

Modeling the Performance, Emissions, and Cost of an Entrained-Flow Gasification Combined Cycle System Using ASPEN

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ABSTRACT

Gasification is a globally emerging technology in commercial markets for the conversion of a variety of feedstocks, including coal, heavy residue oil, biomass, solid waste, and others, to a variety of products, including electricity, steam, sulfur, transportation fuels, and other chemicals. One of the most developed and versatile gasification technologies is based upon entrained-flow reactors, which typically employ high temperatures and therefore can gasify a broad range of materials. In this study, we focus on the development of a comprehensive performance, emissions, and cost model of a Texaco gasifier-based Integrated Gasification Combined Cycle (IGCC) system using ASPEN. ASPEN is a steady-state chemical process simulator. The comprehensive model enables the evaluation of the interactions among various process areas within the IGCC system, as well as the performance and cost of alternative system designs (e.g., based upon different gas turbine designs). The technical basis for the model is briefly presented. The key process area performance models are described, as is the framework for estimation of air pollutant emissions and the cost model. In the paper and presentation, an example case study of the system model is presented to illustrate the typical performance, emissions, and cost of a coal-based system for the production of power and elemental sulfur byproduct. In future work, the Texaco gasifier-based IGCC model will be used as a bench mark in comparisons with other coal-based power generation systems, models for many of which have been developed in previous work at both Carnegie Mellon University and NC State. Additional gasification systems models based upon entrained flow gasifiers are also under development. Thus, the model presented here is one of a set of complimentary models that enables comparisons of competing systems for strategic planning purposes.

INTRODUCTION

This study deals with the modeling of a Texaco-based entrained-flow Integrated Gasification Combined Cycle (IGCC) system. This study aims at developing a base case analysis of an existing commercially proven IGCC technology which can act as a benchmark to be used for comparative evaluation of more advanced power generation systems. The IGCC system is modeled using a chemical process simulator, Advanced System for Process Engineering (ASPEN). This paper describes the technical basis for a Texaco gasifier-based IGCC system, a simulation model of the system, calibration of the model, and an example case study. The case

study illustrates the types of results that may be obtained by a model user for comparison with other systems analysis case studies.

TECHNICAL DESCRIPTION OF A TEXACO GASIFIER-BASED IGCC SYSTEM

In an IGCC power plant, coal is converted to a syngas, composed mainly of hydrogen and carbon monoxide, using a gasification process. After passing through a gas cleanup system, the syngas is utilized in a combined cycle power plant. IGCC systems are capable of significantly higher thermal efficiencies and lower emissions of CO₂, SO₂, and NO_x, and particulate matter than conventional pulverized coal fired steam (PCFS) plants. This creates the possibility of developing technology options to reliably achieve stringent emission reductions. Different variations of IGCC systems exist based upon the type of coal gasifier technology, oxidant (e.g., oxygen or air), and gas cleanup system employed.

This paper describes performance and cost models for a Texaco gasifier-based IGCC system. The IGCC system is illustrated schematically in Figure 1. Coal is fed to the gasifier in a slurry. Oxygen is used to combust only a portion of the coal in order to provide thermal energy needed by endothermic gasification reactions. The raw syngas leaves the gasifier at approximately 2400 °F and passes through a radiant heat exchanger and a convective heat exchanger in series where it exits at a temperature of 650 °F. The syngas passes through a wet scrubbing system to remove particulate matter and water soluble gases such as NH₃. The scrubbed gas is further cooled to 101 °F prior to entering a Selexol acid gas separation unit where H₂S and COS are removed from the syngas and sent to a Claus plant and a Beavon-Stretford tail gas treatment unit for sulfur recovery. The clean gas is reheated to 570 °F and saturated to 28.2 weight percent moisture prior to firing in a gas turbine. The saturation helps prevent formation of thermal NO_x during combustion. The hot gas turbine exhaust passes through a Heat Recovery Steam Generator (HRSG) to provide energy input to a steam turbine bottoming cycle. Power is generated by both the gas turbine and the steam turbine.

The IGCC concept has been demonstrated commercially. In particular, the Texaco coal gasification process has been successfully used in a number of chemical plants since the early 1980s for the production of syngas from coal. For example, a Texaco gasifier-based 95 MW IGCC power plant was successfully operated from 1984 to 1988 in California.¹ Tampa Electric Company's 250 MW Polk Power station also utilizes Texaco gasification, gasifying about 2000 tons of coal per day.

The details of the major process areas are briefly described.

Gasification

Texaco gasification can handle a wide variety of feedstocks including coal, heavy oils, and sewage sludge. The current study focuses on IGCC systems using coal feed. The feed coal is crushed and slurried in wet rod mills. Coal/water slurry containing about 66.5 weight percent solids is fed into the gasifier, along with a feed stream of oxygen. The slurry is transferred to the gasifier at high pressure through charge pumps. The water in the coal slurry acts as a temperature moderator and also as a source of hydrogen in gasification.² Gasification takes place rapidly in an entrained flow reactor at temperatures exceeding 2300 °F. As a result of the partial oxidation of

coal using oxygen, and the gasification of the resulting solids and moisture, a raw syngas composed mainly of carbon dioxide, carbon monoxide, and water vapor is produced. The syngas contains soot particles. The syngas leaves the gasifier at temperatures in the range of 2300 °F to 2700 °F. Because of the high temperatures characteristic of entrained-flow gasifiers, the syngas contains small amounts of methane compared to other types of gasifiers and is free of tars and other hydrocarbons.² The present study assumes Illinois No. 6 coal as feedstock, the properties of which are listed in Table 1.

High-Temperature Gas Cooling

The hot gas from the gasifier is initially cooled in an open radiant heat transfer-type of heat exchanger. High pressure steam is generated in tubes built into the heat transfer surface at the perimeter of the cylindrical gas flow zone. Molten slag entrained in the raw gas drops into a water quench pool at the bottom of the radiant gas cooler, where it is cooled and removed for disposal. The gas leaves the radiant cooler at a temperature exceeding 1500 °F, and enters a convection-type heat exchanger.

In the convective gas cooler, the gas flows across boiler tube banks, where high pressure steam is generated. The syngas leaves the convective cooler at a temperature of approximately 650 °F, and flows to the gas scrubbing unit.

Gas Scrubbing Process and Low Temperature Gas Cooling

The cooled syngas is scrubbed with water to remove fine particles. The scrubbed gas enters a series of heat exchangers in the low temperature gas cooling section. The heat removed from the syngas is utilized to generate low-pressure steam to heat feed water or as a source of heat for fuel gas saturation.

Cold Gas Cleanup

The syngas from the low temperature gas cooling section enters the acid gas removal section of the plant at a temperature of 101 °F. The acid gas removal system employs the Selexol process for selective removal of hydrogen sulfide (H₂S) and a smaller portion of carbonyl sulfide (COS). H₂S is removed by absorption in the Selexol solvent,² with a typical removal efficiency of 95 to 98 percent. COS removal efficiencies are typically around 30 percent. Sulfur stripped from the Selexol solvent is recovered in the Claus sulfur plant and Beavon-Stretford tail gas treatment plant.

Fuel Gas Saturation and Combustion

To control the formation of thermal NO_x emissions in the gas turbine combustor, water vapor is introduced into the cleaned syngas. The addition of water vapor also allows the flow rate of gases through the gas turbine expander to be increased relative to the compressor flow, thereby increasing the gas turbine net power output. The clean gas from the acid gas removal system enters the saturator vessel from the bottom while hot water is sprayed from the top of the vessel. The syngas is heated by the hot water. A portion of the hot water is evaporated while the remainder is cooled by contact with the syngas and exits from the bottom of the vessel. The heat needed for heating the water is transferred from low temperature gas cooling units and the heat

recovery steam generators to the fuel gas saturation unit via hot water circulation. The clean saturated medium BTU syngas is combusted in the gas turbine combustors.

Combined Cycle

Syngas is combusted in a gas turbine combined cycle system. In a typical gas turbine, such as the “F” designs typical of General Electric and Westinghouse, ambient air is compressed to approximately 13 to 16 atmospheres, and is fed to a combustor with syngas. The combustion products and excess air are expanded through a turbine. A portion of the recovered energy is used to rotate the compressor while the remainder, after losses, is used to turn a generator. The hot exhaust gas from the gas turbine is at a temperature of approximately 1100 °F. The exhaust gas passes through a series of heat exchangers in the HRSG to produce steam at various temperatures and pressures for use in the steam cycle, as well as to produce hot feed water. The exhaust gases flow out of the HRSG at temperatures in the range of 250 °F to 300 °F. Most of the steam generated in the HRSGs is sent to the steam turbines where it is expanded and more electric power is generated. A portion of hot water is sent to the fuel gas saturation unit. The HRSG system also superheats the high-pressure saturated steam that is generated in the high-temperature gas cooling section.

OVERVIEW OF ASPEN

ASPEN is a FORTRAN-based deterministic steady-state chemical process simulator developed by the Massachusetts Institute of Technology (MIT) for the Department of Energy (DOE) to evaluate synthetic fuel technologies.³ The ASPEN framework includes a number of generalized unit operation “blocks”, which are models of specific process operations or equipment (e.g., chemical reactions, pumps). By specifying configurations of unit operations and the flow of material, heat, and work streams, it is possible to represent a process plant in ASPEN. In addition to a varied set of unit operations blocks, ASPEN contains an extensive physical property database and convergence algorithms for calculating results in closed loop systems, all of which make ASPEN a powerful tool for process simulation.

ASPEN uses a sequential modular approach to flowsheet convergence. In this approach, mass and energy balances for individual unit operation blocks are computed sequentially, often in the same order as the sequencing of mass flows through the system being modeled. However, when there are recycle loops in an ASPEN flowsheet, stream and block variables have to be manipulated iteratively in order to converge upon the mass and energy balance. ASPEN has a capability for converging recycle loops using a feature known as “tear streams”.

In addition to calculations involving unit operations, there are other types of blocks used in ASPEN to allow for iterative calculations or incorporation of user-created code. These include design specifications and FORTRAN blocks.

A design specification is used for feedback control. Any flowsheet variable or function of flowsheet variables can be set to a particular design value by the user. A feed stream variable or block input variable is designated to be manipulated in order to achieve the design value. FORTRAN statements can be used within the design specification block to compute design specification function values.

FORTRAN blocks are used for feedforward control. Any FORTRAN operation can be carried out on flowsheet variables by using in-line FORTRAN statements that operate on these variables. FORTRAN blocks are one method for incorporating user code into the model. It is also possible to call any user-provided subroutine from either a design specification or FORTRAN block.

ASPEN MODEL OF A TEXACO GASIFIER-BASED IGCC SYSTEM

The Federal Energy Technology Center (FETC) of the U.S. Department of Energy has developed a number of performance simulations of IGCC systems in the ASPEN modeling environment. A number of these models have been refined by Frey and others in order to calculate mass and energy balances for IGCC systems, conduct sensitivity analyses of performance parameters, track environmental species, and evaluate design modification.^{4,5} The models consists of unit operations blocks, FORTRAN blocks, and design specifications which are specific to IGCC systems. Subroutines that calculate capital, annual, and levelized costs have also been developed and incorporated with the refined performance models.

The Texaco gasifier-based IGCC system model employed in this study is based primarily on the general configuration and design basis of a study sponsored by the Electric Power Research Institute (EPRI).⁶ The original flowsheet for the present model was developed by K.R. Stone in 1985 at FETC. The FETC model has been substantially refined for this study.

The key refinements to the model include complete replacement of the gas turbine flowsheet with a more detailed model, implementation of a more detailed fuel gas saturation model, incorporation of NO_x emissions as a model output, refinement and more comprehensive inclusion of auxiliary power demand estimates, and implementation of a capital, annual, and levelized cost model. The key improvements to the original FETC model are briefly described in more detail for the gas turbine and the cost model.

Gas Turbine

The gas turbine in the flowsheet in the FETC was replaced by a new gas turbine flowsheet with more detailed characterization of the multiple compressor and turbine stages, cooling air splits from the compressor to the high temperature turbine stages, and energy losses. In addition the new gas turbine flowsheet includes a new calculation sequence based upon choked flow conditions at the turbine inlet nozzle, which limits the mass flow of gases into the gas turbine. Using a design specification, the gas turbine flowsheet is solved iteratively to determine the amount of compressor air that must be combusted with the fuel in order to exactly match the turbine nozzle flow rate constraint. In addition, the new model is based upon updated assumptions regarding pressure ratios, compressor and turbine isentropic efficiencies, and firing temperature. The gas turbine exhaust gas temperature is maintained at a temperature lower than 1120 °F by varying the firing temperature of the gas turbine.

In order to calibrate the gas turbine model, a simple cycle system was simulated for natural gas and one gas turbine. The simple cycle efficiency, power output, and exhaust gas temperature vary with the isentropic efficiencies of compressors and expanders of the gas turbine, as illustrated in Figure 2. For natural gas firing, published data are available for a “Frame 7F” type of gas turbine and are used to calibrate the model. For example, the published values for a General Electric MS7001F gas turbine are a simple cycle efficiency of 36.35 percent, a power output of 169.9

MW, and an exhaust gas temperature of 1,116 °F. The required turbine isentropic efficiency is selected from Figure 2(a) based upon the desired exhaust temperature; in this case, an isentropic efficiency of 87.2 percent was selected. A compressor isentropic efficiency of 91.8 percent is selected based on Figure 2 (b) in order to obtain the correct simple cycle efficiency. The estimated power output of 170.0 MW, obtained from the ASPEN gas turbine model with the selected values of isentropic efficiencies, is within 0.11 percent of the published data. A similar procedure was used to calibrate the gas turbine to data for a coal gasification application.

Cost Model

The new cost model includes capital, annual, and levelized costs. It estimates the direct capital costs of each major plant section as a function of key performance and design parameters. The total capital costs is calculated based on direct and indirect capital costs. The total direct cost is a summation of the plant section direct costs and general facilities cost. The total indirect cost is the sum of indirect construction costs, engineering and home office fees, sales tax, and environmental permitting costs. The latest process contingency factors have been incorporated in the cost model and are included in the total capital cost.

The annual cost model includes both fixed and variable operating costs. Fixed operating costs include operating labor, maintenance labor and materials, and overhead costs associated with administrative and support labor. The latest maintenance cost factors have been included in the cost model in order to calculate process area annual maintenance cost. Variable operating costs include fuel, consumables, ash disposal, and byproduct credits. The operating costs are estimated based on approximately 40 to 50 cost parameters such as unit prices and costs.⁷

The cost model has been developed as a FORTRAN subroutine which is linked to the ASPEN simulation model. The cost model obtains approximately 50 process parameters from the ASPEN performance model for use in both capital and annual cost calculations. Newly developed regression models are used to calculate the auxiliary power requirements for many of the process areas. The overall plant efficiency is calculated in the cost model subroutine taking into account the gross gas turbine and steam turbine output and auxiliary power demands.

Calculation Sequencing of the ASPEN Simulation Model

The ASPEN model consists of flowsheets of each of the important sections of the IGCC systems. The flowsheets are connected by material, heat, and/or work streams. Each flowsheet consists of unit operation blocks and may also include design specifications or FORTRAN blocks. The major section flowsheets and overall sequencing of calculations are briefly described here and are illustrated in Figure 3.

The GASIFIER flowsheet models the gasification and radiant cooling sections of the IGCC system. SOLIDSEP flowsheet implements the convective cooling section and particulate scrubbing sections. Low temperature syngas cooling, acid gas removal, fuel gas saturation, and heat recovery from the hot exhaust gases from the gas turbine are modeled in the GASPROC flowsheet. A “Frame 7F” type of gas turbine is modeled in the GASTURB flowsheet. CLAUS simulates a Claus sulfur recovery plant and STREFD simulates Beavon-Stretford tailgas treatment plant. Finally, the STEAMCYC flowsheet models the steam cycle of the IGCC system

consisting of the HRSG, auxiliaries system consisting mostly of pumps, and steam turbine sections.

Design Specifications

A few examples of key design specifications are briefly described, with a focus on new ones added in the course of refining the original FETC model. In order to set the saturator fuel gas temperature to 347 °F once it exits the saturator, the design specification SETSATR is used. The saturator is modeled as a mixing chamber in which hot water is mixed with the clean syngas arriving from the acid gas removal section. Boiler feed water from HRSG, and reheated water from the saturator mix to form the hot water entering the saturator. The amount of hot water injected in this chamber is varied until the saturated gas temperature is 347 °F.

At high exhaust gas temperatures, the gas turbine blades' lifetime can be reduced. To prevent possible damage to the gas turbine blades, the temperature of the gas turbine exhaust gas is controlled such that it is kept below 1120 °F. The control temperature of 1120 is obtained from published data.⁸ This is achieved by varying the gas turbine firing temperature in the SETHRST design specification until the desired expander exhaust gas temperature is obtained.

The mass flow at the turbine inlet nozzle is assumed to be choked.⁹ The choked mass flow is calculated based on a reference mass flow, adjusted for differences in pressure, temperature, and molecular weight of the exhaust gas, and assuming that the critical area and ratio of specific heats of exhaust gas for reference and actual cases are constant. The TCHOKE design specification achieves the specified turbine nozzle gas mass flow rate by adjusting the gas turbine inlet air flow.

Fortran Blocks

The FORTRAN block STCTAIL initializes parameters such as temperatures, pressures, and conversion efficiencies for a wide range of flowsheet unit operations, such as the gas turbine. GTHOC and AIRCOOL are FORTRAN blocks associated with the gas turbine, with the former calculating the actual fuel heating value which is used for estimating the gas turbine efficiency, and the latter setting the gas turbine internal cooling air flows. SETFEED maintains a specified slurry water mass flow to coal mass flow ratio at the gasifier inlet. SETSTEAM acts as the steam cycle flow controller.

FORTTRAN block SUMMARY writes the system summary report listing the user specified results. TEXCOST passes the performance model parameters to the cost model subroutine USRTEXRC.

MODEL RESULTS

An example case study is presented here to illustrate the use of the new IGCC system model. The key steps in running the ASPEN simulation model of the Texaco gasifier-based IGCC system are: (1) specify input assumptions; (2) execute the model; (3) collect results; and (4) interpret the results.

Model input assumptions were developed for the performance and cost model based upon a review of design and performance parameters obtained from literature.^{4,5,6,7,8} The assumed composition of the 3.9 weight percent (dry basis) sulfur Illinois No. 6 coal is given in Table 1.

The model is configured to represent three parallel trains of heavy duty “Frame 7F” gas turbines. Table 2 summarizes a number of the input assumptions for the example case study, with a focus on the key inputs for the gasifier and gas turbine process areas of the model. Many of these assumptions have been previously described in the technical description of the technology. Two of the assumptions listed in the table are initial values that may be modified during the simulation. These are the Oxygen/Coal ratio in the gasifier and the Turbine Inlet Temperature in the gas turbine. The Oxygen/Coal ratio is varied by a design specification in order to achieve the specified syngas exit temperature and overcome a two percent heat loss from the gasifier. The Turbine Inlet Temperature may be lowered from the initial value of 2,350 °F in order to maintain the exhaust gas temperature below 1,120 °F. There are literally hundreds of other input assumptions to the model. Only the most significant ones affecting plant design and operation are shown here. The cost model assumptions used in this case study are similar to those reported by Frey and Rubin.⁷

To execute the ASPEN model, an input file is prepared using standard ASPEN keywords and is submitted to a multi-step process leading to model execution. In the first step, the input file is translated into a FORTRAN program, which is then compiled and linked to the extensive library of ASPEN unit operation and other subroutines. The model is then executed and produces numerous output files. This particular case study was executed on a VAX 4000 located at Carnegie Mellon University, and the clock time for the run was 5.3 minutes.

Selected performance and cost results from the model output are summarized in Tables 3 and 4. The overall energy balance is indicated in Table 3. The plant is estimated to produce a net of 863 MW with an overall plant efficiency of 39.8 percent on a higher heating value basis. The breakdown of plant power production and internal plant power consumption for auxiliaries is given in the table.

Estimated emission rates estimated for SO₂, NO_x, particulate matter (PM), CO₂, are provided in Table 3. SO₂ emissions from IGCC systems are controlled by removing sulfur species from the syngas prior to combustion in the gas turbine. NO_x emissions tend to be low for this particular IGCC system because there is very little fuel-bound nitrogen in the fuel gas and thermal NO formation is low due to the low syngas heating value and correspondingly relatively low adiabatic flame temperature. PM emissions are controlled in the syngas cleanup system prior to the gas turbine. A primary purpose of the gas cleanup system is to protect the gas turbine from contaminants in the fuel. Hence, no post-combustion control is assumed. However, it is possible to further control NO_x emissions, for example, through use of Selective Catalytic Reduction (SCR) downstream of the gas turbine. The emission rates of these pollutants are lower than for conventional power plants and for many advanced coal-based power generation alternatives. CO₂ emissions are lower than for conventional coal-fired power plants because of the higher thermal efficiency of the IGCC system (e.g., nearly 40 percent in this case versus typical values of 35 percent for conventional pulverized coal-fired power plants).

The estimated costs for the IGCC system given in Table 4 include capital, annual, and levelized costs. These costs are inclusive of the entire power plant, including the environmental control system. Two case studies are presented based upon different assumptions regarding engineering and home office fees, project contingency, and process contingency. For Case 1, the breakdown of total capital cost of \$1,724/kW includes a 47.1 percent contribution from direct costs, a 5.4

percent contribution from process contingencies, a 12.2 percent contribution from project contingencies, and a 13.1 percent contribution from allowances for funds used during construction. The remaining contributions are from other indirect costs and startup costs. The largest annual cost is for fuel consumption. The byproduct credit for sale of elemental sulfur offsets the incremental variable costs for all consumables other than fuel. The levelized cost of electricity, based upon a 65 percent capacity factor, is 50.6 mills/kWh (5.06 cents/kWh). This cost of electricity is comparable to that of many other coal-based power generation systems evaluated using similar financial assumptions. For Case 2, the cost of electricity is 7.3 percent less than that for Case 1 because of the lower indirect and contingency costs.

CONCLUSIONS

The present study deals with the development of a Texaco gasifier-based IGCC system model using ASPEN. A new performance, emissions, and cost model was developed based upon refinements and modifications to a performance model previously developed by DOE/FETC. The new model incorporates more performance details regarding key process areas, such as the gas turbine and gasifier, and includes a comprehensive capital, annual, and levelized cost model. In addition, the new model includes additional features regarding flowsheet calculation sequencing and convergence schemes, as illustrated by the addition of a number of key design specifications to enhance the scope of important design assumptions and constraints. The new gas turbine performance model was calibrated to published data for operation on natural gas and also to data for operation on syngas. An example case study illustrates the type of results that may be obtained from the model regarding plant performance, emissions, and cost. The results indicate that this particular system is capable of high thermal efficiencies and low emissions, but may be relatively costly. Additional work is needed and will be performed in the future to evaluate the sensitivity of model predictions to alternative assumptions regarding model inputs, and to further refine and update the input model assumptions. The model will be used in future work as a benchmark for comparison with more advanced and technologically-risky power generation system concepts.

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Table 1. Characteristics of the Coal Assumed for IGCC System Studies

<u>Proximate Analysis</u>	<u>Wt-%, run-of-mine basis</u>
Moisture	10.00
Fixed Carbon	48.87
Volatile Matter	32.22
Ash	8.91
<u>Ultimate Analysis</u>	<u>Wt-%, dry basis</u>
Carbon	69.62
Hydrogen	5.33
Nitrogen	1.25
Sulfur	3.87
Oxygen	10.03
Ash	9.90
<u>Ash Fusion Temperature, °F</u>	2,300
<u>Higher Heating Value, BTU/lb</u>	12,774

Table 2. Summary of the Base Case Parameters Values for the Texaco Coal Gasification Radiant and Convective System

<u>Description, Units</u>	<u>Value</u>
<i>Gasifier Process Area</i>	
Gasifier Pressure, psia	600
Gasifier Outlet Temperature, °F	2,400
Oxygen/Coal Ratio, lb O ₂ / lb Coal	0.915
(Initial Value)	
Slurry Water/Coal Ratio, lb H ₂ O / lb Coal	0.504
Radiant Cooler Outlet Temperature, °F	1,500
Convective Cooler Outlet Temperature, °F	650
Radiant Cooler Heat Loss, %	6
<i>Gas Turbine Process Area</i>	
Inlet Syngas Temperature, °F	570
Fuel Moisturization, wt-% of Clean Gas	28.2
Pressure Ratio	15.5
Turbine Inlet Temperature, °F	2,350
(Initial Value)	
Exhaust Flow, lb/sec	1,049
Compressor Isentropic Efficiency, %	81.0
Expander Isentropic Efficiency, %	91.9
Generator Efficiency, %	98.5

Table 3. Summary of Selected Performance Model Results from the Example Case Study

Description, Units	Value
Gas Turbine Output, MW	579.5
Steam Turbine Output, MW	400.0
<i>Auxiliary Power Demand</i>	
Coal Handling, MW	7.2
Oxidant Feed, MW	82.7
Gasification, MW	1.2
Low T. Cool., MW	2.4
Selexol, MW	4.8
Claus, MW	0.4
Beavon-Stretford, MW	1.3
Steam Cycle, MW	5.3
Process Condensate, MW	0.6
General Facilities, MW	10.6
Total Auxiliary Load, MW	116.4
Net Power Output, MW	863.1
Heat Rate, BTU/kWh (HHV basis)	8,575
Efficiency, %	39.8
SO ₂ Emissions, lb/10 ⁶ BTU	0.22
NO _x Emissions, lb/10 ⁶ BTU	0.13
Particulate Matter (PM) Emissions, lb/10 ⁶ BTU	< 0.03
CO ₂ Emissions, lb/kWh	1.70

Table 4. Summary of Cost Model Results for the Example Case Study (1998 Dollars)

Description, Units	Case 1 (see notes below)	Case 2 (see notes below)
<i>Capital Cost Summary (\$/kW)</i>		
Total Direct Cost	811	811
Total Indirect Costs	297	277
Process Contingencies	94	70
Project Contingency	210	116
Total Plant Cost	1,413	1,274
AFDC (see note below)	226	204
Total Plant Investment	1,639	1,478
Startup Costs and Land	43	39
Total Capital Requirement	1,724	1,558
Fixed Operating Cost, \$(/kW-yr)	50.1	46.1
Incremental Variable Costs, mills/kWh	1.2	1.2
Byproduct Credit, mills/kWh	1.5	1.5
Fuel Cost, mills/ kWh	10.8	10.8
Variable Operating Cost, mills/kWh	10.5	10.5
Cost of Electricity, mills/kWh	50.6	46.9

Note: AFDC = Allowances for Funds used During Construction

Fuel Cost, \$/MMBTU = 1.26 (Jan 1998 Dollars)

Capital Recovery Factor = 0.1034

Case 1: Engineering & Home Office Fees = 10%

Project Contingency = 17%

Overall Process Contingency = 11.5% of Total Direct Cost

Case 2: Engineering & Home Office Fees = 8%

Project Contingency = 10%

Overall Process Contingency = 8.6% of Total Direct Cost

Figure 1. Process Areas of Texaco-Gasification IGCC System.

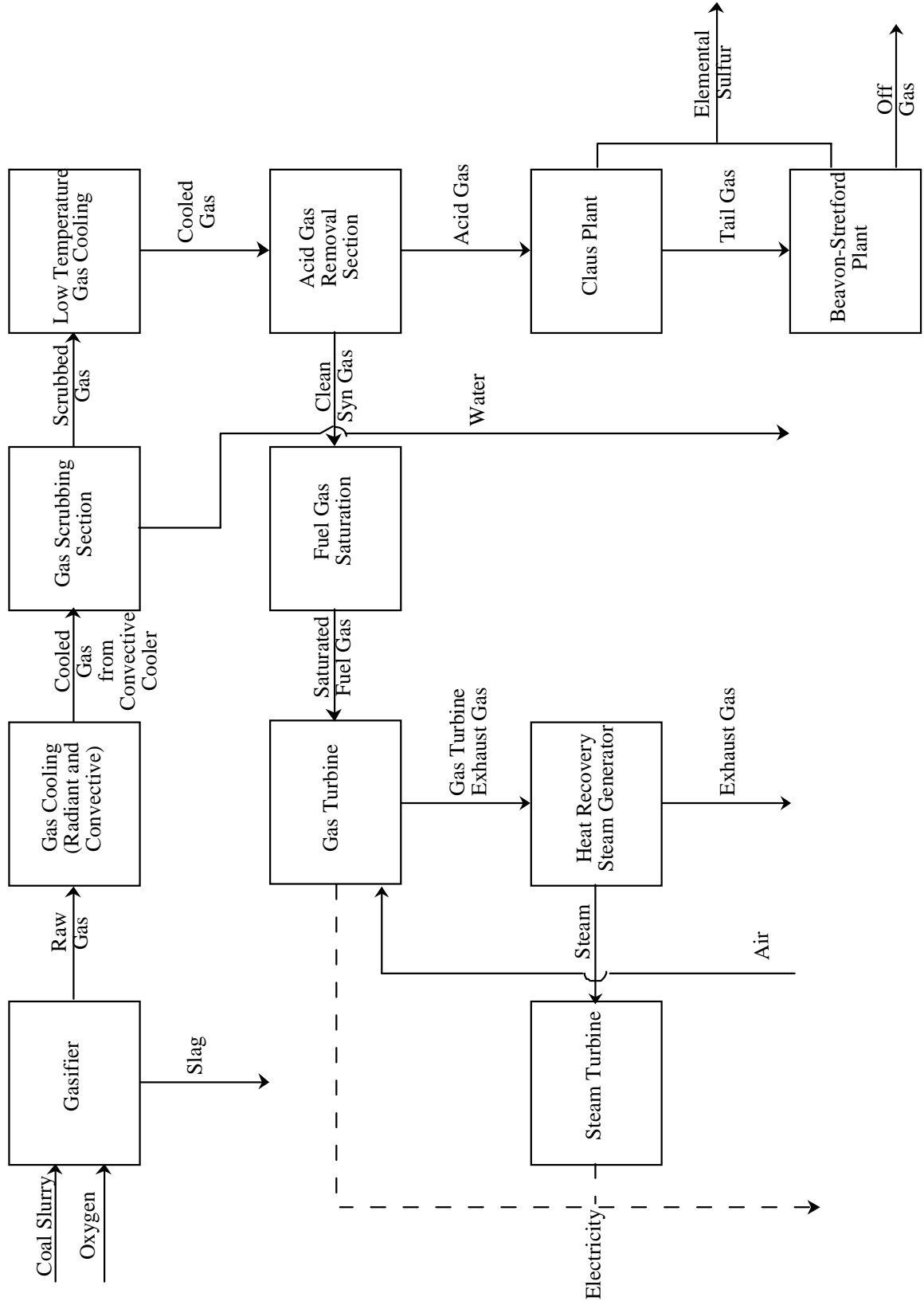
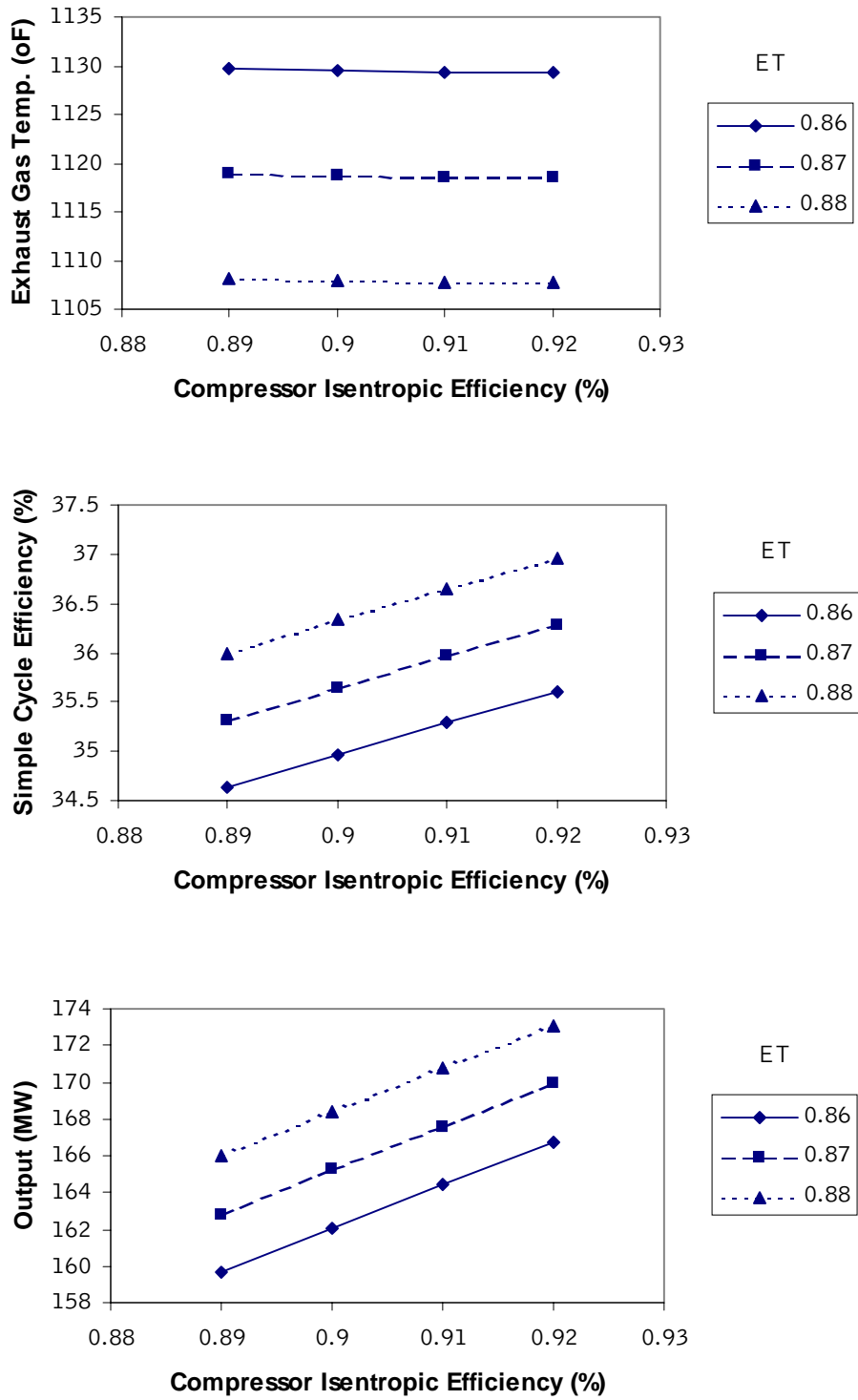


Figure 2. Plots of (a) Exhaust Gas Temperature , (b) Simple Cycle Efficiency, and (c) Output versus Gas Turbine Compressor Isentropic Efficiency.



Note: ET = Gas Turbine Expander Isentropic Efficiency

Figure 3. Flowsheets, Design Specifications, and FORTRAN blocks of the Model.

