.

6.1.4.6 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 6-4.

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 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 greater than 1371°C (2500°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 565.6°C (1050°F), given the assumed ambient conditions, back-end loss, and heat recovery steam generator (HRSG) pressure drop. This value, 28.8°C (50°F) lower than the ISO assumed value of 594.4°C (1102°F) for a natural -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 6-5. Waste heat rejected by the gas turbine is recovered by the HRSG. Steam generated in the HRSG, along with that generated in the high-temperature shift converter cooler, is utilized in the steam turbine to generate electrical power.

High-temperature flue gas at 2,157,322 kg/hour (4,756,000 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 1.7°C (3°F). The HRSG flue gas exit temperature is assumed to be 146°C (295°F), which should be high enough to avoid sulfur dew-point complications.

The HRSG is configured with a high-pressure (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 367,643 kg/hour (810,500 lb/hour) of 15.86 MPa (2300 psia) boiler feed water is heated to 326.7°C (620°F) in the economizer. This high-pressure economizer water stream is then split between the HRSG HP evaporator and drum and the high-temperature shift converter raw gas cooler. Saturated steam returned from these three sources is superheated in the HRSG to 540°C (1004°F) 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, 37,301 kg/hour (82,234 lb/hour) of cold reheat is heated from 321°C (610°F) to 539.4°C (1003°F). Combustion turbine cooling duties heat 135,543 kg/hour (298,816 lb/hour) of cold reheat to 537.8°C (1000°F). These two hot reheat streams are recombined and routed to the intermediate-pressure (IP) steam turbine inlet.

The HRSG also contains heat transfer surface for low-pressure (LP) steam generation. The heat transfer surface consists on an economizer, evaporator, and superheater. This surface was added to maximize thermal rejection rates in the HRSG and raise 45,360 kg/hour (100,000 lb/hour) of superheated LP steam at 315.6°C (600°F) and 0.5 MPa (72 psia).

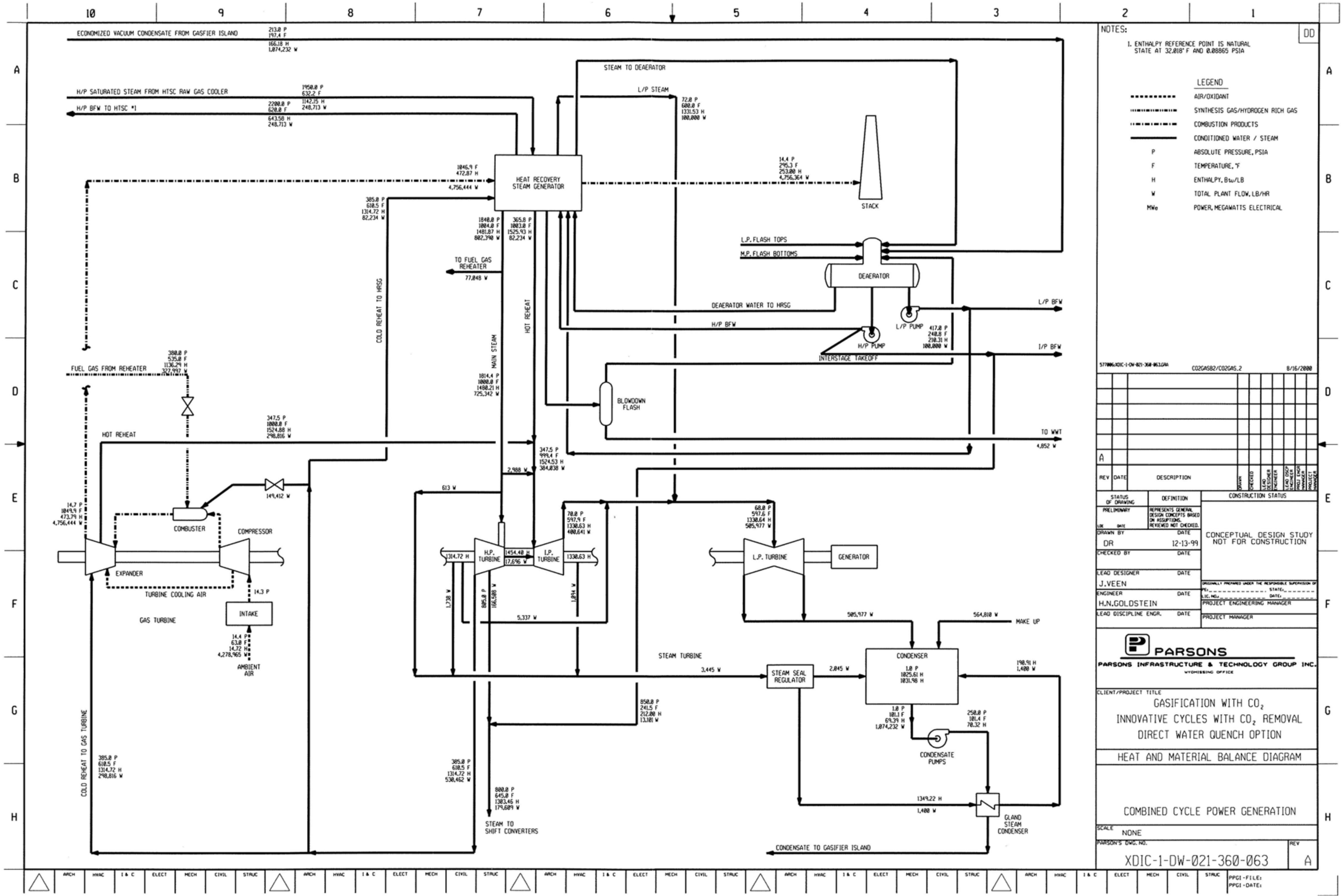

Figure 6-4
Heat and Material Balance Diagram – Case 8A – Combined Cycle Power Generation

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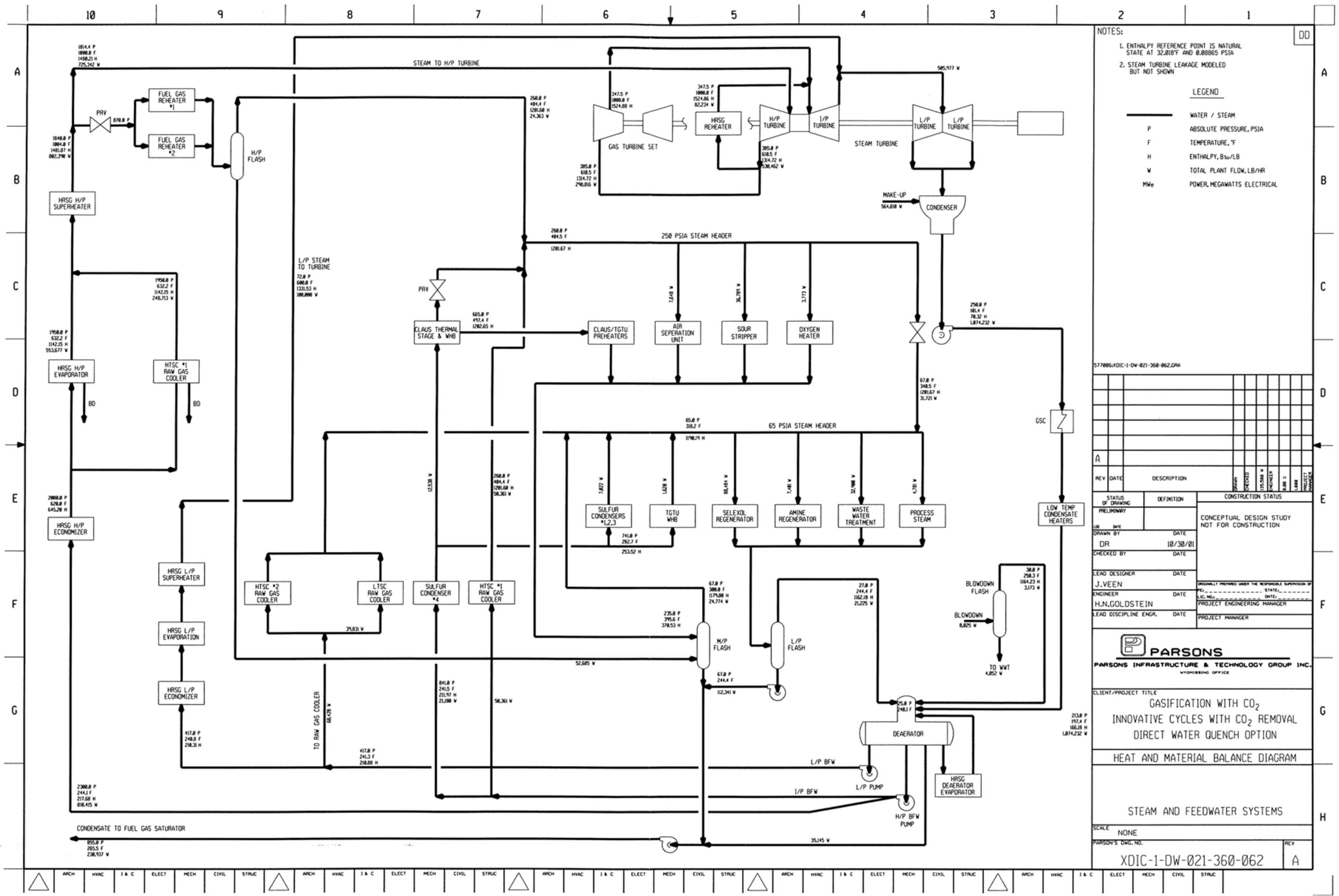

Figure 6-5
Heat and Material Balance Diagram – Case 8A – Steam and Feedwater Systems

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Steam Turbine

The Rankine cycle used in this case is based on a state-of-the-art 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 HP, IP, and double-flow 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 centimeters (72 inches) and a last-stage bucket length of 66 centimeters (26 inches).

Main steam at a rate of 329,015 kg/hour (725,342 lb/hour) passes through the HP stop valves and control valves and enters the turbine at 12.5 MPa (1815 psia) and 537.8°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 2.39 MPa (347 psia) and 537.8°C (1000°F). After passing through the IP section, the steam enters a crossover pipe. In the crossover piping section, 45,360 kg/hour (100,000 lb/hour) of LP steam generated in the HRSG is added to the IP turbine exhaust. The combined flow 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 97 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 96 MWe.

6.1.4.7 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.

6.1.4.8 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 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.

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 manually with operator selection of available modular automation routines.

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, an 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.

6.1.5 Qualitative Discussion of Performance and Cost

The work described in this report is an extension of previously completed work, which can be found in “Natural Gas and Coal Baseline Plants,” submitted by Parsons to DOE Office of Fossil Energy in October 2000 (referred to as the original or October 2000 Interim Report). The same general evaluation basis was used in both cases; ambient conditions, coal, and site characteristics. It was envisioned that this work could be compared side-by-side to the previous effort.

As such, this case is directly comparable to case 3A of the referenced report. The only differences are that this case utilizes a supercritical CO_2-coal slurry, rather than a conventional coal-water slurry, and that direct water injection was used instead of a fired-tube heat exchanger. This section provides some qualitative insight into this work from a cost perspective as it compares to the previous effort. The emphasis is cost savings directly related to the use of supercritical CO_2-coal slurry rather than water-coal slurry.

The most obvious cost advantage of this case over case 3A is that there is no need for a fire-tube boiler. This would result in a cost advantage of more than $70 million dollars. However, this cost savings is not a direct result of the application of supercritical CO_2-coal slurry to the gasification process. A direct water quench approach could easily be applied to case 3A. (This approach was evaluated in a subsequent effort and will be discussed in a forthcoming write-up.) Therefore, this cost advantage will not be applied as a credit to the CO_2 slurry case.

As shown in Table 6-3, the specific gas turbine power output (345 MWe) is the same for both cases. Coal flow, however, is quite different. The CO_2–coal slurry case presented in this report uses 5 percent less coal. Consequently, the coal handling system for the CO_2 slurry case would be slightly less capital intensive. This, however, would be overshadowed by the increased capital expenditure required for the CO_2 slurry system, which would be relatively more capital intensive than that required for simple water-coal slurry preparation. A CO_2 slurry system would require additional unit operations outside the scope of conventional water-coal slurry systems. This would include vapor recompression, high-pressure surge tanks, filters, and disengaging vessels. Therefore, there is no cost benefit realized from reduced coal requirements in the CO_2 slurry case.

As discussed above, the CO_2 slurry case presented here requires less coal flow to produce the same gas turbine power output generated in case 3A. This implies higher simple cycle efficiency for the gas turbine. Most of this increase in gas turbine simple cycle efficiency is due to the elevated cold gas efficiency (CGE) of the CO_2 slurry case. Using 85 percent coal slurry in supercritical CO_2 versus a 63 weight percent coal-water slurry requires considerably less oxygen and results in a higher CGE. As shown in the table, the oxygen-to-coal ratio decreases from 0.81 in the previous effort to 0.72 in this case. So, there would be an approximately 12 percent decrease in oxygen plant capital cost due to the use of the CO_2 slurry approach.

Table 6-3
VARIABLE COMPARISON
DIRECT WATER QUENCH OPTION AND CASE 3A

Variable	Case 3A	This Case
G/T Power, MWe	345	345
S/T Power, MWe	143	97
Auxiliary Power Load, MWe	86.9	79.5
Net Plant Power, MWe	403.5	365
Net Plant Efficiency, % HHV	37.0	35.2
Gasifier CGE, %	77	80
As-Received Coal Flow, kg/hour (lb/hour)	144,748 (319,110)	137,518 (303,170)
Oxygen/Coal Ratio	0.81	0.72

Intuitively, it would follow that the CO_2 slurry case would have a cost advantage above and beyond that of the oxygen plant advantage given the higher CGE and subsequent lower coal usage. However, there is only a very slight cost advantage. The gas flows downstream of the gasifier are more or less equal in both cases, so there is no cost advantage for decreased vessel and piping diameters. The only part of the plant that benefits is the Claus unit. The acid gas and sulfur recovered are slightly decreased for the CO_2 slurry case. However, this is more or less a moot point because the Claus unit is such a small fraction of the overall plant capital cost.

Unfortunately, steam turbine power output is greatly decreased by the fact that a direct water quench is used instead of a fired-tube boiler. The use of the fire-tube boiler allows for the generation of a significant amount of high-pressure, high-temperature steam. This loss in high-pressure steam production, which directly affects the net plant power output, greatly drops the specific power output of the plant. The benefits of using a CO_2 slurry – increased CGE, increased simple cycle efficiency, decreased oxidant utilization – are negated by the decrease in specific power output of the plant. This is also reflected in the net plant efficiency estimate, which is essentially the same in both the CO_2 slurry case and case 3A.

This qualitative discussion shows that there is no real cost advantage for using supercritical CO_2-coal slurry rather than the conventional approach of water-coal slurry in the IGCC application evaluated in this study. The cost savings to the oxygen plant and Claus unit would be nullified by the increased capital expenditure of the CO_2-coal slurry system. This being known to the authors and participants resulted in a decision not to pursue this plant design any further outside of the academic treatment discussed here.

6.2 Case 8B – Gasification with CO_2 – Raw Gas Cooler Option

6.2.1 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 set. 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 and generator connected on a single shaft.

A high-pressure E-Gas™ gasifier was chosen as the basis for this IGCC configuration. Supercritical CO_2 is used to slurry the coal, rather than the more traditional water-based slurry approach. Raw fuel gas exiting the gasifier is cooled in a fire-tube boiler. Particulate matter is then removed from the cool raw fuel gas stream in a metallic candle filter. The particulate-free fuel gas stream is then 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. A portion of the CO_2 is routed to the coal handling and feed preparation section for slurry preparation. 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
- Qualitative Discussion of Performance and Cost

The thermal performance section contains a summary of plant performance including a breakdown of individual auxiliary power consumption. 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. No attempt at a refined economic analysis was made. The authors and managers of this study believe that the IGCC approach evaluated here has too many shortcomings to be competitive with conventional IGCC approaches; i.e., coal-water slurry fed gasifiers. Therefore, only a qualitative cost assessment will be provided. This section ends with a short discussion of conclusions generated by the study.

6.2.2 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 set. The resulting power plant thus utilizes a combined cycle for conversion of thermal energy to electric power. Table 6-4 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 6-4 shows an estimated larger-than-expected gas turbine power output compared to that generated with the H-based, natural-gas-fired combined cycle. This power output level 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 is possible, while maintaining a similar firing temperature. This can result in as much as a 20 percent increase in net plant power output, though this operation may result in reduced turbine life. As a result, gross combustion turbine power has been estimated at 345 MWe in this IGCC case as compared to 272 MWe estimated for an H-based natural gas combined cycle.

Plant auxiliary power is also summarized in Table 6-4. The total is estimated to be 80.8 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 almost 30 percent of the total auxiliary power load for the entire plant.

Net plant power output for this IGCC configuration is estimated at 381.1 MWe. This power output is generated with a net plant thermal efficiency of 36.8 percent, HHV, with a corresponding heat rate of 9,790 kJ/kWh (9,281 Btu/kWh). Plant efficiency and heat rate numbers are slightly inferior to those expected for coal-fired IGCC of the H-class technology with CO_2 separation, which are 37.0 percent and 9,726 kJ/kWh (9,221 Btu/kWh), respectively. As discussed above, lower system thermal efficiency is primarily due to the increased auxiliary power requirements of the CO_2 removal equipment.

Table 6-4
IGCC WITH CO_2-COAL SLURRY – RAW GAS COOLER OPTION
PLANT PERFORMANCE SUMMARY – 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, MPa (psig)	12.4 (1,800)
Throttle Temperature, °C (°F)	537.8 (1,000)
Reheat Outlet Temperature, °C (°F)	537.8 (1,000)
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	345,355
Steam Turbine Power	114,949
Generator Loss	(6,904)
Turbo-Set Power (Note 1)	453,400
Fuel Gas Expander Power	8,470
Gross Plant Power	461,870
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	340
Coal Milling	790
Coal Slurry Pumps	220
Slag Handling and Dewatering	160
Recycle Gas Blower	350
Air Separation Plant	21,680
Oxygen Boost Compressor	12,560
Selexol Plant	8,600
Claus/TGTU	100
Tail Gas Recycle	820
Humidification Tower Pump	100
Humidifier Makeup Pump	240
Low-Pressure CO_2 Compressor	810
High-Pressure CO_2 Compressor (Note 3)	24,240
Condensate Pumps	380
High-Pressure Boiler Feed Pump	3,120
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	1,440
Total Auxiliary Power Requirement	80,780
NET PLANT POWER, kWe	381,090
PLANT EFFICIENCY	
Net Efficiency, % HHV	36.8
Net Heat Rate, kJ/kWh (Btu/kWh) (HHV)	9,790 (9,281)
CONDENSER COOLING DUTY, GJ (10^6 Btu/h)	548 (520)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h) (Note 4)	137,525 (303,186)
Oxygen (95% pure), kg/h (lb/h)	101,758 (224,335)
Water, kg/h (lb/h)	359,750 (793,099)

Note 1 - Single shaft turbo set.
Note 2 - Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure 8.3 MPa (1200 psia)
Note 4 - As-received coal heating value: 27,135 kJ/kg (11,666 Btu/lb) (HHV)

6.2.3 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 6-5. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four bases: (1) kilograms per gigajoule (pounds per million Btu) of HHV thermal input, (2) tonnes per year (tons per year) for a 65 percent capacity factor, (3) tonnes per year (tons per year) for an 85 percent capacity factor, and, (4) kilograms per hour (pounds per hour) of MWe power output.

Table 6-5
IGCC WITH CO_2-COAL SLURRY – RAW GAS COOLER OPTION
AIRBORNE EMISSIONS

	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)	122 (270)	159 (350)	0.113 (0.25)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	10.7 (25)	100,790 (222,200)	131,816 (290,600)	82.1 (181)

As shown in the table, values of SO_2 emission and particulate discharge 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 6-5. These levels are greater than those achieved with the same gas turbine fired on natural gas. However, they are much less than those realized with coal-fired IGCC without CO_2 removal and recovery.

6.2.4 System Description

This greenfield power plant is a 381 MW coal-fired IGCC power plant with CO_2 removal through the Selexol absorption process. 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
- Supercritical CO_2-Coal Slurry Preparation and Feeding
- Coal Gasification and Air Separation Unit
- Water-Gas Shift / Syngas Humidification
- Sulfur Removal and Recovery / CO_2 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.

6.2.4.1 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 over the design load condition for a 16-hour period and long-term operation at the 100 percent of design load point for 90 days or more.

The 6" x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 90.8-tonne (100-ton) rail cars. Each unit train consists of 100, 90.8-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 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 3" x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 1" x 0, and 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.

6.2.4.2 Supercritical CO_2-Coal Slurry Preparation and Feeding

Supercritical CO_2 at 8.27 MPa (1200 psia) and 40.6°C (105°F) is provided by the CO_2 removal system. (CO_2 is removed from the fuel gas stream in a double-staged Selexol unit and compressed to supercritical conditions in a multi-staged intercooled compressor.) For plant startup, liquid CO_2 is stored in a refrigerated storage tank at 21.1°C (70°F). A reciprocating pump with a discharge pressure of 6.9 MPa (1000 psia) is used to remove CO_2 from the storage tank during startup.

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 the pulverized coal hopper. Pulverized coal is removed from the hopper via a transfer screw and enters the slurry tank. Supercritical (or liquid – at startup) CO_2 enters the tank along with the coal. Enough CO_2 is added to produce 85 percent solids in the coal-CO_2 slurry. The slurry tank is agitated and operates at 6.07 MPa (880 psia) and 21.1°C (70°F). The slurry must be kept below 21.7°C (71°F) to avoid flashing. Slurry from the tank is then either fed to the gasifier or routed to an agitated storage tank. Slurry feed to the gasifier is pressurized to 6.14 MPa (890 psia) via the positive displacement feed pumps of the slurry preparation system. The slurry storage tank is sized to hold 8 hours of slurry product.

6.2.4.3 Coal Gasification and Air Separation Unit

This section gives a cursory description of the gasification process and air separation unit (ASU). 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 will be used. Each train will produce 1,208 tonnes/day (1,330 tons/day) of 95 percent oxygen product (1,153 tonnes/day (1,270 tons/day) 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 will be maintained in order to ensure reliability. A slipstream of vent nitrogen will be compressed and available for miscellaneous plant requirements.

A simplified schematic of the oxygen plant is shown in Figure 6-6. State point data are 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 (954 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.

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 (5.52 MPa (800 psig)). Maximum coal throughput per gasifier is established as 1,135 tonnes/day (1,250 tons/day) dry. This relatively low coal throughput is due to the high operating pressure of the gasifier. This power plant requires 2,933 tonnes/day (3,230 tons/day) (dry) coal feed. Therefore, three gasification trains at 33.3 percent will be used.

Figure 6-1 contains a schematic of the gasifier. Approximately 90 percent of the supercritical CO_2-coal 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 the high-pressure 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 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 gasifier for reinjection. The gasifier operates with a cold gas efficiency of approximately 80 percent.

Raw Gas Cooling

Hot raw gas from the secondary gasification zone exits the gasifier at 5.52 MPa (800 psig) and 1040.6°C (1905°F). This gas stream is cooled to 360°C (680°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 272,160 kg/hour (600,000 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 an input temperature to the ceramic candle filter. Raw gas exits this cooler at 288°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 5.45 MPa (791 psia).

6.2.4.4 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. The moisture content of the fuel gas stream is approximately 50.5 percent following the addition of the steam.

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 6-7. 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 358°C (677°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-staged shift was utilized in order to maximize CO conversion while maintaining reasonable reactor volumes.

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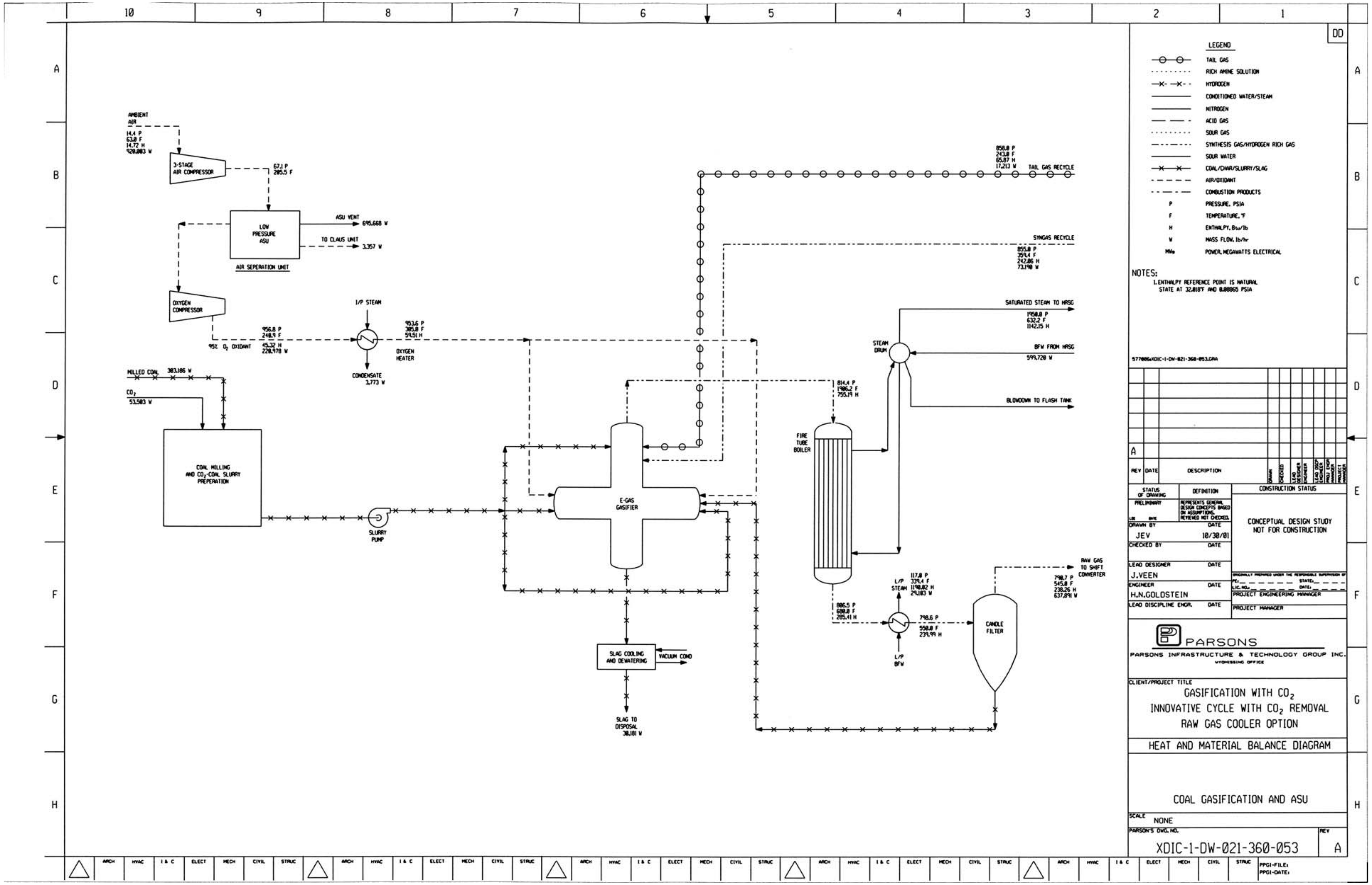

Figure 6-6
Heat and Material Balance Diagram – Case 8B – Coal Gasification and ASU

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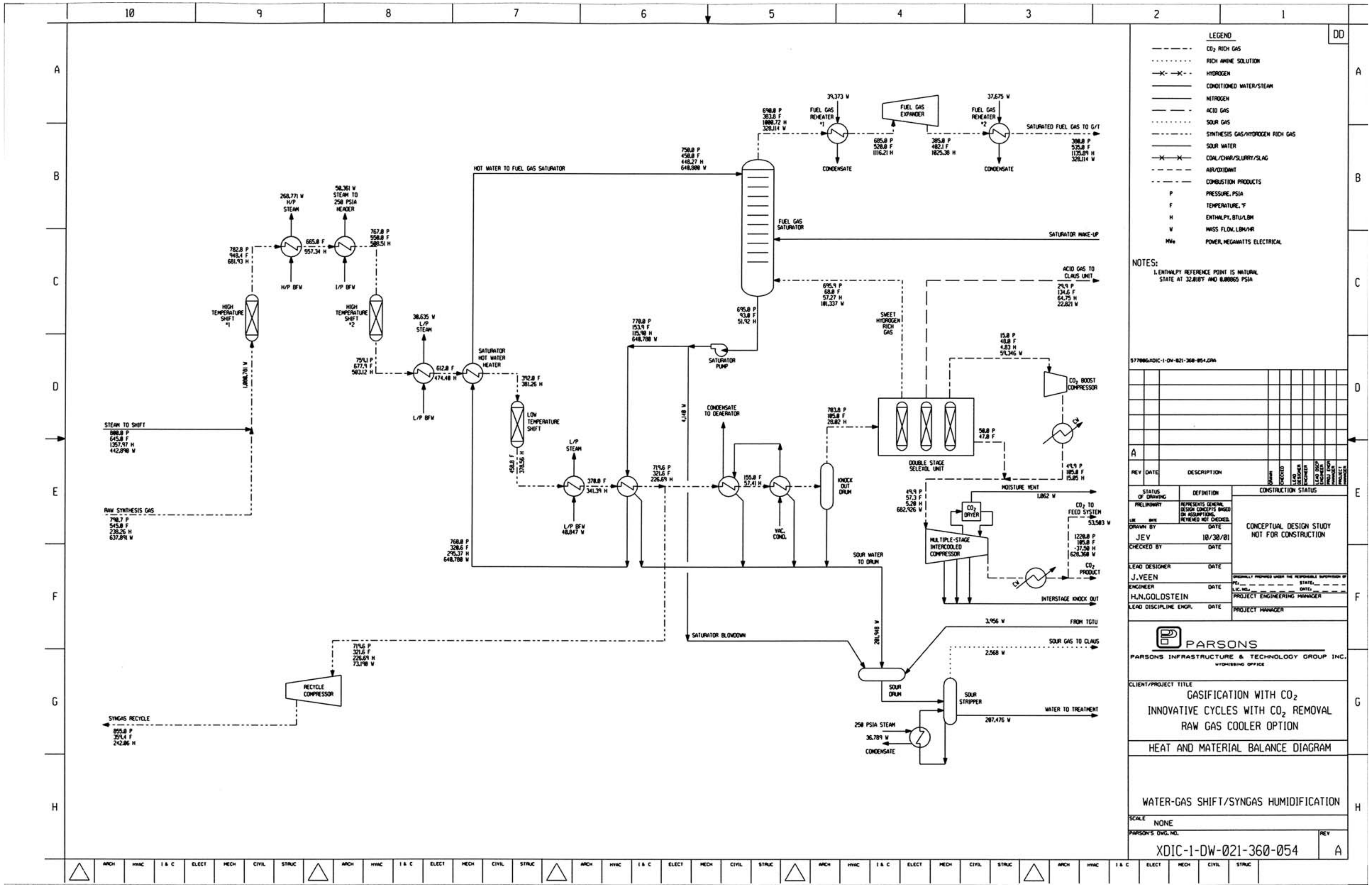

Figure 6-7
Heat and Material Balance Diagram – Case 8B – Water-Gas Shift/Syngas Humidification

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The shifted raw gas temperature exiting the low-temperature shift converter is approximately 238°C (460°F). This stream is cooled to 160°C (320°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 drum.

The fuel gas saturator can also be seen in Figure 6-7. 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 4.76 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 2.65 MPa (385 psia) to recover approximately 8.5 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 34°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.

6.2.4.5 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 Figure 6-7 and Figure 6-8. The discussion follows below.

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 4.85 MPa (704 psia) and 40.6°C (105°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 38 percent H_2S and 52 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 0.34 MPa (50 psia), while the remainder is flashed off at atmospheric pressure. The second low-pressure CO_2 stream is "boosted" to 0.34 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. A portion of this CO_2 product stream is returned to the slurry preparation unit.

Claus Unit

Acid gas from the first-stage 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 6-8. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. Approximately 3,438 kg/hour (7,580 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.

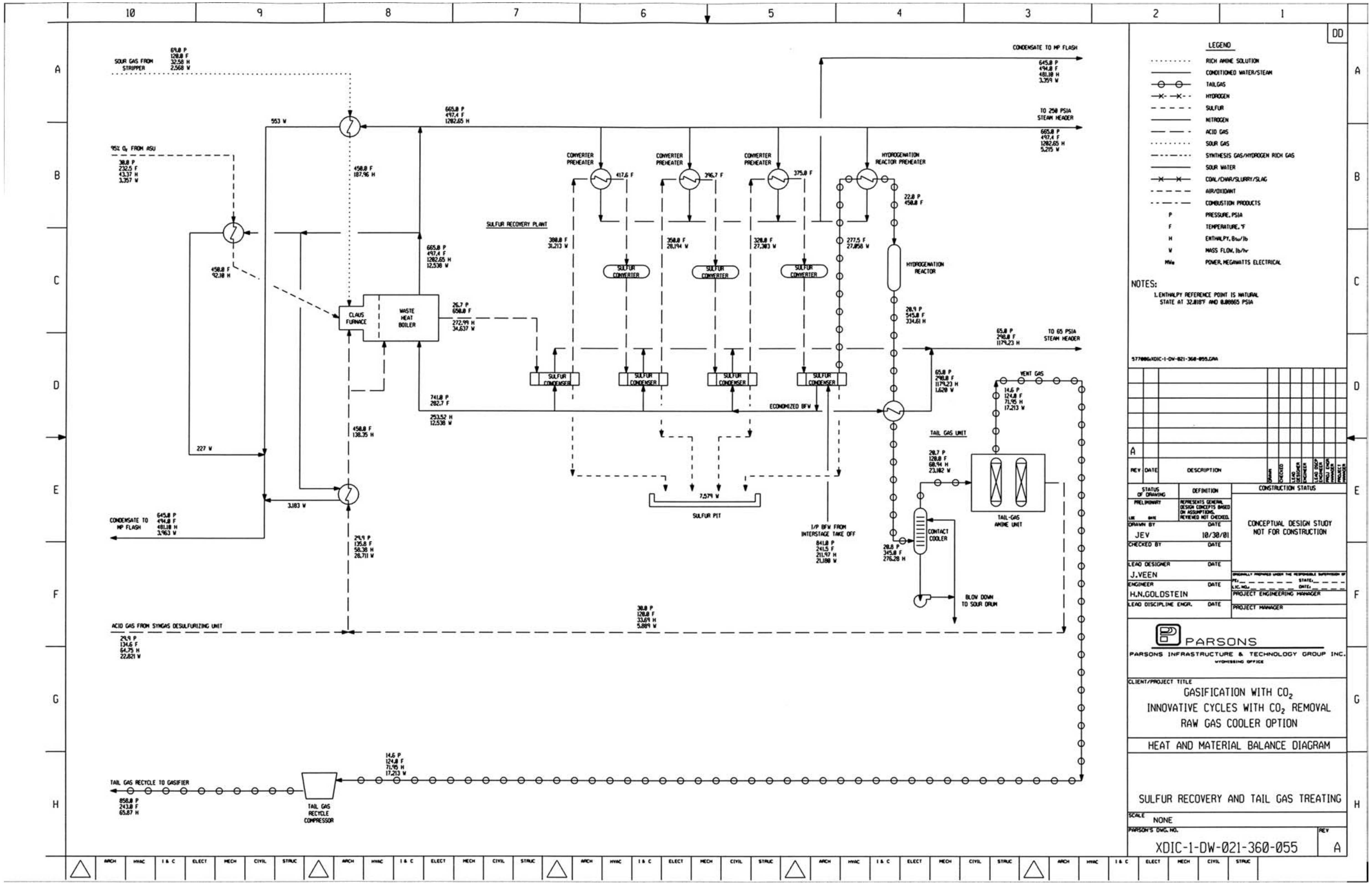

Figure 6-8
Heat and Material Balance Diagram – Case 8B – Sulfur Recovery and Tail Gas Treating

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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, 5,670 kg/hour (12,500 lb/hour) of 4.48 MPa (650 psia) steam is generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as 2,359 kg/hour (5,200 lb/hour) of steam to the intermediate-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 catalytically 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.

6.2.4.6 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 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 6-9.

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 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 greater than 1371°C (2500°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 565.6°C (1050°F), given the assumed ambient conditions, back-end loss, and heat recovery steam generator (HRSG) pressure drop. This value, 28.8°C (50°F) lower than the ISO assumed value of 594.4°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 6-10. Waste heat rejected by the gas turbine is recovered by the HRSG. Steam generated in the HRSG, along with that generated in the high-temperature shift converter cooler, is utilized in the steam turbine to generate electrical power.

High-temperature flue gas at 2,157,322 kg/hour (4,756,000 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 1.7°C (3°F). The HRSG flue gas exit temperature is assumed to be 138.3°C (281°F), which should be high enough to avoid sulfur dew-point complications.

The HRSG is configured with a high-pressure (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 522,865 kg/hour (1,152,700 lb/hour) of 15.86 MPa (2300 psia) boiler feed water is heated to 326.7°C (620°F) in the economizer. This high-pressure economizer water stream is then split between the HRSG HP evaporator and drum and the high-temperature shift converter raw gas cooler. Saturated steam returned from these three sources is superheated in the HRSG to 540°C (1004°F) and then routed to the HP steam turbine inlet.

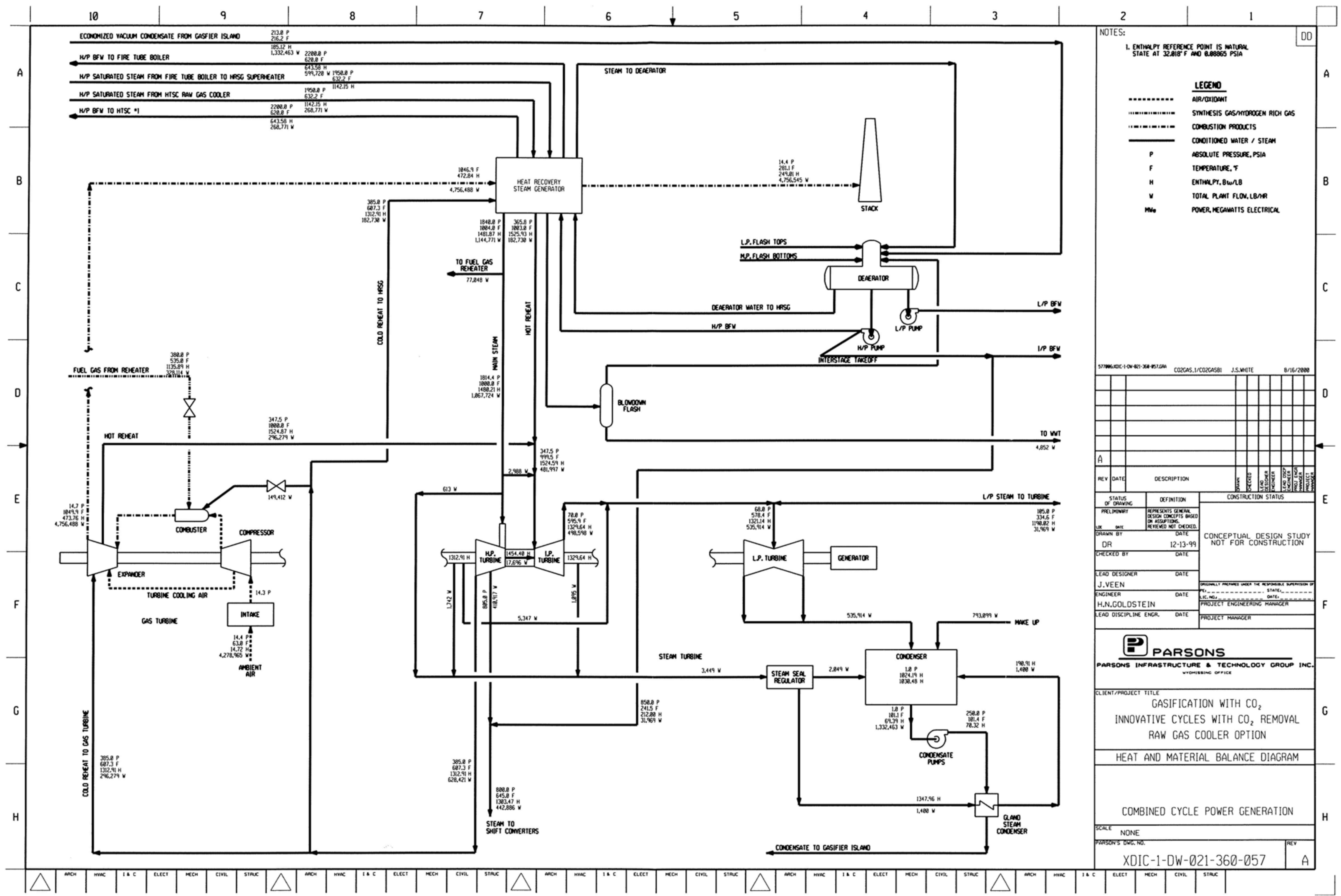

Figure 6-9
Heat and Material Balance Diagram – Case 8B – Combined Cycle Power Generation

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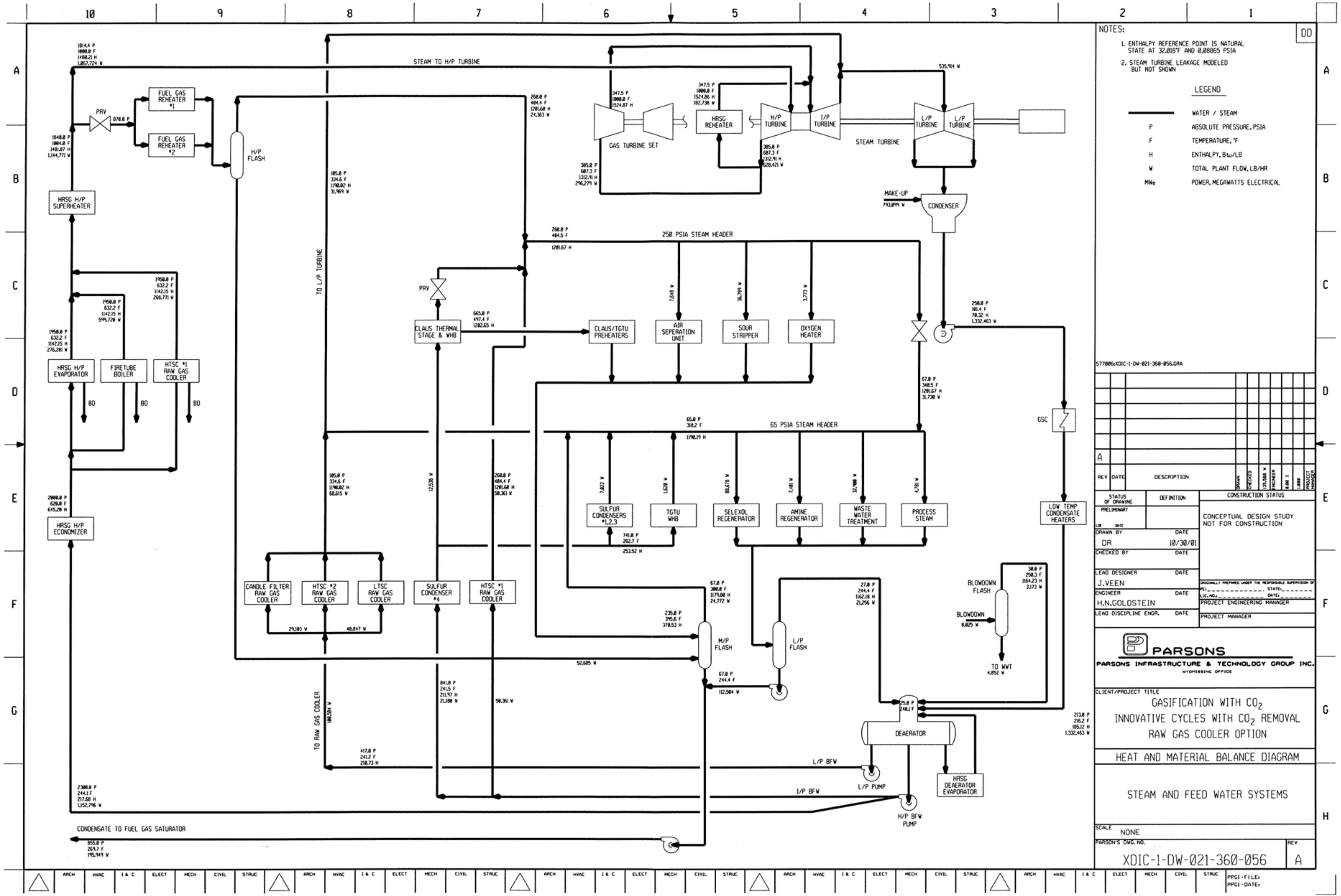

Figure 6-10
Heat and Material Balance Diagram – Case 8B – Steam and Feedwater Systems

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Cold reheat from the HP steam expander is split between gas turbine cooling duties, combustor turbine steam injection, and the HRSG. In the HRSG, 82,873 kg/hour (182,700 lb/hour) of cold reheat is heated from 321°C (610°F) to 539.4°C (1003°F). Combustion turbine cooling duties heat 134,392 kg/hour (296,279 lb/hour) of cold reheat to 537.8°C (1000°F). These two hot reheat streams are recombined and routed to the intermediate-pressure (IP) steam turbine inlet.

Steam Turbine

The Rankine cycle used in this case is based on a state-of-the-art 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 HP, IP, and double-flow 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 centimeters (72 inches) and a last-stage bucket length of 66 centimeters (26 inches).

Steam at a rate of 484,320 kg/hour (1,067,724 lb/hour) passes through the HP stop valves and control valves and enters the turbine at 12.5 MPa (1815 psia) and 537.8°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 2.39 MPa (347 psia) and 537.8°C (1000°F). After passing through the IP section, the steam enters a crossover pipe. In the crossover piping section, approximately 14,515 kg/hour (32,000 lb/hour) of LP steam generated in the HRSG is added to the IP turbine exhaust. The combined flow 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 115 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 113 MWe.

6.2.4.7 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 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. Pneumatic flow control valves control the recirculation flow. 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.

6.2.4.8 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 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.

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 manually with operator selection of available modular automation routines.

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, an 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.

6.2.5 Qualitative Discussion of Performance and Cost

The work described in this report is an extension of previously completed work. The same general evaluation basis was used in both cases; ambient conditions, coal, and site characteristics. It was envisioned that this work could be compared side-by-side to the previous effort. Consequently, this case is directly comparable to case 3A of the October 2000 Interim Report. The only differences are that this case utilizes supercritical CO_2-coal slurry, rather than coal-water slurry. This section provides some qualitative insight into this work – from a cost perspective – as it compares to the previous effort. The emphasis is cost savings directly applicable and related to the use of supercritical CO_2-coal slurry rather than water-coal slurry as applied to the IGCC configurations presented in this study.

As shown in Table 6-6, the specific gas turbine power output is the same for both cases: 345 MWe. Coal flow, however, is quite different. The CO_2 slurry case presented in this report uses 5 percent less coal. As such, the coal handling system for the CO_2 slurry case would be slightly less capital intensive. This, however, would be overshadowed by the increased capital expenditure required for the CO_2 slurry system, which would be relatively more capital intensive than that required for simple water-coal slurry preparation. A CO_2 slurry system would require additional unit operations outside the scope of conventional water-coal slurry systems. This would include vapor recompression, high-pressure surge tanks, filters, and disengaging vessels. Therefore, there is no cost benefit realized from reduced coal requirements in the CO_2 slurry case.

Table 6-6
VARIABLE COMPARISON
RAW GAS COOLER OPTION AND CASE 3A

Variable	Case 3A	This Case
G/T Power, MWe	345	345
S/T Power, MWe	143	115
Auxiliary Power Load, MWe	86.9	80.8
Net Plant Power, MWe	403.5	381
Net Plant Efficiency, % HHV	37.0	36.8
Gasifier CGE, %	77	80
As-Received Coal Flow, kg/hour (lb/hour)	144,748 (319,110)	137,525 (303,186)
Oxygen/Coal Ratio	0.81	0.73

As discussed in the preceding paragraph, the CO_2 slurry case presented here requires less coal flow to produce the same gas turbine power output as case 3A. This implies higher simple cycle efficiency for the gas turbine. Most of this increase in gas turbine simple cycle efficiency is due to the elevated cold gas efficiency (CGE) of the CO_2 slurry case. Using an 85 percent coal slurry in supercritical CO_2 versus a 63 weight percent coal-water slurry requires considerably less oxygen and results in a higher CGE. As shown in the table, the oxygen-to-coal ratio decreases from 0.81 in the previous effort to 0.73 in this case, so there would be an approximately 12 percent decrease in oxygen plant capital cost due to the use of the CO_2 slurry approach.

Intuitively, it would follow that the CO_2 slurry case would have a cost advantage above and beyond that of the oxygen plant advantage given the higher CGE and subsequent lower coal usage. However, there is only a very slight cost advantage. The gas flows downstream of the gasifier are more or less equal in both cases, so there is no cost advantage for decreased vessel and piping diameters. The only part of the plant that benefits is the Claus unit. The acid gas and sulfur recovered are slightly decreased for the CO_2 slurry case. However, this is more or less a moot point because the Claus unit is such a small fraction of the overall plant capital cost.

The expected increase in gasifier performance is what precipitated the application of this coal feeding approach to this particular IGCC system. The “improved” gasifier performance was expected to carry over and benefit the net cycle efficiency. However, as can be seen in Table 6-6, this expected result was not realized. An unexpected outcome of applying the CO_2-coal slurry feeding system to this specific IGCC process is decreased steam turbine power output. This occurs due to the relatively large amount of IP steam required to properly “tune” the H_2O/CO ratio for the shift converters. In the original case, case 3A, approximately 131,544 kg/hour (290,000 lb/hour) of IP steam was required for the shift converter. In the case presented here, almost 200,945 kg/hour (443,000 lb/hour) of steam is required. The use of this steam is an unrecoverable loss that impacts net system efficiency in a negative manner. This loss overshadows the benefits of using CO_2 slurry – increased CGE, increased simple cycle efficiency, decreased oxidant utilization – resulting in a slightly depressed net plant efficiency.

This qualitative discussion shows that there is no real cost advantage for using supercritical CO_2-coal slurry rather than the conventional approach of water-coal slurry in the IGCC application evaluated in this study. The cost savings to the oxygen plant and Claus unit would be nullified by the increased capital expenditure of the CO_2-coal slurry system. This being known – in conjunction with the unrealized “boost” in net plant efficiency – to the authors and participants resulted in a decision not to pursue this plant design any further outside of the academic treatment discussed here.

7 COAL-FIRED CONFIGURATIONS – TECHNICAL DESCRIPTIONS

Several coal-fired combined cycle power plants were evaluated, one of which (case 9A) is presented in this section. Each design is market-based and consists of an advanced 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 9A – Base Case IGCC Plant without CO_2 Removal
- Case 9B – Base Case IGCC Plant with CO_2 Removal and Recovery

Case 9A is described in greater detail in this section. As of the writing of this report, case 9B has not been completed. In developing case 9A as the base case, several sensitivity cases were also studied. Table 7-1 contains the results of these cases.

Case 9C is a conventional dual train IGCC plant without air integration of the gas turbine and ASU, as was incorporated in case 9A. It is fired on the study coal (Illinois No. 6), and the syngas is diluted with steam from the cold reheat line of the steam turbine, in contrast to case 9A, which used steam and nitrogen. The net plant output is 559.1 MWe with a net plant efficiency (HHV basis) of 39.2 percent. Case 9D reflects the same configuration as case 9C, though is fired on an alternate coal (Pittsburgh No. 8) with a slightly higher heating value (28,954 kJ/kg (12,450 Btu/lb, HHV). The resulting performance showed a slight decrease in net plant output (554 MWe) with a similar plant efficiency (39.1 percent).

Cases 9E and 9F employ gas turbine and ASU air-side integration to minimize ASU compressor power requirements by extracting high-pressure air from the gas turbine air compressor, reducing the amount of air that must be compressed from ambient conditions for use in the ASU. Both nitrogen and steam are used for syngas dilution for case 9E, while only steam dilution is used in case 9F. The increase in gross power output from 599.2 MWe for case 9F to 663.6 MWe for case 9E shows that the steam, taken from the steam cycle, used for syngas dilution has significant power generation value. The increase in auxiliary load from 50.2 MWe for case 9F to 90.9 MWe for case 9E shows that the power required for the compression of nitrogen gas to assist in syngas dilution can be costly, but is offset by the added power produced by the steam that is not used for dilution purposes. The increase in net plant power output from 549 MWe to 572.4 MWe show that the combination of nitrogen and steam for syngas dilution will pay off both in increased plant output as well as efficiency.

Case 9A was chosen because it exhibited the highest net power output (583.6 MWe) and the highest net plant efficiency (39.6 percent, HHV). Utilizing nitrogen in addition to steam for syngas dilution allows for greater power output, while the elevated pressure ASU produces nitrogen and oxygen at higher pressures (up to 56 psia as opposed to near ambient pressures in low-pressure ASU practice), decreasing compression power requirements and decreasing auxiliary power requirements.

Table 7-1
DUAL TRAIN IGCC WITH 7FA BASED GAS TURBINE SENSITIVITY CASES

Sensitivity Case	**9A (Base Case)**	**9C**	**9D**	**9E**	**9F**
Coal Type	Illinois 6	Illinois 6	Pittsburgh 8	Illinois 6	Illinois 6
ASU Integration	50% (HP)	0%	0%	50% (LP)	50% (LP)
Syngas Diluent	N_2 / Steam	Steam	Steam	N_2 / Steam	Steam
Gas Turbine Power, MWe	414.8	414.8	414.8	414.8	414.8
Steam Turbine Power, MWe	248.8	210.9	206.5	248.5	184.4
Auxiliary Power, MWe	80.0	66.5	67.2	90.9	50.2
Net Power, MWe	583.6	559.1	554.1	572.4	549.0
Coal Flowrate, lb/h	430,690	416,960	388,840	428,040	425,320
Thermal Input, MW_{th}	1,472.5	1,425.6	1,418.8	1,463.5	1,454.2
Net Plant Efficiency, HHV	39.6%	39.2%	39.1%	39.1%	37.8%
Net Plant Heat Rate, HHV	8,609	8,700	8,737	8,723	9,038

Notes: Illinois 6 Coal: 27,135 kJ/kg (11,666 Btu/lb); Pittsburgh No. 8 Coal: 28,954 kJ/kg (12,450 Btu/lb) HHV basis
HP: high-pressure air separation unit
LP: low-pressure air separation unit

7.1 Case 9A – E-Gas™ IGCC, F Class Turbine Without CO_2 Removal

7.1.1 Introduction

This market-based design centers on the use of two trains of gasifiers and combustion turbines coupled with a heat recovery system that generates steam for a single steam turbine generator. The gas turbine technology chosen for this integrated gasification combined cycle (IGCC) study is based on General Electric's frame 7FA technology, taking into account the anticipated uprating to 210 MWe power output.

A conventional pressure E-Gas™ gasifier was chosen as the basis for this IGCC configuration. Raw fuel gas exiting each 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 turbines. 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

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, is used in generating the estimated plant cost.

7.1.2 Thermal Plant Performance

This market-based design centers on the use of two trains of gasifiers and combustion turbines coupled with a heat recovery system that generates steam for a single steam turbine generator. The gas turbine technology chosen for this integrated gasification combined cycle (IGCC) study is based on General Electric's frame 7FA technology, taking into account an anticipated uprating to 210 MWe power output. Table 7-2 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 7-2 shows an increase in estimated gas turbine power output compared to the appropriate natural-gas-fired case 1C (case 1C is discussed in the Interim Report, October 2000). 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. GE has reported that a 14 percent increase in expander throughput is possible, while the gas turbine combustor temperature is modified due to the firing of synthesis gas. This can result in as much as a 20 percent increase in net plant power output, though the turbine life may be reduced by this operation. As a result, dual-train gross combustion turbine power output has been estimated at 421 MWe in this IGCC case, compared with 335 MWe estimated for case 1C.

Gross plant power output after accounting for generator losses is 663.6 MWe. The auxiliary power load has been estimated as 79.9 MWe, which corresponds to an estimated net plant power output for this IGCC configuration of 583.6 MWe. This power output is generated with a net plant efficiency of 39.6 percent, HHV, with a corresponding heat rate of 8,609 Btu/kWh. A block flow diagram depicting this case is shown in Figure 7-1.

Table 7-2
CASE 9A – DUAL-TRAIN (2 x GE7FA+e G/T) IGCC POWER CASE
PLANT PERFORMANCE SUMMARY – 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	421,105
Steam Turbine Power	253,905
Generator Loss	(11,395)
Gross Plant Power	663,615
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	500
Coal Milling	1,120
Coal Slurry Pumps	300
Slag Handling and Dewatering	230
Scrubber Pumps	440
Recycle Gas Blower	880
Air Separation Plant	28,700
Nitrogen Boost Compressor	320
Nitrogen Compressor	20,810
Oxygen Boost Compressor	10,300
Amine Units	1,930
Claus/TGTU	120
Incinerator Fan	100
Humidification Tower Pump	140
Humidifier Makeup Pump	90
Condensate Pumps	410
High-Pressure Boiler Feed Pump	4,240
Low-Pressure Boiler Feed Pump	100
Miscellaneous Balance of Plant (Note 2)	1,000
Gas Turbine Auxiliaries	800
Steam Turbine Auxiliaries	200
Circulating Water Pumps	3,570
Cooling Tower Fans	2,110
Flash Bottoms Pump	50
Transformer Loss	1,520
Total Auxiliary Power Requirement	79,980
NET PLANT POWER, kWe	583,635
PLANT EFFICIENCY	
Net Efficiency, % HHV	39.6
Net Heat Rate, Btu/kWh (HHV)	8,609
CONDENSER COOLING DUTY, 10^6 Btu/h	1,244
CONSUMABLES	
As-Received Coal Feed, lb/h (Note 3)	430,690
Oxygen (95% pure), lb/h	338,631

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).

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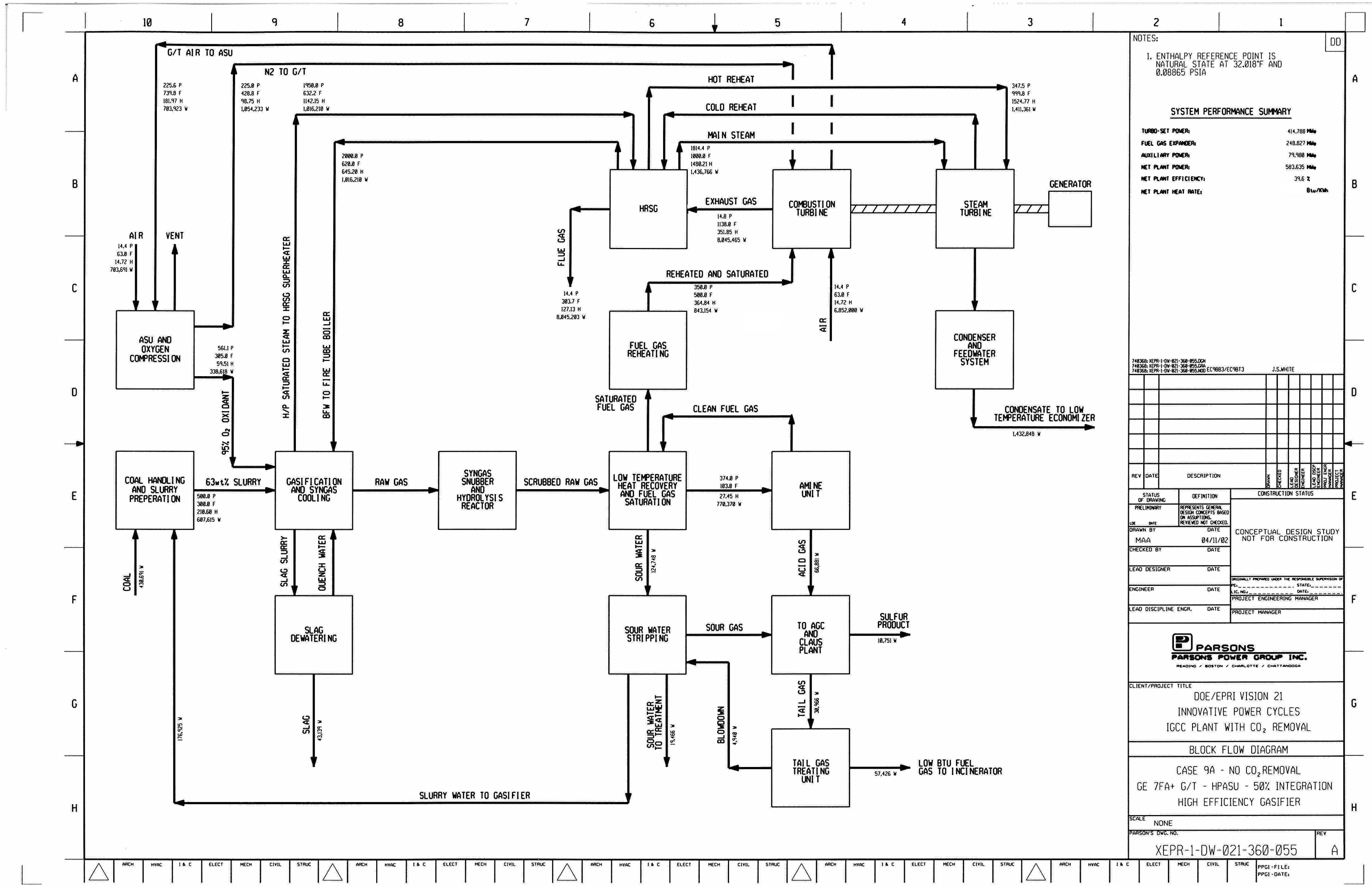

Figure 7-1
Block Flow Diagram – Case 9A – No CO_2 Removal – GE 7FA+ G/T – HPASU – 50% Integration – High Efficiency Gasifier

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7.1.3 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. A summary of the estimated plant emissions for this case is presented in Table 7-3. Emissions for SO_2, NOx, particulate, and CO_2 are shown as a function of four bases: (1) kilograms per gigajoule of HHV 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 of MWe power output (pounds per hour of MWe power output).

Table 7-3
CASE 9A AIRBORNE EMISSIONS
IGCC F 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 65% (Tons/year 65%)**	**Tonnes/year 85% (Tons/year 85%)**	**kg/MWh (lb/MWh)**
SO_2	0.006 (0.013)	120 (132)	156 (172)	0.05 (0.11)
NOx	< 0.012 (< 0.028)	259 (285)	336 (370)	0.11 (0.25)
Particulate	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)	Neg. (Neg.)
CO_2	81 (189)	2,438,500 (2,687,940)	3,188,000 (3,515,000)	734 (1,620)

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 15 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 4,485 kJ/scm (120 Btu/scf, LHV basis). Humidifying the desulfurized fuel gas stream and injecting high-pressure nitrogen from the ASU at the combustion turbine inlet accomplish syngas dilution, which serves to mitigate NOx emissions and to 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.

7.1.4 System Description

This greenfield power plant is a 584 MW coal-fired IGCC power plant without provision for CO_2 removal. The gasifier technology choice is E-Gas™, and the combustion turbine choice is the General Electric frame 7FA gas turbine. 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, located in Section 7.1.5, 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.

7.1.4.1 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 the 105 percent over the design load condition for a 16-hour period and long-term operation at the 100 percent of design load point for 90 days or more.

The 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 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 3" x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 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.

7.1.4.2 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. Two trains at 50 percent are provided for each of the two gasifier trains.

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.

7.1.4.3 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 100 percent will be used. Each train will produce 1,842 tonne/day (2,032 tpd) of 95 percent oxygen product (1,750 tonne/day (1,930 tpd) on a 100 percent O_2 basis) at elevated pressure. Each train consists of a multi-staged air compressor, an air separation cold box, an oxygen compression system, a nitrogen boost compressor, and a main nitrogen compressor. A liquid oxygen storage tank will be maintained in order to ensure reliability. A slipstream of vent nitrogen will be compressed and available for miscellaneous plant requirements.

A simplified schematic of the oxygen plant is shown in Figure 7-2. State point data are also shown. Approximately 50 percent of the ASU air requirement is met by ambient air at 0.099 MPa (14.4 psia) and 17.2°C (63ºF), which is compressed in a four-staged, intercooled compressor to 1.37 MPa (198 psia). The remaining air requirement is met by air extracted from the gas turbine air compressor. The combined 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 elevated-pressure oxidant stream from the cold box is compressed to 3.9 MPa (564 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 3.1 MPa (450 psig). Maximum coal throughput for an E-Gas™ gasifier operating at this pressure is estimated to be approximately 2,177 tonne/day (2,400 tpd) dry. This power plant requires 4,167 tonne/day (4,594 tpd) (dry) coal feed. Therefore, two gasification trains at 100 percent will be used.

Figure 7-2 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 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 that of the primary zone.

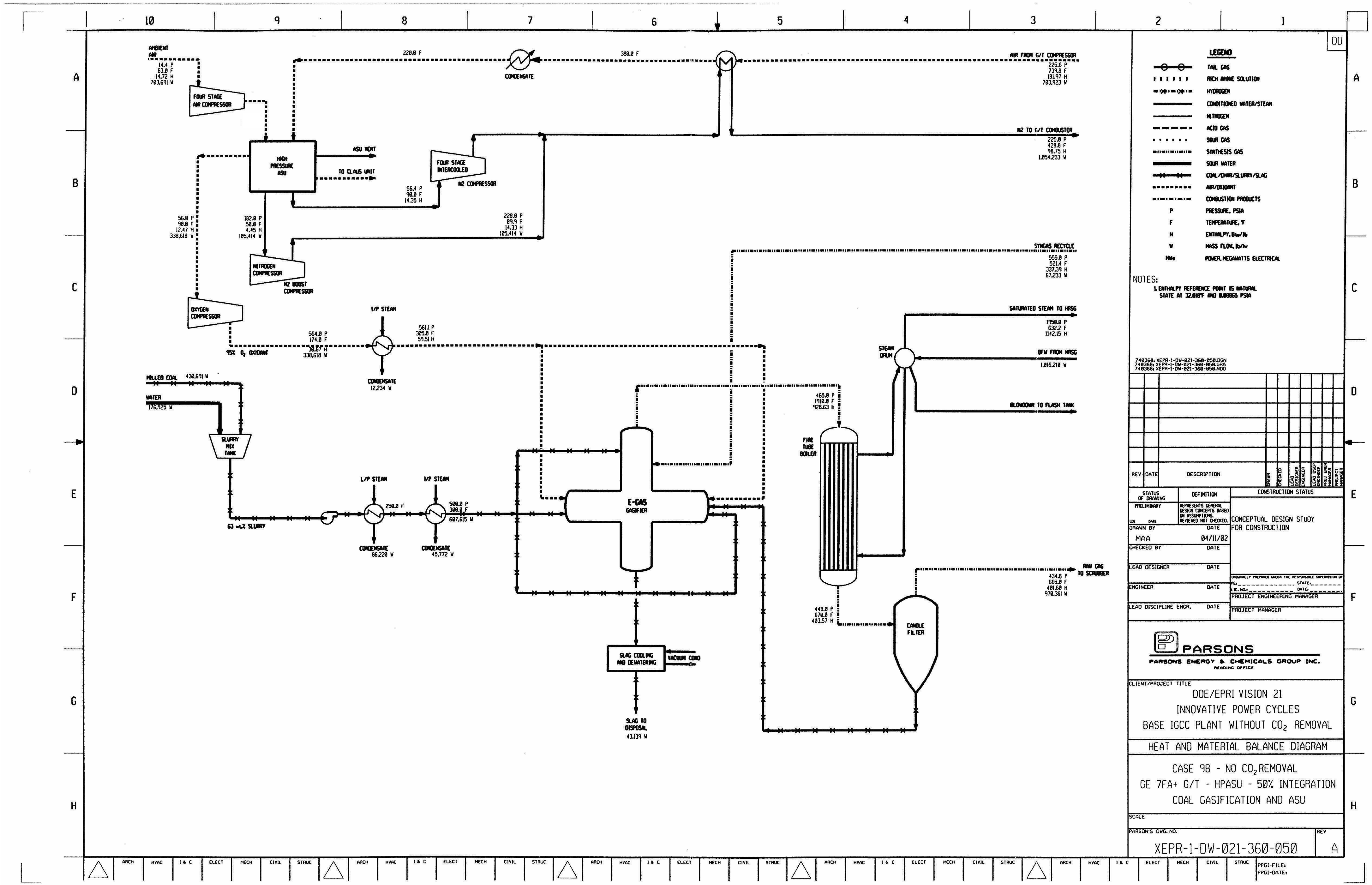

Figure 7-2
Heat and Material Balance Diagram – Case 9A – No CO_2 Removal – GE 7FA+ G/T – HPASU – 50% Integration – Coal Gasification and ASU

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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 gasifier for reinjection. The gasifier operates with a coal gas efficiency of approximately 79 percent.

Raw Gas Cooling

Hot raw gas from the secondary gasification zone exits the gasifier at 3.1 MPa (450 psig) and 1041°C (1910°F). This gas stream is cooled to 354°C (670°F) in a fire-tube boiler. The waste heat from this cooling is used to generate high-pressure steam. Boiler feedwater in the tube walls is saturated, and then steam and water are separated in a steam drum. Approximately 460,950 kg/h (1,016,210 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 352°C (665°F) and 2.99 MPa (435 psia).

7.1.4.4 Raw Gas Cooling / Syngas Humidification

As shown schematically in Figure 7-3, raw gas from the filter at 352°C (665°F) is indirectly cooled to 179°C (355°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.

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 7-3. 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 and increases the sensible heat content of the fuel gas.

Warm, humid fuel gas exits the top of the saturator at 145°C (293°F) and 2.45 MPa (355 psia). It is indirectly heated further to 260°C (500°F) by condensing high-pressure steam. The fuel gas stream is then routed to the combustion turbine burner inlet.

Saturator water exits the column at 98°C (208°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.

7.1.4.5 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

Heat and mass balance diagrams of these systems can be seen in Figure 7-3 and Figure 7-4.

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 2.58 MPa (374 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 20 percent H_2S and 75 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; however, in this case the concentration is well below that number. Consequently, an acid gas concentrator was used to further concentrate the H_2S stream.

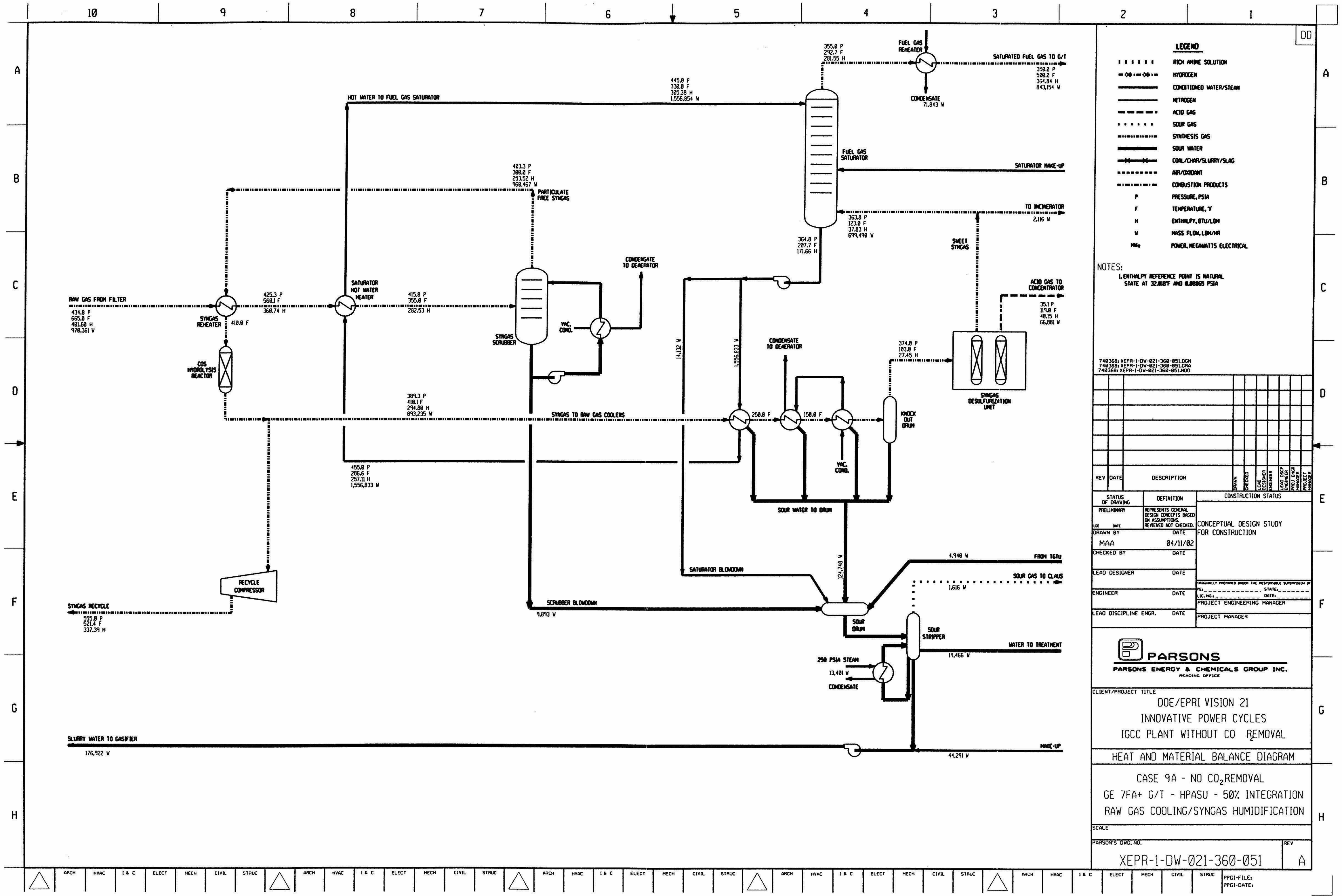

Figure 7-3
Heat and Material Balance Diagram – Case 9A – No CO_2 Removal – GE 7FA+ G/T – HPASU – 50% Integration – Raw Gas Cooling/Syngas Humidification

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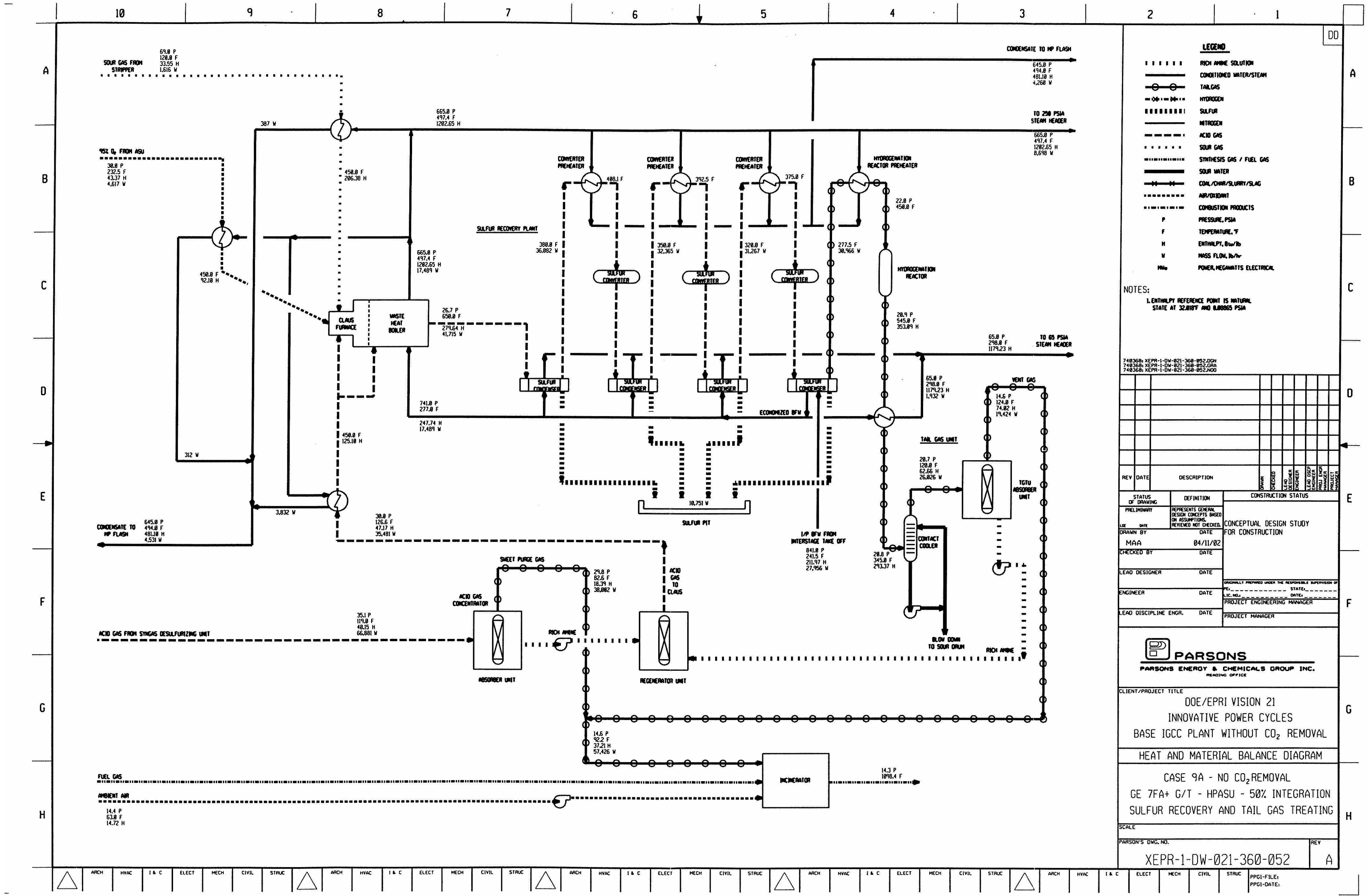

Figure 7-4
Heat and Material Balance Diagram – Case 9A – No CO_2 Removal – GE 7FA+ G/T – HPASU – 50% Integration – Sulfur Recovery and Tail Gas Treating

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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 44 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 7-4. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. Approximately 4,875 kg/hour (10,750 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, is 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, 7,933 kg/hour (17,490 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 3,946 kg/hour (8,700 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.

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 species are catalytically 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.

7.1.4.6 Combined Cycle Power Generation

The combustion turbine selected for this application is based on the General Electric model 7FA. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. 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 7-5.

Combustion Turbine

Inlet air at 432 kg/sec (952 lb/sec) is compressed in a single spool compressor at a pressure ratio of approximately 15.5:1. This airflow is lower than the ISO airflow 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.) Most of 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. A portion of the air, approximately ten percent, is routed to the ASU. This integration of the gas turbine and ASU reduces ASU air compression requirements.

Humidified fuel gas from the gasifier island is injected into the gas turbine along with high-pressure nitrogen such that the combined mixture has a heating content less than 4,485 kJ/scm (120 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.

Hot combustion products are expanded in the three-stage turbine-expander. It is assumed that all of the expander stages are air-cooled. The expander exhaust temperature is estimated as 616°C (1141°F), given the assumed ambient conditions, back-end loss, and HRSG pressure drop. This value is slightly higher than the ISO value due to the reduced cooling air availability as a result of air extraction to meet ASU air requirements.

Gross turbine shaft power, as measured prior to the generator terminals, is estimated as 212 MWe. The generator is assumed to be a standard hydrogen-cooled machine with static exciter. Net combustion turbine power (following generator losses) is estimated at 415 MWe. This value reflects the expected uprating of GE’s 7FA gas turbine power output when firing coal-derived fuel gas.

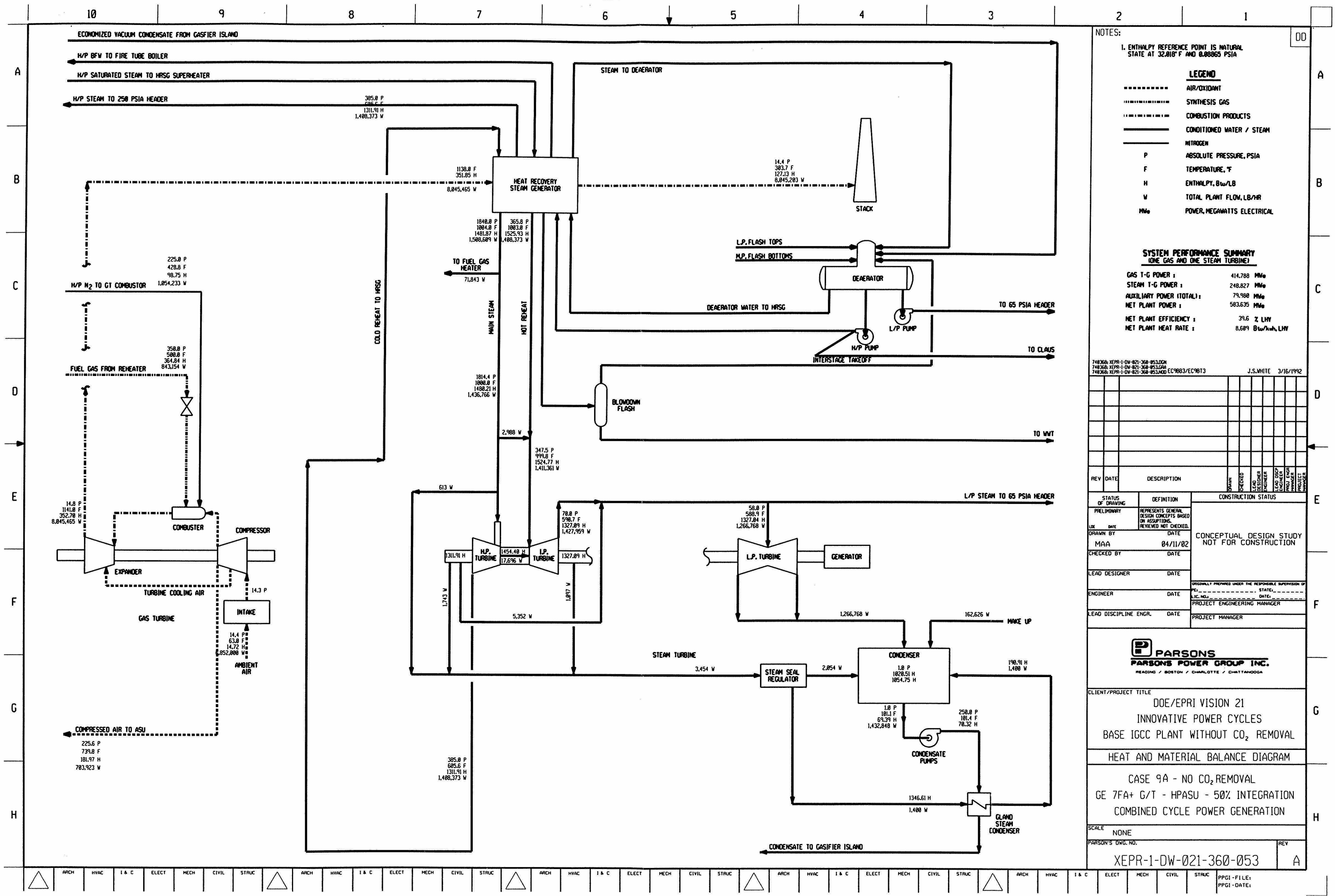

Figure 7-5
Heat and Material Balance Diagram – Case 9A – No CO_2 Removal – GE 7FA+ G/T – HPASU – 50% Integration – Combined Cycle Power Generation

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Heat Recovery System

As schematically illustrated in Figure 7-6, 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.

High-temperature flue gas at 1,824,710 kg/hour (4,022,730 lb/hour) exiting each CT expander is conveyed through one HRSG per train 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 151°C (304°F), which should be high enough to avoid sulfur dew-point complications.

Each HRSG is configured with an 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 355,696 kg/hour (784,160 lb/hour) of 15.86 MPa (2300 psia) boiler feedwater is heated to 327°C (620°F) in each 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 each HP steam expander is sent to the HRSG, where 319,420 kg/hour (704,190 lb/hour) of cold reheat is heated from 319°C (607°F) to 540°C (1004°F). The hot reheat streams from each HRSG are recombined and routed to the IP steam turbine inlet.

Steam Turbine

The Rankine cycle used in this case is based on a state-of-the-art 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.

Main steam at a rate of 651,720 kg/hour (1,436,770 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 routed to the HRSG for reheating.

Hot reheat is returned to the steam turbine from each HRSG. 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 254 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 to be 249 MWe.

7.1.4.7 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 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.

7.1.4.8 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

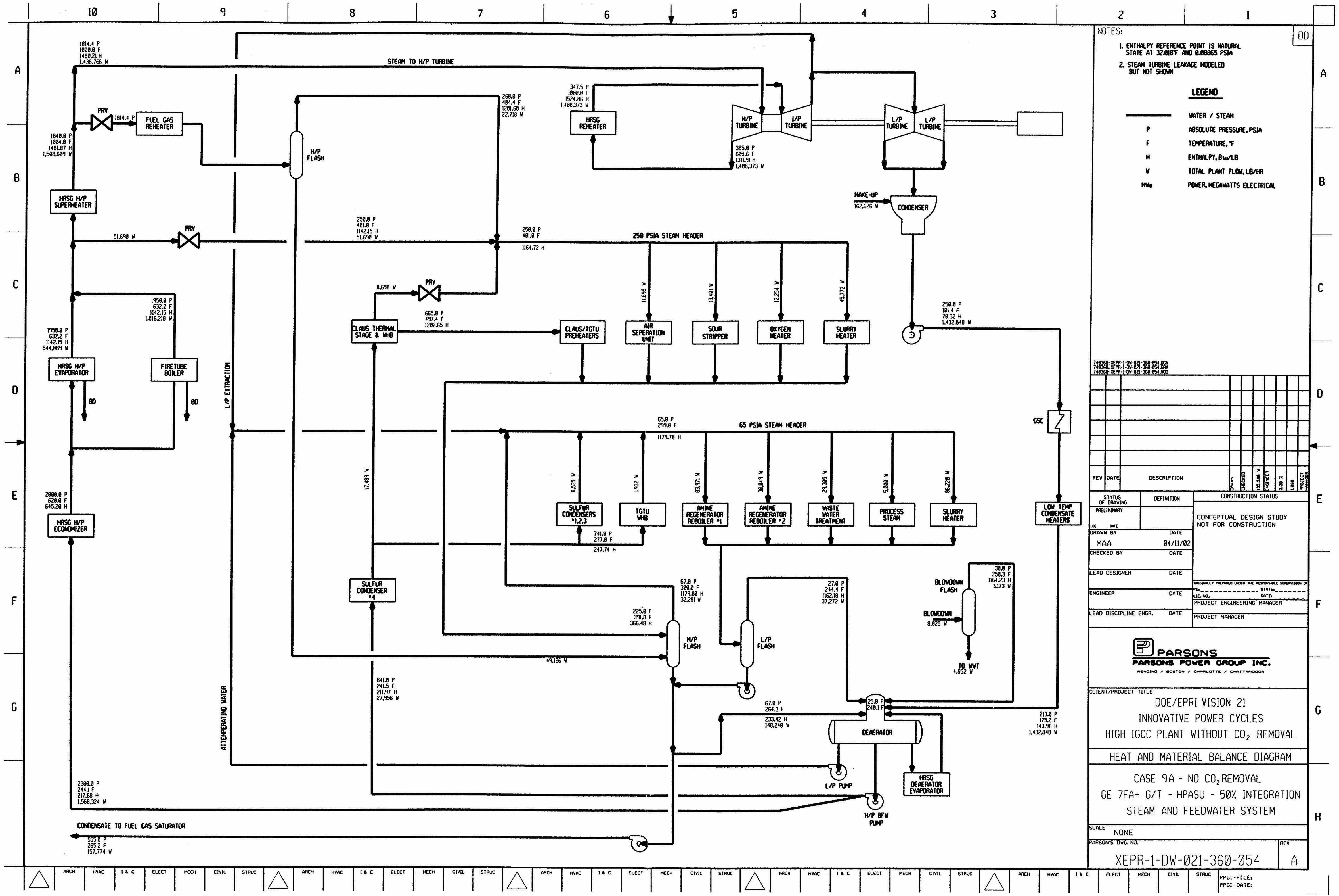

Figure 7-6
Heat and Material Balance Diagram – Case 9A – No CO_2 Removal – GE 7FA+ G/T – HPASU – 50% Integration – Steam and Feedwater System

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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.

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.

7.1.5 Case 9A –Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 7-1. 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.

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	700 gpm @ 2,500 ft	2
8	LT Slurry Heater	Shell and tube	45×10^6 Btu/h	2
9	HT Slurry Heater	Shell and tube	20×10^6 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	53×10^6 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, 3000 gpm	2
10	Filtered Water Pumps	S.S., single suction	160 ft, 120 gpm	2
11	Filtered Water Tank	Vertical, cylindrical	100,000 gal	1
12	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
13	Sour Water Stripper System	Vendor supplied	155,000 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	2,300 std (dry-coal basis) @ 500 psig	2
2	Syngas Cooler	Fire-tube with steam drum	260 x 10^6 Btu/h	2
3	Low-Temperature Candle Filter	Metal	500 psia, 700°F	2
4	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	1,000,000 lb/h, medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	80,000 scfm, 200 psia discharge pressure	2
2	Cold Box	Vendor supplied	2,100 ton/day O_2	2
3	Oxygen Compressor	Centrifugal, multi-stage	32,000 scfm, 600 psig discharge pressure	2
4	Liquid Oxygen Storage Tank	Vertical	60' dia x 80' vert	1
5	Oxygen Heater	Shell and tube	5 x 10^6 Btu/h @ 600 psia and 300°F	2
6	Nitrogen Boost Compressor	Reciprocating	12,000 scfm 4.1 PR @ 230 psia	2
7	Nitrogen Compressor	Centrifugal, multi-stage	100,000 scfm, 230 psig discharge pressure	2
8	Air Cooler/N_2 Heater	Shell and Tube	33 x 106 Btu/h @ 250 psia and 450°F	2
9	Air Cooler	Shell and Tube	20 x 106 Btu/h @ 250 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	20 x 10^6 Btu/h @ 450 psia, 670°F	2
2	Saturator Hot Water Heater	Shell and tube	40 x 10^6 Btu/h @ 450 psia, 560°F	2
3	Syngas Scrubber	Vertical, water tower	430 psia, 400°F	2
4	Scrubber Pump	Centrifugal	5,100 gpm @ 120 ft	2
5	Scrubber Cooler	Shell and tube	14 x 10^6 Btu/h @ 450 psia, 370°F	2
6	Hydrolysis Reactor	Fixed bed	150,000 scfm (8,000 acfm) 450 psia, 410°F	2
7	Fuel Gas Recycle Compressor	Reciprocating	10,000 scfm (600 acfm) 1.3 PR @ 500 psia	2
8	Low Temperature Saturation Water Economizer	Shell and tube	60 x 10^6 Btu/h @ 450 psia and 400°F	2
9	Raw Gas Coolers	Shell and tube with condensate drain	45 x 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, 120,000 scfm 400 psia, 350°F	2
12	Saturator Water Pump	Centrifugal	3,500 gpm @ 120 ft	2
13	Fuel Gas Reheater	Shell and tube	35 x 10^6 Btu/h @ 400 psia, 550°F	2

ACCOUNT 5B SULFUR REMOVAL AND RECOVERY

Equipment No.	Description	Type	Design Condition	Qty
1	Acid Gas Removal Unit	Absorber / stripper Tray column Proprietary amine	115,000 scfm (4,500 acfm) @ 430 psia	2
2	Acid Gas Concentrator	Absorber column Proprietary amine	10,000 scfm (4,200 acfm) 35 psia, 120°F	1
3	Amine Regenerator	Tray column with reboiler	8,300 scfm (3,900 acfm) 35 psia, 120°F	1
4	Claus Unit	Vendor design	130 tpd sulfur product	1
5	Hydrogenation Reactor	Vertical fixed bed	5,800 scfm (4,000 acfm) 25 psia, 500°F	1
6	Contact Cooler	Spray contact, tray wash tower	5,800 scfm (4,000 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	Air Blower	Axial	3,000 scfm @ ambient	1
9	Tail Gas Incinerator	Uncooled duct	12,000 scfm @ 1100°F	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	212 MWe Gas Turbine Generator	Axial flow single spool based on General Electric 7FA	952 lb/sec airflow air cooled burner/rotor 15.8:1 pressure ratio	2
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	2
3	Air Inlet Filter/Silencer	Two-stage	952 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	2
4	Starting Package	Electric motor, torque converter drive, turning gear	2,100 hp, time from turning gear to full load ~30 minutes	2
5	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		2
6	Oil Cooler	Finned air cooler with fan		2
7	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	2
8	Generator Glycol Cooler	Finned air cooler with fan		2
9	Compressor Wash Skid			2
10	Fire Protection Package	Halon		2

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 225,000 lb/h	2
2	Raw Gas Cooler Steam Generator	Fire-tube boiler	1800 psig/850°F 510,000 lb/h	2
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	260 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	1,440,000 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	81,000 gpm @ 60 ft	2
2	Cooling Tower	Mechanical draft	190,000 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	600 tpd	1

7.1.6 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 GE 7FA combustion turbine and without CO_2 removal, case 9A, 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 Ton of CO_2 Removed.

The capital cost for case 9A represents a plant with a net output of 583.6 MWe. This capital cost result at the level of Total Plant Cost (TPC) is summarized in Table 7-4. A detailed estimate for case 9A is included in Appendix A.

Table 7-4
CASE 9A SUMMARY TPC COST

Account Number	Title	Cost ($x1000)
	BARE ERECTED COST	
4	Gasifier, ASU & Accessories	151,120
5A	Gas Cleanup & Piping	35,410
5B	CO_2 Removal and Compression	0
6	Combustion Turbine and Accessories	77,450
7	HRSG, Ducting and Stack	51,310
8&9	Steam T-G Plant, including Cooling Water System	58,480
11	Accessory Electric Plant	30,780
	Balance of Plant	97,790
	SUBTOTAL	502,340
	Engineering, Construction Management Home Office and Fee	30,140
	Process Contingency	18,870
	Project Contingency	74,400
	TOTAL PLANT COST (TPC)	$625,760
	TPC $/kW	1,070

The production costs for case 9A 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 7-5, and supporting detail is contained in Appendix A.

Table 7-5
CASE 9A ANNUAL PRODUCTION COST

Item	First-Year Cost ($x1000)	First-Year Unit Cost (¢/kWh)
Operating Labor	5,503	0.17
Maintenance	10,022	0.31
Administrative & Support Labor	2,378	0.07
Consumables	2,923	0.09
By-Product Credits	(1,308)	-0.04
Fuel	35,476	1.07
TOTAL PRODUCTION COST	54,994	1.66

A revenue requirement analysis was performed to determine the economic figures-of-merit for case 9A. 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 Ton 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 7-6.

Table 7-6
CASE 9A LEVELIZED ECONOMIC RESULT SUMMARY

Component (unit)	Value
Production Cost (¢/kWh)	1.66
Annual Carrying Charge (¢/kWh)	2.93
Levelized Busbar Cost of Power Charge (¢/kWh)	4.59
Levelized Cost per Ton of CO_2 Removed ($/ton of CO_2 Removed)	0

7.2 Case 9B – E-Gas™ IGCC, F Class Turbine With CO_2 Removal

Not included in this draft report.

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, 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 required. The average labor rate to determine annual cost was $30.20, 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 $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

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, S/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.

SUMMARY DATA FOR CASE 2B

This section contains the following economic data for case 2B:

- Capital Investment and Revenue Requirement Summary
- Total Plant Cost
- Capital Investment and Revenue Requirement Summary for case 2B including fuel cell stack replacement costs

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	Natural Gas Combined Cycle-"FA" CHAT W/ SOFC			
Unit Size:/Plant Size:	556.5	MW,net	556.5	MWe
Location:	East-West Region			
Fuel: Primary/Secondary	Natural Gas			
Energy From Primary/Secondary Fuels	5,716	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	65	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(December)		
Delivered Cost of Primary/Secondary Fuel	2.70	$/MBtu		$/MBtu
Design/Construction Period:	2.5	years		
Plant Startup Date (1st. Year Dollars):	2000	(January)		
Land Area/Unit Cost	100	acre	$1,644	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:		%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	Over Book Lif	Constant Dollars		

Capital Structure	% of Total	Cost(%)
Common Equity	45	12.00
Preferred Stock	10	8.50
Debt	45	9.00
Weighted Cost of Capital:(after tax)		8.76 %

Escalation Rates		Over Book Life	1999 to 2000
	General	% per year	% per year
	Primary Fuel	% per year	% per year
	Secondary Fuel	% per year	% per year

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	Natural Gas Combined Cycle-"FA" CHAT W/ SOFC			
Plant Size:	556.5 (MW,net)	HeatRate:	5,716	(Btu/kWh)
Primary/Secondary Fuel(type):	Natural Gas	Cost:	2.70	($/MMBtu)
Design/Construction:	2.5 (years)	BookLife:	20	(years)
TPC(Plant Cost) Year:	1999 (Dec.)	TPI Year:	2000	(Jan.)
Capacity Factor:	65 (%)	CO_2 Removed		(tons/year)

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		252,204	453.2
Engineering(incl.C.M.,H.O.& Fee)		15,132	27.2
Process Contingency			
Project Contingency		51,963	93.4
TOTAL PLANT COST(TPC)		$319,299	573.7
TOTAL CASH EXPENDED	$319,299		
AFDC	$17,017		
TOTAL PLANT INVESTMENT(TPI)		$336,316	604.3
Royalty Allowance			
Preproduction Costs		8,927	16.0
Inventory Capital		889	1.6
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		164	0.3
TOTAL CAPITAL REQUIREMENT(TCR)		$346,296	622.2

OPERATING & MAINTENANCE COSTS (2000 Dollars)	**$x1000**	**$/kW-yr**
Operating Labor	1,720	3.1
Maintenance Labor	1,816	3.3
Maintenance Material	2,724	4.9
Administrative & Support Labor	884	1.6
TOTAL OPERATION & MAINTENANCE	$7,144	12.8
FIXED O & M		7.94 $/kW-yr
VARIABLE O & M		0.09 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (2000 Dollars)	**$x1000**	**¢/kWh**
Water	139	0.00
Chemicals	157	0.00
Other Consumables		
Waste Disposal		
TOTAL CONSUMABLE OPERATING COSTS	$296	0.01
BY-PRODUCT CREDITS (2000 Dollars)		
FUEL COST (2000 Dollars)	$48,905	1.54

	Levelized (Over Book Life $)		
PRODUCTION COST SUMMARY	**$/ton CO_2**		**¢/kWh**
Fixed O & M		7.9/kW-yr	0.14
Variable O & M			0.09
Consumables			0.01
By-product Credit			
Fuel			1.54
TOTAL PRODUCTION COST			1.78
LEVELIZED CARRYING CHARGES(Capital)		85.9/kW-yr	1.51
LEVELIZED (Over Book Life) BUSBAR COST OF POWER			3.29

Client:	EPRI/DOE VISION 21			**Report Date:**	14-Dec-2001	
Project:	INNOVATIVE POWER CYCLES				10:24 AM	
	TOTAL PLANT COST SUMMARY					
Case:	Natural Gas Combined Cycle-"FA" CHAT W/ SOFC					
Plant Size:	556.5 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Dec)**	1999	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
2	COAL & SORBENT PREP & FEED											
3	FEEDWATER & MISC. BOP SYSTEMS	1,517	806	2,297	161		**$4,781**	287		1,307	**$6,375**	11
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries											
4.2	High Temperature Cooling											
4.3	Recycle Gas System											
4.4-4.9	Other Gasification Equipment											
	SUBTOTAL 4											
5A	GAS CLEANUP & PIPING											
5B	CO_2 REMOVAL & COMPRESSION											
6	CHAT & SOFC											
6.1-6.3	CHAT Turbomachinery	69,841	2,602	10,989	769		**$84,202**	5,052		17,851	**$107,105**	192
6.2-6.9	SOFC, Inverters & Accessories	78,652	16,306	10,827	758		**$106,543**	6,393		22,742	**$135,677**	244
	SUBTOTAL 6	*148,493*	*18,908*	*21,816*	*1,527*		***$190,745***	*11,445*		*40,592*	***$242,783***	*436*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	15,212		6,249	437		**$21,899**	1,314		2,321	**$25,534**	46
7.2-7.9	HRSG Accessories, Ductwork and Stack		327	469	33		**$830**	50		264	**$1,143**	2
	SUBTOTAL 7	*15,212*	*327*	*6,718*	*470*		***$22,728***	*1,364*		*2,585*	***$26,677***	*48*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories											
8.2-8.9	Turbine Plant Auxiliaries and Steam Pipin											
	SUBTOTAL 8											
9	COOLING WATER SYSTEM	155	185	202	14		**$556**	33		118	**$707**	1
10	ASH/SPENT SORBENT HANDLING SYS											
11	ACCESSORY ELECTRIC PLANT	4,713	1,920	7,216	505		**$14,354**	861		2,591	**$17,806**	32
12	INSTRUMENTATION & CONTROL	2,308	290	2,824	198		**$5,620**	337		811	**$6,768**	12
13	IMPROVEMENTS TO SITE	1,356	736	5,133	359		**$7,584**	455		2,412	**$10,451**	19
14	BUILDINGS & STRUCTURES		2,799	2,838	199		**$5,836**	350		1,547	**$7,733**	14
	TOTAL COST	**$173,754**	**$25,973**	**$49,043**	**$3,433**		**$252,204**	**$15,132**		**$51,963**	**$319,299**	**574**

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	Natural Gas Combined Cycle-"FA" CHAT W/ SOFC (incl.FC Stack		
Plant Size:	556.5 (MW,net)	HeatRate:	5,716 (Btu/kWh)
Primary/Secondary Fuel(type):	Natural Gas	Cost:	2.70 ($/MMBtu)
Design/Construction:	2.5 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Dec.)	TPI Year:	2000 (Jan.)
Capacity Factor:	65 (%)	CO_2 Removed	(tons/year)

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		252,204	453.2
Engineering(incl.C.M.,H.O.& Fee)		15,132	27.2
Process Contingency			
Project Contingency		51,963	93.4
TOTAL PLANT COST(TPC)		$319,299	573.7
TOTAL CASH EXPENDED	$319,299		
AFDC	$17,017		
TOTAL PLANT INVESTMENT(TPI)		$336,316	604.3
Royalty Allowance			
Preproduction Costs		9,267	16.7
Inventory Capital		889	1.6
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		164	0.3
TOTAL CAPITAL REQUIREMENT(TCR)		$346,636	622.9

OPERATING & MAINTENANCE COSTS (2000 Dollars)	**$x1000**	**$/kW-yr**
Operating Labor	1,720	3.1
Maintenance Labor	3,300	5.9
Maintenance Material	4,951	8.9
Administrative & Support Labor	1,255	2.3
TOTAL OPERATION & MAINTENANCE	$11,226	20.2
FIXED O & M		11.28 $/kW-yr
VARIABLE O & M		0.16 ¢/kWh
CONSUMABLE OPERATING COSTS,less Fuel (2000 Dollars)	**$x1000**	**¢/kWh**
Water	139	0.00
Chemicals	157	0.00
Other Consumables		
Waste Disposal		
TOTAL CONSUMABLE OPERATING COSTS	$296	0.01
BY-PRODUCT CREDITS (2000 Dollars)		
FUEL COST (2000 Dollars)	$48,905	1.54

	Levelized (Over Book Life $)		
PRODUCTION COST SUMMARY	**$/ton CO_2**		**¢/kWh**
Fixed O & M		11.3/kW-yr	0.20
Variable O & M			0.16
Consumables			0.01
By-product Credit			
Fuel			1.54
TOTAL PRODUCTION COST			1.91
LEVELIZED CARRYING CHARGES(Capital)		86.0/kW-yr	1.51
LEVELIZED (Over Book Life) BUSBAR COST OF POWER			3.42

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	Natural Gas Combined Cycle-"FA" CHAT W/ SOFC (i			
Unit Size:/Plant Size:	556.5	MW,net	556.5	MWe
Location:	East-West Region			
Fuel: Primary/Secondary	Natural Gas			
Energy From Primary/Secondary Fuels	5,716	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	65	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(December)		
Delivered Cost of Primary/Secondary Fuel	2.70	$/MBtu		$/MBtu
Design/Construction Period:	2.5	years		
Plant Startup Date (1st. Year Dollars):	2000	(January)		
Land Area/Unit Cost	100	acre	$1,644	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:		%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	Over Book Lif	Constant Dollars		

Capital Structure	% of Total	Cost(%)
Common Equity	45	12.00
Preferred Stock	10	8.50
Debt	45	9.00
Weighted Cost of Capital:(after tax)	8.76 %	

Escalation Rates		Over Book Life	1999 to 2000
	General	% per year	% per year
	Primary Fuel	% per year	% per year
	Secondary Fuel	% per year	% per year

SUMMARY DATA FOR CASE 3B

This section contains the following updated economic data for case 3B:

- Capital Investment and Revenue Requirement Summary
- Total Plant Cost

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	IGCC w/o CO d2 Removal (3B)	
Unit Size:/Plant Size:	424.5 MW,net	424.5 MWe
Location:	East-West Region	
Fuel: Primary/Secondary	Illnois #6	0
Energy From Primary/Secondary Fuels	7,915 Btu/kWh	0 Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent month	65 %	1 months
Capital Cost Year Dollars (Reference Year Dollars):	1999 (December)	
Delivered Cost of Primary/Secondary Fuel	1.24 $/MBtu	0 $/MBtu
Design/Construction Period:	4 years	
Plant Startup Date (1st. Year Dollars):	2000 (January)	
Land Area/Unit Cost	350 acre	$2,000 /acre

FINANCIAL CRITERIA

Project Book Life:	20 years	
Book Salvage Value:	0.0 %	
Project Tax Life:	20 years	
Tax Depreciation Method:	Accel. based on ACRS Class	
Property Tax Rate:	1.0 % per year	
Insurance Tax Rate:	1.0 % per year	
Federal Income Tax Rate:	34.0 %	
State Income Tax Rate:	4.2 %	
Investment Tax Credit/% Eligible	0.0 %	0.0 %
Economic Basis:	Over Book Life Constant Dollars	

Capital Structure	% of Total	Cost(%)
Common Equity	45	12.00
Preferred Stock	10	8.50
Debt	45	9.00
Weighted Cost of Capital:(after tax)	8.81 %	

Escalation Rates		Over Book Life	1999 to 2000
	General	0 % per year	0 % per year
	Primary Fuel	0.0 % per year	0 % per year
	Secondary Fuel	0.0 % per year	0 % per year

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	IGCC w/o CO d2 Removal (3B)			
Plant Size:	424.5 (MW,net)	HeatRate:	7,915	(Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6 , 0	Cost:	1.24	($/MMBtu)
Design/Construction:	4 (years)	BookLife:	20	(years)
TPC(Plant Cost) Year:	1999 (Dec.)	TPI Year:	2000	(Jan.)
Capacity Factor:	65 (%)	CO d2 Remo	0	

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		376,295	886.4
Engineering(incl.C.M.,H.O.& Fee)		22,578	53.2
Process Contingency		16,267	38.3
Project Contingency		56,340	132.7
TOTAL PLANT COST(TPC)		$471,480	1110.6
TOTAL CASH EXPENDED	$471,480		
AFDC	$41,806		
TOTAL PLANT INVESTMENT(TPI)		$513,286	1209.0
Royalty Allowance		0	0.0
Preproduction Costs		12,708	29.9
Inventory Capital		4,293	10.1
Initial Catalyst & Chemicals(w/equip.)		0	0.0
Land Cost		700	1.6
TOTAL CAPITAL REQUIREMENT(TCR)		$530,987	1250.7

OPERATING & MAINTENANCE COSTS (1999 Dollars)	**$x1000**		**$/kW-yr**
Operating Labor	5,503		13.0
Maintenance Labor	3,823		9.0
Maintenance Material	5,734		13.5
Administrative & Support Labor	2,331		5.5
TOTAL OPERATION & MAINTENANCE	$17,390		41.0
FIXED O & M		27.46	$/kW-yr
VARIABLE O & M		0.24	¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	**$x1000**	**¢/kWh**
Water	237	0.01
Chemicals	270	0.01
Other Consumables	0	0.00
Waste Disposal	1,306	0.05
TOTAL CONSUMABLE OPERATING COSTS	$1,814	0.08
BY-PRODUCT CREDITS (1999 Dollars)	($876)	-0.04
FUEL COST (1999 Dollars)	$23,725	0.98

		Levelized (Over Book Life $)	
PRODUCTION COST SUMMARY	**$/ton CO d2**		**¢/kWh**
Fixed O & M		27.5/kW-yr	0.48
Variable O & M			0.24
Consumables			0.08
By-product Credit			-0.04
Fuel			0.98
TOTAL PRODUCTION COST	$0.00		1.74
LEVELIZED CARRYING CHARGES(Capital)		172.6/kW-yr	3.03
LEVELIZED (Over Book Life) BUSBAR COST OF POWER	$0.00		4.77

Client:	EPRI/DOE VISION 21	**Report Date:**	15-Feb-02
Project:	INNOVATIVE POWER CYCLES		03:03 PM

TOTAL PLANT COST SUMMARY

Case:	IGCC w/o CO d2 Removal (3B)						
Plant Size:	424.5 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Dec)**	1999	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	6,248	1,284	5,712	400	0	**$13,643**	819	0	2,892	**$17,354**	41
0.0	0.0											
2	COAL & SORBENT PREP & FEED	8,023	1,978	6,248	437	0	**$16,686**	1,001	562	2,402	**$20,651**	49
0.0	0.0											
3	FEEDWATER & MISC. BOP SYSTEMS	4,074	3,818	4,157	291	0	**$12,340**	740	0	2,946	**$16,026**	38
0.0	0.0											
4	GASIFIER & ACCESSORIES	0	0	0	0	0	**$0**	0	0	0	**$0**	0
4.1	Gasifier, Syngas Cooler & Auxiliaries (E	45,887	0	24,236	1,697	0	**$71,820**	4,309	7,182	8,331	**$91,642**	216
4.2	Syngas Cooling	w/4.1	0	w/ 4.1	w/ 4.1	0	**$0**	w/ 4.1	0	w/ 4.1	**$0**	0
4.3	ASU/Oxidant Compression	36,423	0	w/equip.	0	0	**$36,423**	2,185	0	3,861	**$42,469**	100
4.4-4.9	Other Gasification Equipment	10,808	4,280	6,521	456	0	**$22,065**	1,324	758	3,624	**$27,771**	65
	SUBTOTAL 4	*93,118*	*4,280*	*30,757*	*2,153*	*0*	***$130,308***	*7,818*	*7,940*	*15,816*	***$161,882***	*381*
5A	GAS CLEANUP & PIPING	15,575	2,245	8,109	568	0	**$26,496**	1,590	1,113	5,259	**$34,457**	81
5B	CO D2 REMOVAL & COMPRESSION	0	0	0	0	0	**$0**	0	0	0	**$0**	0
0.0	0.0											
6	COMBUSTION TURBINE/ACCESSORI	0	0	0	0	0	**$0**	0	0	0	**$0**	0
6.1	Combustion Turbine Generator	58,076	0	2,825	198	0	**$61,100**	3,666	6,110	7,088	**$77,963**	184
6.2-6.9	Combustion Turbine Accessories	0	337	398	28	0	**$763**	46	0	243	**$1,051**	2
	SUBTOTAL 6	*58,076*	*337*	*3,223*	*226*	*0*	***$61,863***	*3,712*	*6,110*	*7,330*	***$79,014***	*186*
7	HRSG, DUCTING & STACK	0	0	0	0	0	**$0**	0	0	0	**$0**	0
7.1	Heat Recovery Steam Generator	13,652	0	2,054	144	0	**$15,850**	951	0	1,680	**$18,481**	44
7.2-7.9	HRSG Accessories, Ductwork and Stac	2,038	962	1,713	120	0	**$4,834**	290	0	784	**$5,908**	14
0.0	*SUBTOTAL 7*	*15,690*	*962*	*3,767*	*264*	*0*	***$20,684***	*1,241*	*0*	*2,464*	***$24,389***	*57*
8	STEAM TURBINE GENERATOR	0	0	0	0	0	**$0**	0	0	0	**$0**	0
8.1	Steam TG & Accessories	13,355	0	2,090	146	0	**$15,590**	935	0	1,653	**$18,179**	43
8.2-8.9	Turbine Plant Auxiliaries and Steam Pip	4,163	383	3,284	230	0	**$8,060**	484	0	1,490	**$10,033**	24
0.0	*SUBTOTAL 8*	*17,518*	*383*	*5,374*	*376*	*0*	***$23,650***	*1,419*	*0*	*3,142*	***$28,212***	*66*
9	COOLING WATER SYSTEM	4,799	3,049	4,786	335	0	**$12,968**	778	0	2,548	**$16,294**	38
0.0	0.0											
10	ASH/SPENT SORBENT HANDLING SY	4,710	739	2,495	175	0	**$8,118**	487	542	1,067	**$10,215**	24
0.0	0.0											
11	ACCESSORY ELECTRIC PLANT	8,671	3,864	9,842	689	0	**$23,066**	1,384	0	4,131	**$28,581**	67
0.0	0.0											
12	INSTRUMENTATION & CONTROL	4,935	746	3,720	260	0	**$9,661**	580	0	1,447	**$11,687**	28
0.0	0.0											
13	IMPROVEMENTS TO SITE	2,028	1,195	4,753	333	0	**$8,309**	499	0	2,642	**$11,450**	27
0.0	0.0											
14	BUILDINGS & STRUCTURES	0	3,613	4,571	320	0	**$8,504**	510	0	2,254	**$11,268**	27
0.0	0.0											
	TOTAL COST	**$243,465**	**$28,493**	**$97,512**	**$6,826**	**$0**	**$376,295**	**$22,578**	**$16,267**	**$56,340**	**$471,480**	**1111**

SUMMARY DATA FOR CASE 3E

This section contains the following economic data for case 3E:

- Capital Investment and Revenue Requirement Summary
- Total Plant Cost

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	IGCC w/ CO d2 Removal & Water Scrubber (3E)	
Unit Size:/Plant Size:	386.8 MW,net	386.8 MWe
Location:	East-West Region	
Fuel: Primary/Secondary	Illnois #6	0
Energy From Primary/Secondary Fuels	9,638 Btu/kWh	0 Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months	65 %	1 months
Capital Cost Year Dollars (Reference Year Dollars):	1999 (December)	
Delivered Cost of Primary/Secondary Fuel	1.24 $/MBtu	0 $/MBtu
Design/Construction Period:	4 years	
Plant Startup Date (1st. Year Dollars):	2000 (January)	
Land Area/Unit Cost	350 acre	$2,000 /acre

FINANCIAL CRITERIA

Project Book Life:	20 years	
Book Salvage Value:	0.0 %	
Project Tax Life:	20 years	
Tax Depreciation Method:	Accel. based on ACRS Class	
Property Tax Rate:	1.0 % per year	
Insurance Tax Rate:	1.0 % per year	
Federal Income Tax Rate:	34.0 %	
State Income Tax Rate:	4.2 %	
Investment Tax Credit/% Eligible	0.0 %	0.0 %
Economic Basis:	Over Book Life Constant Dollars	

Capital Structure	% of Total	Cost(%)
Common Equity	45	12.00
Preferred Stock	10	8.50
Debt	45	9.00
Weighted Cost of Capital:(after tax)	8.81 %	

Escalation Rates		Over Book Life	1999 to 2000
	General	0 % per year	0 % per year
	Primary Fuel	0.0 % per year	0 % per year
	Secondary Fuel	0.0 % per year	0 % per year

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	IGCC w/ CO d2 Removal & Water Scrubber (3E)				
Plant Size:	386.8	(MW,net)	HeatRate:	9,638	(Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6	0	Cost:	1.24	($/MMBtu)
Design/Construction:	4	(years)	BookLife:	20	(years)
TPC(Plant Cost) Year:	1999	(Dec.)	TPI Year:	2000	(Jan.)
Capacity Factor:	65	(%)	CO d2 Remov	1,940,418	(tons/year)

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		468,980	1212.5
Engineering(incl.C.M.,H.O.& Fee)		28,139	72.8
Process Contingency		17,647	45.6
Project Contingency		69,347	179.3
TOTAL PLANT COST(TPC)		$584,112	1510.2
TOTAL CASH EXPENDED	$584,112		
AFDC	$51,793		
TOTAL PLANT INVESTMENT(TPI)		$635,905	1644.1
Royalty Allowance		0	0.0
Preproduction Costs		15,466	40.0
Inventory Capital		4,920	12.7
Initial Catalyst & Chemicals(w/equip.)		0	0.0
Land Cost		700	1.8
TOTAL CAPITAL REQUIREMENT(TCR)		$656,991	1698.6

OPERATING & MAINTENANCE COSTS (1999 Dollars)	**$x1000**		**$/kW-yr**
Operating Labor	5,503		14.2
Maintenance Labor	4,731		12.2
Maintenance Material	7,097		18.3
Administrative & Support Labor	2,559		6.6
TOTAL OPERATION & MAINTENANCE	$19,889		51.4
FIXED O & M		33.07	$/kW-yr
VARIABLE O & M		0.32	¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	**$x1000**	**¢/kWh**
Water	223	0.01
Chemicals	256	0.01
Other Consumables	0	0.00
Waste Disposal	1,449	0.07
TOTAL CONSUMABLE OPERATING COSTS	$1,927	0.09
BY-PRODUCT CREDITS (1999 Dollars)	($972)	-0.04
FUEL COST (1999 Dollars)	$26,321	1.20

PRODUCTION COST SUMMARY	**Levelized (Over Book Life $)** **$/ton CO d2**		**¢/kWh**
Fixed O & M	$1.12	33.1/kW-yr	0.58
Variable O & M	$0.97		0.32
Consumables	$0.14		0.09
By-product Credit	($0.09)		-0.04
Fuel	$2.42		1.20
TOTAL PRODUCTION COST	$4.56		2.14
LEVELIZED CARRYING CHARGES(Capital)	$12.32	234.4/kW-yr	4.12
LEVELIZED (Over Book Life) BUSBAR COST OF POWER	$16.88		6.26
MC ($/tonne of CO d2 avoided)		**$23.1**	

Client:	EPRI/DOE VISION 21	**Report Date:**	15-Feb-02
Project:	INNOVATIVE POWER CYCLES		02:18 PM

TOTAL PLANT COST SUMMARY

Case:	IGCC w/ CO d2 Removal & Water Scrubber (3E)						
Plant Size:	386.8 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Dec)**	1999	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	6,657	1,368	6,086	426	0	**$14,537**	872	0	3,082	**$18,491**	48
0.0	0.0											
2	COAL & SORBENT PREP & FEED	8,584	2,116	6,685	468	0	**$17,853**	1,071	601	2,570	**$22,095**	57
0.0	0.0											
3	FEEDWATER & MISC. BOP SYSTEMS	4,326	4,216	4,329	303	0	**$13,174**	790	0	3,113	**$17,077**	44
0.0	0.0											
4	GASIFIER & ACCESSORIES	0	0	0	0	0	**$0**	0	0	0	**$0**	0
4.1	Gasifier, Syngas Cooler & Auxiliaries (E	45,631	0	24,103	1,687	0	**$71,422**	4,285	7,142	8,285	**$91,134**	236
4.2	Syngas Cooling	w/4.1	0	w/ 4.1	w/ 4.1	0	**$0**	w/ 4.1	0	w/ 4.1	**$0**	0
4.3	ASU/Oxidant Compression	40,651	0	w/equip.	0	0	**$40,651**	2,439	0	4,309	**$47,399**	123
4.4-4.9	Other Gasification Equipment	9,537	4,325	2,509	176	0	**$16,547**	993	477	2,016	**$20,033**	52
	SUBTOTAL 4	*95,820*	*4,325*	*26,613*	*1,863*	0	***$128,621***	*7,717*	*7,619*	*14,610*	***$158,567***	*410*
5A	GAS CLEANUP & PIPING	39,943	1,681	29,891	2,092	0	**$73,607**	4,416	2,707	11,771	**$92,502**	239
5B	CO d2 COMPRESSION	31,045	0	10,857	760	0	**$42,662**	2,560	0	6,783	**$52,005**	134
0.0	0.0											
6	COMBUSTION TURBINE/ACCESSORI	0	0	0	0	0	**$0**	0	0	0	**$0**	0
6.1	Combustion Turbine Generator	58,375	0	2,825	198	0	**$61,398**	3,684	6,140	7,122	**$78,344**	203
6.2-6.9	Combustion Turbine Accessories	0	337	398	28	0	**$763**	46	0	243	**$1,051**	3
	SUBTOTAL 6	*58,375*	*337*	*3,223*	*226*	0	***$62,161***	*3,730*	*6,140*	*7,365*	***$79,395***	*205*
7	HRSG, DUCTING & STACK	0	0	0	0	0	**$0**	0	0	0	**$0**	0
7.1	Heat Recovery Steam Generator	13,433	0	2,021	141	0	**$15,596**	936	0	1,653	**$18,184**	47
7.2-7.9	HRSG Accessories, Ductwork and Stac	2,038	962	1,713	120	0	**$4,833**	290	0	784	**$5,908**	15
0.0	*SUBTOTAL 7*	*15,471*	*962*	*3,734*	*261*	0	***$20,429***	*1,226*	*0*	*2,437*	***$24,092***	*62*
8	STEAM TURBINE GENERATOR	0	0	0	0	0	**$0**	0	0	0	**$0**	0
8.1	Steam TG & Accessories	12,092	0	1,892	132	0	**$14,116**	847	0	1,496	**$16,460**	43
8.2-8.9	Turbine Plant Auxiliaries and Steam Pip	3,803	349	2,999	210	0	**$7,361**	442	0	1,361	**$9,164**	24
0.0	*SUBTOTAL 8*	*15,894*	*349*	*4,891*	*342*	0	***$21,478***	*1,289*	*0*	*2,857*	***$25,623***	*66*
9	COOLING WATER SYSTEM	4,421	2,821	4,408	309	0	**$11,958**	717	0	2,351	**$15,026**	39
0.0	0.0											
10	ASH/SPENT SORBENT HANDLING SY	5,022	782	2,660	186	0	**$8,650**	519	580	1,136	**$10,885**	28
0.0	0.0											
11	ACCESSORY ELECTRIC PLANT	10,179	4,824	12,011	841	0	**$27,855**	1,671	0	5,023	**$34,549**	89
0.0	0.0											
12	INSTRUMENTATION & CONTROL	4,792	724	3,612	253	0	**$9,381**	563	0	1,405	**$11,349**	29
0.0	0.0											
13	IMPROVEMENTS TO SITE	2,029	1,196	4,754	333	0	**$8,311**	499	0	2,643	**$11,453**	30
0.0	0.0											
14	BUILDINGS & STRUCTURES	0	3,540	4,452	312	0	**$8,303**	498	0	2,200	**$11,002**	28
0.0	0.0											
	TOTAL COST	**$302,558**	**$29,241**	**$128,206**	**$8,974**	**$0**	**$468,980**	**$28,139**	**$17,647**	**$69,347**	**$584,112**	**1510**

SUMMARY DATA FOR CASE 7F

This section contains the following economic data for case 7F:

- Capital Investment and Revenue Requirement Summary
- Total Plant Cost

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS				
GENERAL DATA/CHARACTERISTICS				
Case Title:	Super-Critical PC w/ CO_2 (Case 7F)			
Unit Size:/Plant Size:	379.5	MW,net	379.5	MWe
Location:	East-West Region			
Fuel: Primary/Secondary	Illnois #6			
Energy From Primary/Secondary Fuels	11,862	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent mon	65	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(December)		
Delivered Cost of Primary/Secondary Fuel	1.24	$/MBtu		$/MBtu
Design/Construction Period:	4	years		
Plant Startup Date (1st. Year Dollars):	2000	(January)		
Land Area/Unit Cost	340	acre	$1,600	/acre
FINANCIAL CRITERIA				
Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	4.2	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	Over Book Lif	Constant Dollars		
Capital Structure	% of Total		Cost(%)	
Common Equity	45		12.00	
Preferred Stock	10		8.50	
Debt	45		9.00	
Weighted Cost of Capital:(after tax)		8.76 %		
	Over Book Life		1999 to 2000	
Escalation Rates — General		% per year		% per year
Primary Fuel		% per year		% per year
Secondary Fuel		% per year		% per year

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	Super-Critical PC w/ CO_2 (Case 7F)		
Plant Size:	379.5 (MW,net)	HeatRate:	11,862 (Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6	Cost:	1.24 ($/MMBtu)
Design/Construction:	4 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Dec.)	TPI Year:	2000 (Jan.)
Capacity Factor:	65 (%)	CO_2 Removed	2,339,810 (tons/year)

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		587,017	1546.9
Engineering(incl.C.M.,H.O.& Fee)		35,221	92.8
Process Contingency		6,800	17.9
Project Contingency		92,846	244.7
TOTAL PLANT COST(TPC)		$721,884	1902.3
TOTAL CASH EXPENDED	$721,884		
AFDC	$58,565		
TOTAL PLANT INVESTMENT(TPI)		$780,449	2056.6
Royalty Allowance			
Preproduction Costs		20,427	53.8
Inventory Capital		7,238	19.1
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		544	1.4
TOTAL CAPITAL REQUIREMENT(TCR)		$808,658	2131.0

OPERATING & MAINTENANCE COSTS (1999 Dollars)	**$x1000**	**$/kW-yr**
Operating Labor	5,272	13.9
Maintenance Labor	3,877	10.2
Maintenance Material	5,815	15.3
Administrative & Support Labor	2,287	6.0
TOTAL OPERATION & MAINTENANCE	$17,251	45.5
FIXED O & M		30.14 $/kW-yr
VARIABLE O & M		0.27 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	**$x1000**	**¢/kWh**
Water	343	0.02
Chemicals	11,850	0.55
Other Consumables	2,389	0.11
Waste Disposal	3,836	0.18
TOTAL CONSUMABLE OPERATING COSTS	$18,418	0.85
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$31,782	1.47

	Levelized (Over Book Life $)		
PRODUCTION COST SUMMARY	**$/ton CO_2**		**¢/kWh**
Fixed O & M	$1.62	30.1/kW-yr	0.53
Variable O & M	$1.10		0.27
Consumables	$3.33		0.85
By-product Credit			
Fuel	$3.94		1.47
TOTAL PRODUCTION COST	$9.99		3.12
LEVELIZED CARRYING CHARGES(Capital)	$19.02	294.1/kW-yr	5.16
LEVELIZED (Over Book Life) BUSBAR COST OF POWER	$29.00		8.29

	Client:	EPRI/DOE VISION 21								**Report Date:**	18-Dec-2001	
	Project:	INNOVATIVE POWER CYCLES									12:14 PM	
		TOTAL PLANT COST SUMMARY										
	Case:	Super-Critical PC w/ CO_2 (Case 7F)										
	Plant Size:	379.5 MW,net		**Estimate Type:**	Conceptual			**Cost Base (Dec)**		1999	($x1000)	
Acct No.	**Item/Description**	**Equipment Cost**	**Material Cost**	**Labor Direct**	**Labor Indirect**	**Sales Tax**	**Bare Erected Cost $**	**Eng'g CM H.O.& Fee**	**Contingencies Process**	**Contingencies Project**	**TOTAL PLANT COST $**	**TOTAL PLANT COST $/kW**
1	COAL & SORBENT HANDLING	8,032	2,427	6,412	449		**$17,320**	1,039		3,672	**$22,031**	58
2	COAL & SORBENT PREP & FEED	10,124		3,301	231		**$13,656**	819		2,895	**$17,370**	46
3	FEEDWATER & MISC. BOP SYSTEMS	16,819		7,929	555		**$25,302**	1,518		5,934	**$32,755**	86
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	82,408		32,881	2,302		**$117,591**	7,055		12,465	**$137,111**	361
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/FD & ID Fans)	3,370		1,163	81		**$4,614**	277		489	**$5,380**	14
	SUBTOTAL 4	*85,779*		*34,043*	*2,383*		*$122,205*	*7,332*		*12,954*	*$142,491*	*375*
5A	FLUE GAS CLEANUP	40,430		23,362	1,635		**$65,427**	3,926		6,935	**$76,288**	201
5B	CO_2 REMOVAL & COMPRESSION	74,596		47,583	3,331		**$125,510**	7,531	6,800	20,976	**$160,817**	424
6	COMBUSTION TURBINE/ACCESSORIE											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	9,962	891	8,499	595		**$19,948**	1,197		3,498	**$24,642**	65
	SUBTOTAL 7	*9,962*	*891*	*8,499*	*595*		*$19,948*	*1,197*		*3,498*	*$24,642*	*65*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	39,232		6,771	474		**$46,477**	2,789		4,927	**$54,192**	143
8.2-8.9	Turbine Plant Auxiliaries and Steam Pipin	14,041	575	7,896	553		**$23,064**	1,384		4,291	**$28,739**	76
	SUBTOTAL 8	*53,273*	*575*	*14,667*	*1,027*		*$69,541*	*4,172*		*9,218*	*$82,931*	*219*
9	COOLING WATER SYSTEM	5,706	6,602	6,170	432		**$18,909**	1,135		3,877	**$23,921**	63
10	ASH/SPENT SORBENT HANDLING SYS	6,815	92	13,046	913		**$20,867**	1,252		3,354	**$25,472**	67
11	ACCESSORY ELECTRIC PLANT	12,885	4,793	15,033	1,052		**$33,764**	2,026		5,813	**$41,602**	110
12	INSTRUMENTATION & CONTROL	6,440		2,695	189		**$9,324**	559		1,251	**$11,134**	29
13	IMPROVEMENTS TO SITE	2,210	1,303	5,180	363		**$9,056**	543		2,880	**$12,479**	33
14	BUILDINGS & STRUCTURES		16,234	18,649	1,305		**$36,188**	2,171		9,590	**$47,950**	126
	TOTAL COST	**$333,071**	**$32,917**	**$206,569**	**$14,460**		**$587,017**	**$35,221**	**$6,800**	**$92,846**	**$721,884**	**1902**

SUMMARY DATA FOR CASE 7G

This section contains the following economic data for case 7G:

- Capital Investment and Revenue Requirement Summary
- Total Plant Cost

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	Ultra-Critical PC w/ CO_2 (Case 7G)		
Plant Size:	384.6 (MW,net)	HeatRate:	10,967 (Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6	Cost:	1.24 ($/MMBtu)
Design/Construction:	4 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Dec.)	TPI Year:	2000 (Jan.)
Capacity Factor:	65 (%)	CO_2 Removed	2,192,347 (tons/year)

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		600,126	1560.5
Engineering(incl.C.M.,H.O.& Fee)		36,008	93.6
Process Contingency		6,441	16.7
Project Contingency		93,820	244.0
TOTAL PLANT COST(TPC)		$736,394	1914.8
TOTAL CASH EXPENDED	$736,394		
AFDC	$59,742		
TOTAL PLANT INVESTMENT(TPI)		$796,136	2070.1
Royalty Allowance			
Preproduction Costs		20,552	53.4
Inventory Capital		6,950	18.1
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		544	1.4
TOTAL CAPITAL REQUIREMENT(TCR)		$824,182	2143.1

OPERATING & MAINTENANCE COSTS (1999 Dollars)	**$x1000**	**$/kW-yr**
Operating Labor	5,272	13.7
Maintenance Labor	3,914	10.2
Maintenance Material	5,872	15.3
Administrative & Support Labor	2,297	6.0
TOTAL OPERATION & MAINTENANCE	$17,355	45.1
FIXED O & M		29.86 $/kW-yr
VARIABLE O & M		0.27 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	**$x1000**	**¢/kWh**
Water	293	0.01
Chemicals	11,077	0.51
Other Consumables	2,421	0.11
Waste Disposal	3,594	0.16
TOTAL CONSUMABLE OPERATING COSTS	$17,384	0.79
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$29,779	1.36

	Levelized (Over Book Life $)		
PRODUCTION COST SUMMARY	**$/ton CO_2**		**¢/kWh**
Fixed O & M	$1.89	29.9/kW-yr	0.52
Variable O & M	$1.17		0.27
Consumables	$3.24		0.79
By-product Credit			
Fuel	$3.69		1.36
TOTAL PRODUCTION COST	$9.99		2.95
LEVELIZED CARRYING CHARGES(Capital)	$20.39	295.7/kW-yr	5.19
LEVELIZED (Over Book Life) BUSBAR COST OF POWER	$30.38		8.14

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS				
GENERAL DATA/CHARACTERISTICS				
Case Title:	Ultra-Critical PC w/ CO_2 (Case 7G)			
Unit Size:/Plant Size:	384.6	MW,net	384.6	MWe
Location:	East-West Region			
Fuel: Primary/Secondary	Illnois #6			
Energy From Primary/Secondary Fuels	10,967	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent mon	65	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(December)		
Delivered Cost of Primary/Secondary Fuel	1.24	$/MBtu		$/MBtu
Design/Construction Period:	4	years		
Plant Startup Date (1st. Year Dollars):	2000	(January)		
Land Area/Unit Cost	340	acre	$1,600	/acre
FINANCIAL CRITERIA				
Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	4.2	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	Over Book Lif	Constant Dollars		
Capital Structure	% of Total		Cost(%)	
Common Equity	45		12.00	
Preferred Stock	10		8.50	
Debt	45		9.00	
Weighted Cost of Capital:(after tax)			8.76	%
	Over Book Life		1999 to 2000	
Escalation Rates — General		% per year		% per year
Primary Fuel		% per year		% per year
Secondary Fuel		% per year		% per year

Client: EPRI/DOE VISION 21 — Report Date: 18-Dec-2001 12:16 PM
Project: INNOVATIVE POWER CYCLES

TOTAL PLANT COST SUMMARY

Case: Ultra-Critical PC w/ CO_2 (Case 7G)
Plant Size: 384.6 MW,net — Estimate Type: Conceptual — Cost Base (Dec) 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	7,714	2,331	6,158	431		**$16,634**	998		3,526	**$21,159**	55
2	COAL & SORBENT PREP & FEED	9,700		3,163	221		**$13,084**	785		2,774	**$16,643**	43
3	FEEDWATER & MISC. BOP SYSTEMS	17,032		8,063	564		**$25,659**	1,540		5,965	**$33,164**	86
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	88,090		35,369	2,476		**$125,934**	7,556		13,349	**$146,839**	382
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/FD & ID Fans)	3,220		1,111	78		**$4,409**	265		467	**$5,141**	13
	SUBTOTAL 4	*91,310*		*36,479*	*2,554*		*$130,343*	*7,821*		*13,816*	*$151,979*	*395*
5A	FLUE GAS CLEANUP	38,660		22,435	1,570		**$62,666**	3,760		6,643	**$73,068**	190
5B	CO_2 REMOVAL & COMPRESSION	70,843		45,168	3,162		**$119,173**	7,150	6,441	19,915	**$152,678**	397
6	COMBUSTION TURBINE/ACCESSORIE											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	9,518	852	8,121	568		**$19,059**	1,144		3,342	**$23,545**	61
	SUBTOTAL 7	*9,518*	*852*	*8,121*	*568*		*$19,059*	*1,144*		*3,342*	*$23,545*	*61*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	51,200		8,836	619		**$60,655**	3,639		6,429	**$70,724**	184
8.2-8.9	Turbine Plant Auxiliaries and Steam Pipin	16,704	575	9,365	656		**$27,299**	1,638		5,189	**$34,126**	89
	SUBTOTAL 8	*67,904*	*575*	*18,202*	*1,274*		*$87,954*	*5,277*		*11,618*	*$104,849*	*273*
9	COOLING WATER SYSTEM	5,703	6,598	6,166	432		**$18,898**	1,134		3,875	**$23,907**	62
10	ASH/SPENT SORBENT HANDLING SYS	6,573	89	12,583	881		**$20,126**	1,208		3,235	**$24,568**	64
11	ACCESSORY ELECTRIC PLANT	12,644	4,665	14,667	1,027		**$33,002**	1,980		5,679	**$40,661**	106
12	INSTRUMENTATION & CONTROL	6,482		2,713	190		**$9,385**	563		1,259	**$11,207**	29
13	IMPROVEMENTS TO SITE	2,194	1,293	5,142	360		**$8,989**	539		2,858	**$12,387**	32
14	BUILDINGS & STRUCTURES		15,793	18,095	1,267		**$35,154**	2,109		9,316	**$46,579**	121
	TOTAL COST	**$346,276**	**$32,195**	**$207,155**	**$14,501**		**$600,126**	**$36,008**	**$6,441**	**$93,820**	**$736,394**	**1915**

SUMMARY DATA FOR CASE 9A

This section contains the following economic data for case 9A:

- Capital Investment and Revenue Requirement Summary
- Total Plant Cost

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	IGCC w/ ASU Integration w/o CO2 Removal (9A)			
Unit Size:/Plant Size:	583.6	MW,net	583.6	MWe
Location:	East-West Region			
Fuel: Primary/Secondary	Illnois #6		0	
Energy From Primary/Secondary Fuels	8,609	Btu/kWh	0	Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months	65	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(December)		
Delivered Cost of Primary/Secondary Fuel	1.24	$/MBtu	0	$/MBtu
Design/Construction Period:	4	years		
Plant Startup Date (1st. Year Dollars):	2000	(January)		
Land Area/Unit Cost	350	acre	$2,000	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:	0.0	%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	4.2	%		
Investment Tax Credit/% Eligible	0.0	%	0.0	%
Economic Basis:	Over Book Life	Constant Dollars		

Capital Structure	% of Total	Cost(%)
Common Equity	45	12.00
Preferred Stock	10	8.50
Debt	45	9.00

Weighted Cost of Capital:(after tax) 8.81 %

Escalation Rates		Over Book Life	1999 to 2000
	General	0 % per year	0 % per year
	Primary Fuel	0.0 % per year	0 % per year
	Secondary Fuel	0.0 % per year	0 % per year

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	IGCC w/ ASU Integration w/o CO2 Removal (9A)			
Plant Size:	583.6 (MW,net)	HeatRate:	8,609	(Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6 0	Cost:	1.24	($/MMBtu)
Design/Construction:	4 (years)	BookLife:	20	(years)
TPC(Plant Cost) Year:	1999 (Dec.)	TPI Year:	2000	(Jan.)
Capacity Factor:	65 (%)	CO d2 Remo'	0	

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		502,341	860.7
Engineering(incl.C.M.,H.O.& Fee)		30,140	51.6
Process Contingency		18,875	32.3
Project Contingency		74,403	127.5
TOTAL PLANT COST(TPC)		$625,759	1072.2
TOTAL CASH EXPENDED	$625,759		
AFDC	$55,486		
TOTAL PLANT INVESTMENT(TPI)		$681,245	1167.2
Royalty Allowance		0	0.0
Preproduction Costs		16,652	28.5
Inventory Capital		6,269	10.7
Initial Catalyst & Chemicals(w/equip.)		0	0.0
Land Cost		700	1.2
TOTAL CAPITAL REQUIREMENT(TCR)		$704,865	1207.7

OPERATING & MAINTENANCE COSTS (1999 Dollars)	**$x1000**		**$/kW-yr**
Operating Labor	5,503		9.4
Maintenance Labor	4,110		7.0
Maintenance Material	6,165		10.6
Administrative & Support Labor	2,403		4.1
TOTAL OPERATION & MAINTENANCE	$18,181		31.2
FIXED O & M		20.59	$/kW-yr
VARIABLE O & M		0.19	¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	**$x1000**	**¢/kWh**
Water	448	0.01
Chemicals	510	0.02
Other Consumables	0	0.00
Waste Disposal	1,965	0.06
TOTAL CONSUMABLE OPERATING COSTS	$2,923	0.09
BY-PRODUCT CREDITS (1999 Dollars)	($1,308)	-0.04
FUEL COST (1999 Dollars)	$35,476	1.07

		Levelized (Over Book Life $)	
PRODUCTION COST SUMMARY	**$/ton CO d2**		**¢/kWh**
Fixed O & M		20.6/kW-yr	0.36
Variable O & M			0.19
Consumables			0.09
By-product Credit			-0.04
Fuel			1.07
TOTAL PRODUCTION COST	$0.00		1.66
LEVELIZED CARRYING CHARGES(Capital)		166.7/kW-yr	2.93
LEVELIZED (Over Book Life) BUSBAR COST OF POWER	$0.00		4.59

Client:	EPRI/DOE VISION 21		**Report Date:**	30-Oct-02	
Project:	INNOVATIVE POWER CYCLES			09:22 AM	
	TOTAL PLANT COST SUMMARY				
Case:	IGCC w/ ASU Integration w/o CO2 Removal (9A)				
Plant Size:	583.6 MW,net	**Estimate Type:** Conceptual	**Cost Base (Dec)**	1999	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	8,017	1,647	7,330	513	0	**$17,507**	1,050	0	3,712	**$22,269**	38
0.0	0.0											
2	COAL & SORBENT PREP & FEED	10,462	2,580	8,147	570	0	**$21,760**	1,306	733	3,132	**$26,931**	46
0.0	0.0											
3	FEEDWATER & MISC. BOP SYSTEMS	5,706	5,266	5,961	417	0	**$17,351**	1,041	0	4,159	**$22,551**	39
0.0	0.0											
4	GASIFIER & ACCESSORIES	0	0	0	0	0	**$0**	0	0	0	**$0**	0
4.1	Gasifier, Syngas Cooler & Auxiliaries (E	49,680	0	26,201	1,834	0	**$77,715**	4,663	7,771	9,015	**$99,164**	170
4.2	Syngas Cooling	w/4.1	0	w/ 4.1	w/ 4.1	0	**$0**	w/ 4.1	0	w/ 4.1	**$0**	0
4.3	ASU/Oxidant Compression	47,098	0	w/equip.	0	0	**$47,098**	2,826	0	4,992	**$54,916**	94
4.4-4.9	Other Gasification Equipment	13,053	4,959	7,751	543	0	**$26,306**	1,578	915	4,274	**$33,074**	57
	SUBTOTAL 4	*109,831*	*4,959*	*33,952*	*2,377*	0	***$151,119***	*9,067*	*8,687*	*18,282*	***$187,154***	*321*
5A	GAS CLEANUP & PIPING	21,034	3,087	10,553	739	0	**$35,413**	2,125	1,110	6,786	**$45,434**	78
5B	CO D2 REMOVAL & COMPRESSION	0	0	0	0	0	**$0**	0	0	0	**$0**	0
0.0	0.0											
6	COMBUSTION TURBINE/ACCESSORI	0	0	0	0	0	**$0**	0	0	0	**$0**	0
6.1	Combustion Turbine Generator	73,300	0	2,901	203	0	**$76,404**	4,584	7,640	8,863	**$97,491**	167
6.2-6.9	Combustion Turbine Accessories	0	465	548	38	0	**$1,051**	63	0	334	**$1,449**	2
	SUBTOTAL 6	*73,300*	*465*	*3,449*	*241*	0	***$77,455***	*4,647*	*7,640*	*9,197*	***$98,940***	*170*
7	HRSG, DUCTING & STACK	0	0	0	0	0	**$0**	0	0	0	**$0**	0
7.1	Heat Recovery Steam Generator	37,208	0	5,599	392	0	**$43,199**	2,592	0	4,579	**$50,370**	86
7.2-7.9	HRSG Accessories, Ductwork and Stacl	2,737	2,116	3,041	213	0	**$8,107**	486	0	1,396	**$9,989**	17
0.0	*SUBTOTAL 7*	*39,945*	*2,116*	*8,639*	*605*	0	***$51,306***	*3,078*	*0*	*5,975*	***$60,359***	*103*
8	STEAM TURBINE GENERATOR	0	0	0	0	0	**$0**	0	0	0	**$0**	0
8.1	Steam TG & Accessories	23,292	0	3,280	230	0	**$26,802**	1,608	0	2,841	**$31,252**	54
8.2-8.9	Turbine Plant Auxiliaries and Steam Pip	6,283	577	4,955	347	0	**$12,162**	730	0	2,248	**$15,140**	26
0.0	*SUBTOTAL 8*	*29,575*	*577*	*8,236*	*576*	0	***$38,965***	*2,338*	*0*	*5,089*	***$46,392***	*79*
9	COOLING WATER SYSTEM	7,207	4,627	7,181	503	0	**$19,517**	1,171	0	3,839	**$24,527**	42
0.0	0.0											
10	ASH/SPENT SORBENT HANDLING SY	6,063	927	3,210	225	0	**$10,424**	625	704	1,367	**$13,120**	22
0.0	0.0											
11	ACCESSORY ELECTRIC PLANT	12,262	4,811	12,812	897	0	**$30,781**	1,847	0	5,435	**$38,063**	65
0.0	0.0											
12	INSTRUMENTATION & CONTROL	5,463	826	4,118	288	0	**$10,696**	642	0	1,602	**$12,939**	22
0.0	0.0											
13	IMPROVEMENTS TO SITE	2,380	1,403	5,577	390	0	**$9,749**	585	0	3,100	**$13,434**	23
0.0	0.0											
14	BUILDINGS & STRUCTURES	0	4,327	5,581	391	0	**$10,298**	618	0	2,729	**$13,645**	23
0.0	0.0											
	TOTAL COST	**$331,245**	**$37,617**	**$124,747**	**$8,732**	**$0**	**$502,341**	**$30,140**	**$18,875**	**$74,403**	**$625,759**	**1072**

Strategic Science and Technology Program

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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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