Proceedings of ASME Turbo Expo 2012
GT2012
June 11-15, 2012, Copenhagen, Denmark

GT2012-69519

A Parametric Investigation of Integrated Gasification Combined Cycles with Carbon Capture

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ABSTRACT

IGCC (Integrated Gasification Combined Cycle) technology is being developed to enable electricity to be generated at high efficiency and low emissions. Continuous improvement is essential to make IGCC reliable and cost-effective. As environmental concerns over carbon emissions escalate, development of a practical carbon capture and storage (CCS) technology has become an important issue. Combining IGCC and CCS has become a promising technology to reduce the cost of CCS. This study investigates the pros and cons of different methods used to put together an approximately 250 MW IGCC plant with and without CCS by using the commercial software Thermoflow. Seven different IGCC plants have been designed with various parameters examined, including: oxygen-blown vs. air-blown, with/without integration, with/without CCS, sour vs. sweet water shift for carbon capture, and dry- vs. slurry-fed. This study is based on technologies that are commercially available or close to commercialization. The results show that

(a) integration between the gas turbine and the air separation unit (ASU) can boost the cycle efficiency about 4.5% (1.6 percentage points);
(b) dry-feeding increases the CO content, the syngas heating value (19%), and the efficiency about 11% (4.7 percentage points);
(c) carbon capture reduces the power output by 2.7% and efficiency by 10% (or 4.5 percentage points) and the slurry-fed system takes a heavier toll on power output and efficiency than the dry-fed system;
(d) air-blown systems do away with the ASU, resulting in syngas with a 50% lower heating value and a small reduction in efficiency, but harvesting savings on reduced capital, operating, and maintenance costs;
(e) for CO_2, sweet water shift results in 5.5% (2 percentage points) higher cycle efficiency than sour shift.

Acronyms

ASU	air separation unit
BFW	boiler feed water
CCT	clean coal technology
CCS	carbon capture and storage
COS	carbonyl sulfide
CSC	convective syngas cooler
DGAN	diluent nitrogen
GHG	green house gas
GOX	gaseous oxygen
GT	gas turbine
HHV	higher heating value
HP	high pressure
HPGAN	high pressure gaseous nitrogen
HRSG	heat recovery steam generator
IGCC	integrated gasification combined cycle
IP	intermediate pressure
ITM	ion transport membrane
H	total enthalpy
LHV	lower heating value
LIN	liquid nitrogen
LP	lower pressure
LTGC	lower temperature gas cooling
MAC	main air compressor
MDEA	methyl di-ethanol amine
NGCC	natural gas fired combined cycle
PSA	pressure swing absorption
RSC	radiant syngas cooler
SAP	sulfuric acid plant
SGC	syngas cooler
ST	steam turbine
TSA	temperature swing absorption
WGS	water gas shift

1.0 INTRODUCTION

Around the world, coal has been used to generate a large portion of electricity. For example, coal generates 45% of the electricity in the United States and 70% in China. However, the conventional coal burning power plants are dirty and have relatively lower efficiency. To replace the direct coal combustion practice, gasification technology has been employed to gasify coal into synthesis gas (syngas,) which consists primarily of CO and H_2 as fuel. After cleaning the ashes and sulfur, the syngas can be combusted in gas turbines with low emissions comparable to those of natural gas combustion. The technology of combing the gasification process with the combined cycle is called the Integrated Gasification Combined Cycle (IGCC) [1].

In 1984, the first demonstration of IGCC technology was constructed at the Southern California Edison Cool Water Station where a GE (previously Texaco) gasifier was installed, along with a STAG107 combined cycle unit. In 1990s, two renowned demonstration IGCC power plants in the United States were constructed in Tampa and Wabash River plants respectively [2,3]. IGCC plants have the potential to become the new standard fossil-fuel power plants that will predominantly be used to add to the existing electrical power supply by replacing many aging coal power plants. Emissions such as SO_x, NO_x, and particulates are much lower in IGCC plants than from a modern coal plant. IGCC plants use 20-40% less water and operate at higher efficiencies than conventional coal-fired power plants. However, the high relative cost, availability, and reliability are still concerns that prohibit IGCC from being widely accepted. Therefore, continuous research and development are essential to make IGCC a reliable and cost-effective commercial product.

For an IGCC power plant, the Cost of Electricity, without CO_2 capture, is about 20% higher than in a modern coal plant. Typically, the air separation unit (ASU) represents approximately 15-20% of the capital cost of an IGCC plant and represents about 15% of gross plant power output to drive its high-pressure compressors. By using a smaller air separation unit, the cost can be significantly reduced in building, operation, and maintenance. The integration between the gas turbine and air separation unit in the IGCC plant system has a significant impact on the overall plant performance. Since the ASU requires high pressure, integrating the gas turbine and ASU by taking advantage of the high-pressure air generated by the gas turbine compressor can save the cost of installing and operating an external air compressor as well as boost the overall plant efficiency by 2 to 4 percentage points [4].

Carbon Dioxide is one of the so-called “greenhouse gases” (which trap heat in the atmosphere) and many scientists believe that increased greenhouse gas emission will lead to global climate change. In the event that serious carbon dioxide emission limitations are adopted, technological solutions will be needed to avoid CO_2 emissions if the use of coal continues to be the predominant means of generating electricity. In coal-based IGCC power plants, CO_2 can be captured relatively easily and economically by using conventional gas processing technologies. Syngas is fed to a CO-shift converter prior to cooling, and the acid gas removal unit removes CO_2. During this process, CO is converted into CO_2, and most CO_2 in the syngas can then been removed [5].

1.1 Objectives

A coal-based IGCC power plant is a very complicated system. To reduce the cost and pollutant emissions from power plants, more detailed information and a better understanding of the working process of the whole system are needed. The **objective** of this paper is to conduct a parametric study of several sample IGCC power plants to better understand the effect of different degrees of air integration and carbon capture technology on the plant's performance under the following different applications: oxygen-blown vs. air-blown, dry- vs. slurry-fed, and sweet vs. sour water gas shift.

1.2 Background of IGCC

IGCC is a power plant system designed to run more efficiently than conventional coal firing systems by combining coal gasification with a gas turbine combined-cycle power plant. It gasifies coal into synthesis gas (syngas) consisting primarily of CO and H_2 as a fuel to power a gas turbine. The heat from the gas turbine exhaust is recovered to generate steam to run a steam turbine.

The feedstock (coal, petroleum coke, or biomass) is pulverized and fed (in either dry or slurry form) into the gasifier along with air or oxygen that is produced in an on-site air separation unit (ASU). The combination of heat, pressure, and steam breaks down the feedstock and, through various chemical reactions, produce synthesis gas (syngas) consisting primarily of hydrogen (H_2) and carbon monoxide (CO) as a fuel with a slight composition of CH_4. Feedstock minerals become an inert, glassy slag product used in road beds, landfill covers, and other applications. Ashes and particulates are removed by water spray or a cyclone separator. To allow sulfur and mercury to be removed from the syngas, it is cooled to generate high-pressure steam, which can be used for the bottom Rankine cycle to recover the energy. Depending on the selected process, the sulfur can be removed and recovered as sulfuric acid (H_2SO_4) or elemental sulfur; both are marketable commodities. The cleaned syngas then goes to the gas turbine where it is burned to drive the turbine and generate power. The heat in the gas turbine’s exhaust gases is recovered through a heat recovery steam generator (HSRG) to generate steam. The nitrogen (from the air separation unit) or carbon dioxide (from carbon capture) can be routed back to the combustor as a diluent to reduce the flame temperature and thus reduce NO_x production and they can also be expanded through the turbine to increase power production. The steam from gasification can be used for water-gas shift or acid gas removal.

If hydrogen is needed, or CCS is incorporated, the CO in the syngas can be shifted to CO_2 with steam via water-gas shift (WGS) reactors. CO_2 and H_2 can then be separated. H_2 can be burned in a hydrogen gas turbine, and CO_2 can be removed and stored underground.

An IGCC power plant can be typically divided into four main islands (five if CCS is included:)

- Air Separation Plant and Fuel-Prepare System
- Gasification
- Gas Clean-up Unit and Sulfuric Acid Gas Removal (AGR) unit
- Power Block (gas turbine + steam turbine)
- CO_2 removal (with CCS)

1.3 Coal Gasification

The gasification of coal particles involves three major steps: (a) thermal decomposition (pyrolysis and devolatilization), (b) thermal cracking of the volatiles, and (c) char gasification. Coal particles undergo pyrolysis when they enter the hot combustion environment. Moisture within the coal boils and leaves the coal’s core structure when the particle temperature reaches the boiling point. The volatiles are then released as the particle temperature continues to increase. This volatile-releasing process is called devolatilization. The long hydrocarbon chains are then thermally cracked into lighter volatile gases, such as H_2, CO, C_2H_2, C_6H_6, CH_4, etc. These lighter gases can react with O_2, releasing more heat, which is needed to continue the pyrolysis reaction.

With only char and ash left, the char particles undergo gasification with CO_2 or steam to produce CO and H_2 ($C + CO_2 \rightarrow 2CO$ and $C + H_2O \rightarrow CO_2 + H_2$,) leaving only ash. The heat required for the pyrolysis and devolatilization processes can be provided externally or internally by burning the char and/or volatiles.

1.4 Types of Gasifiers

There are many types of gasifiers. The operating principles of two commonly used gasifiers (the entrained-flow and fluidized bed gasifier) are briefly introduced below:

Fluidized Bed Gasifier

In a fluidized bed gasifier, air or oxygen is injected upward at the bottom of a solid fuel bed, suspending the fuel particles. The fluidized bed acts like a multiphase, granular flow field. The fuel feed rate and the gasifier temperature are lower compared to those of entrained-flow gasifiers. The operating temperature of a fluidized bed gasifier is around 1000°C (1830°F,) which is roughly only half of the operating temperature of a coal burner. This lower temperature has several advantages: lower NO_x emissions, no slag formation, and low syngas exit temperature, which can result in a cheaper syngas cooling system being used prior to gas clean up, meaning higher cycle efficiency. Fluidized bed gasifiers require a moderate supply of oxygen and steam.

Entrained-Flow Gasifier

In the entrained-flow gasifier, a dry, pulverized coal, an atomized liquid fuel, or a fuel slurry is gasified with oxygen (or, much less frequently: air) in a flow at a speed of 10-15 m/s under an operating pressure ranging from 1 to 40 atm. The gasification reactions take place in a dense cloud of very fine particles. Most coals are suitable for this type of gasifier because of the high operating temperatures and the high heat transfer rates to the individual particles, resulting from the fact that the coal particles are well separated from one another. All entrained-flow gasifiers remove the major part of the ash as slag because the operating temperature is typically well above the ash fusion temperature. A smaller fraction of the ash is produced either as a very fine fly ash or as a black ash slurry. The merit of an entrained-flow gasifier is its high mass flow rate and high product yield. The entrained-flow gasifier produces a better mixing of fuel and oxidant, resulting in a higher efficiency compared to moving-bed and fluidized-bed gasifiers. This makes it widely used in power generation plant. An entrained-flow gasifier does have disadvantages as it requires the highest amount of O_2. Entrained-flow gasifiers predominantly used in commercial applications are the GE, Shell, E-gas, Prenflo, and GSP gasifiers.

1.5 Air Separation Unit (ASU)

An ASU is mainly used to separate oxygen from nitrogen and other minor gases in the air. There are several different types of ASU available commercially, but by far the most common type for large plants is the cryogenic ASU. Compressed air is cooled and cleaned prior to cryogenic heat exchange and distillation into oxygen-, nitrogen-, and, optionally, argon-rich streams. Pressurizing these streams for delivery is accomplished by gas compression, liquid pumping, or combinations of pumping followed by compression. Product storage can be provided as backup or for "peaking" duty, supplying higher than design rates of product delivery for short periods of time. A typical cryogenic type ASU can be ready to supply oxygen to the gasifier within 4 hours [6].

1.6 Gas Cleanup Unit and Sulfuric Acid Plant

Syngas leaves the syngas coolers usually between 700°F and 800°F and enters the syngas scrubbers, which remove most of the particulates and HCl from the gas through a series (usually three) of water/gas contact steps. The sulfur content is removed through two steps. The first step is to convert carbonyl sulfide (COS) to hydrogen sulfide (H_2S) through COS hydrolysis ($COS + H_2O \leftrightarrow CO_2 + H_2S$). The typical conversion rate is about 85-95%. This hydrolysis step is necessary because about 5% of the coal's sulfur is converted to COS in the gasifier and is present in the syngas at a concentration of up to 500 ppmv (dry basis). The second step is to remove H_2S through the acid gas removal (AGR) unit. There are generally two groups of AGR processes: chemical absorption and physical absorption.

Chemical absorption is performed using commercially available compounds such as monoethanolamine (MEA), diethanolamine (DEA), and methyl-diethanolamine (MDEA), while physical absorption is typically performed with two patented commercial processes: (a) the Selexol process which uses dimethyl ethers of the substance polyethylene glycol and (b) the Rectisol process which uses cryogenic methanol as the solvent. A 50% water solution of MDEA can removes 99% of the H_2S from the syngas. Here, the syngas passes through a large 10-micron cartridge filter which catches most of the rust and iron sulfide particles picked up in the steel line and any other particulate contaminants the syngas contains.

A Sulfuric Acid Plant (SAP) collects the acid gas, and converts it into marketable products such as H_2SO_4 or elemental sulfur.

1.7 Power Block and HRSG

The power plant is a combined cycle adapted for syngas fuel operation. The equipment includes a Combustion Turbine, a Steam Turbine, Cooled Generators for both turbines, and a Heat Recovery Steam Generator. The HRSG recovers heat in the combustion turbine exhaust to produce and superheat steam and preheat boiler feedwater for the generation of additional power in the steam turbine. A highly-efficient IGCC plant will need to use an HRSG with three-pressure levels under either forced circulation or natural circulation design. The combustion turbine exhaust gases enter the superheater and preheater sections of the HRSG, which heats the high pressure (HP) and intermediate pressure (IP) steam to 1,000°F. Next is the HP evaporator. It generates 25% to 30% of the HP steam. A small IP steam superheater is next, followed by the hottest HP economizer, which finishes preheating boiler feedwater for the HRSG's HP evaporator and the syngas coolers. The IP evaporator generates steam at a pressure of about 25 bars (370 psig) and the gasification plant's IP steam, which is generated at a pressure of 28.6 bars (420 psig), flows to the HRSG IP drum for demisting before it goes to the HRSG superheaters and turbine. The IP evaporator is followed by the economizer sections, which preheat HP and IP boiler feedwater. The low pressure (LP) steam is generated in the LP evaporator for the air separation plant and the gasification plant. Finally, boiler feed water (BFW) is preheated in the last HRSG section for additional heat recovery. The exhaust gas to the stack is typically between 154°C (310°F) and 171°C (340°F).

1.8 Carbon Dioxide Capture Technology

There are three basic systems for capturing CO_2: Post-combustion capture, Oxy-fuel combustion capture, and Pre-combustion capture. In this study, only pre-combustion capture is investigated because one of the major advantages of using IGCC is its readiness for implementing pre-combustion CCS: the most economic carbon capture process [7].

1.8.1 Types of carbon capture technologies

CO_2 capture systems use many of the known technologies for gas separation, which are integrated into the basic systems for CO_2 capture.

Separation with sorbents/solvents– The separation is achieved by passing the CO_2-containing gas in intimate contact with a liquid absorbent or solid adsorbent that is capable of capturing the CO_2 through either the *absorption* or *adsorption* process. The absorption process occurs when the contaminant substance passes through a medium and is trapped within the medium; whereas, adsorption occurs when the contaminant passes over a medium and is trapped upon the surface. Pressure-Swing Adsorption (PSA) and Temperature-Swing Adsorption (TSA) are two commonly used commercial processes.

Separation with membranes – Membranes are specially manufactured materials that allow the selective permeation of a gas through them. There are many different types of membrane materials (polymeric, metallic, ceramic) that may find application in CO_2 capture systems to preferentially separate H_2 from a fuel gas stream, CO_2 from a range of process streams, or O_2 from air, which can then subsequently aid in the production of a highly concentrated CO_2 stream.

Distillation of a liquefied gas stream and refrigerated separation – As in the air separation unit, the refrigerated separation process can also be used to separate CO_2 from other gases. Since it is very expensive to liquefy a gas stream, this method isn't considered to be a viable method for carbon capture for now.

1.9 Water-Gas Shift (WGS)

The water-gas-shift reaction was discovered over two centuries ago and nowadays serves in various chemical processes, such as ammonia production and Fischer-Tropsch synthesis. The equilibrium reaction ($CO + H_2O \leftrightarrow H_2 + CO_2$) converts carbon monoxide into hydrogen and carbon dioxide and is moderately *exothermic*.

There are two possible arrangements for shift conversion: *sour shift* in which the shift process occurs with sulfur in the gas and sweet shift in which the shift process occurs after sulfur is removed from the gas stream. In the "sour shift" arrangement, the fuel gas from gasification, after water scrubbing, is reheated and fed to a shift reactor which uses a sulfur-tolerant catalyst. This catalyst also hydrolyses COS to H_2S. The fuel gas is then cooled, water is condensed, and the gas is fed to a solvent scrubber, which removes sulfurous compounds and CO_2.

In the "s*weet shift*" arrangement, the fuel gas from water scrubbing is reheated and fed to a COS hydrolysis reactor. It is then cooled and fed to a solvent scrubber that removes sulfurous compounds. The sulfur-free gas is reheated, fed to a shift reactor, cooled, and fed to a second solvent scrubber for removal of CO_2.

To avoid carbon deposition at the catalyst surface and formation of larger hydrocarbon molecules, the steam/carbon monoxide ratio is usually maintained at about 2. The high- and low-temperature shift catalysts are often operated in sequence, where the high-temperature catalysts convert the bulk of carbon monoxide at a faster rate and a low-temperature shift catalyst brings the CO_2 to the required ppm levels at the reactor outlet with a slower rate. The shift reaction is equilibrium limited, which implies that the extent of CO-conversion is dependent on the temperature in the shift reactor.

2.0 SYSTEM SETUPS

IGCC system modeling has been performed by many researchers. Some recent work can be referred to [9-11]. In this study, the desired capability of an IGCC plant is around 250 MW, consisting of approximately 150 MW from the gas turbine (GT) and 100 MW from the steam turbine (ST). The IGCC system capacity is used to design around the appetite of the selected commercially available gas turbines. In this case, the robust GE7FA model (7221FA) is selected as the core of the studied IGCC systems. The simulations are conducted under a controlled condition using same coal (Pittsburgh No. 8), ambient conditions, and combustion turbine (GE 7221 FA) for all cases. The oxygen or air provided for all simulations is based on the theoretical energy needed to produce all gasification processes for a complete carbon conversion. The theoretical energy needed to complete the reactions is calculated from the endothermic gasification reactions. This results in an overall oxygen over carbon mole ratio (O_2 : C) of approximately 0.3. The oxidant of the oxygen-blown cases consists of 95% O_2 and 5% N_2 by weight. For the air-blown cases, the air consists of 24% O_2 and 76% N_2 by weight. The simulated coal-slurry mixture contains 65% coal and 35% H_2O by weight. The major subsections of the studied IGCC cases include coal and air preparation, gasification, the gas cleaning system, and the power block (GT, ST, HRSG). Slag treatment and sulfuric acid plants are not included. In the cases with CO_2 capture, the CO_2 compressor for transport and storage is not included. The GT PRO program of the Thermoflow software is used for the simulation.

The ambient conditions consist of air temperature at 77°F, pressure at 14.7 psia, relative humidity at 60%, and cooling water temperature at 59°F. The baseline case (Case 1) consists of an oxygen-blown, slurry-fed gasifier, without integration between the GT and ASU, i.e. without any air extraction from the GT compressor, and without CCS. The other six studied cases (shown in Table 1) are simulated to investigate the following parameters:

- With or without integration between the GT and ASU with GT Air Extraction
- Different types of oxidant (Oxygen- or Air- blown)
- Different types of coal mixture (Slurry or Dry feed)
- With or without CO_2 Capture
- Different types of shift converter (Sour or Sweet/Clean)

Table 1 List of studied cases

Case #	Gasification Process		GT Air Extraction	CO_2 Capture	WGS
1	Slurry	Oxygen	No	No	No
2	Slurry	Oxygen	Yes	No	No
3	Slurry	Oxygen	Yes	Yes	Sweet
4	Dry	Oxygen	Yes	No	No
5	Dry	Air	Yes	No	No
6	Dry	Air	Yes	Yes	Sweet
7	Dry	Air	Yes	Yes	Sour

2.1 Software utilized

The commercial software, Thermoflow, is selected to conduct simulation. GT PRO is one of the programs within the suite and is used to design and simulate the IGCC plants in this study and to calculate each component's performance and overall thermal efficiency of each case.

Based on user-input thermodynamics design criteria and hardware assumptions, the GT PRO program generates plant heat balances, flow schematics, and preliminary hardware design for the major equipment. To design an IGCC plant, GT PRO prompts the selection of "gasification" as a first step and specification of the size of plant, then the number of pressure streams in the steam cycle followed by detailed site conditions, the method of cooling, the configuration of the steam cycle, settings of the gasifier and other parameters step by step. The selected GT is GE Model 7221FA that can produce 161.65 MW of power with 36.9% thermal efficiency by burning natural gas. The selected feedstock is Pittsburgh No. 8 coal. The built-in feedstock database provides both proximate analysis, ultimate analysis, and ash analysis. The higher heating value (HHV) is 12,450 Btu/lbm (28.96 MJ/kg) and the lower heating value (LHV) is 11,901 Btu/lbm (27.68 MJ/kg). The difference of HHV and LHV is the latent heat of water vapor.

3.0 RESULTS AND DISCUSSIONS

3.1 Baseline Case

The baseline case (Case 1) uses a slurry-fed, oxygen-blown, single-stage GE gasifier with a radiant syngas cooler and slag quench chamber. The plant doesn't include the gas turbine air extraction or carbon capture. The distributions of flow temperature, pressure and mass flow rate in the whole system for Case 1 are illustrated in Figs. 1–6. In all figures, pressure is represented by the absolute value, P (psia), temperature by T (°F), and mass flow rate by M (lbm/s.)

In Figs. 1 and 2, each important state is shown next to the associated line of flow. The coal slurry consists of 2,328.9 tons/day coal mixed with 24.05 lbm/s water and 52.86 lbm/s of oxygen is fed into the gasifier. The gasifier operates at a temperature of 2600^{o}F and 430 psia. The combination of heat, pressure, and steam breaks down the feedstock and creates chemical reactions that produce synthesis gas. After the radiant and convective coolers, the raw syngas goes into the gas cleanup system (GCS) with a mass flow rate of 123.6 lbm/s at 388 psia and 953°F. Due to the sulfur and mercury being removed from GCS, the mass flow rate is reduced to 98.53 lbm/s. The cleaned syngas (349.3 psia, 348.7°F) then goes to the gas turbine where it is burned to drive the turbine and generate power. The steam from gasification is combined with the steam produced in the HRSG and fed to the steam turbine generator. The gas turbine provides approximately 60.6% of the total power output, while the steam turbine provides the rest of the power. The net power of the whole system is 268.082 MW, and the net LHV electrical efficiency is 39.61%.

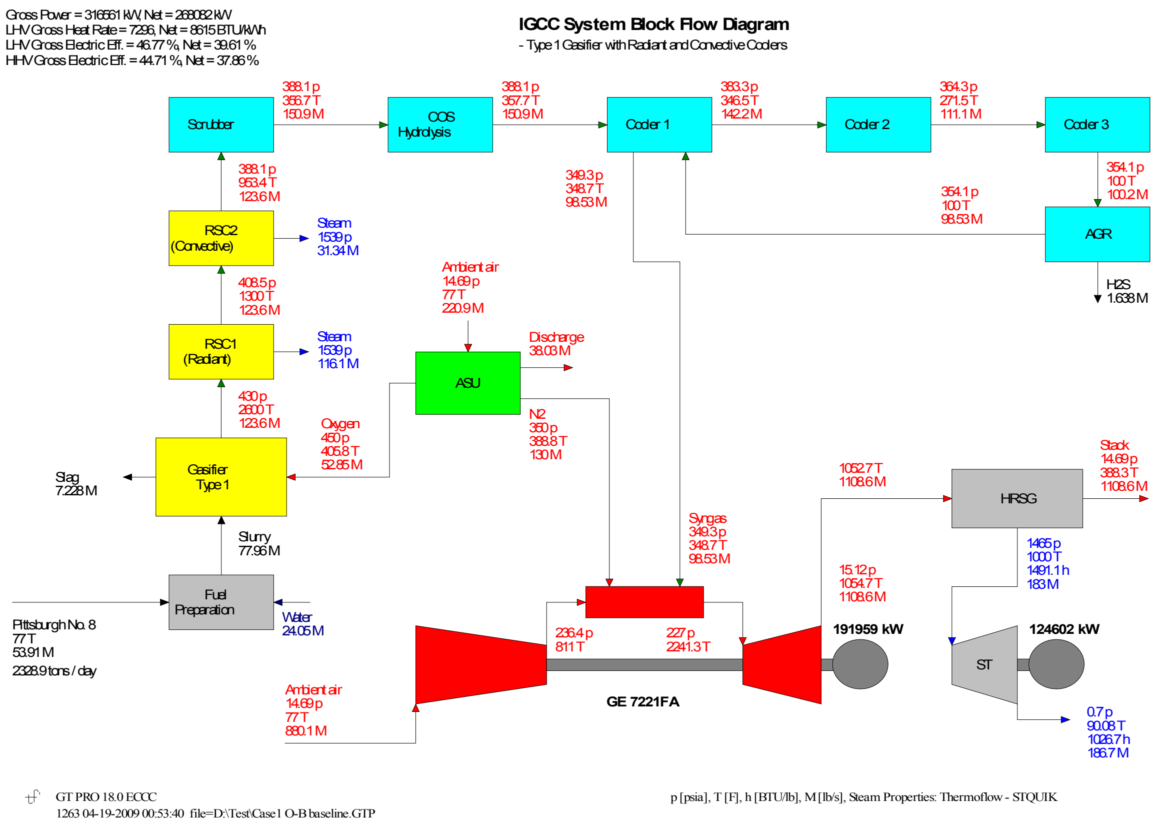

Figure 2 Baseline IGCC system block diagram for Case 1

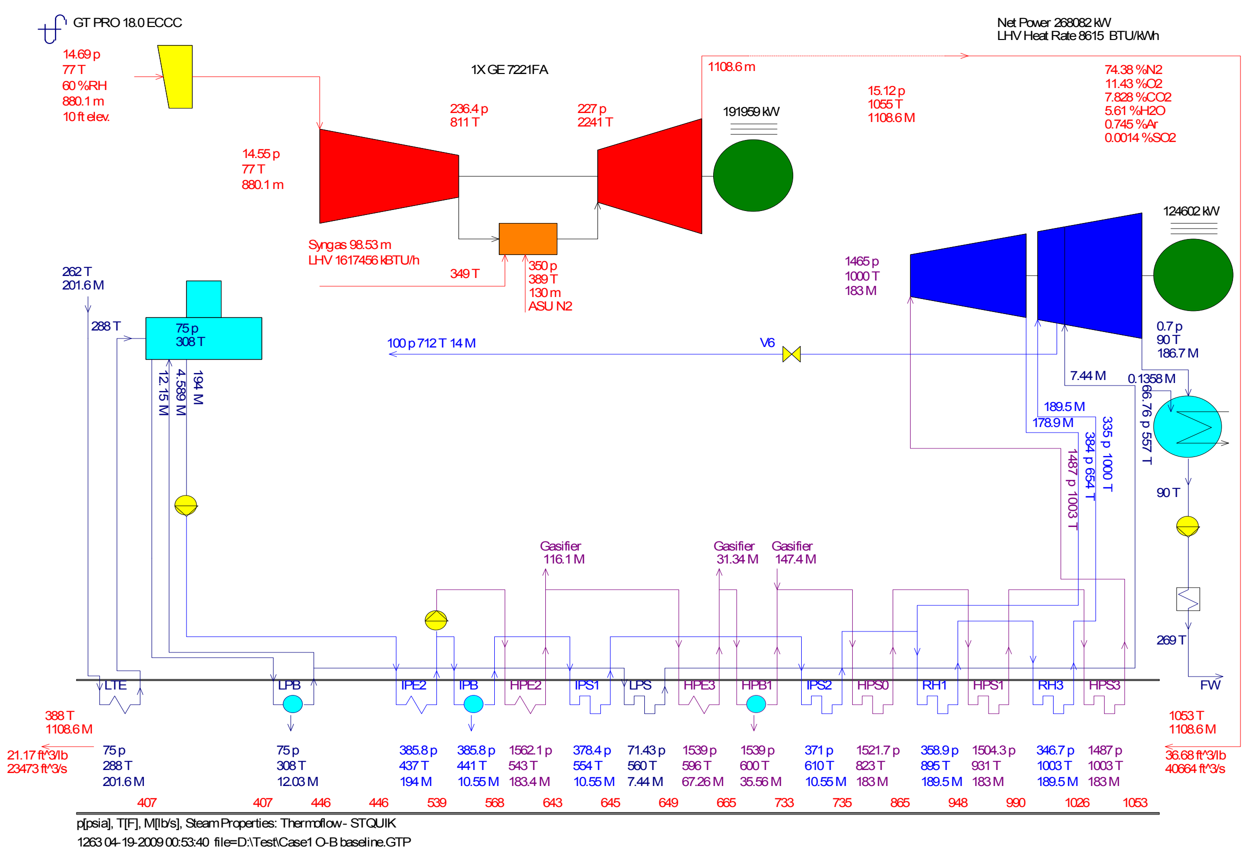

Figure 3 Schematic of the power island flow diagram in baseline IGCC system for Case1

In Fig. 3, the ASU cryogenically separates ambient air (14.7 psia, 77°F) into its major constituents: O_2 and N_2. Most of the O_2 (52.85 lbm/s at 95% purity) is needed in the gasification plant for the production of fuel gas. Other available O_2 is used in the sulfur acid plant. Most of the N_2 (80% at 350 psia, 388.8°F, and 130 lbm/s) goes to the power plant's combustion turbine to dilute the fuel gas and reduce the flame temperature for NO_x abatement. This diluent N_2 also increases the combustion turbine's power production as it expands though the turbine. The gasification plant and power plant use a small portion of the N_2 for purges and seals. The ASU also produces a small stream of liquid nitrogen to fill storage tanks. It is used during ASU outages to supply low pressure purge nitrogen to the gasification plant for safety.

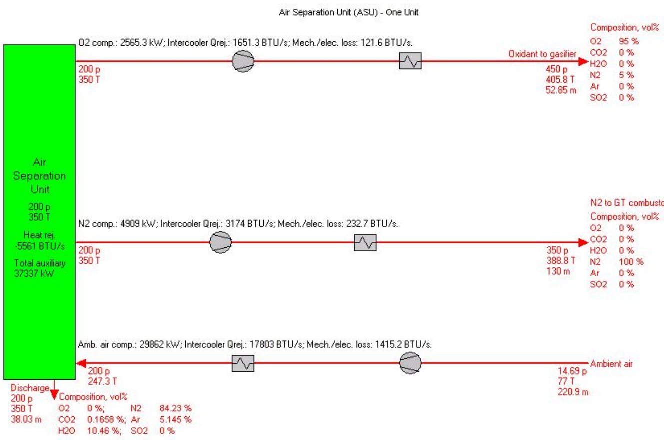

Figure 3 Graphical output of the baseline air separation unit (ASU) for Case 1

The Air Separation Unit requires a lot of energy to start and operate. The auxiliary energy for the three main compressors (for ambient air, oxygen, and nitrogen) is 37.337 MW. It uses 77% of all the energy for auxiliaries and heat losses in the entire IGCC system (shown in Fig. 4.) Reducing the energy requirement of the ASU is a way to improve the plant's electric efficiency. To this end, Cases 4, 5, and 6 will investigate the air-blown gasification situation without using the ASU.

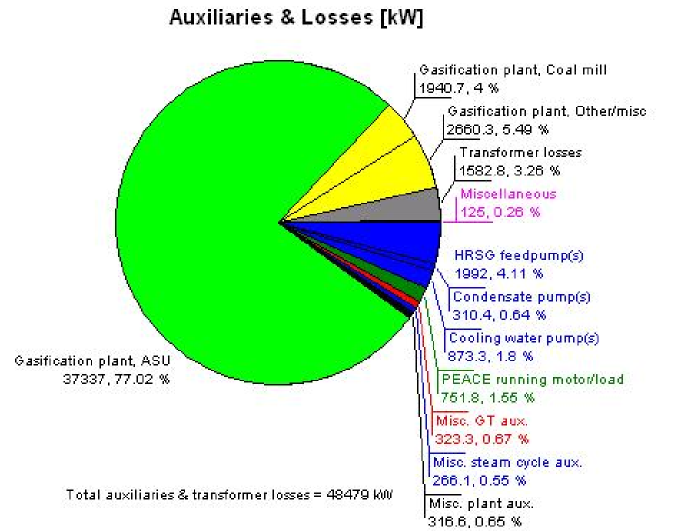

Figure 4 Distribution energy for auxiliaries and losses (KW) for Case 1 (baseline)

In Fig. 5, the coal slurry and oxygen interact in the gasifier at 430 psia and 2600°F to produce synthesis gas and slag. Slag is quenched in the water bath and comes out from the bottom of the gasifier at 212°F. The high pressure steam is produced by two syngas coolers. The raw syngas, which consists of 39.79% CO, 9.76% CO_2, 25.8% H_2, and 22.4% H_2O by volume, goes into the gas cleanup system.

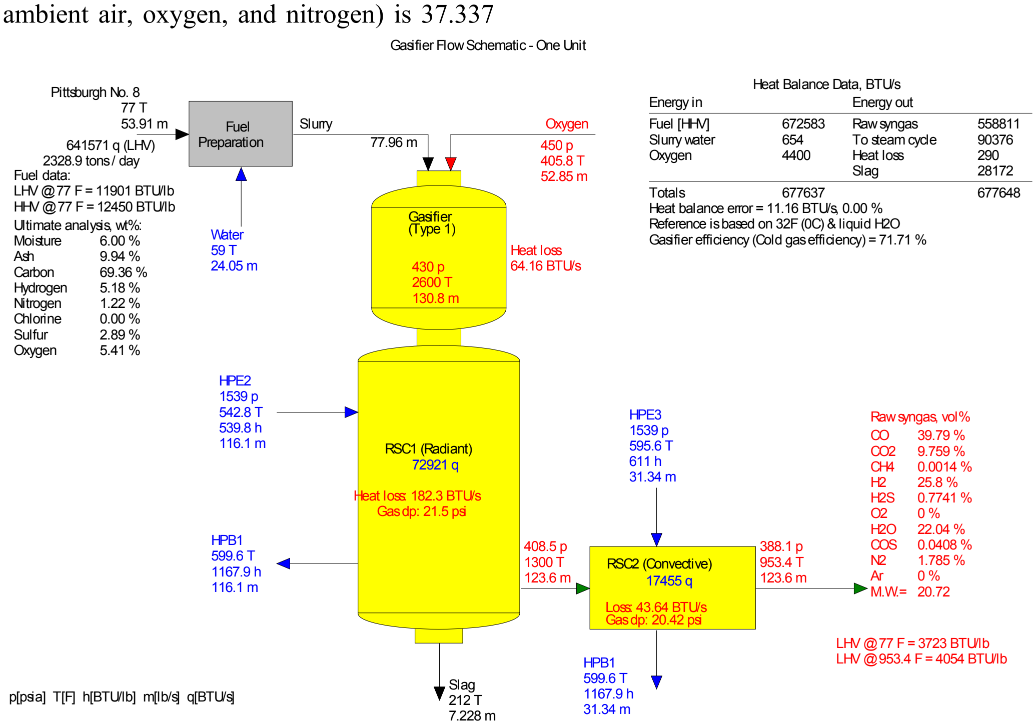

Figure 5 Graphical output of baseline gasifier for Case 1

In the Syngas Scrubber (shows in Fig. 6) most particulates and hydrogen chloride (HCI) are removed. Then, the water-saturated gas containing 30%±3% water vapor leaves the scrubber and enters the COS hydrolysis reactor. About 95% of the COS in the syngas is converted to hydrogen sulfide (H_2S) by the hydrolysis reaction: $COS + H_2O \rightarrow H_2S + CO_2$. Following COS hydrolysis, the gas goes through three low temperature coolers, and for H_2S removal, cools to near ambient temperature. After acid gas removal, clean syngas, which consists of 51.41% CO, 12.66% CO_2, 33.34% H_2, and 0.27% H_2O by volume, goes to the combustor of the gas turbine.

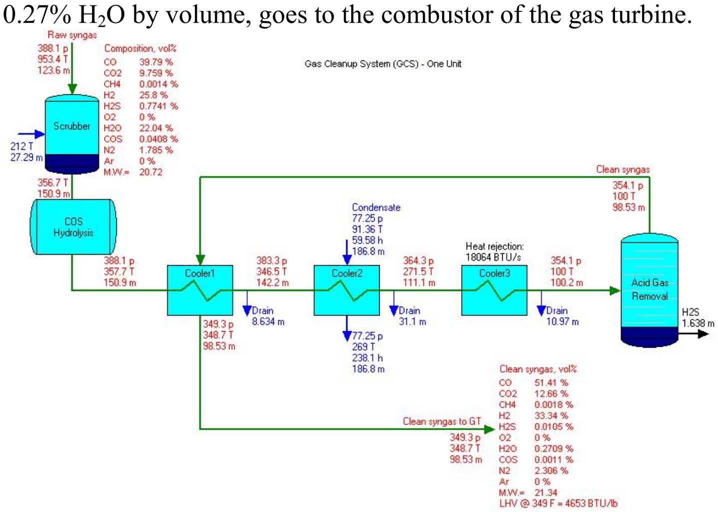

Figure 6 Graphical output of baseline gas cleanup system for Case 1

3.2 Case 2 – Gas Turbine Air Extraction

Case 2 uses a coal slurry-fed, oxygen-blown, single stage GE gasifier. Since the extent of integration between the gas turbine and the air separation unit has a significant impact on the system performance, Case 2 employs partial air integration (50%). Higher than 50% integration, although it can continue to increase the plant efficiency, can adversely impact the flow within the turbomachinery and on IGCC plant performance. Furthermore, higher percentages of integration can also create more complicated plant control issues, including more difficult startup procedures and sensitive dynamic responses to other types of transients.

The system block diagram of Case 2 is similar to Fig. 1 except that an air extraction line is connected between the GT compressor outlet and the ASU unit (not shown due to space limit.) This air-extraction line can be seen in Fig. 7 later in Case 3. The high pressure and temperature air extracted from the exit of gas turbine's compressor first preheats the nitrogen, which is sent to the GT to reduce the combustion flame temperature as well as increase the output power, then the extracted air is combined with the compressed ambient air before they enter the ASU. The auxiliary energy consumed in Case 2 is 21.461 MW. It is 66.12% of the total auxiliary energy consumptions and losses, about 11% less than in Case 1, thanks to the 50% air integration.

The net power output of the plant is 262.418 MW, and the net electrical efficiency is 41.27%. The gas turbine provides approximately 61.8% of the total power output, while the steam turbine provides the rest of the power. Compared to the baseline case, the air separation unit receives half of the air requirement from the gas turbine's compressor, and the gas mass flow rate expanding in the gas turbine is about 120 lbm/s less.

When compared with the baseline case, as shown in Table 2, the ASU uses less auxiliary energy and ejects more heat in Case 2. The coal feed rate has decreased from 2,328.9 tons/day to 2,187.6 tons/day. Although there is a big difference in gross power output between Case 1 and Case 2, the net power outputs are close. The energy savings of the ASU translate to a 1.66 percentage point (or 4.2%) increase in LHV electric efficiency in Case 2.

Table 2 Effect of GT air extraction (50% integration between GT and ASU) on an IGCC plant performance Case 2 vs. Case 1

	Case 1	Case 2	Difference
Oxidant feed	Oxygen	Oxygen	
Coal mixture	Slurry	Slurry	
GT Air Extraction	No	50%	
Coal input (tons/day)	2328.9	2187.6	-141.3 (6%)
ASU aux.(MW)	37.337	21.461	-15.876 (42.5%)
ASU Heat Rej (Btu/s)	-5,561	3,973	9, 534 (171%)
Gross Power (MW)	316.581	294.874	-21.707 (6.9)
Net Power (MW)	268.082	262.418	-5.664 (2.1%)
LHV Elec Eff.(%)	39.61	41.27	1.66 (4.2%)

3.3 Case 3 - CO_2 Capture

Case 3 employs a coal slurry-fed, oxygen-blown, single-stage GE gasifier with 50% air integration and added water shift with a CO_2 removal process for CCS. The net power output of the plant is 255.235 MW, and the net LHV electrical efficiency is 36.46%. The gas turbine provides approximately 73.0% of the total power output and the steam turbine provides the rest of the power (see Fig. 7).

In the Gas Cleanup System (Fig. 8), the fuel gas from water scrubbing is reheated and fed to a COS-hydrolysis reactor. It is then cooled and fed to a solvent scrubber that removes sulfur compounds. The sulfur-free gas is reheated, fed to a water-shift reactor, and fed to a second solvent scrubber for removal of CO_2. The high pressure steam fed into the CO shift reactor comes from the high pressure steam turbine at 772°F and 615.4 psia. Since the shift is performed after AGR, this process is called *"sweet shift."*

In the water shift reactors in Fig. 8, the syngas reacts with high temperature (774°F) and pressure (615.4 psia) steam to produce CO_2 and H_2. Since the water shift is an exothermic reaction, the temperature of the hydrogen-rich fuel increases from 100°F to 920°F. After CO_2 removal, the mass flow rate decreases to 69.12 lbm/s. With hydrogen and steam rich fuel gas, the GT exhaust gases consist mainly of water (H_2O) and nitrogen (N_2) with very little carbon dioxide (CO_2) in Case 3.

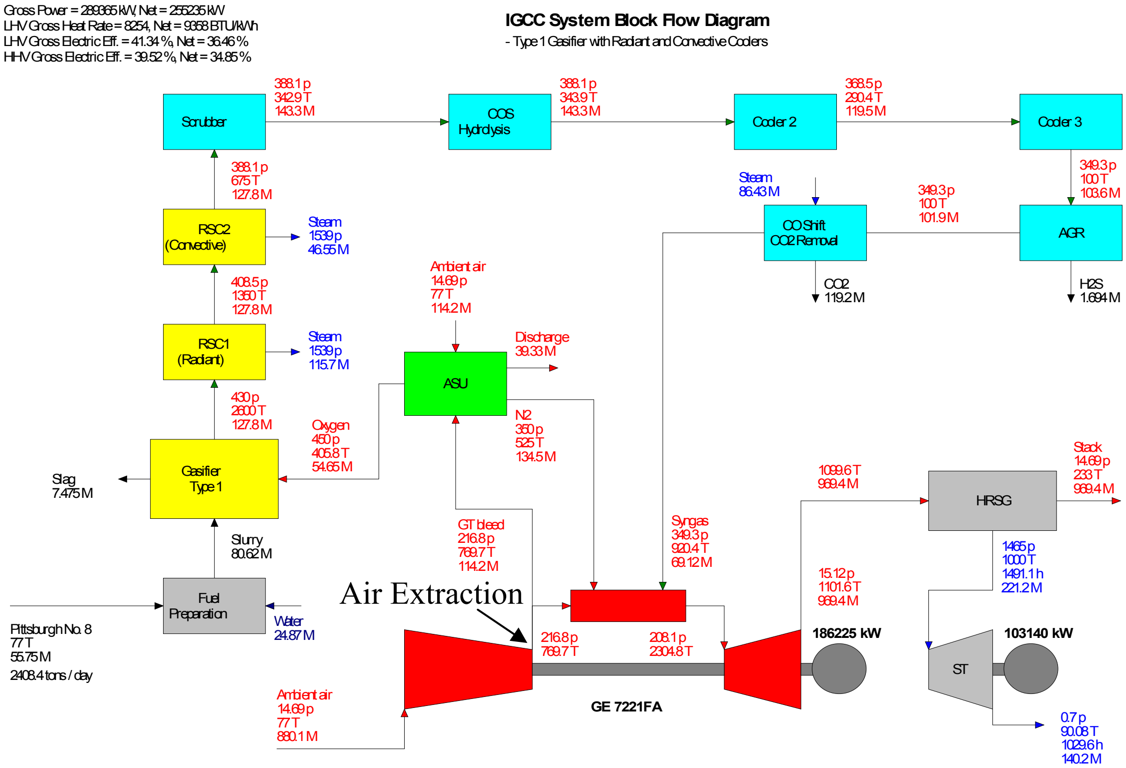

Figure 7 IGCC system block diagram for Case 3 with 50% air extraction from GT compressor

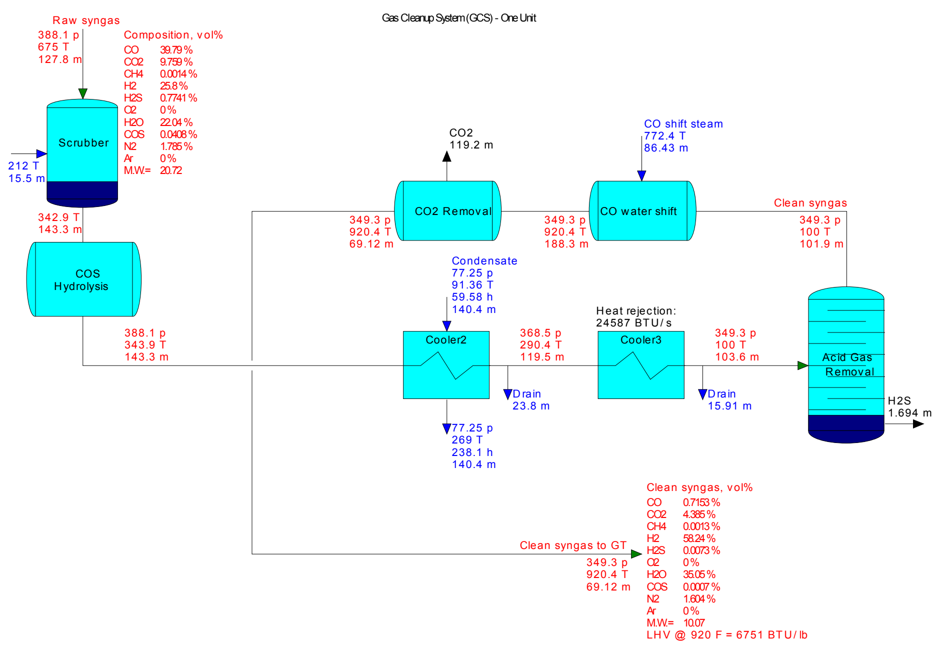

Figure 8 Graphical output of gas cleanup system for Case 3

Compared with Case 2 in Table 3, most of the CO in Case 3 is converted to CO_2 and only 4.385% CO_2 exists in the cleaned syngas. In Case 2, there is only 0.27% vol. water vapor in the cleaned syngas because, during the H_2S removal process, the syngas is cooled to near the ambient temperature, and most of the water vapor is condensed and removed; whereas in Case 3, the shifted fuel gas consists of a large percentage of water vapor (35% by volume.)

When compared with Case 2 in Table 4, the coal feed increases from 2,187.6 tons/day to 2,408.4 tons/day, the ASU power increases by 10.1%, and the net power decreases by 2.7%. Since the high temperature CO_2 is removed from the gas cleanup system, the energy cost in CO shift and CO_2 capture translates into a significant 4.81 percentage point (or 11.6%) decrease in LHV electric efficiency in Case 3.

Table 3 Effect of carbon capture on cleaned syngas composition (Case 3 vs. Case 2)

Syngas property	Case 2 No CCS	Case 3 W/CCS
Pressure (psia)	349.3	349.3
Temperature (°F)	334.9	920.4
Mass flow rate (lbm/s)	92.55	69.12
CO (%)	51.41	0.715
CO_2 (%)	12.66	4.385
H_2 (%)	33.34	58.24
H_2O (%)	0.27	35.05
LHV (Btu/lb)	4648	6751

Table 4 Effect of carbon capture on cycle performance (Case 3 vs. Case 2)

	Case 2	Case 3	Difference
GT Air Extraction	50	50%	
CO_2 Capture	No	Yes (sweet)	
Coal input (tons/day)	2,187.6	2,408.4	220.8 (10.1%)
ASU aux. (MW)	21.461	23.627	2.166 (10.1%)
ASU Heat Rej. (Btu/s)	3,973	4,721	748 (18.8%)
Gross Power (MW)	294.874	289.365	-5.509 (-1.9%)
Net Power (MW)	262.418	255.235	-7.183 (-2.7%)
LHV Elec. Eff. (%)	41.27	36.46	-4.81 (-11.6%)

3.4 Case 4 – Dry Feed Gasification

Case 4 employs a coal dry-fed, oxygen-blown, two-stage gasifier with 50% air integration. Simulation for Case 4 is conducted to investigate the effects of using dry coal powder as fuel on IGCC performance. There are three important parameters: the ratio of mass flow rates between oxygen and fuel (O_2/f) is 0.8, the ratio of mass flow rates between nitrogen and fuel (N_2/f) is 0.1, and the ratio of mass flow rates between steam and fuel (H_2O/f) is 0.1. 75% of the steam and fuel is reacted in the first stage. The net power output of the plant is 237.969 MW, and the net LHV electrical efficiency is 45.98%. The gas turbine provides approximately 65.2% of the total power output, while the steam turbine provides the rest of the power.

The first important factor is the significantly increased gasifier temperature from 2600°F in the slurry-fed Case 2 to 3800°F in the dry-fed gasifier in Case 4. The gasifier in Case 2 using coal slurry has a higher water mass fraction, which absorbs some of the heat in the gasifier. Both the absorbed sensible and latent heats lower the gas temperature. Dry coal feed in Case 4 yields a higher CO fraction in comparison with Case 2 fed with coal-slurry (see Table 5). This is expected because less steam drives the water-gas shift reaction ($CO + H_2O \leftrightarrow CO_2 + H_2$), so more CO remains in the syngas in Case 4.

In comparison with Case 2 in Table 6, the coal input (1,780.9 tons/day) decreases by 18.6%, the slag output (4.527 lbm/s) decreases by 33.3%, and the net output power decreases by 9.3%, but the LHV efficiency significantly increases by 4.71 percentage points (or 11.4%) in Case 4. This large efficiency increase could be attributed to the energy saving from not heating and vaporizing the water as in the slurry-fed system.

Table 5 Comparison of cleaned syngas between slurry-fed Case 2 and dry-fed Case 4 without carbon capture

Syngas property	Case 2	Case 4
Pressure (psia)	349.3	367.6
Temperature (°F)	334.9	277.2
Mass flow rate (lbm/s)	92.55	75.2
CO (%)	51.41	58.78
CO_2 (%)	12.66	2.04
H_2 (%)	33.34	32.2
H_2O (%)	0.27	0.2549
LHV (Btu/lb)	4648	5547

Table 6 Comparison of cycle performance between slurry-fed Case 2 and dry-fed Case 4 without carbon capture

	Case 2	Case 4	Difference
Oxidant feed	Oxygen	Oxygen	
Coal Mixture	Slurry	Dry	
GT Air Extraction	50%	50%	
Coal input (tons/day)	2,187.6	1,780.9	-406.7 (-18.6%)
Slag (lbm/s)	6.79	4.527	-2.263 (33.3%)
ASU aux. (MW)	21.461	14.293	-7.168 (-33.4%)
ASU Heat Rej. (Btu/s)	3,973	2,556.6	-1,416.4 (-35.6%)
Gross Power (MW)	294.87	261.24	-33.631 (-11.4%)
Net Power (MW)	262.41	237.96	-24.45 (-9.3%)
LHV Elec. Eff. (%)	41.27	45.98	4.71 (11.4%)

3.5 Case 5 – Air Blown Gasification without Carbon Capture

An air-blown gasifier has the advantage of not using an ASU to supply the oxygen. An ASU is an intensive energy consumption device that reduces overall plant output and efficiency. Case 5 simulates a two-stage gasifier operating as a dry-fed and air-blown with 50% integration. The oxidant is air with a composition of 23.1% O_2 and 76% N_2 by weight. Similar to the previous cases, the overall mole ratio of O_2:C is 0.3. The ratio of mass flow rates between oxygen and fuel (O_2/f) is 3.0. The temperature (2032°F) in the air-blown gasifier of Case 5 in Fig. 9 is lower than that of the oxygen-blown in Case 4 due to the abundance of N_2, which absorbs heat in the gasifier. The exit syngas of the air-blown gasifier also has a lower mole number of CO than the oxygen-blown gasifier (Table 7).

The net power output of the plant is 245.417 MW, and the net LHV electrical efficiency is 44.92%. The gas turbine provides approximately 66.4% of the total power output, while the steam turbine provides the rest of the power (Table 8). The syngas heating value in the air-blown gasifier is 2,639.1Btu/lbm (6.14 MJ/kg) and is the lowest among the cases discussed so far (Table 7). Of course, this is expected due to the lower carbon input and the dilution introduced by N_2. It is a bit disappointed to see that the LHV efficiency in air-blown Case 5 is lower than that of oxygen-blown Case 4 even though Case 5 produces more output power (7.45MW more) by not using an ASU.

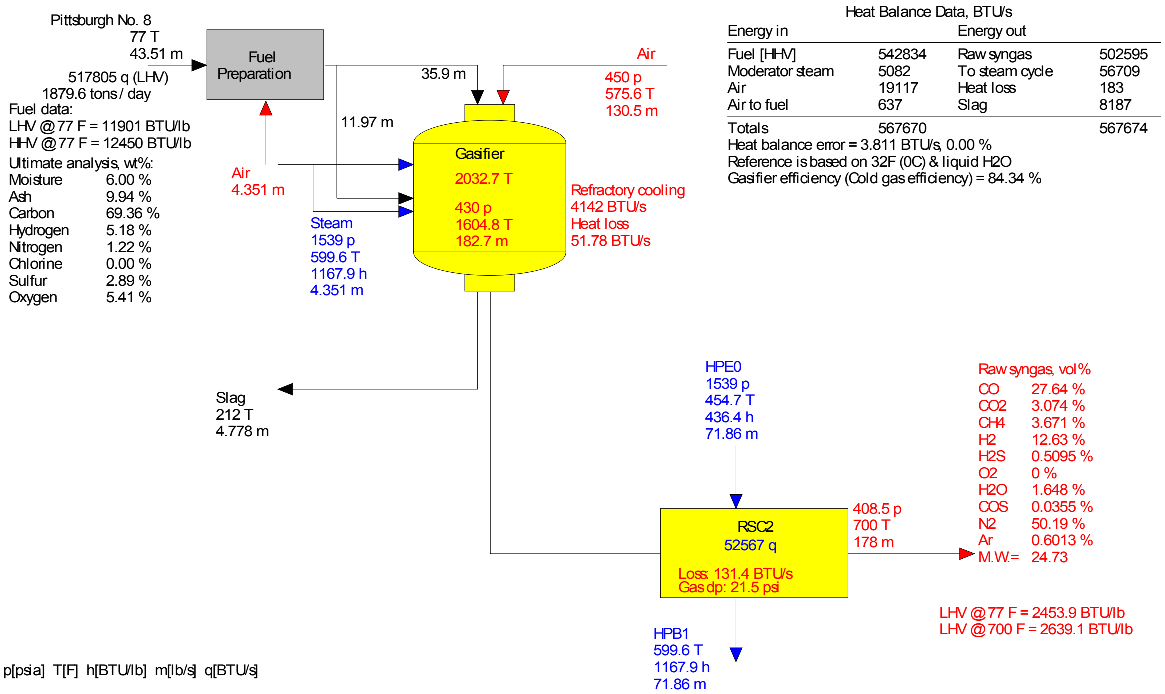

Figure 9 Graphical output of the air-blown gasifier with 50% air integration for Case 5

Table 7 Comparison of cleaned syngas between oxygen-blown Case 4 and air-blown Case 5

Syngas property	Case 4	Case 5
Pressure (psia)	367.6	367.6
Temperature (°F)	277.2	261.9
Mass flow rate (lbm/s)	75.2	174.9
CO (%)	58.78	28.17
CO_2 (%)	2.04	3.17
N_2 (%)	5.716	51.17
H_2 (%)	32.2	12.88
H_2O (%)	0.2549	0.2541
LHV (Btu/lb)	5547	2500

Table 8 Comparisons between oxygen-blown Case 4 and air-blown Case 5 in cycle performance

	Case 4	Case 5	Difference
GT Air Extraction	50%	50%	
Coal Mixture	Dry	Dry	
Oxidant type	Oxygen	Air	
Coal input (tons/day)	1,780.9	1,879.6	98.7(5.5%)
Slag (lbm/s)	4.527	4.778	0.251(5.5%)
Air Supply aux. (MW)	14.293	18.059	3.766(26.3%)
Air Sup. Heat Rej.(Btu/s)	2,556.6	0	-2,556.6
Gross Power (MW)	261.24	275.48	14.24(5.45%)
Net Power(MW)	237.97	245.42	7.45(3.13%)
LHV Elec. Eff. (%)	45.98	44.92	-1.06(2.3%)

3.6 Case 6 – Air-Blown, Sweet CO Water Shift with Carbon Capture

Case 6 employs a two-stage gasifier operated under dry-fed, air-blown conditions, 50% integration with sweet water-gas shift, and CO_2 removal. Similar to Case 3 in Fig. 8, in the "sweet shift" arrangement, the fuel gas from water scrubbing is reheated and fed to a COS hydrolysis reactor. It is then cooled and fed to a solvent scrubber which removes sulfur compounds. The sulfur-free gas is reheated, fed to a shift reactor, cooled, and fed to a second solvent scrubber for removal of CO_2. The ratio of mass flow rates between air and fuel (Air/f) is 3.0. The net power output of the plant is 236.697 MW, and the net LHV electrical efficiency is 40.01. The gas turbine provides approximately 73.8% of the total power output, while the steam turbine provides the rest of the power.

Table 9 Effect of carbon capture on raw syngas and clean syngas composition in air-blown Case 5 vs. Case 6

		CO	CO_2	H_2	H_2O	N_2	LHV(Btu/lb)
Case 5 no CCS	Cleaned Syngas	28.17	3.17	12.88	0.25	51.17	2500.6 @262°F
Case 6 w/ CCS	Raw Syngas	27.66	3.05	12.66	1.66	50.18	2639.8 @700°F
	Cleaned Syngas	0.44	2.41	31.84	21.71	40.18	2753.3 @720°F

Similar to the gas clean-up system of Case 3 in Fig. 8, the fuel gas leaving the gasifier at 1606°F and 197.9 lbm/s. After the RSC2, the raw syngas temperature and pressure reduce to 700°F and 408.5 psia, respectively. The syngas's LHV at this point is 2639.8 Btu/lbm (6.14 MJ/kg,). After water shift, the temperature of the fuel gas increases up to 720°F. An amount of 93.25 lbm/s of CO_2 are removed, and cleaned hydrogen-rich syngas is produced. The LHV (Table 9) of the cleaned syngas is 2753.3 Btu/lbm (6.40 MJ/kg).

Table 10 Effect of carbon capture on cycle performance between air-blown Case 5 (no capture) and Case 6 (with carbon capture)

	Case 5 No CCS	Case 6 W/ CCS	Difference
GT Air Extraction	50%	50%	
Coal Mixture	Dry	Dry	
Oxidant type	Air	Air	
CO_2 Capture	No	Yes	
CO Shift Converter	No	Sweet	
Coal input (tons/day)	1,879.6	2036.7	157.1(8.36%)
Slag (lbm/s)	4.778	5.174	0.396(8.29%)
Air Sup. Aux.(MW)	18.059	19.397	1.338(7.4%)
Air Sup. Heat Rej(Btu/s)	0	0	0
Gross Power (MW)	275.482	267.962	-7.25(2.7%)
Net Power (MW)	245.417	238.697	-6.72(2.7%)
LHV Elec. Eff. (%)	44.92	40.01	-4.91(10.9%)

When compared with Case 5 without carbon capture, the coal feed rate of Case 6 (see Tables 9 and 10) increases from 1,879.6 tons/day to 2,036.7 tons/day to get approximately the same amount of syngas, the air supply power increases by 7.4%, and the net output power decreases by 2.7%. Since the high temperature CO_2 is removed from the gas cleanup system, the energy cost in CO shift and CO_2 capture translates into a significant 4.91 percentage point (or 10.9%) decrease in LHV electric efficiency in Case 6. For slurry-fed, oxygen-blown gasification, the system with CO_2 capture (Case 3) has a 4.81 percentage point (or 11.6%) decrease in LHV electric efficiency when compared with the system without CO_2 capture (Case 2). This indicates that the loss of efficiency for carbon capture is similar in both air-blown, dry-fed and oxygen-blown, slurry-fed systems, although the dry-fed, air-blown system with CO_2 capture (Case 6) has a higher LHV efficiency (40.01%) than the slurry-fed, oxygen-blown system (Case 3) with CO_2 capture (36.46%). Since the syngas clean systems are same in both Case 3 and Case 6, the loss of efficiency for carbon capture is similar. The difference in LHV efficiency is caused by the power consumption of the ASU.

3.7 Case 7 – Air-blown, Sour CO WGS, with Carbon Capture

Case 7 employs a two-stage, dry-fed, air-blown gasifier with 50% integration, sour CO water-gas shift, and CO_2 capture. In the "*sour shift*" arrangement, the fuel gas from gasification, after water scrubbing, is reheated and fed to a shift reactor that uses a sulfur-tolerant catalyst. The catalyst also shifts the COS into H_2S. The fuel gas is then cooled and water vapor is condensed. The gas is then fed into a solvent scrubber, which removes sulfurous compounds and CO_2. The ratio of the mass flow rates between oxygen and fuel (O_2/f) is 3.0. The net power output of the plant is 226.645 MW, and the net LHV electrical efficiency is 37.93%. The gas turbine provides approximately 73.8% of the total power output, while the steam turbine provides the rest of the power.

After CO water shift, the temperature of the fuel gas is increased up to 700~850°F (Fig. 11). To remove H_2S, the gas must be cooled down to near the ambient temperature. For this, a cooler following the CO water shift is needed. The heat rejected form this cooler and cooler 3 is expelled to the environment and results in a reduced efficiency. Although a waste-heat recovery scheme could be added, the impact is considered small and, thus, this option is not pursued. An amount of 94.11 lbm/s of CO_2 is removed, and the cleaned hydrogen-rich syngas is produced.

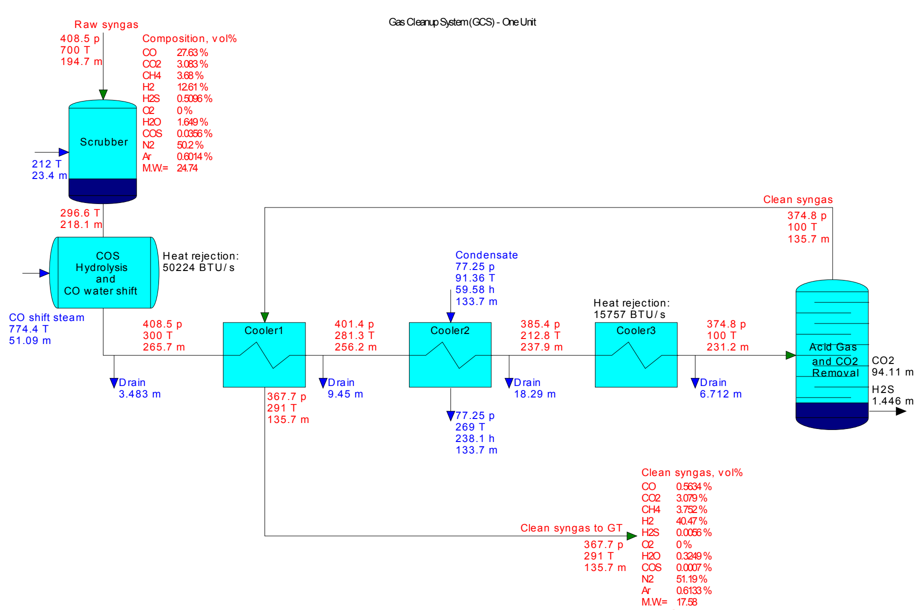

Figure 11 Graphical output of gas cleanup system for sour shift of Case 7

In comparison with sweet shift in Case 5 (see Table 11), the cleaned syngas's LHV increases by 30%, and the coal feed rate increases by 9.4%, but the net power decreases by 7.65% with a significant reduction of 8.76 percentage points (or 19.3%) in efficiency. This is worse than implementing sweet carbon capture in Case 3 (Oxygen-blown and slurry-fed). The major difference between sweet and sour shifts is the significantly increased amount of water vapor in the sweet-shifted fuel gas. The sour-shifted syngas (Case 7) only contains 0.32% vol. water vapor. Since the steam requirement for the sweet shift section (75.78 lbm/s) is higher than that of the sour shift section (51.09 lbm/s), Case 6 has more high-pressure steam bled from steam turbine and results in a lower ST power output than in Case 7. In Case 7, however, a large amount of heat is rejected during gas cleanup. It should be recovered to help increase the LHV efficiency of the whole power plant.

Table 11 Comparison of cycle performance in air-blown, dry-fed Cases 5, 6, and 7

	Case 5	Case 6	Case 7	Diff.(5 & 7)
GT Air Extraction	50%	50%	50%	
Coal Mixture	Dry	Dry	Dry	
Oxidant type	Air	Air	Air	
CO_2 Capture	No	Yes	Yes	
CO Shift Converter	No	Sweet	Sour	
Coal input (tons/day)	1,879.6	2036.7	2056.1	176.5 (9.4%)
Slag (lbm/s)	4.778	5.174	5.226	0.448 (9.4%)
Air Supply Aux.(MW)	18.059	19.397	19.839	1.78 (9.85%)
Air Sup. Heat Rej (Btu/s)	0	0	0	0
Gross Power (MW)	275.482	267.962	257.342	-18.14 (6.58%)
Net Power (MW)	245.417	238.697	226.645	-18.77 (7.65%)
LHV Elec. Eff.(%)	44.92	40.01	36.25	-8.76 (19.3%)

4.0 CONCLUSIONS

In this study, simulations of approximately 250 MW coal-based IGCC power plants have been conducted to investigate the effects of various parameters on the syngas composition and IGCC plant performance, including. The results are shown in Tables 13 and 14.)

Effects of Gas Turbine Air Extraction (GT-ASU Integration) - The gas turbine air extraction (or GT-ASU integration) significantly reduces the air separation unit power consumption. The results show that 50% GT-ASU integration (i.e. 50% of the air required by ASU is supplied by extracting the compressed air from the GT compressor) saves about 48% of the energy, including 30% of the total auxiliary power consumption and 18% of the total heat rejection. Furthermore, the extracted, compressed air is used to preheat the nitrogen entering the GT combustor to save on fuel consumption.

Effects of Carbon Dioxide Capture - To capture CO_2, the WGS reaction is prioritized to convert CO and steam to CO_2 and H_2. The WGS process requires high-pressure steam that takes useful power away from the ST, and CO_2 removal reduces the GT output due to decreased flue gas mass flow rate. In summary, CO_2 capture reduces the total IGCC power output by 2.7% and efficiency (LHV) by 11.6 % (4.81 percentage points.)

Effects of Coal Mixture - The dry-fed IGCC system produces more CO and less H_2 than the slurry-fed system and utilizes less water. The dry-fed IGCC system has a much higher operating temperature (around 3800^{o}F) in the gasifier and produces more superheated steam to increase the ST power output. Carbon capture in a dry feed IGCC system takes much higher tolls on the net plant output power (-6.72%) and efficiency (-10.9% or -4.91 percentage point).

Effects of Oxidant -- Air-Blown versus Oxygen-Blown - The air-blown IGCC systems do away with the ASU, resulting in a significant reduction (~ 30%) of the capital and O&M costs. As expected, due to the abundance of nitrogen, the overall temperature in the air-blown gasifier is lower than in the oxygen-blown unit. The syngas of the air-blown gasifier has a higher mole number of CO_2, a lower mole number of CO, and significantly lower heating value (55% reduction) than that produced by the oxygen-blown gasifier. For air-blown gasification, the sizes for all equipment in the gas cleanup system are larger because the mass flow rate almost doubles from the oxygen-blown system.

Effects of Sour or Sweet CO Water Shift - The dry-fed IGCC system allows for the implementation of both sour and sweet shift processes. Coal slurry-fed gasification is better suited for sour shift due to the high moisture content in its syngas. The application of sweet shift in the slurry-fed process is less preferable than sour shift because it would result in water vapor condensation prior to the desulfurization section, which is operated at the ambient temperature. The sour water shift operation requires less water than the sweet water shift operation.

Table 13 Summary of clean syngas compositions and LHVs for simulated cases

(Vol. %)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
CO	51.41	51.41	0.7153	58.78	28.17	0.443	0.5634
CO_2	12.66	12.66	4.385	2.04	3.17	2.418	3.079
CH_4	0.0018	0.0018	0.0013	0.994	3.742	2.925	3.752
H_2	33.34	33.34	58.24	32.2	12.88	31.48	40.47
H_2S	0.0105	0.0105	0.0073	0.0098	0.0055	0.0044	0.0056
O_2	0	0	0	0	0	0	0
H_2O	0.2709	0.2704	35.05	0.2549	0.2541	21.71	0.3249
COS	0.0011	0.0011	0.0007	0.0011	0.0007	0.0006	0.0007
N_2	2.306	2.306	1.604	5.716	51.17	40.18	51.19
Ar	0	0	0	0	0.613	0.4814	0.6133
M.W.	21.34	21.34	10.07	19.82	24.77	17.66	17.58
LHV (Btu/lb)	4653 @349°F	4648 @335°F	6751 @920°F	5547 @277°F	2500.6 @262°F	1753.3 @720°F	3259 @291°F

Table 14 Summary of IGCC System performance result for simulated cases

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Oxidant Type	Oxygen	Oxygen	Oxygen	Oxygen	Air	Air	Air
Coal Mixture	Slurry	Slurry	Slurry	Dry	Dry	Dry	Dry
GT Air Extraction	No	50%	50%	50%	50%	50%	50%
CO_2 Capture	No	No	Yes	No	No	Yes	Yes
CO Shift Conversion	No	No	Sweet	No	No	Sour	Sweet
Coal Input (tons/day)	2,328.9	2,187.6	2,408.4	1,780.9	1,879.6	2,056.1	2,035.7
Gross Power (MW)	316.561	294.874	289.365	261.243	275.482	257.342	267.962
GT Power (MW)	191.959	162.279	186.225	155.138	162.922	167.221	185.945
ST Power (MW)	124.602	132.595	103.140	106.105	112.560	90.121	82.017
ASU Aux. Power (MW)	37.337	21.461	23.627	14.293	18.059	19.839	19.397
Total Aux. Losses(MW)	48.479	32.456	34.130	23.275	30.065	30.697	31.264
Net Power (MW)	268.082	262.418	255.235	237.969	245.417	226.645	236.697
Net LHV Heat Rate (Btu/KWh)	8615	8268	9258	7422	7596	8997	8529
Electric Efficiency (LHV %)	39.61	41.27	36.46	45.98	44.29	37.93	40.01
Efficiency Increase (%)	0.0	4.2	-8.0	16.1	11.8	-4.2	1.0

5.0 ACKNOWLEDGMENTS

This study was supported by the Department of Energy and the Louisiana Governor's Energy Initiative via the Clean Power and Energy Research Consortium (CPERC), administered by the Louisiana Board of Regents.

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