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Research paper

Chemical, thermal and economic aspects for the energy balance of coal gasification power plants with and without CO_2 recovery

Said M. A. Ibrahim [1] *, Mostafa E. M. Samy [1]

[1] Department of Mechanical Engineering, Al-Azhar University, Nasr City, Cairo 11371, Egypt
**Corresponding author E-mail: prof.dr.said@hotmail.com*

Abstract

This paper presents a methodology for studying the chemical, thermal processes and economics for the gasification systems employed in coal fired power stations through thermodynamic analyses based on thermodynamic laws in order to gain some new aspects of the plant performance. A resourceful computer program is developed and designed to calculate all necessary design and performance data for four selected coal fired power plants for all coal ranks. Detailed manual calculations were performed for the results. Comparison of computer and manual results are in excellent agreement which indicates that the present program is an accurate quick powerful tool for all users. The main findings of this paper are that Integrated Coal Gasification Combined Power Generation Plants with CO_2 recovery increase the plant's thermal efficiency and decrease the CO_2 emission. The thermodynamics, hydrodynamics, and kinetics of each reaction to the gas combinations were most likely tested by each of the techniques when using a variety of fuels under the condition of "Oxygen gas at 30 bar pressure". The economic analysis is based on analyzing the economics of carbon dioxide capture and storage and the amount of carbon dioxide emitted from power plants. Finally, with new developments, the capture and sequestration of CO_2 could lead to.

Keywords: *Coal Gasification and Syngas; Efficiency; Power Plant; CO_2 Recovery; Cost.*

1. Introduction

IGCC is an acronym for Integrated Gasification Combined Cycle. The main purpose of IGCC is to use hydrocarbon fuels in solid or liquid forms to produce cleaner and more efficient electric power via gasification compared to the direct combustion of fuel. Hydrocarbon fuels can include coal, biomass, refinery bottom residues, and municipal wastes. The way to produce a cleaner power is firstly to convert solid/liquid fuels to gas, so that they can be cleaned before being burned by getting rid mainly of particulates, sulfur, mercury, and other trace elements. The cleaned gas, called synthesis gas (syngas), consists primarily of carbon monoxide and hydrogen , can then be fed to a conventional combined cycle to produce electricity [1].

Thermal integration can be incorporated by interconnecting the different grades of steam generated during the cooling of the syngas, gas cleanup, and/or water gas shift processes with the heat recovery steam generator (HRSG) and the steam turbine. Full air integration will enhance the overall plant efficiency by approximately 3 to 4 %. However, this increases the complexity of construction, operation, and maintenance, which may result in increasing the construction phase delay and/or cost overrun, increased maintenance, low availability, and degraded reliability. Accordingly, the concept of nonintegrated IGCC has been raised by some developers to trade reduced efficiency for higher availability and reliability, even though the term “nonintegrated IGCC” could be confusing [1].

When global warming became a serious concern, the emission of carbon dioxide a greenhouse gas (GHG) from power stations was subjected to stringent regulations. CO_2 is produced profusely and becomes the main culprit in global warming. Practically, there are three methods to reduce CO_2 emissions: increasing the plant's overall efficiency, capturing a portion of CO_2 and sequestering it, which is known as carbon capture and sequestration (CCS), or utilizing the captured CO_2 several times. The syngas generated by means of the gasification process can be readily separated into highly concentrated H_2 and CO_2 through the water-gas shift (WGS) process before the combustion stage (i.e., pre combustion) in an IGCC plant, as opposed to pulverized coal (PC) power stations, which have to use a post-combustion carbon capture method. It is significantly cheaper to perform pre combustion carbon capture in an IGCC system rather than post-combustion carbon capture in a PC power plant due to the nature of the processes involved and the reduced size of equipment. CCS exerts a severe penalty on power output, plant efficiency, and cost of electricity (COE) [1].

2. Computer program

A main aim of this research is to develop and design a commercial useful computer program to calculate all the necessary data for the different coal power plants for all ranks of coal.. It is a quick resourceful powerful easy tool for getting all the necessary chemical, thermodynamic, and energy calculations in addition to cost of electricity from any plant. The output results are many as they are proportional to the complexity of the program. Four computer programs were designed; one for each of the studied power stations.

The present program is a simulation of several power plants including four main types, power plants without coal gasification

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with CO_2 recovery and storage, and power plants with coal gasification and CO_2 recovery and storage.

Each program consists of input, process, control, and output. The input data which provide all output data include: mass flow rate of coal, efficiency of combustor and so on. This includes many processes in the cycle which represent chemical, heat transfer, accountant, and economic processes. The economic process as one of the main results of the programs includes all cycle costs as represented by capital cost, operating cost, COE, and cost of CO_2 capture analogue to plant, cost of CO_2 with capture avoided, and so on. The control in the program is established to change the state according to coal type which depends on the heating value of coal, CO_2 capture and storage system which reflects on the efficiency of CO_2 capture, the high pressure (HP) CO_2 capture which reflects on the efficiency of CO_2 compressor.

In the first program used for steam power plants the input data are mass flow rate of coal, high heating value (HHV) of coal; efficiencies of: boiler, heat transfer of boiler, steam turbine, condenser, CO_2 compressor, and CO_2 capture; enthalpies of: water inlet to boiler, steam outlet from boiler or steam inlet to turbine, steam outlet from turbine, CO_2 inlet to compressor at 1 bar, and CO_2 outlet from compressor at 150 bar; capital cost of plant, coal cost, and life time of plant.

In the second program for entrained flow gasification power plants the input data are mass flow rate of coal, HHV of coal; efficiencies of: syngas cooler, CO_2 capture, gas turbine, air compressor, HRGS, CO_2 compressor, steam turbine, condenser, air compressor, and ASU; enthalpies of: water inlet to syngas cooler or water inlet to HRGS or condenser cooling water or cooling water inlet for CO_2 capture, steam outlet from syngas cooler or steam outlet from HRGS steam inlet to turbine), air inlet to compressor or air inlet to compressor of ASU, air outlet from compressor, gas inlet to turbine, gas outlet from turbine or gas inlet to HRGS, gas outlet from HRGS , CO_2 inlet to compressor at 1 bar, CO_2 inlet to compressor at 15.8 bar, CO_2 outlet from compressor at 150 bar, steam outlet from HRGS for CO_2 capture, steam outlet from turbine, and air outlet from compressor of ASU; in addition to same cost items as before.

In the programs used for fluidized bed gasification and fixed bed gasification power plants the input data are as in the second program in addition to enthalpy of steam outlet from HRGS to gasifier.

When discussing the control of the program, reference should be made to the data on which the control steps are based on in the program. These data are similar in all the programs of the studied power stations, and are: (1) coal HHV which controls the program by determining the type of coal that is used in the plant, and the program is run according to the corresponding HHV of the used coal (=33000, 23600, 16800, 27800 kJ/kg for bituminous, subbituminous, lignite, and anthracite coals, respectively), (2) efficiency of CO_2 capture; this controls the program by determining whether the station is operating a CO_2 recovery system or not. For a system without CO_2 recovery, the system efficiency is zero, and if employing CO_2 recovery then the system efficiency is according to the operating conditions and so on, and (3) efficiency of CO_2 compressor which controls the program to specify whether the station is operating a high-pressure carbon dioxide recovery system or not. If not then the compressor efficiency is zero, and if used then the pressure of CO_2 is increased according to compressor efficiency and so on.

In the program for steam power plants the output data are mass flow rates of: air inlet for complete combustion, outlet steam from boiler, and cooling water in condenser, and CO_2 emission; mass of CO_2 captured, molar weight of coal, thermal cycle efficiency, heat of combustion in boiler, power of steam turbine, power of CO_2 compressor, output power of cycle, total cost for useful life of plant, total cost in first year, operating costs, energy output, and COE.

For entrained flow, fluidized bed, and fixed bed gasification power plants the output data are mass flow rates of: carbon, H_2, O_2, N_2, S, moisture, and ash in coal, oxygen outlet from ASU, air in ASU, N_2 outlet from ASU, water in slurry, water in slag, H_2 in syngas, CO in syngas, CH_4 in syngas, CO_2 in syngas, N_2 in syngas, steam in syngas, H_2S in syngas, syngas, outlet steam from syngas cooler, air inlet for complete combustion, syngas after cleaning, air inlet to compressor, nitrogen inlet for combustion, inlet gas to turbine, steam outlet steam to HRGS, total steam inlet to turbine, cooling water, CO_2 emission for complete combustion, steam required for CO_2 capture, CO_2 captured, H_2 after CO_2 capture, CO after CO_2 capture, and CO_2 emissions; molar weight of coal, heat of combustion of syngas, summation of heat in syngas cooler, heat of combustor, heat of combustion of syngas after CO_2 capture, heat released by carbon capture, cold gas efficiency, carbon conversion efficiency, gas turbine efficiency, mass of CO_2 emissions, thermal cycle efficiency, power of air compressor, power of gas turbine, net power of gas turbine, power of steam turbine, power of CO_2 compressor, cycle output power, power of air compressor of ASU, total cost for useful life time of plant, total cost in first year, operating costs, energy output and COE.

The present programs provide: (1) the capacity, efficiency and economics of the plant, whether coal gasification includes recovery of carbon dioxide and storage or without gasification or retrieval at different situations and these cases include: climatic, economic, strategic, and political situations, (2) make comparisons of results between plants, whether in terms of efficiency or cost per station and to give important guidance when operating the station, and (3) offer comparisons of the results between all stations to determine the best of them.

3. Methodology

Step by step manual calculations are conducted for the thermal and energy balances with a comprehensive cost model for each of the selected power plants. These stations include coal-fired ones with and without the possibility of recovering carbon dioxide, as well as stations without coal gasification with and without CO_2 recovery.These results are then compared with those obtained from the present computer programs. The following procedure indicates the calculation processes in the present programs.

3.1. Reference calculation data

The following manual calculations are made for only one type of coal, bituminous, based on the data provided in Table 1, for all the studied power stations. The present computer program can provide such results and more for all coal ranks.

Table 1: Design Technical Data

Coal type (Bituminous)	
Mass of coal	2500 TPD
Gasifier pressure	30 bar
Steam pressure	9 MPa
Steam temperature	1150 ºC
Pressure ratio of gas turbine	15.8
Air temperature	27 ºC
Water temperature	25 ºC
Condensate pressure	0.1 bar
Efficiency of any system	100 %
Any losses	0 %

- Carbon conversion

Table 2 gives carbon conversion ratios (CCR) or carbon conversion efficiency (CCE) for different gasifiers, as taken from Ref. [1]. These represent the mass percentage of total carbon in the gasifier feedstock (i.e., coal or biomass) which is converted to syngas for different gasification technologies.

The values in Table 2 are used in the next thermodynamic calculations for power plants, since the calculations depend on them.

Table 2: Carbon Conversion

Gasifier	Carbon conversion %
Entrained flow	99.999
Fluidized bed	97

Fixed/moving bed	98

The entrained flow gasifier exhibits high carbon conversion because of the high temperature involved and hence low tar. The fluidized bed gasifier has the lowest carbon conversion because the solid waste agglomerates and results in high tar.

3.2. Algorithm procedure

1) Calculate the thermodynamic properties (pressure P, temperature T, entropy s, enthalpy h, moisture content X; at inlet and outlet in all parts of the plant's components).
2) Perform heat balance for feed water, and generated steam and gases.
3) Calculate the useful work of the turbines.
4) Calculate the amount of heat added to generate steam by syngas cooler and heat recovery gas system as well as the amount of heat rejected from the condenser and calculate the efficiency of the plant.
5) Determine all chemical reactions in the gasifier and carbon capture system and determine the heat from these reactions.
6) Determine the economics of the plant.

3.3. Thermodynamic equations

- Boiler in steam power plant

Total heat in boiler = $\dot{m}_C \times HHV = \dot{m}_{st,\,w}\,(h_{out} - h_{in})$
Where
$\dot{m}_C$= mass flow rate of coal, tone/day (TPD),
HHV = high heating value of coal, kJ/kg,
$\dot{m}_{St,\,w}$ = mass flow rate of steam or water, TPD,
h_{out} = enthalpy of outlet steam, kJ/kg. and
h_{in} = enthalpy of inlet water, kJ/kg.

- Syngas cooler in IGCC power plant

Total heat in syngas cooler = $[CCE \times (\dot{m}_C \times HHV)] - \Delta HC = \dot{m}_{st,\,w}\,(h_{out} - h_{in})$
Where
CCE = carbon conversion efficiency, %,
$\dot{m}_C$= mass flow rate of coal, kg/s,
HHV = high heating value of coal, kJ/kg
ΔH_C = heat of combustion of product gases from gasifier, kW,
$\dot{m}_{St,w}$ = mass flow rate of steam or water, kg/s,
h_{out}= enthalpy of outlet steam, kJ/kg, and
h_{in}= enthalpy of inlet water, kJ/kg.

- Carbon capture (pre combustion) system in IGCC

$\Delta H = \Delta H_{\text{without ccs}} - \Delta H_{\text{with ccs}} = \dot{m}_w\,(h_o - h_{in})$
where
ΔH = heat rejected from CCS, kW,
$\Delta H_{\text{without ccs}}$ = heat of combustion of syngas before CCS, kW,
$\Delta H_{\text{With ccs}}$= heat of combustion of syngas after CCS, kW,
$\dot{m}_w$= mass flow rate of water, kJ/kg,
h_o= enthalpy of outlet water, kJ/kg, and
h_{in}= enthalpy of inlet water, kJ/kg.

- Gas turbine

$\Delta H_C = h_3\,(\dot{m}_{air} + \dot{m}_{N2} + \dot{m}_{Syn}) - h_2\dot{m}_{air}$
$\dot{m}_{gas} = \dot{m}_{air} + \dot{m}_{N2} + \dot{m}_{Syn}$
$P_C = \dot{m}_{air}\,(h_2 - h_1)$
$P_T = \dot{m}_{gas} \times (h_3 - h_4)$
$W_{net} = PT - PC$
$\eta_C = [W_{net} / \Delta H_C] \times 100$
Where
ΔH_C = heat of combustor, kW
$\dot{m}_{air}$= mass flow rate of air, kg/s,
$\dot{m}_{N2}$= mass flow rate of N_2, kg/s,
$\dot{m}_{Syn}$= mass flow rate of syngas, kg/s,
$\dot{m}_{gas}$ = mass flow rate of syngas, kg/s,
P_C = power of compressor, kW,
h_1 = enthalpy of air inlet to compressor, kJ/kg,
h_2= enthalpy of air outlet from compressor, kJ/kg
P_T = power of turbine, kW,
h_3= enthalpy of air inlet to compressor, kJ/kg,
h_4= enthalpy of air outlet from compressor, kJ/kg
W_{net}= net work of gas turbine, kW, and
η_C= efficiency of gas turbine, %.

- Heat recovery in gas system

$\dot{m}_w h_w + \dot{m}_{G1} h_{G1} + \dot{m}_{m1} h_{m1} = \dot{m}_{st} h_{st} + \dot{m}_{G2} h_{G2} + \dot{m}_{m2} h_{m2}$
Where
$\dot{m}_w$= mass flow rate of inlet water, TPD,
h_w = enthalpy of inlet water, kJ/kg,
$\dot{m}_{G1}$= mass flow rate of inlet gas, TPD,
h_{G1} = enthalpy of inlet gas, kJ/kg,
$\dot{m}_{m1}$= mass flow rate of steam mixture from CCS, TPD,
h_{m1}= enthalpy of steam mixture from CCS, kJ/kg,
$\dot{m}_{st}$= mass flow rate of steam inlet to turbine, TPD,
h_{st}= enthalpy of steam inlet to turbine, kJ/kg,
$\dot{m}_{G2}$ = mass flow rate of outlet gas, TPD,
h_{G2} = enthalpy of outlet gas, kJ/kg,
$\dot{m}_{m2}$= mass flow rate of inlet steam CCS, TPD, and
h_{m2}= enthalpy of inlet steam CCS, kJ/kg.

- Steam turbine

$P_T = \dot{m}_{st} \times (h_{in} - h_o)$
Where
P_T = power of steam turbine, kW,
$\dot{m}_{st}$= mass flow rate of inlet steam, kg/s,
h_{in}= enthalpy of inlet steam, kJ/kg, and
h_o= enthalpy of outlet steam, kJ/kg.

- Condenser

$\dot{m}_{st}\,(h_{in} - h_o)_{st} = \dot{m}_w\,(h_o - h_{in})_w$
Where
$\dot{m}_{st}$= mass flow rate of inlet steam inlet, TPD,
$(h_{in} - h_o)_{st}$= enthalpy of inlet and outlet steam, kJ/kg,
$\dot{m}_w$= mass flow rate of inlet water, TPD, and
$(h_o - h_{in})_w$ = enthalpy of water outlet and inlet, kJ/kg.

- Oxygen blown in gasifier (main compressor)

$P_C = \dot{m}_{air}\,(h_o - h_{in})$
Where
P_C = power of main compressor, kW,
$\dot{m}_{air}$= mass flow rate of air, kg/s,
h_o= enthalpy of outlet air, kJ/kg, and
h_{in}= enthalpy of inlet air, kJ/kg.

3.4. Energy balance and economics of steam power plant without CCS

The chosen steam power plant, depicted in Fig. 1 contains the boiler, heater tubes, boiler drum, steam turbines, generator, cooling tower, pumps, valves and condenser. The output of this station is 475 MW and its thermal efficiency is 49 % with a capital cost of $ 520 million.

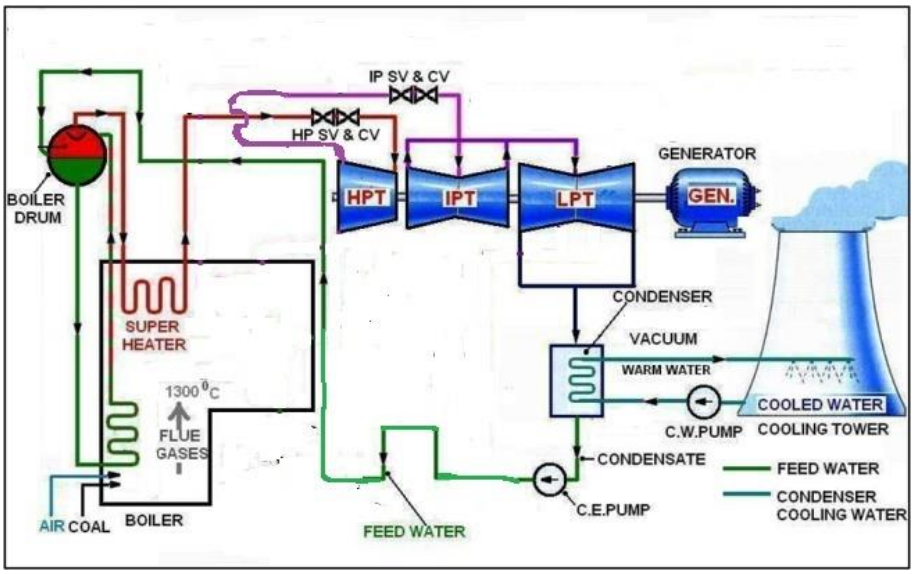


Fig. 1: Steam Power Plant without CCS [2].

- Properties of coal

Coal type: Bituminous coal
Coal composition: C $H_{0.67}$ $O_{0.022}$ $N_{0.0116}$ $S_{0.008}$
M_C = 100/6.725 = 14.869 gm/mole
Moisture = 3.3 % of weight
Ash = 6.2 % of weight
$\dot{m}_C$= 2500 TPD HHV= 33.3 MJ/kg

- Boiler

– Chemical reaction in boiler

C $H_{0.67}$ $O_{0.022}$ $N_{0.0116}$ $S_{0.008.}$+1.1645 (O_2 + 3.78N_2) = CO_2 + 0.335 H_2O + 0.008 SO_2 + 4.40181 N_2
14.869 160.51468 44 6.03 0.512 123.25068
2500TPD 26988.14 7397.942 1013.8543 86.085144 20722.759
For complete combustion, $\dot{m}a$= 26988.143 TPD = 312.363 kg/s

– Calculations of boiler

Summation of heat in boiler,S = $[\dot{m} \times HHV]_{Coal}$
S = 963541.67 kW
This heat converts water to superheated steam
Steam: P= 9 MPa T = 1150 ºC h = 4997 kJ/kg
Water: P= 9 MPa T = 25 ºC h = 105 kJ/kg
$\dot{m}_{St}$ × 4892 = 963541.67
$\dot{m}_{St}$= 196.962 kg/s = 17017.517 TPD

- Steam turbine

1) Inlet conditions

$\dot{m}_{st\ in}$= 196.962 kg/s, T= 1150 ºC, P= 9 MPa,
h= 4997 kJ/kg, s= 8.1648 kJ/kg K

2) Outlet conditions

T= 45 ºC, P= 0.1 bar, X=1, h= 2584.7 kJ/kg, s= 8.1648 kJ/kg K
Power of turbine = $\dot{m}_{St} \times (h_{in} - h_o)$ = 475131.43 kW

- Condenser

The cooling water cools steam in the condenser from saturated steam X= 1 to saturated water X= 0; this cooling water is coming from a cooling tower in which the inlet temperature = 50 ºC and the temperature outlet = 25 ºC. So one can get the mass flow rate of cooling water, $\dot{m}_w$ from the energy balance equation
$\dot{m}_{St} \times (h_{in} - h_o) = \dot{m}_w \times (h_o - h_{in})$
196.962 × (2584.7 – 105) = $\dot{m}_w$×4.18× (50 - 25)
Mass of cooling water = 4673.7481 kg/s = 403811.83 TPD

- Cycle efficiency

Total power = 475131.43 kW
$\eta_{th} = [P_{Total} / \dot{m}_C\ HHV] \times 100$ = 49.311 %

- CO_2 Emission

Mass of CO_2 emission = 7397.942 TPD
CO_2 emission % = 100 %

- Economics

a) Capital cost per unit power output = 1095 $/kW

Capital cost = $ 520.271 million
Output power = 475131.43 kW

b) The cost of electricity (COE) per unit energy output ($/kWh).

The COE is calculated over the entire useable life of the plant.
The entire useable life of the plant = 20 years
Capital cost = $ 520.271 million
Operating costs =??

– Fuel = Bituminous coal

Tone = $ 47
$\dot{m}_{Coal}$ = 2500 TPD
Fuel cost = 2500 × 47 × 365 = 42887500 $/year

– Operation and maintenance (O & M) cost = 2 % of the capital cost / year

O & M cost= 0.02 × 520.271= 10.405 $M/year
So the operating costs = 53.292 $M/year
For 20 years the costs = 520.271 + (53.292 × 20) = $ 1586.111 million
Unit output energy = (475131.43 × 8760) / 1000 = 4162151.3 MWh
Total cost in first year $ million = $ 573.563 million
Cost of electricity (COE) per unit energy output = 137.804 $/MWh

3.5. Energy balance and economics of entrained flow gasification plant without CCS.

In Fig. 2 the selected entrained flow gasification plant is shown which contains the gasifier, heater tubes, syngas cooler, gas clean-up, air separation unit, slurry plant, gas turbine, steam turbine, generators, cooling tower, pumps, valves and condenser. The plant produces 593 MW and 61.5 % efficiency and a capital cost of $ 678.7 million.

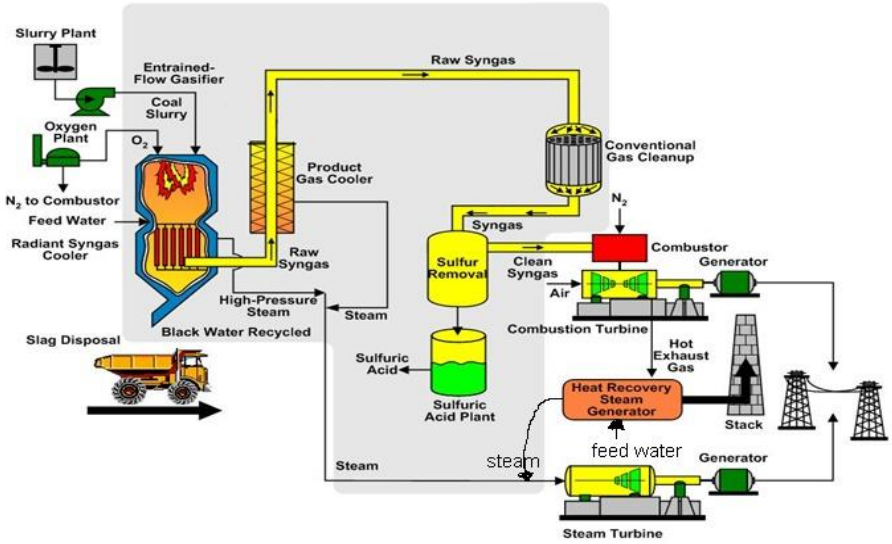


Fig. 2: Entrained Flow Gasification Plant without CCS [3].

- Properties of coal

Coal type: Bituminous coal
Coal composition: C $H_{0.67}$ $O_{0.022}$ $N_{0.0116}$ $S_{0.008}$
M_C = 100/6.725 = 14.869 gm/mole
Moisture = 3.3 % of weight
Ash = 6.2 % of weight
$\dot{m}_{Coal}$= 2500 TPD
$\dot{m}_{O2}$ = 2100 TPD 84% by weight of coal
$\dot{m}_{H2O}$ = 1008.81 TPD 40.352% of [slurry feed]
Moisture = 82.5 TPD Ash = 155 TPD

- Gasifier

– Chemical reaction in gasifier:

C $H_{0.67}$ $O_{0.022}$ $N_{0.0116}$ $S_{0.008}$.+ a H_2O + b O_2 = e CO + f H_2 + g COS + j H_2S + k CO_2 + l CH_4 + m H_2O

– Reactions in gasifier:

1) Pyrolysis and devolatilization for [C $H_{0.67}$ $O_{0.022}$ $N_{0.0116}$ $S_{0.008}$]

$C_{(S)}$ = 0.3345 H_2 +0.272 H_2O +0.0058 N_2 +0.008 H_2S+0.0115 O_2
14.869 0.669 0.4896 0.1624 0.272 0.3568
2500TPD 112.5 82.5 27.5 47.812 60

H_2 + S = H_2S
2 32 34
2.812 45 47.812

2) Gasification

$3C_{(S)}$ + H_2O + O_2 = 3 CO + H_2
44.607 18 32 84 2
2500 TPD 1008.81 1793.44 4707.781 112.09

3) Combustion

CO + 0.5 O_2 = CO_2
28 16 44
536.48 TPD 306.56 843.04

4) Water from partial combustion

H_2 + 0.5 O_2 = H_2O (Water with slag)
2 16 18
7.5 60 67.5

- Mass of gasses in syngas

$\dot{m}_{CO2}$= 843.04 TPD $\dot{m}_{CO}$= 4171.301 TPD
$\dot{m}_{H2}$= 214.278 TPD $\dot{m}_{N2}$= 27.5 TPD
$\dot{m}_{H2S}$= 47.812 TPD $\dot{m}_{Steam}$= 82.5 TPD
Mass of syngas ($\dot{m}_{Syn(1)}$) = 843.04 + 4171.301 + 214.278 + 27.5 + 47.812 + 82.5 TPD
$\dot{m}_{Syn(1)}$ = 5386.431 TPD

- Cold gas efficiency

LHV of H_2 = 121000 kJ/kg
LHV of CO = 10095 kJ/kg
LHV of CH_4 = 49995 kJ/kg HHV_{COAL} = 33.3 MJ/kg
ΔH_C = 300088.4 + 487375.97 = 787464.37 kW

– CGE = [ΔHC / ($\dot{m}$ × HHV) Coal] × 100 = [787464.37/963541.67]×100 = 81.726 %

- Carbon conversion

CCE = $\dot{m}_C$ in coal / $\dot{m}_C$ in syngas = (2500 / 2500) × 100 = 100 %

- Syngas cooler

The syngas cooler cools the syngas by the boiler fire tubes which are heated by radiation and convective heat transfer. Assume the heat by radiation is equal to the heat needed to change water in slurry to vapor for gasification.
Summation of heat in syngas cooler,S = [CCE × HHV_{Coal}] - ΔH_C
S = 963541.67 - 787464.37 = 176077.3 kW
This heat converts water to superheated steam
Steam: P= 9 MPa T = 1150 ºC h = 4997 kJ/kg
Water: P= 9 MPa T = 25 ºC h = 105 kJ/kg
$\dot{m}_{St(1)}$× 4892 = 176077.3 $\dot{m}_{St(1)}$= 35.993 kg/s = 3109.787 TPD

- Gas turbine

Pressure ratio = 15.8
h_1 = 300.19 kJ/kg P_r = 1.386 for air inlet to the compressor
h_3 = 2566.4 kJ/kg P_r = 3464 for gas inlet to the turbine

1) Combustor

Heat of combustion ΔH_C =787464.37 kW
$\dot{m}_{Syn}$ = $\dot{m}_{Syn(1)}$ - $\dot{m}_{H2S}$ - $\dot{m}_{Steam}$ = 5386.431 - 47.812 - 82.5 = 5256.119 TPD = 60.835 kg/s

– H_2 + 0.5 (O_2 + 3.78 N_2) = H_2O + 1.89 N_2
2 68.92 18 52 .92
214.278 TPD 7384.02 1928.502 5669.796

– CO + 0.5 (O_2 + 3.78 N_2) = CO_2 + 1.89 N_2
28 68.92 44 52.92
4171.301 TPD 10267.359 6554.902 7883.759

For complete combustion $\dot{m}_{air}$= 17651.379 TPD = 204.298 kg/s

– O_2 + 3.78 N_2 = air
32 105.84 137.84
2100 TPD 6945.75 9045.75

$\dot{m}_{N2}$ = 6945.75 TPD = 80.39 kg/s
ΔH_C = h_3 ($\dot{m}_{air}$ + $\dot{m}_{N2}$ + $\dot{m}_{Syn}$) - h_2 $\dot{m}_{air}$
787464.37 = 2566.4 ($\dot{m}_{air}$ + 80.39 + 60.835) - 660.16 $\dot{m}_{air}$
425024.53 = 1906.24 $\dot{m}_{air}$
$\dot{m}_{air}$= 222.965 kg/s $\dot{m}_{gas}$ = 364.19 kg/s

2) Air compressor

The pressure ratio = 15.8 and the air inlet conditions are T= 300K, P= 1bar, h=300.19 kJ/kg, Pr=1.386
The outlet conditions are T= 650 K, P= 15.8 bar, h= 660.16 kJ/kg, Pr= 21.898
$\dot{m}_{air}$= 222.965 kg/s
$\dot{m}_{gas}$= $\dot{m}_{air}$+ $\dot{m}_{N2}$ + $\dot{m}_{Syn}$ = 364.19 kg/s
Power of compressor = $\dot{m}_{air}$ (h_o - h_{in}) = 222.965 (660.16 – 300.19)
P_C = 80260.711 kW

3) Gas turbine

We find the outlet conditions from the gas turbine
For pressure ratio = 15.8, the outlet conditions are: Pr= 219.24, T= 1175 K
P= 1 bar, h= 1249.68 kJ/kg
Power of turbine $P_T = \dot{m}_{gas} \times (h_o - h_{in})$ = 479536.26 kW
Power of gas turbine = $P_T - P_C$ = 399275.55 kW
$\eta_C = [w_{net} / \Delta H_C] \times 100$ = 50.704 %

- Heat recovery gas system (HRGS)

1) inlet:
a) Water at T_a= 25 °C, P_a= 9 MPa, h_a= 105 kJ/kg
b) Gas at T_{G1}= 1175 K, h_{G1}= 1249.68 kJ/kg, $\dot{m}_{G1}$= 364.19 kg/s
2) outlet:
a) Steam at T_b= 1150 °C, Pb= 9 MPa, h_b= 4997 kJ/kg
b) Gas at T_{G2}= 370 K, h_{G2}= 370.67 kJ/kg

$\dot{m}_a h_a + \dot{m}_{G1} h_{G1} = \dot{m}_{st} h_{st} + \dot{m}_{G2} h_{G2}$
$\dot{m}_{st}$ = 320126.65 / 4892 = 65.439 kg/s = 5653.929 TPD

- Steam turbine

1) Inlet conditions
$\dot{m}_{st\ in}$= 101.432 kg/s, T= 1150 °C, P= 9 MPa,
h= 4997 kJ/kg, s= 8.1648 kJ/kg K
2) Outlet conditions
T= 45 °C, P= 0.1 bar, X= 1, h= 2584.7 kJ/kg, s= 8.1648 kJ/kg K
Power of turbine = $\dot{m}_{st} \times (h_{in} - h_o)$ = 244684.41 kW

- Condenser

The cooling water cools steam in condenser from saturated steam X= 1 to saturated water X= 0, this water cooling is coming from a cooling tower where the inlet temperature = 50 ^{0}C and the outlet temperature = 25 ^{0}C. Thus, the mass flow rate of cooling water, $\dot{m}_w$ is estimated from the energy balance equation
$\dot{m}_{st} (h_{in} - h_o) = \dot{m}_w (h_o - h_{in})$
$101.432 \times (2584.7 - 105) = \dot{m}_w \times 4.18 \times (50 - 25)$
Mass of cooling water = 2406.899 kg/s = 207956.06 TPD

- Oxygen blown in gasifier (main compressor)

Pressure in gasifier = 30 bar
1) Inlet conditions: T= 300 K, P= 1 bar, h = 300.19 kJ/kg
2) Outlet conditions: T= 770 K, P=30 bar, h= 789.11 kJ/kg
$\dot{m}_{air}$ = 9045.75 TPD = 104.696 kg/s
$P_C = \dot{m}_{air} (h_o - h_{in})$ = 51187.968 kW

- Cycle efficiency

Total power = 399275.55 + 244684.41 - 51187.968 = 592772 kW
$\eta_{th} = [P_{Total} / \dot{m}_{Coal}\ HHV] \times 100$ = 61.52 %

- CO_2 emission

Mass of CO_2 emission = 7397.942 TPD
CO_2 emission % = 100 %

- Economics

a) The capital cost per unit power output = 1145 $/kW
Capital cost = $ 678.706 million
Output power = 592257.56 kW
b) The cost of electricity (COE) per unit energy output ($/kWh).
The COE is calculated over the entire useable life of the plant.
The entire useable life of the plant = 20 years
Capital cost = $ 678.706 million
Operating costs =??

– Fuel = Bituminous Coal

Tone = $ 47
$\dot{m}_{Coal}$ = 2500 TPD
Fuel cost = 2500 × 47 × 365 = 42887500 $/year

– Operation and maintenance cost = 2 % of the capital cost / year

O & M = 0.02 × 678.706 = 13.574 $M/year
So operating costs = 56.461 $/year
For 20 years the costs = 678.706 + (56.461 × 20) = $ 1807.926 million
Total cost in first year $ million = $ 735.167 million
Unit output energy = (592257.56 × 8760) / 1000 = 5188176.2 MWh
Cost of electricity (COE) per unit energy output = 141.7 $/MW

3.6. Energy balance and economics of steam power plant with CCS (Post combustion).

The representative steam power plant, shown in Fig. 3 comprises a boiler, heater tubes, boiler drum, carbon capture system, steam turbines, generator, cooling tower, pumps, valves and condenser. The output of this station is 393 MW and its thermal efficiency is 40.8 % with a capital cost of $ 816 million.

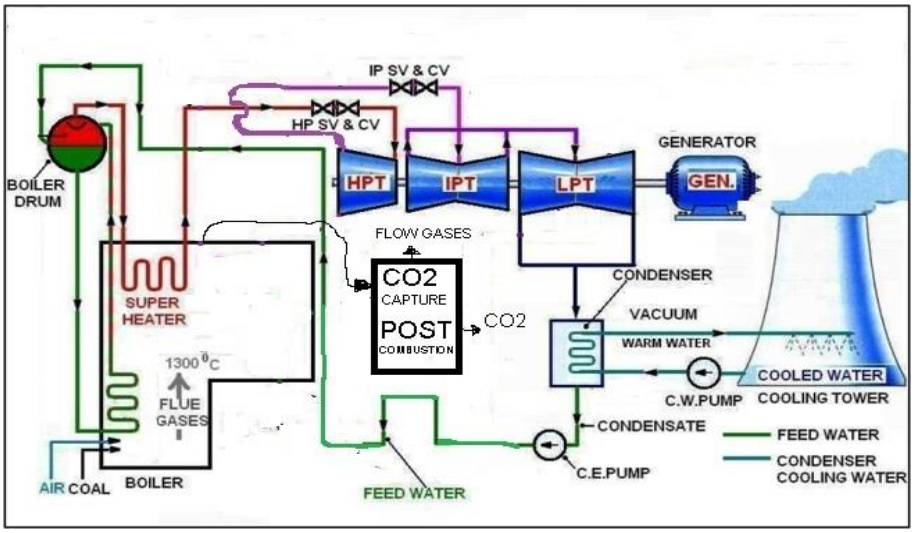


Fig. 3: Steam Power Plant with CCS [3].

- Properties of coal

Coal type: Bituminous coal
Coal composition: C $H_{0.67}$ $O_{0.022}$ $N_{0.0116}$ $S_{0.008}$
M_C = 100/6.725 = 14.869 gm/mole
Moisture = 3.3 % of weight Ash = 6.2 % of weight
$\dot{m}_C$= 2500 TPD HHV= 33.3 MJ/kg

- Boiler

– Chemical reaction in boiler

C $H_{0.67}$ $O_{0.022}$ $N_{0.0116}$ $S_{0.008.}$ +1.1645 (O_2 + 3.78N_2) = CO_2 + 0.335 H_2O + 0.008 SO_2 + 4.40181 N_2
14.869 160.51468 44 6.03 0.512 123.25068
2500TPD 26988.143 7397.5 1013.8543 86.085144 20722.759
For complete combustion $\dot{m}_a$= 26988.143 TPD = 312.363 kg/s

– Calculations of boiler

Summation of heat in boiler,S = $[\dot{m} \times HHV]_C$
S = 963541.67 kW
This heat converts water to superheated steam

Steam: P= 9 MPa, T= 1150 ^{0}C, h = 4997 kJ/kg
Water: P= 9 MPa, T = 25 ^{0}C, h = 105 kJ/kg
$\dot{m}_{St} \times 4892 = 963541.67$ $\dot{m}_{St}$= 196.962 kg/s = 17017.517 TPD

- Steam turbine

1) Inlet conditions

$\dot{m}_{st\ in}$= 196.962 kg/s, T= 1150 ^{0}C, P= 9 MPa,
h= 4997 kJ/kg, s= 8.1648 kJ/kg K

2) Outlet conditions

T= 45 ^{o}C, P= 0.1bar, X= 1, h= 2584.7 kJ/kg, s= 8.1648 kJ/kg K
Power of turbine = $\dot{m}_{st} \times (h_{in} - h_o)$ = 475131.43 kW

- Condenser

The cooling water in the condenser converts steam from saturated X= 1 to saturated water X= 0, this cooling water is coming fed from a cooling tower where the inlet and outlet temperatures are 50 and 25 ^{0}C, respectively. Now the mass flow rate of cooling water, $\dot{m}_w$ can be obtained from the energy balance equation
$\dot{m}_{st} \times (h_{in} - h_o) = \dot{m}_w \times (h_o - h_{in})$
$196.962 \times (2584.7 - 105) = \dot{m}_w \times 4.18 \times (50 - 25)$
Mass of cooling water = 4673.7481 kg/s = 403811.83 TPD

- CO_2 compressor of carbon capture (post combustion)

1) Inlet conditions are: CO_2 at P= 1 bar, h = 214.34 kJ/kg
2) Outlet conditions are: P= 150 bar, h= 1172.772 kJ/kg

$\dot{m}_{CO2}$ = 7397.5 TPD = 85.624 kg/s
$P_C = \dot{m}_{CO2} (h_o - h_{in}) = 85.624 \times (1172.772 - 214.34) = 82064.782$ kW

- Cycle efficiency

1) For low pressure CO_2

Total power = 475131.43 kW
$\eta_{th} = [P_{Total} / \dot{m}_{Coal}$ HHV] × 100 = 49.31 %

2) For high pressure CO2

Total power = 475131.43 - 82064.782 = 393066.65 kW
$\eta_{th} = [P_{Total} / \dot{m}_{Coal}$ HHV] × 100 = 40.794 %

- CO_2 emission

$\dot{m}_{CO2\ capture}$ = 7397.942 TPD
Mass of CO2 emission = 7397.942 - 7397.942 = 0 TPD
CO_2 capture % = 100 %
CO_2 emission % = 0 %

- Economics
- Power plant with LP CCS

a) The capital cost per unit power output = 1718 $/kW

Capital cost = $ 816.275 million
Output Power = 475131.43 kW

b) The cost of electricity (COE) per unit energy output ($/kWh).

The COE is calculated over the entire useable life of the plant.
The entire useable life of the plant = 20 years
Capital cost = $ 816.275 million
Operating costs =??

- Fuel = Bituminous Coal

Tone = $ 47
$\dot{m}_{Coal}$ = 2500 TPD
Fuel cost = 2500 × 47 × 365 = 42887500 $/year

- Operation and maintenance cost = 2 % of the capital cost / year

O & M = 0.02 × 816.275 = 16.325 $M/year
So the operating costs = 59.213 $M/year
For 20 years the costs = 816.275 + (59.213 × 20) = $ 2000.535 million
Unit output energy = (475131.43 × 8760) / 1000 = 4162151.3 MWh
Total cost in first year $ million = $ 875.488 million
Cost of electricity (COE) per unit energy output = 210.345 $/MWh

b) The cost of CO_2 capture.

Cost of CO_2 captured (or removed) =
(COE_{CCS} - COE_{NonCCS}) $/MWh / ($CO_2$ captured) Ton/MWh
$\dot{m}_{CO2}$Capatur = 7397.5 TPD
CO_2 captured (Ton/MWh) = (7397.5 × 365) / 4162151.3 = 0.648 Tone/MWh
Cost of CO_2 captured = (210.345 - 137.804) / 0.648 = 111.946 $/Tone

- Power plant with HP CCS

a) Capital cost per unit power output = 1718 $/kW

Capital cost = $ 816.275 million
Output power= 475131.43 kW

b) The cost of electricity (COE) per unit energy output ($/kWh).

We calculate the COE over the entire useable life of the plant.
Entire useable life of the plant = 20 years
Capital cost = $ 816.275 million
The operating costs =??

- Fuel = Bituminous Coal

Tone = $ 47
$\dot{m}_{Coal}$ = 2500 TPD
The fuel cost = 2500 × 47 × 365 = 42887500 $/year

- Operation and maintenance cost = 2 % of the capital cost / year

O & M = 0.02 × 816.275 = 16.325 $M/year
So the operating costs = 59.213 $M/year
For 20 years the costs = 816.275 + (59.213 × 20) = $ 2000.535 million
Unit output energy = (393066.65 × 8760) / 1000 = 3443263.9 MWh
Total cost in first year $ million = $ 875.488 million
Cost of electricity (COE) per unit energy output = 254.261 $/MWh

c) The cost of CO2 capture.

Cost of CO_2 captured (or removed) =
(COE_{CCS} - COE_{NonCCS}) $/MWh / ($CO_2$ captured) Ton/MWh
$\dot{m}_{CO2capture}$ = 7397.5 TPD
CO_2 captured (Ton/MWh) = (7397.5 × 365) / 3443263.9 = 0.784 Tone/MWh
Cost of CO_2 captured = (254.261 - 137.804) / 0.784 = 148.542 $/Tone

3.7. Energy balance and economics of entrained flow gasification plant with CCS (pre combustion)

Figure 4 shows the selected entrained flow gasification plant which includes the gasifier, heater tubes, syngas cooler, gas clean-up, air separation unit, slurry plant, carbon capture system, gas turbine, steam turbine, generators, cooling tower, pumps, valves, and condenser. The plant produces 481.5 MW with 50 % efficiency with a capital cost $ 791 million.

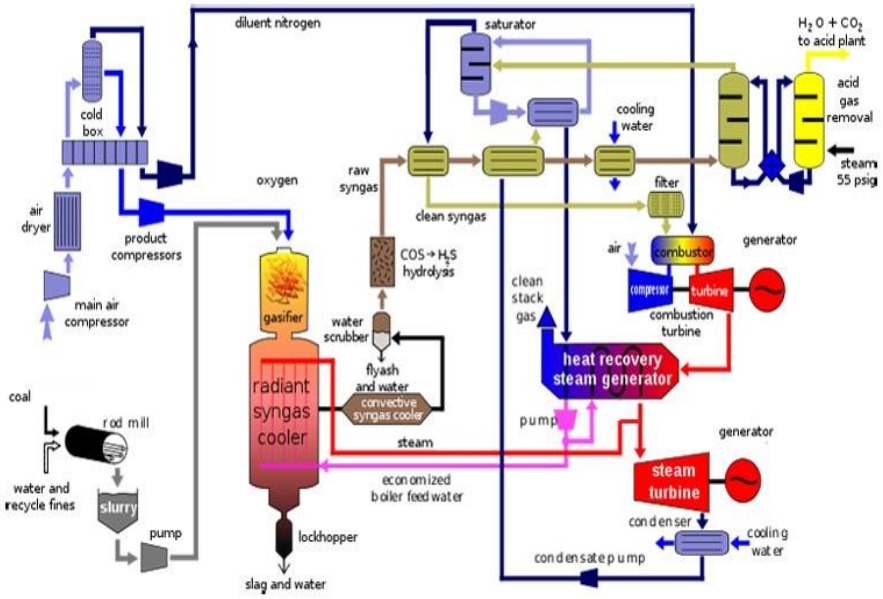


Fig. 4: Entrained Flow Gasification Plant with CCS [3].

- Properties of coal

Coal type: Bituminous coal
Coal composition: $C\ H_{0.67}\ O_{0.022}\ N_{0.0116}\ S_{0.008}$
M_C = 100/6.725 = 14.869 gm/mole
Moisture = 3.3 % of weight
Ash = 6.2 % of weight
$\dot{m}_{Coal}$= 2500 TPD
$\dot{m}_{O2}$ = 2100 TPD 84% by weight of coal
$\dot{m}_{H20}$ = 1008.81 TPD 40.352% of [slurry feed]
Moisture = 82.5 TPD
Ash = 155 TPD

- Gasifier

Chemical reaction in gasifier:
$C\ H_{0.67}\ O_{0.022}\ N_{0.0116}\ S_{0.008.}$ + a H_2O + b O_2 = e CO + f H_2 + g COS + j H_2S + k CO_2 + l CH_4 + m H_2O

– Reactions in gasifier:

1) Pyrolysis and devolatilization for [$C\ H_{0.67}\ O_{0.022}\ N_{0.0116}S_{0.008}$]

$C_{(S)}$ =	0.3345 H_2	+0272 H_2O	+0.0058 N_2	+0.008 H_2S	+0.0115 O_2
14.869	0.669	0.4896	0.1624	0.272	0.3568
2500TPD	112.5	82.5	27.5	47.812	60

H_2	+ S =	H_2S
2	32	34
2.812	45	47.812

2) Gasification

$3C_{(S)}$	+ H_2O	+ O_2 =	3CO	+ H_2
44.607	18	32	84	2
2500 TPD	1008.81	1793.44	4707.781	112.09

3) Combustion

CO	+ 0.5 O_2 =	CO_2
28	16	44
536.48 TPD	306.56	843.04

4) Water from partial combustion

H_2 + 0.5 O_2 = H_2O (Water with slag)

2	16	18
7.5	60	67.5

- Mass of gasses in syngas

$\dot{m}_{CO2}$= 843.04 TPD $\dot{m}_{CO}$= 4171.301 TPD
$\dot{m}_{H2}$= 214.278 TPD $\dot{m}_{N2}$= 27.5 TPD
$\dot{m}_{H2S}$= 47.812 TPD $\dot{m}_{Steam}$= 82.5 TPD
Mass of syngas = 843.04 + 4171.301 + 214.278 + 27.5 + 47.812 + 82.5
$\dot{m}_{Syn(1)}$ = 5386.431 TPD

- Cold gas efficiency

LHV of H_2 = 121000 kJ/kg
LHV of CO = 10095 kJ/kg
LHV of CH_4 = 49995 kJ/kg HHV$_{Coal}$ = 33.3 MJ/kg
ΔH_C = 300088.4 + 487375.97 = 787464.37 kW
CGE = [ΔH_C / ($\dot{m}$ × HHV)$_{Coal}$] × 100 = [787464.37 / 963541.67]×100
CGE = 81.726 %

- Carbon conversion

CCE = $\dot{m}_{Carbon}$ in coal / $\dot{m}_{Carbon}$in syngas = (2500 / 2500) × 100 = 100 %

- Syngas cooler

The syngas cooler cools the syngas from 1480 to 316 ^{0}C by means of the boiler fire tubes which are heated by radiation and convective heat transfer.
Summation of heat of reaction,S = [CGE × HHV$_{Coal}$] - ΔH_C
S = 963541.67 - 787464.37 = 176077.3 kW
This heat converts water to superheated steam
Steam: P=9 MPa T = 1150 ^{o}C h = 4997 kJ/kg
Water: P= 9 MPa T = 25 ^{o}C h = 105 kJ/kg
$\dot{m}_{St(1)}$ × 4892 = 176077.3
$\dot{m}_{St(1)}$= 35.993 kg/s = 3109.787 TPD

- Carbon capture (pre combustion)

– Reaction in CCS (pre combustion)

CO	+	H_2O =	CO_2	+	H_2
28		18	44		2
4171.301		2681.551	6554.902		297.95

$\dot{m}_{H2}$= 512.228 TPD = 5.928 kg/s
$\dot{m}_{H2O}$= 2681.551 – 82.5 TPD = 2599.051 TPD = 30.081 kg/s
$\dot{m}_{Syn}$ = 512.228 + 27.5 = 539.728 TPD = 6.247 kg/s

– Heat in CCS (Pre combustion)

$\Delta H_{With\ CCS}$= 717356.34 kW
$\Delta H = \Delta H_{Without\ CCS} - \Delta H_{With\ CCS}$ = 787464.37 - 717356.34 = 70108.03 kW

1) Inlet:

$\dot{m}_{Water}$ = 31.036 kg/s , h_{in}= 105 kJ/kg, P = 380 kPa

2) outlet:

$\Delta H = \dot{m}_{Water}$ (ho - h_{in}) h_o = 2258.926 kJ/kg

- Gas turbine

Pressure ratio = 15.8
h_1 = 300.19 kJ/kg P_r = 1.386 for air inlet to the compressor
h_3 = 2566.4 kJ/kg P_r = 3464 for gas inlet to the turbine

1) Combustor

Heat of combustion ΔH_C = 717356.34 kw
$\dot{m}_{Syn}$ = 6.247 kg/s

– H_2 + 0.5 (O_2 + 3.78N_2) = H_2O + 1.89N_2

2	68.92	18	52.92
512.228 TPD	17651.377	4610.052	13553.553

For complete combustion $\dot{m}_{air}$= 17651.377 TPD = 204.3 kg/s

– O_2 + $3.78N_2$ = air
32 105.84 137.84
2100 TPD 6945.75 9045.75
$\dot{m}_{N2}$ = 6945.75 TPD = 80.39 kg/s
$\Delta H_C = h_3 (\dot{m}_{air} + \dot{m}_{N2} + \dot{m}_{Syn}) - h_2 \dot{m}_{air}$
$717356.34 = 2566.4 (\dot{m}_{air} + 80.39 + 6.247) - 660.16 \dot{m}_{air}$
$495011.14 = 1906.24 \dot{m}_{air}$
$\dot{m}_{air}$= 259.679 kg/s $\dot{m}_{gas}$ = 346.316 kg/s

2) Air compressor

Pressure ratio = 15.8 and the inlet air conditions are T= 300 K, P= 1 bar, h= 300.19 kJ/kg, Pr= 1.386
The outlet conditions are T= 650 K, P= 15.8 bar, h= 660.16 kJ/kg, Pr= 21.898
$\dot{m}_{air}$= 259.679 kg/s
$\dot{m}_{gas} = \dot{m}_{air} + \dot{m}_{N2} + \dot{m}_{Syn}$ = 346.316 kg/s
Power of compressor = $\dot{m}_{air} (h_o - h_{in}) = 259.679 (660.16 – 300.19)$
P_C= 93476.65 kW

3) Gas turbine

We find the outlet conditions from the gas turbine
For pressure ratio = 15.8, the outlet conditions are: Pr= 219.24, T= 1175 K,
P= 1 bar, h=1249.68 kJ/kg
Power of turbine $P_T = \dot{m}_{gas} \times (h_o – h_{in})$ = 456001.2 kW
Power of gas turbine = $P_T – P_C$ = 362524.55 kW
$\eta_C = [w_{net} / \Delta H_C] \times 100$= 50.536 %

- Heat recovery gas system (HRGS)

1) inlet:
a) Water at T_a= 25 °C, P_a= 9 MPa, h_a= 105 kJ/kg
b) Gas at T_{G1}= 1175K, h_{G1}= 1249.68 kJ/kg, $\dot{m}_{G1}$= 346.316 kg/s
c) Steam (mixture) out let of CCS, h= 2363.926 kJ/kg, $\dot{m}_{st}$= 30.081 kg/s
2) outlet:
a) Steam at T_b= 1150 °C, P_b=9 MPa, h_b= 4997 kJ/kg
b) Gas at T_{G2}= 370K, h_{G2}= 370.67 kJ/kg
c) Steam (saturated vapor), h= 2736.2 kJ/kg

$\dot{m}_a h_a + \dot{m}_{G1} h_{G1} + (\dot{m}_{st} h)_{in} = \dot{m}_{st} h_{st} + \dot{m}_{G2} h_{G2} + (\dot{m}_{st} h)_{out}$
$\dot{m}_{st}$ = (304415.23 – 11198.374) / 4892 = 59.938 kg/s = 5178.643 TPD

- Steam turbine

1) Inlet conditions

$\dot{m}_{st\ in}$= 95.931 kg/s, T=1150 °C, P=9 MPa,
h= 4997 kJ/kg, s=8.1648 kJ/kg K

2) Outlet conditions

T= 45 °C, P= 0.1 bar, X= 1, h= 2584.7 kJ/kg, s= 8.1648 kJ/kg K
Power of turbine = $\dot{m}_{st} \times (h_{in} - h_o)$ = 231414.35 kW

- Condenser

The cooling water in the condenser cools the steam from saturated steam X=1 to saturated water X=0, this water cooling is supplied from a cooling tower for which the inlet temperature = 50 ^{0}C and the outlet temperature = 25 ^{0}C.
Then we get the mass flow rate of water cooling $\dot{m}_w$ from the energy balance equation
$\dot{m}_{st} (h_{in} - h_o) = \dot{m}_w (h_o - h_{in}) = 95.931 \times (2584.7 – 105) = \dot{m}_w \times 4.18 \times (50-25)$
Mass of cooling water = 2276.364 kg/s = 196677.9 TPD

- Oxygen blown in gasifier (main compressor)

Maximum pressure in gasifier = 30 bar

1) Inlet conditions: T= 300 K, P= 1 bar, h = 300.19 kJ/kg
2) Outlet conditions: T= 770 K, P=30 bar, h= 789.11 kJ/kg

$\dot{m}_{air}$ = 9045.75 TPD = 104.696 kg/s
$P_C = \dot{m}_{air} (h_o - h_{in})$ = 51187.968 kW

- CO_2 Compressor

1) Inlet conditions are: 70% of CO_2, P= 15.8 bar, h = 560.772 kJ/kg, and 30% P= 1 bar, h= 214.34 kJ/kg
2) Outlet conditions are: P= 150 bar, h= 1172.772 kJ/kg

$\dot{m}_{CO2}$ = 1008.04 + 6389.9016 = 7397.942 TPD = 85.624 kg/s
$P_C = \dot{m}_{CO2} (h_o - h_{in}) = [(0.7 \times 85.624) \times (1172.772 – 560.772)] + [(0.3 \times 85.624) \times (1172.772 – 214.34)] = (59.9368 \times 612) + (25.6872 \times 958.432) = 36681.322 + 24619.434 = 61300.756$ kW = 61.3 MW

- Cycle efficiency

1) For low pressure CO_2

Total power = 362524.55 + 231414.35 - 51187.968 = 542750.93 kW
$\eta_{th} = [P_{Total} / \dot{m}_{Coal}$ HHV] × 100 = 56.328 %

2) For high pressure CO2

Total power = 362525.39 + 231414.35 - 51187.968 - 61300.756 = 481450.18 kW
$\eta_{th} = [P_{Total} / \dot{m}_{Coal}$ HHV] × 100 = 49.966 %

- CO_2 emission

$\dot{m}_{CO2\ capture}$= 7397.942 TPD
Mass of CO_2 emission = 7397.942 - 7397.942 = 0 TPD
CO_2 capture % = 100 %
CO_2 emission % = 0 %

- Economics
- Power plant with LP CCS

a) Capital cost per unit power output = 1459 $/kW

Capital cost = $ 791.29 million
Output power = 542351.33 kW

b) The cost of electricity (COE) per unit energy output ($/kWh).

The COE is calculated over the entire useable life of the plant.
The entire useable life of the plant = 20 years
Capital cost = $ 791.29 million
Operating costs =??

– Fuel = Bituminous coal

Tone = $ 47
$\dot{m}_{Coal}$ = 2500 TPD
Fuel cost = 2500 × 47 × 365 = 42887500 $/year

– Operation and maintenance cost = 2 % of the capital cost / year

O & M = 0.02 × 791.29 = 15.825 $M/year
So the operating costs = 58.713 $/year
For 20 years the costs = 791.29 + (58.713 × 20) = $ 1965.55 million
Unit output energy = (542351.33 × 8760) / 1000 = 4750997.7 MWh
Total cost in first year $ million = $ 850.003 million
Cost of electricity (COE) per unit energy output = 178.91 $/MWh

c) The cost of CO_2 capturing.

Cost of CO_2 captured (or removed) =
(COE_{CCS} - COE_{NonCCS}) $/MWh / ($CO_2$ captured) Ton/MWh
$\dot{m}_{CO2}$capture = 7397.5 TPD
CO_2 captured (Ton/MWh) = (7397.5 × 365) / 4750997.7 = 0.568 Ton/MWh
Cost of CO_2 captured = (178.91 - 141.7) / 0.568 = 65.51 $/Ton

d) The cost of CO_2 capturing avoided.

Cost of CO_2 captured (or removed) =
(COE_{CCS} – COE $_{PC\ Non\ CCS}$) $/MWh / ($CO_2$ captured) Ton/MWh
$\dot{m}_{CO2}$capture = 7397.5 TPD
CO_2 captured (Ton/MWh) = (7397.5 × 365) / 4750997.7 = 0.568 Ton/MWh
Cost of CO_2 captured = (178.91 – 137.804) / 0.568 = 72.369 $/Ton

- Power plant with HP CCS

a) The capital cost per unit power output = 1459 $/kW

Capital cost = $ 791.29 million
Output power = 542351.33 kW

b) The cost of electricity (COE) per unit energy output ($/kWh).

Calculations of the COE are made over the entire useable life of the plant.
The entire useable life of the plant = 20 years
Capital cost = $ 791.29 million
Operating costs =??

– Fuel = Bituminous Coal

Tone = $ 47
$\dot{m}_{Coal}$ = 2500 TPD
Fuel cost = 2500 × 47 × 365 = 42887500 $/year

- Operation and maintenance cost = 2 % of the capital cost / year

O & M = 0.02 × 791.29 = 15.825 $M/year
So the operating costs = 58.713 $/year
For 20 years the costs = 791.29 + (58.713 × 20) = $ 1965.55 million
Unit output energy = (481450.18 × 8760) / 1000 = 4217503.6 MWh
Total cost in first year $ million = $ 850.003 million
Cost of electricity (COE) per unit energy output = 201.541 $/MWh

c) The cost of CO_2 capturing.

Cost of CO_2 captured (or removed) =
(COE_{CCS} - COE_{NonCCS}) $/MWh / ($CO_2$ captured) Ton/MWh
$\dot{m}_{CO2}$capture = 7397.5 TPD
CO_2 captured (Ton/MWh) = (7397.5 × 365) / 4217503.6 = 0.64 Ton/MWh
Cost of CO_2 captured = (201.541 - 141.7) / 0.64 = 93.501 $/Tone

d) The cost of CO2 capturing avoided.

Cost of CO_2 captured (or removed) =
(COE_{CCS} – $COE_{PC\ Non\ CCS}$) $/MWh / ($CO_2$ captured) Ton/MWh
$\dot{m}_{CO2}$capture = 7397.5 TPD
CO_2 captured (Ton/MWh) = (7397.5 × 365) / 4217503.6
= 0.64 Ton/MWh
Cost of CO_2 captured = (201.541 – 137.804) / 0.64
= 99.589 $/Tone

3.8. Comparisons of manual and computer results

These comparisons are made for the four power stations burning bituminous coal for similar output data. The comparison of results is presented in Tables 3, 4, 5, and 6.

Table 3: Comparison of Results for Steam Power Plant

Steam power plant		
Cycle without CCS	Manual results	Computer results
Thermal cycle efficiency %	49.311	49.311
Cost of electricity $/MWh	137.804	137.804
Cycle with CCS	Manual results	Computer results
Thermal cycle efficiency %	40.794	40.79
Cost of electricity $/MWh	254.261	254.258
Cost of CO_2 capture $/Tone	148.542	148.509

Table 4: Comparison of Results for Entrained Flow Gasification Power Plant

Entrained flow gasification power plant		
Cycle without CCS	Manual results	Computer results
Thermal cycle efficiency %	61.52	61.52
Cost of electricity $/MWh	141.7	141.581
Cycle with CCS	Manual results	Computer results
Thermal cycle efficiency %	49.966	50.08
Cost of electricity $/MWh	201.541	201.612
Cost of CO_2 capture $/Tone	93.501	93.973

Table 5: Comparison of Results for Fluidized Bed Gasification Power Plant

Fluidized bed gasification power plant		
Cycle without CCS	Manual results	Computer results
Thermal cycle efficiency %	59.416	59.42
Cost of electricity $/MWh	141.873	141.874
Cycle with CCS	Manual results	Computer results
Thermal cycle efficiency %	49.701	49.70
Cost of electricity $/MWh	197.47	197.472
Cost of CO_2 capture $/Tone	95.363	95.329

Table 6: Comparison of Results for Fixed Bed Gasification Power Plant

Fixed bed gasification power plant		
Cycle without CCS	Manual results	Computer results
Thermal cycle efficiency %	62.2	62.20
Cost of electricity $/MWh	141.49	141.491
Cycle with CCS	Manual results	Computer results
Thermal cycle efficiency %	52.96	52.96
Cost of electricity $/MWh	192.229	192.230
Cost of CO_2 capture $/Tone	107.726	107.566

These comparisons indicate indisputable agreement between manual and computer results. This gives unquestionable confidence in our present computer results when used to obtain all the necessary design and comparison data for different coal fired power stations.

4. Results and discussion

The objective of this research is to afford a complete thermodynamic design model of power plants which include a steam power plant and an Integrated Gasification Combined Cycle using coal firing. This analysis is conducted by using the present commercial software program so that the detailed thermodynamic data, such as mass flow rate, pressure, temperature, and enthalpy in various places, become available for all interested and beneficiaries.
A comparison is made between power stations with or without carbon capture systems which includes cycle thermal efficiency, cost of electricity, CO_2 emission, and cost of CO_2 capture. The present comparison is aimed to show which of the power plants studied considered the best according to the discussed items.
In the following figures, the power stations are named according to the gasification process used to save space in figures.

4.1. Thermal cycle efficiency

The results in this section are presented in two figures. Figure 5 shows the ideal net plant efficiency (LHV) for different gasification processes for all coal ranks. The IGCC plant using the dry-fed fixed bed gasifier has the highest efficiency of 62.2 % (LHV), for all ranks of coal, in comparison with the slurry fed entrained flow gasifiers and dry-fed fluidized bed gasifier. However, it has the lowest throughput of coal fired because of the low temperature since it is a small capacity gasifire type.
Figure 6 depicts the results for the same gasifiers for all coal types but with CO_2 capture. The entrained flow gasifier is penalized by a reduction of about 11% of efficiency by CO_2 capture than the dry-fed fixed bed processes and the dry-fed fluidized bed processes which only lose 8–9% of efficiency. The penalty for employing post-combustion carbon capture is about 9–10 %of efficiency reduction for sub- and super-critical PC plants. A comparison shows that the changes in efficiency of the plants are not much.

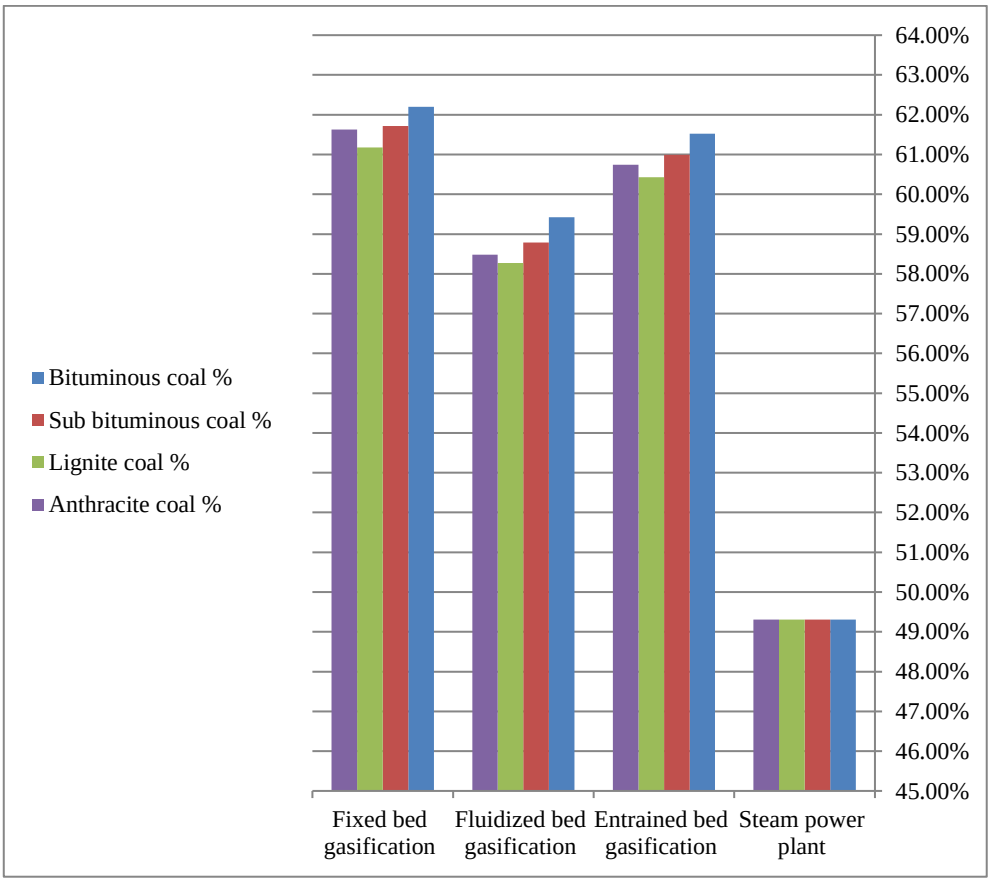


Fig. 5: Thermal Cycle Efficiency without CCS.

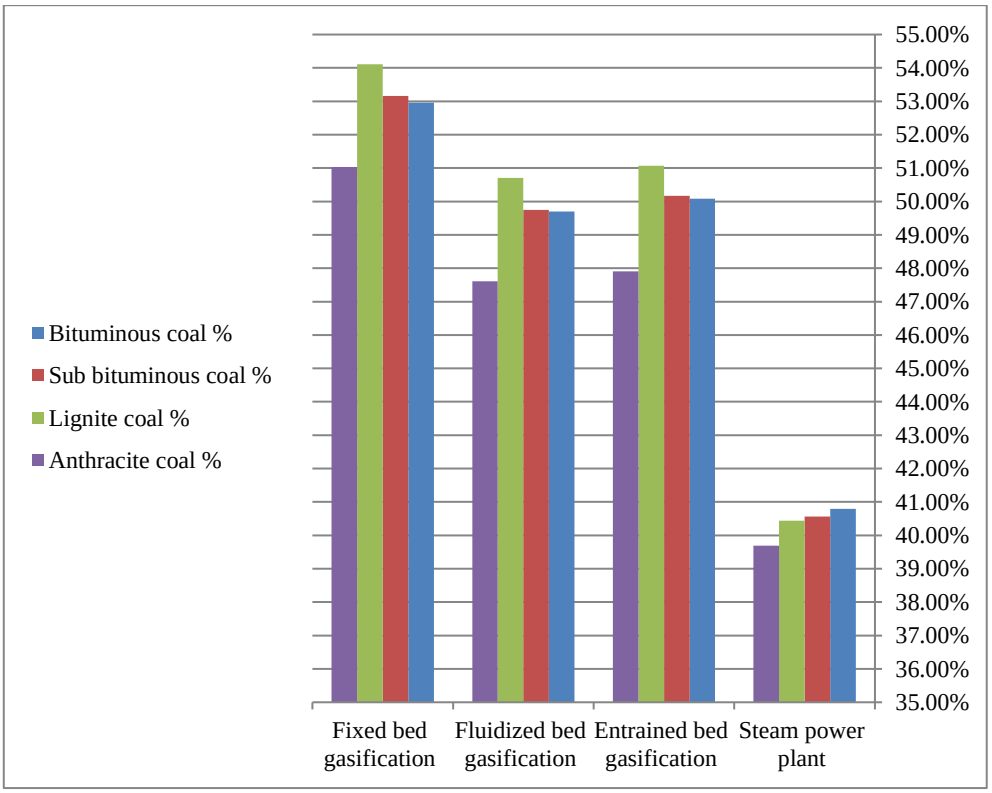


Fig. 6: Thermal Cycle Efficiency with HP CCS.

4.2. Cost of electricity

The results here are presented in two figures. Figure 7 represents COE for several gasification processes for all coal ranks. The trend of COE is different from that of the capital cost in the no-capture condition; the fluidized bed gasification IGCC plant has the highest COE. The PC plant has lowest COEs, but IGCC plants are 2–4% more expensive. These are for all coal ranks.

Figure 8 shows that when the carbon capture is implemented, the COEs increase by 38–48% for IGCC plants, and by 80–85% for PC plants. In IGCC plant the overall cost of electricity (COE) of

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the plant that uses pre combustion carbon capture is slightly cheaper than the PC plants, which use post-combustion carbon capture. The cheaper COE in case of CO_2 capture, for all coals, is obtained for the fixed bed gasifier followed by the fluidized bed. The highest cost is that for the steam power plant.

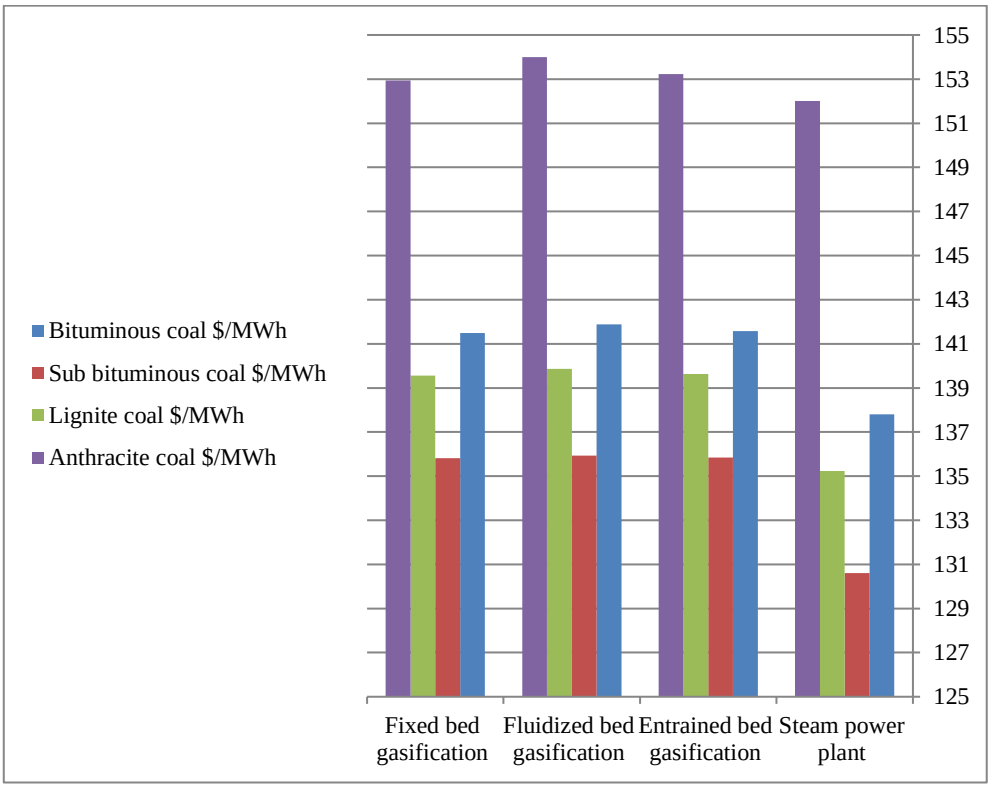


Fig. 7: Cost of Electricity $/MWh for Plants without CCS.

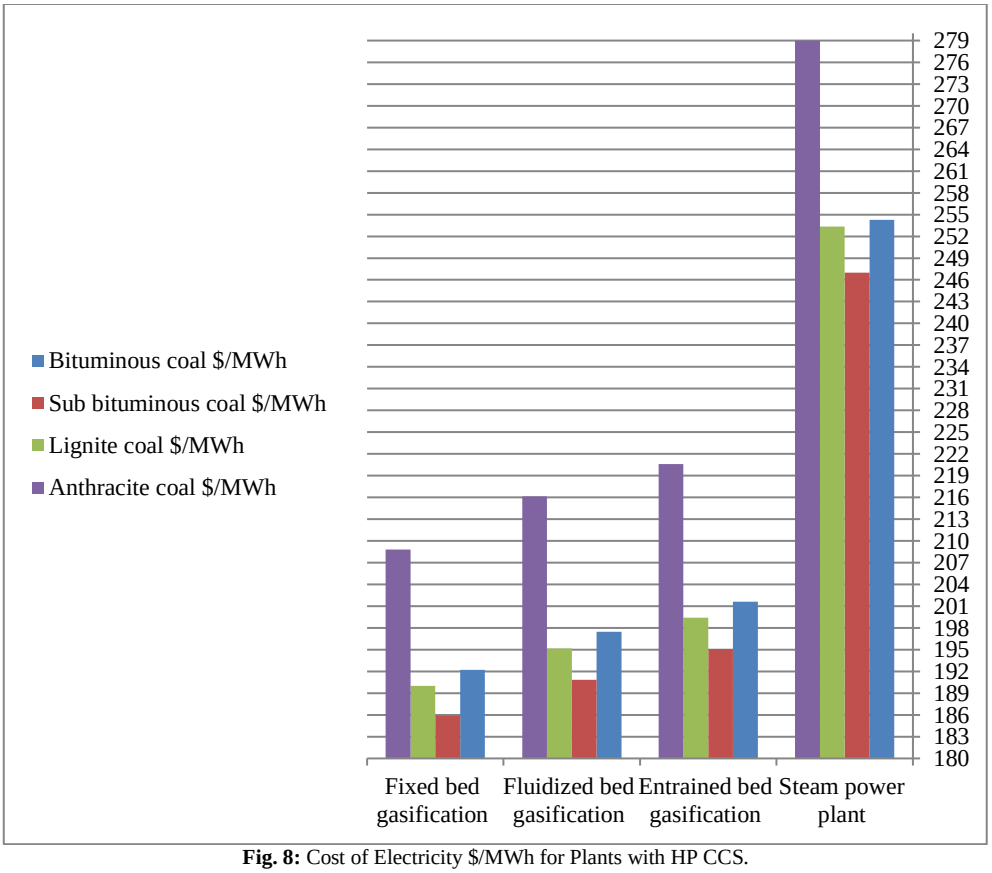


Fig. 8: Cost of Electricity $/MWh for Plants with HP CCS.

4.3. CO_2 emissions

Although the COE of IGCC plants are comparable to those of PC plants, it is important to note that the CO_2 emissions from the IGCC plants with carbon capture (as shown in Fig. 9) are significantly lower than those of the PC plants without carbon capture. Therefore, IGCC provides a great opportunity to perform pre-combustion carbon capture. The CO_2 capture cost (not the avoided

cost of CO_2) is about 2–3 times cheaper than that for post combustion carbon capture which is used in PC plants.

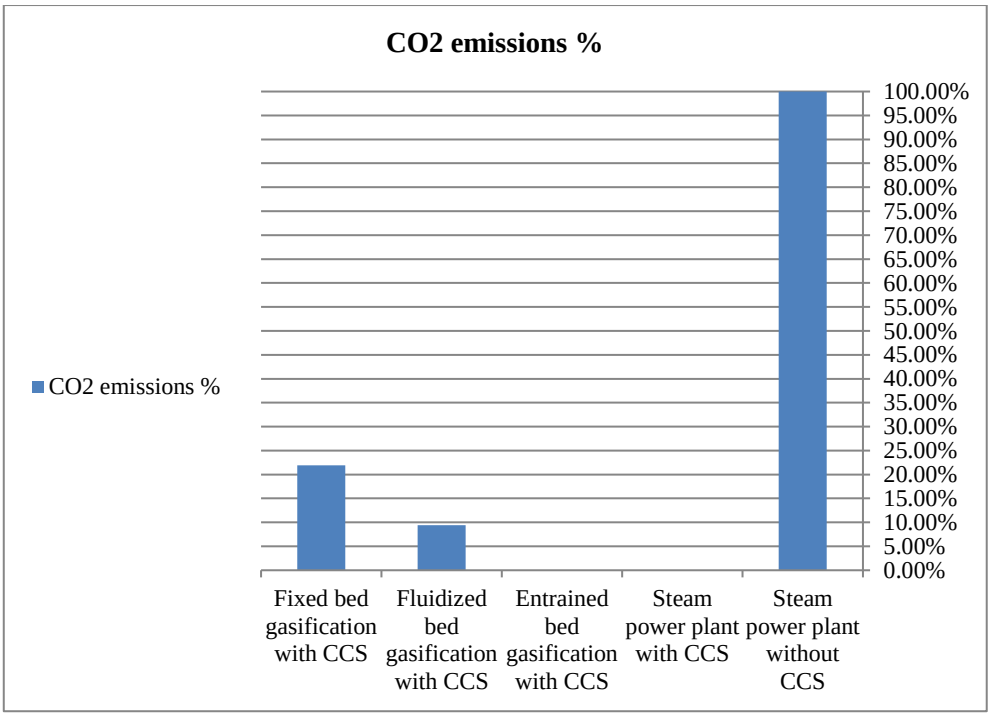


Fig. 9: CO_2 Emissions %.

From these results as offered by the simulation program the entrained flow gasifier and steam power plant, for all coal ranks, are the best because of their low emissions due to the high carbon capture and storage, but the entrained flow gasification power plant with CCS is cheaper than the steam power plant because the latter employs a post combustion carbon capture system.

4.4. Cost of CO_2 capture

The cost of CO_2 captured (or removed) is calculated from the COE difference between analogous plants with and without CO_2 capture. The cost of CO_2 avoided in reference to a specified plant is the cost which will incentivize carbon capture when a carbon emission tax above this value is levied to both a capture and a defined non-capture reference plant.

Figure 10 depicts the total average costs of HP CO_2 capture for the considered four power plants, for all coal ranks. The results are indicated in Table 7.

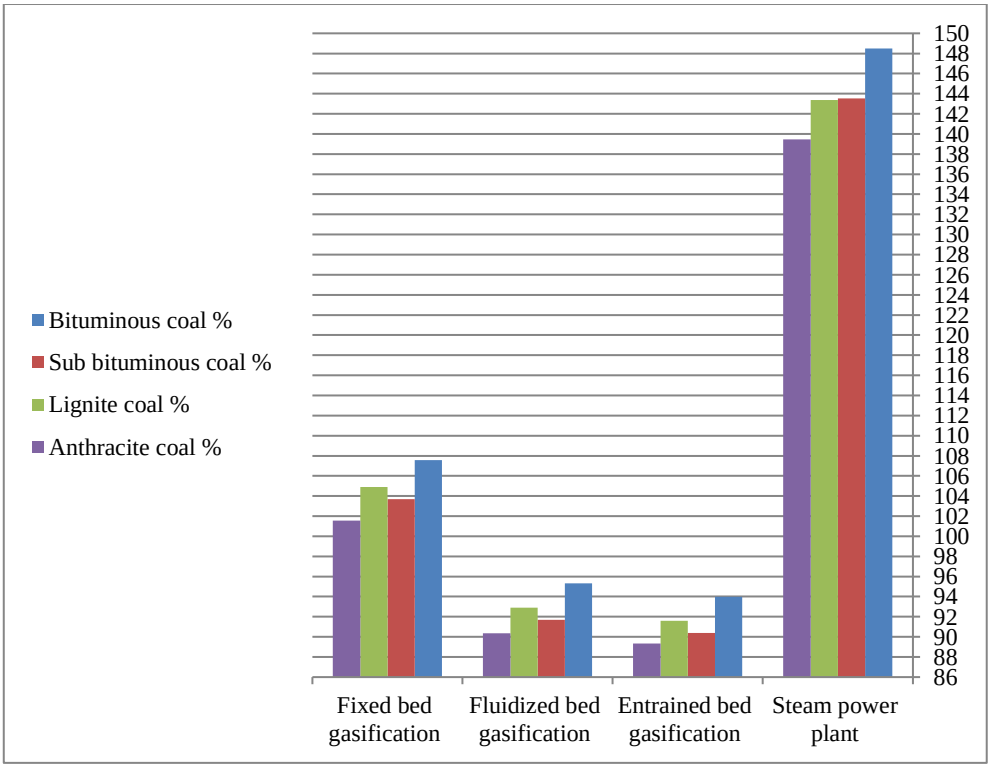


Fig. 10: Cost of HP CO2 Capture $/Tone.

Figure 11 gives the total average costs of HP CO_2 capture avoided for the same above power plants, and coal ranks. The results are tabulated in Table 8.

Table 7: Cost of HP CO_2 Capture $/Ton.

Coal rank	Cost $/ton			
	Steam power plant	Entrained bed gasification	Fluidized bed gasification	Fixed bed Gasification
Bituminous coal	148.509	93.973	95.329	107.566
Sub bituminous coal	143.538	90.386	91.696	103.688
Lignite coal	143.376	91.602	92.905	104.888
Anthracite coal	139.466	89.329	90.344	101.56

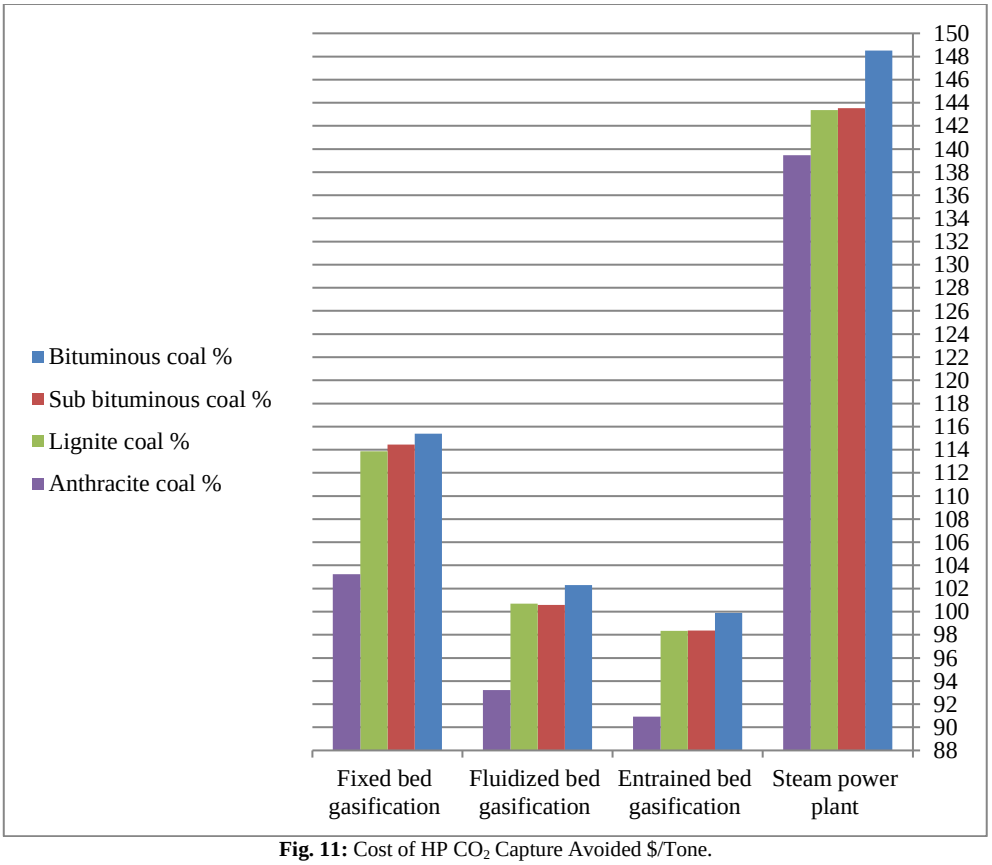


Fig. 11: Cost of HP CO_2 Capture Avoided $/Tone.

Table 8: Cost of HP CO_2 Capture Avoided $/Ton

Coal rank	Cost $/ton			
	Steam power plant	Entrained bed Gasification	Fluidized bed gasification	Fixed bed gasification
Bituminous coal	148.509	99.886	102.307	115.382
Sub bituminous Coal	143.538	98.359	100.577	114.444
Lignite coal	143.376	98.346	100.687	113.878
Anthracite coal	139.466	90.933	93.223	103.238

The results in Figs. 10 and 11 and Tables 7 and 8 indicate that, for all coal types, the entrained bed gasifier plant produced the lowest cost in the two cases, HP CO_2 capture and HP CO_2 capture avoided. This is followed by the fluidized bed gasification technology. The worst in both cases is the steam power plant.

From all the above results furnished by the present simulation program the entrained flow gasification power plant proved to be the most viable one because of its superiority based on all the studied comparison parameters.

5. Conclusions

A stupendous achievment of this research is the devolopment of a computer program which provides all thermodynamic, energy, economic data of coal fired power stations. This program is most important for comparing different technologies. The program provides a rather useful versatile powerful tool for designers and operators as well as buyers. It furnishes surplus pithy tangible results.

Comparisons of computer and manual results show excellent agreement, thus our computer program is incridibly reliable and can be used professionally on commercial scale.

The best power plant is the entrained flow gasification power one because of its high thermal efficiency with high throughput of fired coal, low emissions, low cost of carbon capture, however, it is slightly high in cost of electricity because of the high capital cost of the plant.

Finally, IGCC technology offers clear advantages over pulverized coal combustion, especially for achieving higher net efficiency, lower emissions including dust, heavy metals, hazardous compounds, CO_2, and gaseous pollutants, and a comparatively lower efficiency penalty for CCS.

Nomenclature

M_C	Moller weight	gm/mole
$\dot{m}$	Mass flow rate	Tone per Day (TPD)

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T	Temperature	^{0}C , K
H	Enthalpy	kJ/kg
HHV	High heating value	MJ/kg
P	Pressure , Power	MPa , MW
S	Summation of heat	Kw
X	Moisture content	Dimensionless
S	Entropy	kJ/kg K
CGE	Cold gas efficiency %	Dimensionless
CCE	Carbon conversion efficiency %	Dimensionless
ΔH_C	Heat of combustion of syngas or combustor	MW
P_r	Relative pressure	Dimensionless
O & M	Operating and maintenance cost	$M/year
η	Efficiency %	Dimensionless
IGCC	Integrated gasification combined cycle	
ASU	Air separation unit	
WGS	Water-Gas Shift	
CCS	Carbon Capture and Sequestration	
COE	Cost of Electricity	
GHG	Greenhouse Gases	
HP	High-Pressure	
LP	Low Pressure	
HRSG	Heat Recovery Steam Generator	

6. Conflict of interests

The authors declare that there is no conflict of interests regarding publication of this paper.

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