NTNU – Trondheim
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CO2 capture in power plants- using the oxy-combustion principle

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MASTER THESIS

for

Student Ricardo Llorente Manso

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CO2 capture in power plants – using the oxy-combustion principle

CO2-fangst i termiske kraftverk – bruk av prinsippet om oxy-combustion

Background and objective

One of the main challenges with CO_2 capture in power generation systems is the high energy penalty related to the capture of CO_2. The current status with respect to energy penalty is that post-combustion systems seem to imply a slightly less penalty compared to pre-combustion and oxy-combustion methods. A main disadvantage with the post-combustion method is that capturing CO_2 from an atmospheric flue gas requires large equipment because of the very large volumetric flow rates, as well as a significant energy penalty because of the very low partial pressure of CO_2 in the flue gas.

In the present work the candidate shall investigate oxy-combustions cycles, in order to find the efficiency potential and operational advantages and drawbacks. The basis for work is the Allam Cycle from company NETPOWER, http://netpower.com/technology.html. Other similar cycles may also be investigated for the purpose of comparison.

The tasks for the Master thesis include:

1) A literature review of the Allam cycle and other oxy-combustion cycles, both for coal and natural gas as fuel.
2) Carry out a heat and mass balance of the Allam cycle and compare it similar cycles and other alternatives like the post-combustion technology based on amine absorption.

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Within 14 days of receiving the written text on the master thesis, the candidate shall submit a research plan for his project to the department.

When the thesis is evaluated, emphasis is put on processing of the results, and that they are presented in tabular and/or graphic form in a clear manner, and that they are analyzed carefully.

The thesis should be formulated as a research report with summary both in English and Norwegian, conclusion, literature references, table of contents etc. During the preparation of the text, the candidate should make an effort to produce a well-structured and easily readable report. In order to ease the evaluation of the thesis, it is important that the cross-references are correct. In the making of the report, strong emphasis should be placed on both a thorough discussion of the results and an orderly presentation.

The candidate is requested to initiate and keep close contact with his/her academic supervisor(s) throughout the working period. The candidate must follow the rules and regulations of NTNU as well as passive directions given by the Department of Energy and Process Engineering.

Risk assessment of the candidate's work shall be carried out according to the department's procedures. The risk assessment must be documented and included as part of the final report. Events related to the candidate's work adversely affecting the health, safety or security, must be documented and included as part of the final report.

Pursuant to "Regulations concerning the supplementary provisions to the technology study program/Master of Science" at NTNU §20, the Department reserves the permission to utilize all the results and data for teaching and research purposes as well as in future publications.

The final report is to be submitted digitally in DAIM. An executive summary of the thesis including title, student's name, supervisor's name, year, department name, and NTNU's logo and name, shall be submitted to the department as a separate pdf file. Based on an agreement with the supervisor, the final report and other material and documents may be given to the supervisor in digital format.

☐ Work to be done in lab (Water power lab, Fluids engineering lab, Thermal engineering lab)
☐ Field work

Department for Energy and Process Engineering, February 1, 2013.

Lars E Bakken
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Olav Bolland
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Co-supervisor: Dr. Lars Olof Nord, NTNU

Preface

This thesis, *CO_2 Capture in Power Plants-Using the Oxy-Combustion Principle*, has been written as the Master Thesis of Ricardo Llorente Manso. The Master Thesis is the final work of the 5-year studies of Ingeniería de Minas (Mining Engineer) at the Universidad Politécnica de Madrid (UPM). The thesis has been written in Trondheim, for the Department of Energy and Process Engineering at the Norwegian University of Science and Technology, this was possible thanks the international program ERASMUS.

The aim of the work is the study of the Allam cycle proposes by NET POWER, an oxy-combustion cycle to. The cycle is compared with other cycles to show its potential.

This study may be helpful for the research in the field CO2capture and storage to mitigate the effect of the emission from the fossil fuels power plants.

July 8th 2013, Trondheim

Ricardo Llorente Manso

Abstract

In the CO_2 capture from power generation, the energy penalties for the capture are one of the main challenges. Nowadays, the post-combustion methods have energy penalties lower than the oxy-combustion and pre-combustion technologies. One of the main disadvantages of the post-combustion method is the fact that the capture of CO_2 at atmospheric pressure requires quite big equipment for the high flow rates of flue gas, and the low partial pressure of the CO_2 generates an important loss of energy.

The Allam cycle presented for NETPOWER gives high efficiencies in the power production and low energy penalties. A simulation of this cycle is made together with a simulation of power plants with pre-combustion and post-combustion capture and without capture for natural gas and for coal.

The simulations give lower efficiencies than the proposed for NETPOWER. For natural gas the efficiency is 52% instead of the 59% presented, and 33% instead of 51% in the case of using coal as fuel. Are brought to light problems in the CO2 compressor due the high flow of CO2 that is compressed until 300bar to be recycled into the combustor.

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1 Introduction

Has been probed that the climate is changing and an incensement of the temperature in the atmosphere has been measure. In the next decades the frequency and extent of natural disasters are expected to increase due the change in the climate conditions. Some ecosystems are very sensitive to the increasing of temperature in line with greenhouse gas emissions .During the 21st century the global surface temperature is expected to rise from 1.1-2.9 °C for their lowest emissions scenario and from 2.4-6.4 °C for their highest [1]. The changes in the environmental conditions are somewhat caused by human activity, the emission of CO2 have the greatest impact on the greenhouse effect and it is estimated that represents approximately 5 % of the global warming [1]. The amount of CO2 gradually has been increased during the last years and it expected it is still increasing. The consumption of energy will increase with the increasing of population in the word and the economical development of countries like China of India. The Figure 1.1 gives the international energy agency (IEA) prediction for the future consumption of primary energy and the source of it. The fossil fuels are the energy source that will carry the increase of energy consumption. The main increase in energy source is the coal, which is a cheap an abundant fuel in countries like China and USA.

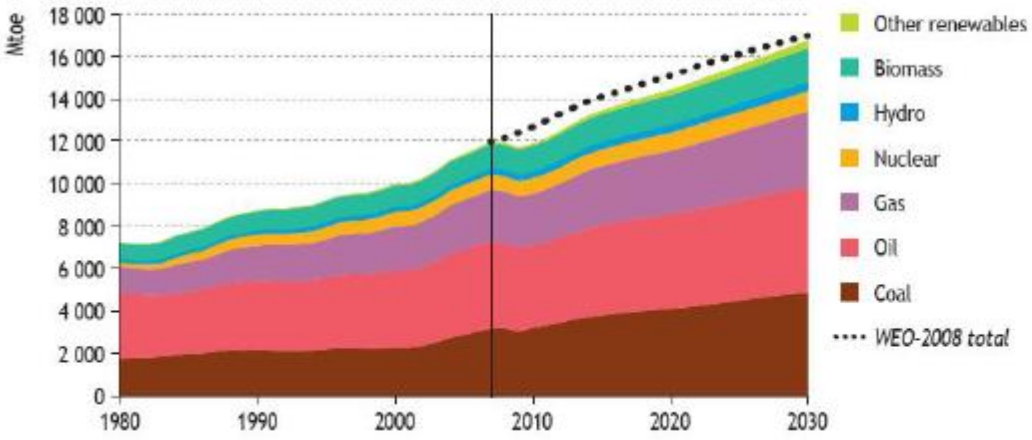


Figure 1.1 World primary energy demand by fuel in reference scenario [2]

There are different solutions for the increasing of CO_2 emissions; one of them is to introduce more renewable energy sources but according the predictions of the IEA it is not realistic solution. Another option is the capture and storage the CO2 to keep it away from the atmosphere, this second option is the studied in the present work.

1.1 Carbon capture and storage

The carbon capture and storage is still a field in development, there are some power plants working that use one or more capture solution like the carried by European Carbon dioxide Capture and Storage Laboratory Infrastructure (ECCSEL) [3]. Actually there are three main methods for the capture of CO_2; pre-combustion, post-combustion and oxy-combustion. In this work a new oxy-fuel cycle will be compared with pre-combustion and post-combustion. In the Figure 1.2 a graph with the different methods is given.

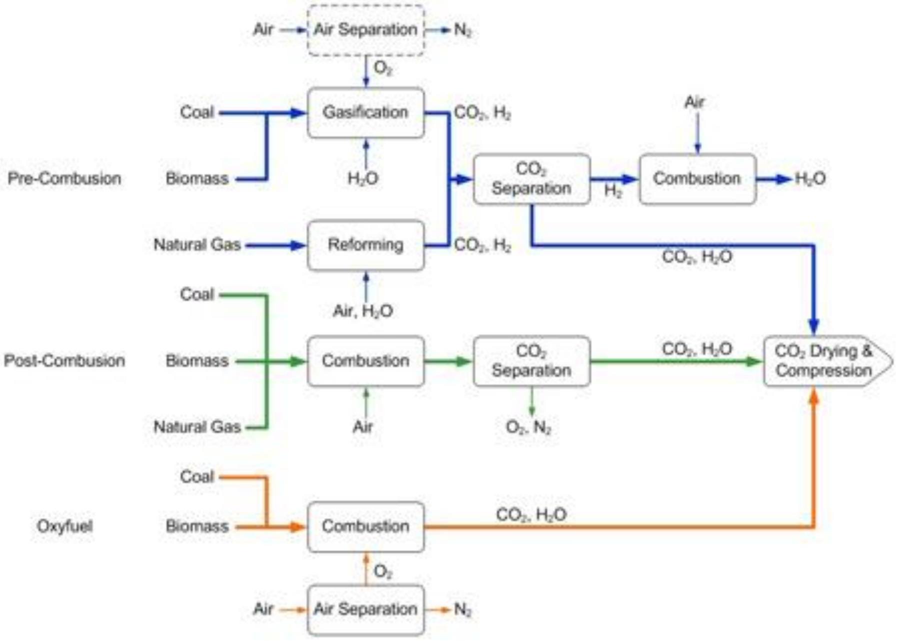


Figure 1.2 Main methods for CO2 capture in power plants using carbonaceous fuels [4]

1.1.1 Pre-combustion

The method is divided in phases, the first consist in the split of the molecule by partial oxidation resulting a syngas composed mainly by CO and H_2. The second steep is shift reaction of the CO with steam to produce CO_2 and H_2. The CO_2 can be separated from the rest of the stream. The idea is the formation of CO_2 while the as much as possible the heating value of the fuel is converted in heating value in the form of molecular hydrogen [5].

1.1.2 Post-combustion

The capture of the CO_2 is made after the combustion; before the discharger of the flue gas the CO_2 is removed making it pass thought equipment. It can be done different methods like chemical absorption, membrane and adsorption processes. The most mature technology for the capture process is the based on chemical absorption with aqueous amines. Post-combustion is considered most mature among the different CO2 capture technologies. During many years the CO_2 techniques have been used for the food processing and chemical industries in the production of pure CO2 from natural gas or industrial processing [6].

1.1.3 Oxy-combustion

The main idea is burn the fuel with almost pure oxygen to obtain mainly H_2O and CO_2 as combustion products. The flame temperature will be very high and the temperature will get down with heat removal or recirculation of combustion product recycled. The H_2O and CO_2 and are easily separated cooling the stream until most of the water is condensed. In section 5 more details are given and some examples are described.

1.2 Scope of the Report and Outline

The aim of the work is the study of the Allam cycle proposed by NET POWER, an oxy-combustion cycle. This new cycle is joined to the rest of cycles that have been proposed and studied during the last years. The cycle is proposed for the natural gas and coal as fuel. The cycle is simulated for both cases and for different fuels to compare the result obtained with the supplied by NET POWER and other plants using other capture methods and without capture.

For the simulation different programs were used. PRO/II and TERMOFLEX were used for the simulation of the Allam cycle and GTPRO for the plants using pre-combustion capture, post-combustion capture and without capture. The efficiencies of the plants are compared as well as the capture efficiency.

The report is structures as follow:

- A theoretical part that describes the fuel, the technologies used in the power plants and how the CO_2 is compressed.
- A literature review of different oxy-combustion cycles proposed before.
- A description of the equations used in the calculations and the technical specifications used in the simulations.
- A description of the cycles simulated.
- The results are expressed and discoursed. First are given for the natural gas, later for the coal and finally other problems are discussed.

2 Fuel

The combustion is the chemical reaction between oxygen and a combustible fuel. The main combustible elements are C, H_2 and with a minor significance S_2. The reactions which take places are the following ones [7].

$$C + O_2 \rightarrow CO_2 \qquad 32800 \text{ kJ/kg} \tag{2.1}$$

$$2\,H_2 + O_2 \rightarrow 2\,H_2O \qquad 142700 \text{ kJ/kg} \tag{2.2}$$

Usually the oxidiser source is the air with a 21% of O2, but it can be use O_2 in a percentage of 95 or 99.5% [8]. For the calculation of the energy content in the fuel it needed to take in account the energy of the molecular formation and the contribution of the other element like the sulphur. The H_2O is released as steam during the combustion. If the fuel content water it reduces the heat transferable in the process, that final result is that is cold the low heating value.

The principals fuel used in the generation of energy are fossil fuels (coal, petroleum and natural gas) and their derivations but it can be used wood or waste. As can be seen in Figure 2.1 in 2010 from the 21431 TWh of electricity produced the 40% if from coal or petroleum peat, the 22,2 % from natural gas ,4.6 % from oil and the rest from nuclear power and renewable [9].

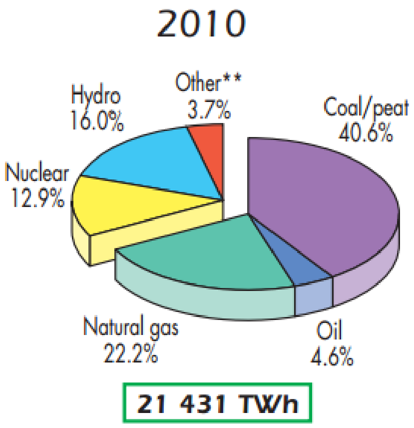


Figure 2.1 **Source for the production of energy in 2010 [9]**

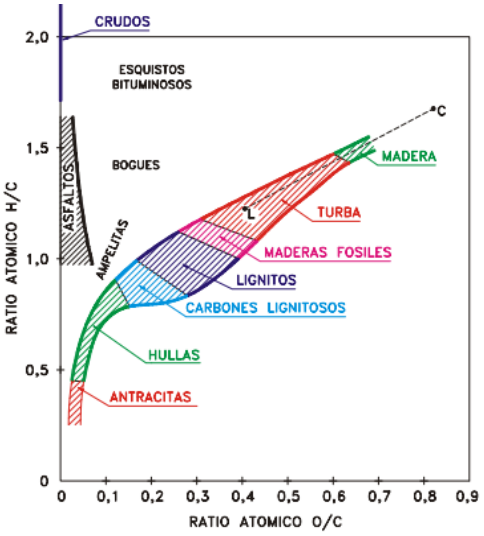
2.1 Coal

The formation of the coal starts in a swamp. The dead mosses, leaves, twigs, and other parts of trees do not decompose completely in the anaerobic environment. Whit the tame the organic material is covered by sand and mud coming from the rivers or from the sea rise. With the time the peat under the sediments stat to lost water and gases turning in lignite, the most immature coal. The pressure and the temperature increase as the more sediments arrived over the deposit, which produce the loss of more water and gases and create the rest of types of coal. The evolution of the coal is made with the decease of the O/C proportion and the decreasing of the H/C proportion.

The molecular composition of the organic material which forms the coal is really complex; they are carbohydrates (cellulose), high weight proteins, glycosides, fats, waxes, resins…. All that components are broken in the transformation of the coal but we don´t know exactly the molecular composition because there are a lot and with a very complicated composition. We only can estimate the elemental composition which is basically carbon, hydrogen nitrogen, oxygen, chlorine and sulfur. The ash in the coal can have two origins, the organic origin is because the original plants have in their structure that molecules and the inorganic one comes from the sediments that are mixed in the deposition of the organic material and the sediment which covert the deposit.

Special importance has the pyrite (FeS_2) in the composition of the ash, it can represent the 50% of the sulfur content of the coal, and it can be easily remover until a 90 % washing the coal [5]. The pyrite which is not removed in the combustion is oxidized into sulfur dioxide (SO_2) and in a smaller proportion into sulfur trioxide (SO_3). The rest of the sulfur is content bound to the carbon atoms, which will be converted in the gasification into hydrogen sulfide (H_2S) and carbonyl sulfide (COS) [5].

There are different classifications of the coal; the principals are the Van Krevelen and the ASME. The fist one is based in the relation of the ratios H/C and O/C, according that classification the most evolutes coals have less proportion of oxygen and hydrogen and more carbon in their composition, in Figure 2.1 the Van Krevelen is given. The ASME classification is based in energy ranks, a higher-rank coal is defined as a coal with a HHV over 24MJ/kg on a moisture and ash-free basis, we can include in that rank the anthracite, bituminous coal and some sub-bituminous coals. In the Figure 2.2 the classifications are illustrated [10].



Madera: Wood.

Turba: Peat.

Lignitos: Lignite.

Carbones lignitosos: Lignitish coals.

Hulla: Bituminous.

Antracita: Anthracite.

Crudos: Oil.

Figure 2.2 Van Krevelen graph representing different combustibles [10]

Both classifications explained have a main coal classification in common based in the moisture and the volatiles gases content, it represent the evolution of the coal and the increasing of the energy content. The peat and the graphite (pure carbon) are not considering coals even when they are the origin and the final end of the coal formation process. The main properties are explained for the different coals.

Increased pressures and temperature from sediments caused buried peat to dry and harden into lignite. Lignite is a brownish-black coal with generally high moisture and ash content and lower heating value. It has the lower rank, containing 25 to 35 percent carbon and a heating value from 4,000 to 8,300 Btus per pound. However, it is an important form of energy for generating electricity in plant near the mine, particularly in the American Southwest, and to produce synthetic natural gas and liquids.

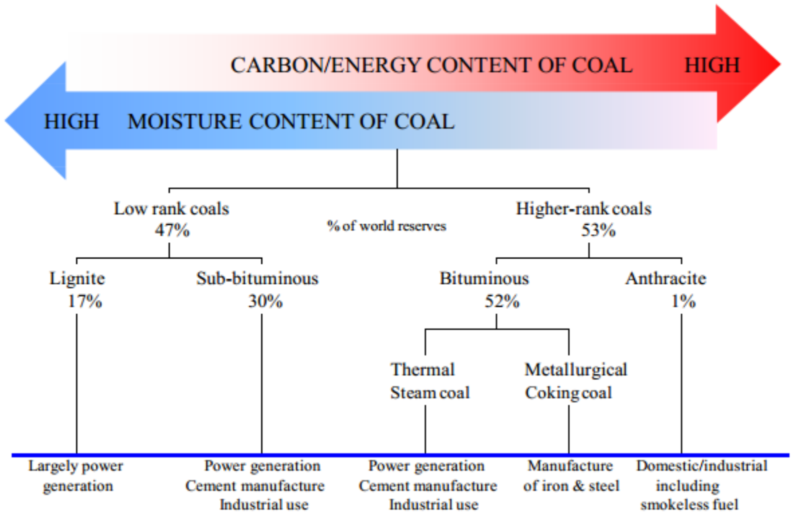


Figure 2.3 **Types of coals, its main uses and reserve shares [5]**

Under more pressure, some lignite was changed into sub-bituminous. It is a dull black coal with a heating value higher than lignite, between 8,300 to 11,500 Btus per pound; it contains about 35 to 45 percent carbon [10].

The bituminous coal also called sometimes “soft coal”. It is 45 to 86 percent carbon, softer than anthracite, and has a heat value between 10,500 and 14,000 Btus per pound. This is the type most commonly used for electric power generation and for production of coke for the steel industry [10].

The anthracite or ‘hard coal,” was formed from bituminous coal when great pressures developed during the creation of mountain ranges. It contains between 86 to 97 percent carbon, and has a heat content of nearly 15,000 Btus per pound. It is used for space heating and generating electricity but the efficiency in the power generation is lower that with the bituminous coal [10].

3 Power plant technologies

There are different technologies to produce energy from the different fuels. The most common fuel used in the power plant is by far the coal. The coal technologies can be divided in direct combustion and in gasification, which flue gas is used in a gas turbine process. The direct combustion possibilities are the pulverized coal combustion (PCC), circulating fluidized bed combustion (CFBC) and pressurized fluidized bed combustion (PFBC). The natural gas is the next fuel most used and there are a lot of plants all over the word with use it as fuel in a gas turbine engine.

The PCC is the most common process in the coal power plants. It works near the ambient pressure and accept a large variety of coals but is not appropriate for the coals with a large content of ash. The dry pulverized coal (300µm) is blown with part of the combustion air into the combustion chamber. The temperature of combustion is high, around 1300-1700 ºC. There is not formation of slag because most of them work with a dry bottom which avoids it. The 60-70% of the ash travel with the flue gas in small particles which need to be recollected [5].

One of the characteristic of the CFBC is the recirculation of the coal particles from the cyclone to the boiler. The size of the particles is less than 25 mm. The combustion takes place near atmospheric pressure at the bottom of the riser where the injection of the coal and the air take place. The flue gases and particles are fluidized up to a cyclone where the gas in cleaned of ash [5].

In PFBC the combustion take place in a pressurized boiler. The main advantages of it are the most compact system, the use of different types of fuels in different qualities, high energy efficiency and good environmental performance. The coal is pulverized under the 5 mm and mixed with water and a solvent to create slurry. The combustion take place at 800-850 ºC and a pressure of 12-16 bar. Different cyclones will clean the flue gas of particles [5].

3.1 Integrated gasification combined cycle (IGCC).

The IGCC can be separated in 3 blocks. The first one is the gasification block, where the coal is burned with pure oxygen and steam to generate syngas (H_2 and CO). The slag and particles are taken away and the syngas is cooled. The second block is the syngas cleaning section where the H_2S and COS. In that step the CO_2 produced can be recuperated to be stored. The final block is the power island, where the electricity is generated in a gas turbine and a in a steam turbine in the steam cycle (HRSG). The different parts will be further explained in the next sections. In Figure gives the different blocks of an IGCC and theirs components. The Figure 3.1 shows a flow diagram of a plant with pre-combustion capture.

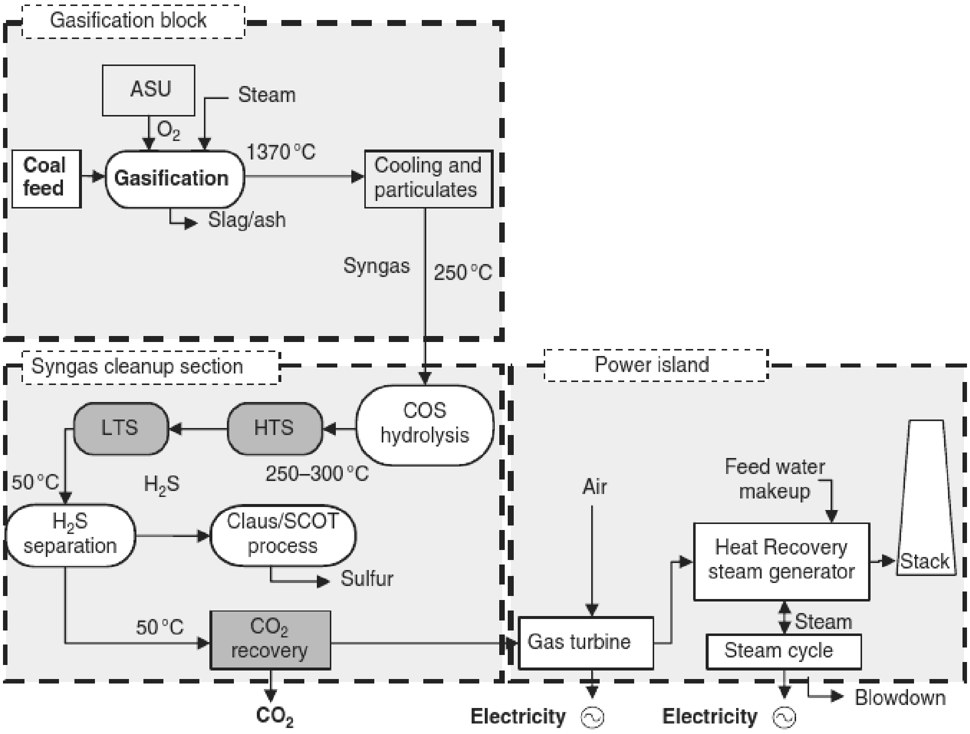


Figure 3.1 **Typical IGCC plant process flow diagram with CO_2 capture [11]**

3.1.1 Air separation unit (ASU)

There are different technologies for the separation of oxygen from the air but the only economically commercial is the cryogenic distillation of air. That unit produces oxygen purity normally in a proportion of 95-99.5 %. As a sub products nitrogen high purity nitrogen and argon can be produced. The nitrogen can be used in the gasifier or in the steam turbine to improve the efficiency of the plat [12].

The cryogenic technology is based in the difference of boiling points of oxygen, nitrogen and argon, at 1 atm are respectively -182.9, -195.8 and -185.9 ºC. The CO2 and the water contained in the stream have to be removed before the distillation of the oxygen and nitrogen using solid adsorbent pellets like alumina or molecular sieves. The separation of the oxygen and the argon take a lot of trays or height of packing in the distillation column [5].

There are different configurations for the distillation, it can be done in one, two or three columns [13]. For I brief explanation, the processing explained is a cryogenic air separation with a double column system and compression of oxygen in liquid state. A flow diagram of the air separation unit is in Figure 3.2.

The low pressure column works slightly over atmospheric pressure while the high pressure works between 4 and 7 bar. The oxygen produced in a gaseous state in pressurized with a pump to be provided to the power plant. The maximum pressure level is 75 bar in the ASU, but it can be compressed until higher levels in the power plant.

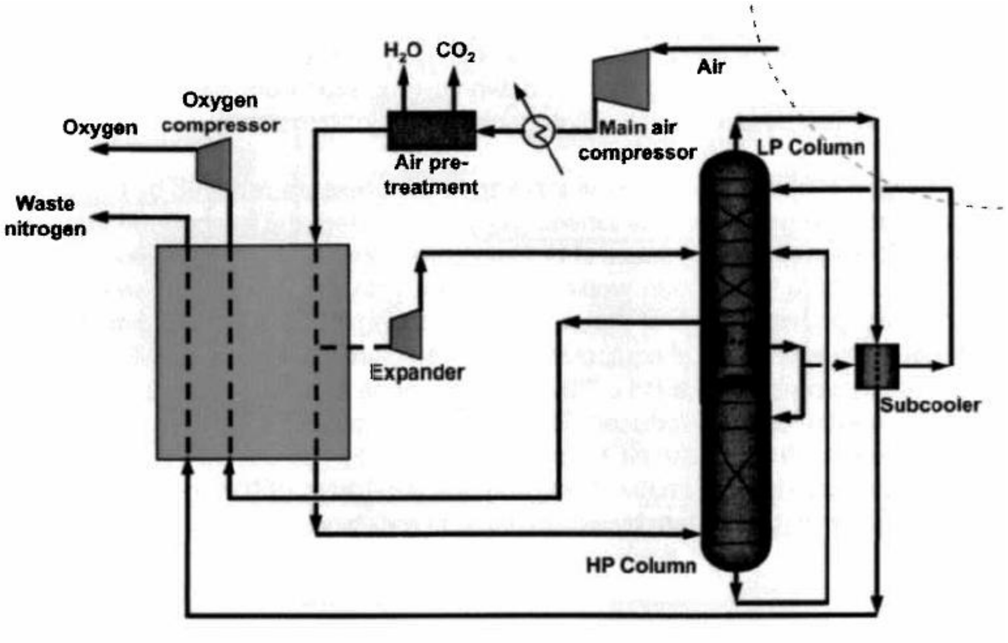


Figure 3.2 Flow diagram of a cryogenic air separation unit with double column system and compression of oxygen in gaseous state

Fist the filtrated air is compressed until 4-6 bar and cooled by water or the exhaust nitrogen. After it the water and the CO2 is removed before main heat exchanger, it takes place in two adsorbers vessels full of zeolite and alumna. The regeneration of the adsorbers is made by heated nitrogen.

In the MHX the air is cooled until the dew point to be sent to the HP column, where the vapor raises against the liquid and there is a exchange of nitrogen. The vapor is almost pure nitrogen, which is recycled at the top of the HP and to the LP column. From the bottom the liquid is recycled at the middle of the LP. In the LP is where the final distillation take place and at the bottom we collect the oxygen and at the top the nitrogen. The final product streams are directed to the MHX to be heated.

For the actual state of the art of air separation the plant can produce between 3000 and 5000 tonm O2/day. The purity of the Oxygen goes from 95% to 99.6%, for the instrumentation of the purity we need more stages in the columns, this involve more investment, pressure drop and energy consumption

3.1.2 Coal preparation

The raw coal is received from the mine in certain condition of moisture and size, these conditions are not usually the adequate for our process and we will need to adequate the coal. The coal should be received as dry as possible because in that way we do not pay the weight of shipping that water. The lignite, as it is mentioned in section 2.1., is used near the mine. It is transported via belt conveyors to the boiler bunkers. The lignite moisture at this stage is 45 – 70 % [7].

For an optimal combustion, a percentage of moisture around 1 to 2 % is required for the solid fuel in dry feed system [7]. The raw coal can be dried inside the coal mill to reduce the moisture. Is the supply is wet (slurry) the control of the reduction of the moisture is not necessary.

Many mills are designed to reject or tolerate small minerals or metallic materials. In any case a magnetic separator could be installed in before the mill to remove larger metallic objects (work tools, parts of equipment) which could damage the conveyors or the pulverized coal feeder.

The size selection will have a big impact in the operation and economic of the system. Fine grinding is necessary to ensure a rapid ignition and complete combustion of carbon to maximize efficiency and to minimize ash and particulate deposits on heat-exchanger surfaces. Each technology have an optimum size and it goes related to the cost, reduce the size cost money in operation and in investment, also we have to take in account the ambient impact. Coal pulverization is currently carried out in ball mills, impact mills, fan mills, or in roller and race mills [7].

3.1.3 Gasification

Gasification consists in convert coal totally or partially into syngas (mainly CO, $H_{2,\ CO2}$ and CH_4). For the gasification are needed coal, stream and oxygen. The oxygen can be replaced by air but the most common technology used today is running with oxygen.

The gasification is non- catalytic partial oxidation and according to the proportion of fuel, steam and oxygen, the temperature, technology used the syngas composition and the proportion of the reactions which take place will be different. The different reactions and gasifiers will be explained.

3.1.3.1 Chemistry

There are two types of reactions, homogeneous and heterogeneous. The gas homogeneous reactions are easily represented in equations but for the reactions in different phases are more complicated because the heat and mass balance.

The gasification can be divided in various steps [13]:

I. Evaporation of moisture. It occur at temperature between 100 and 150ºC
II. Coal pyrolysis, releasing volatile matter. The pyrolysis is the decomposition of organic material without oxygen in the environment. It takes place mainly in 400-525ºC.
III. Combustion of volatiles. The combustion of the CO. CH4, H2, liquid hydrocarbons and tars increase the temperature inside the gasifier.
IV. Char reactions. It is the most complicated process and the slowest one. The coal is consider as pure carbon when react in the gasifier. The process takes place in high temperatures (800-1800ºC). The use of gas phase reactions instead of kinetic equations gives good results. The different reactions are explained divided in different groups.
V. Mineral matter release and transformation.

3.1.3.1.1 Reactions taken place in the gasification

The reaction between the carbon and the oxygen are [13]:

$$C(s)+O_2 \rightarrow CO_2 \quad (3.1)$$

$$2C(s)+ O_2 \rightarrow 2CO \quad (3.2)$$

$$2CO+ O_2 \rightarrow 2CO_2 \quad (3.3)$$

These reactions are highly exothermic and they will provide the heat for the endothermic reactions. The O 2 is completely consumed before these reactions have consumed all of the carbon [13].

$$C +C O_2 \leftrightarrow 2CO \quad (3.4)$$

That is the Boudouard reaction, it is an endothermic reaction. The reaction rate is several times lower that the reactions 3.1 and 3.2 [13].

$$C (s) + H_2O \leftrightarrow CO +H_2 \quad (3.5)$$

$$C (s) + H_2O \leftrightarrow C O_2+ H_2 \quad (3.6)$$

$$CO + H_2O \leftrightarrow C O_2+ H_2 \quad (3.7)$$

The main reaction to produce the CO and the H2 are the 3.5 and the 3.6, both are endothermic [13].

$$C(s) + 2 H_2 \leftrightarrow CH_4 \quad (3.8)$$

$$CO+3 H_2 \leftrightarrow CH_4+ H_2O \quad (3.9)$$

$$2 CO+2 H \leftrightarrow CH_4+ CO_2 \quad (3.10)$$

$$C O_2+4 H_2 \leftrightarrow CH_4+ 2 H_2O \quad (3.11)$$

These reactions of methanation increase the heating value of the syngas but they are very slow, so the presence in the methane is also low [13].

$$S+O_2 \rightarrow S O_2 \quad (3.12)$$

$$SO_2+3H_2 \leftrightarrow H_2S+2 H_2O \quad (3.13)$$

$$SO_2+2CO \leftrightarrow S+CO_2 \quad (3.14)$$

$$2H_2S+SO_2 \rightarrow 3S+2 H_2O \quad (3.15)$$

$$C(s) +2S \leftrightarrow CS_2 \quad (3.16)$$

$$N_2+3 H_2 \leftrightarrow 2NH_3 \quad (3.17)$$

$$2N2+2H_2O+4CO \leftrightarrow 4HCN+3 O_2 \quad (3.18)$$

$$N_2+nO_2 \leftrightarrow 2NO_n \quad (3.19)$$

That last reactions are the responsible of the formation of impurities in the syngas. The impact in the syngas is negligible but is important for the environmental point of view we want to reduce those impurities until a minimum level [13].

3.1.3.2 Gasifier types

There are mainly three commercial types of gasifiers, e fixed-bed, fluidized-bed, and entrained-flow systems. They work at different temperatures, pressures and coal size. For each application and for each type of coal a different type should be selected.

3.1.3.2.1 Fixed-Bed Gasifier

In a fixed-bed gasifier or moving-bed gasifier coal is supplied counter-current to the gasifying medium. The optimal size of the coal is between 5 and 50 mm [13]. Coal moves slowly down in the gasifier against an ascending stream of oxygen and water vapor. The drying and pyrolysis zone is located at the top of the gasifier, the coal is heated and dried and pyrolysis occurs. In the combustion zone, oxygen reacts with the char in a high temperature. The ash is removed from the bottom of the gasifier. The temperature is controlled by exceed of steam to avoid the fusion of the ash. Both the ash and the product gas leave between 400 and 600ºC. Fixed-bed gasifiers have the following characteristics [13]:

- Low oxidant requirements.
- Design modifications required for handling caking coal.
- High cold-gas thermal efficiency when the heating value of the hydrocarbon liquids is included.
- Limited ability to handle fines.

There are two commercial bed gasifiers, the Lurgi dry-ash gasifier with operate at 30-35 bar, 1090ºC at the combustion zone and the exhaust gas between 260 and 540ºC [13]. The other technology is the BLG which can use raw coal, and the gasifier is operated at temperatures above the ash fusion point to form a slag.

3.1.3.2.2 Fluidized-Bed Gasifier

In a fluidized-bed gasifier the size of the coal is between 0.5 and 10 mm and the coal is kept suspended in the gasifying medium. As in the fluidized-bed combustor the mixing and heat transfer are fast, that gives an uniform composition and temperature throughout the gasifier bed. The temperature in the combustion zone is kept below the melting point to avoid the formation of slag and clinker. Some unburned particles follow the syngas as it leaves the gasifier, in some models they are recollected by a cyclone and brought back the gasifier. The char and the ash are recollected at the bottom. The exhaust temperatures are high (700-1000 ºC) [13].the operating pressure is between 10 and 25 bar. Fluidized-bed gasifiers have the following characteristics [13]:

- Acceptance of a wide range of solid feedstock (including solid waste, wood, and high ash content coals).
- Uniform temperature.
- Moderate oxygen and steam requirements.
- Extensive char recycling.

Fluidized-bed gasifiers may differ in ash conditions, dry or agglomerating, and in design configurations for improving char use. The two main commercial versions types are the high-temperature Winkler (HTW) and Kellogg-Rust-Westinghouse (KRW).

3.1.3.2.3 Entrained-Flow Gasifier

In the entrained-flow gasifier the coal grading is very intense, the size have to be below the 500μm [13]. The coal entrance to the gasifying medium is in a co-current flow with the gaseous stream in a high-temperature flame. Residence time in this type of gasifier is very short specially compared with the fixed bed. The operation temperature is fixed well above ash-slagging conditions to ensure high carbon conversion. The ash exits the system as a slag which will be solidified with a water quench or cooled with a gas stream. The product gas and slag exit close to the reaction temperature, between 900 and 1600ºC [13]. Entrained-flow gasifiers have the following characteristics [13]:

- Ability to gasify all coals regardless of coal rank, caking characteristics, or amount of coal fines, although feed stocks with lower ash contents are favored.
- Uniform temperatures.
- Very short fuel residence times in the gasifier.
- Very finely sized and homogenous solid fuel required.
- Relatively large oxidant requirements.
- Large amount of sensible heat in the raw gas.
- High-temperature slagging operation.
- Entrainment of some molten slag in the raw gas.

The different models differ in the feed systems (coal-water slurry or dry coal), internal designs to handle the very hot reaction mixture, and heat-recovery configurations. The most of the coal-based IGCCs power plants running or under construction use that technology. The major commercial entrained-flow gasifiers are the ChevronTexaco (GE), Shell, Prenflo, and E-Gas gasifiers [13]. Especial importance has the GE and the Shell. In the simulations of that paper the gasifier used is based in the GE technology, so is that one which will be further explained.

3.1.3.2.4 GE gasifier

The GE technology offers both a radiant boiler and a total water quench as syngas cooling concepts. The water quench method is the used in the simulation and the one which will be further explained. Figure 3.3 show a flow diagram of a GE gasifier.

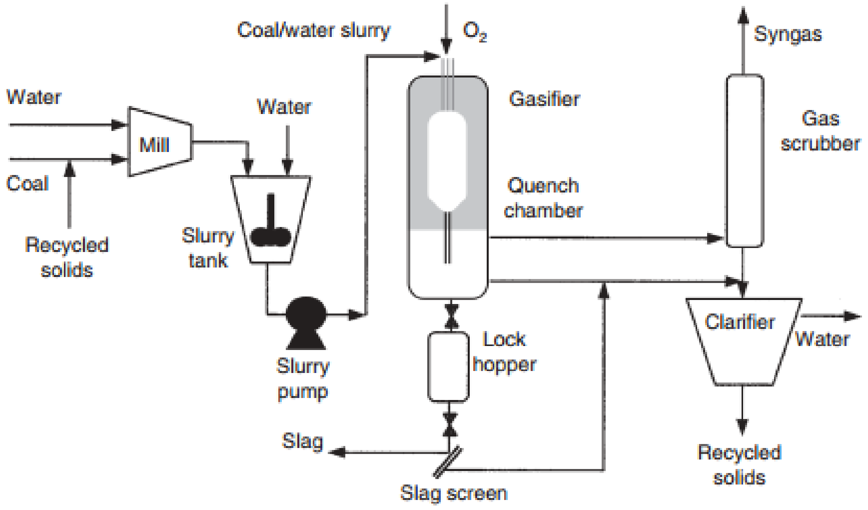


Figure 3.3 Flow diagram of a typical GE coal gasifier with total water quench [11]

The coal is milled with water and additives to create stable coal water slurry (CWS). The slurry is introduced with the oxygen into the gasifier at the top. When the slurry enters the gasifier, the water evaporates and pyrolysis of the coal particles occurs. After pyrolysis the rest of the steps take place in the normal order [11].

The hot syngas and the liquid slag leave the gasifier to be quenched with water. The syngas is saturated with water and it is cooled until 200-300ºC [11]. The solidified slag is removed from the quench chamber with the rest of the water with is separated and recycled if it is necessary. Some small particles are entrained with the syngas and they need to be recollected in a scrubber. Energy in the high - temperature raw syngas is recovered by the quench water/steam directly. Slag is solidified and separated from the gasifier. The quench configuration is simple and easily maintained. Furthermore, the syngas is saturated with steam, making it ideal for the downstream water - gas shift process.

The concentration of coal in the slurry has an important impact in the efficiency of the gasifier. The efficiency of the gasification increases with the coal concentration. The coal concentrations also affect the syngas composition as can be seen in Figure 3.4. Increasing the coal concentration of H_2+ CO production is higher and the CO+CO_2 is constant because the additional water in the slurry react with the CO and generate H2 and CO_2 [11].

A decreasing in the coal size have a positive impact in the efficiency of the gasification but also can be negative in the slurry pump, so the ideal particle size distribution for each plant is determined experimentally.

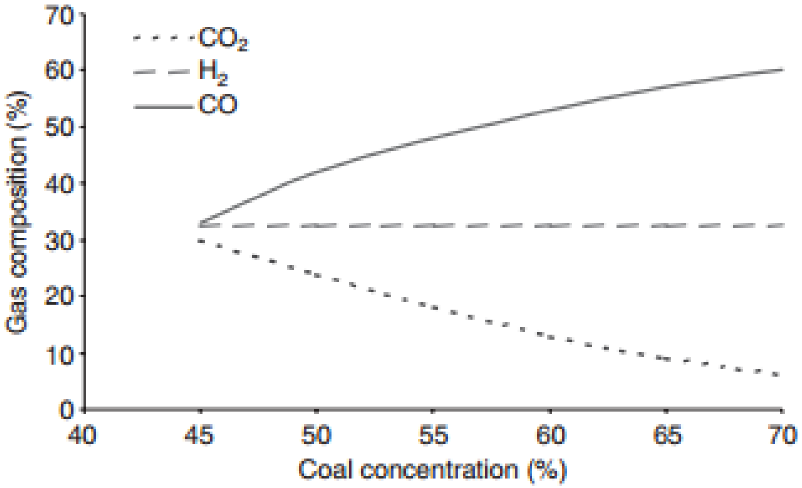


Figure 3.4 **Effect of coal concentration in slurry on syngas composition [11]**

The efficiency of the gasifier is improved with the temperature and the residence time is decreased. The temperature always will be higher than the ash fusion temperature. To improve the lifetime of the components the operational temperature should be in the range of 1350 -1500ºC [11].

The GE gasification has some advantages and disadvantages in comparison with the rest of the gasification technologies. Advantages are:(a) it can use different types of coals including lignite, bituminous, and anthracite; (b) it have one of the lowest CAPEX; (c) it is robust and thus has the highest reliability because of its simplicity; and (d) due it is operated at a high temperature (~ 1400 ° C) a high coal conversion can be achieved [11].

Disadvantages are: (a) more O2 is needed to maintain a high operating temperature; (b) compared with dry feeding technology the CO2 concentration is high; (c) the lifetime of the injector and the refractory is short compared with other gasification technologies because of the high temperature [11].

3.1.4 Syngas cleanup

The block of syngas clean up usually include particle removal, COS hydrolysis, acid gas cooling, sulfur removal, and sulfur recovery. Is in that block where a pre combustion capture can take place.

The char and fly ash can be removed in a cyclone filters, ceramic or metal candle filters, or wet scrubbing. The collected particles can be recycled to the gasifier again. A syngas scrubber can be use to complement the particles recollection and for the reduction of the HCl. Incoming syngas enters the scrubber where it comes into direct contact with water. In the water particles are trapped and they are collected in the pool at the bottom of the vessel. Particle-free syngas, which has been moisturized in the process, leaves the scrubbers through demisters that collect water droplets to prevent carry-over [15].

Before an acid gas removal unit based in amine adsorption is necessary convert the COS in H_2S. The syngas saturated in water is passed through a fixed - bed catalytic hydrolysis reactor where 85% – 95% of the COS is converted to H_2S [11].

The AGC can be done by physical absorption or chemical absorption. The main physical absorption is made with Selexol, with can remove H 2 S, COS, and also CO2.

Selexol can be regenerated thermally. For the chemical absorption it can be used MDEA or DEA [11].

Chemical solvent technologies are usually favored at low acid gas partial pressure, while physical solvents are preferred at high acid gas pressure. Both options work at temperatures around 30 °C, that situation produce a lot of energy losses. To avoids the cooling and reheated of the syngas new technologies at high temperatures are under development [11].

3.1.5 Gas turbine

A gas turbine is an open Brayton cycle composed by a compressor, a combustor and a turbine. In the compressor the air pressurized until the 10-35 bar [16]. The air that is pressurized can be supplied to the combustor for a normal combustion or can be supplied to the air separation unit if we use an oxy-combustion cycle. In Figure 3.5 a gas turbine is given with the main components.

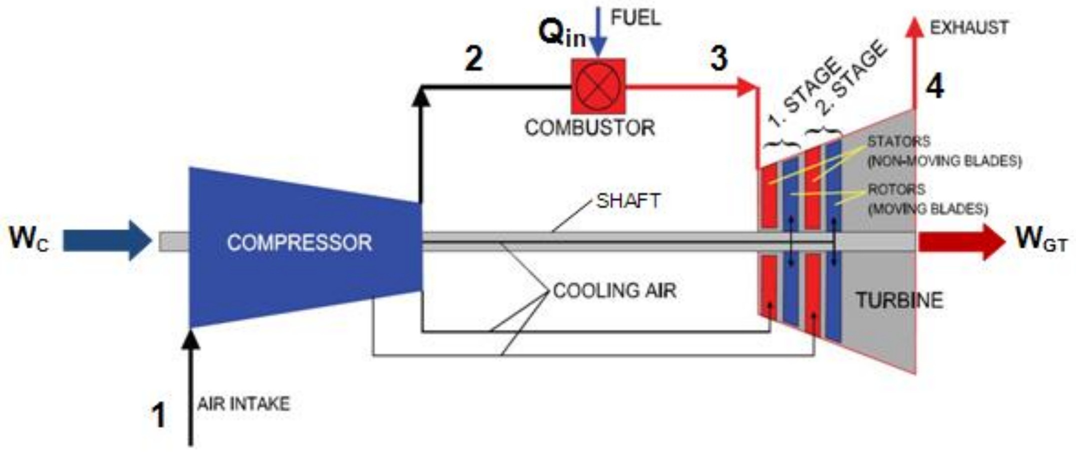


Figure 3.5 **Gas turbine flow diagram**

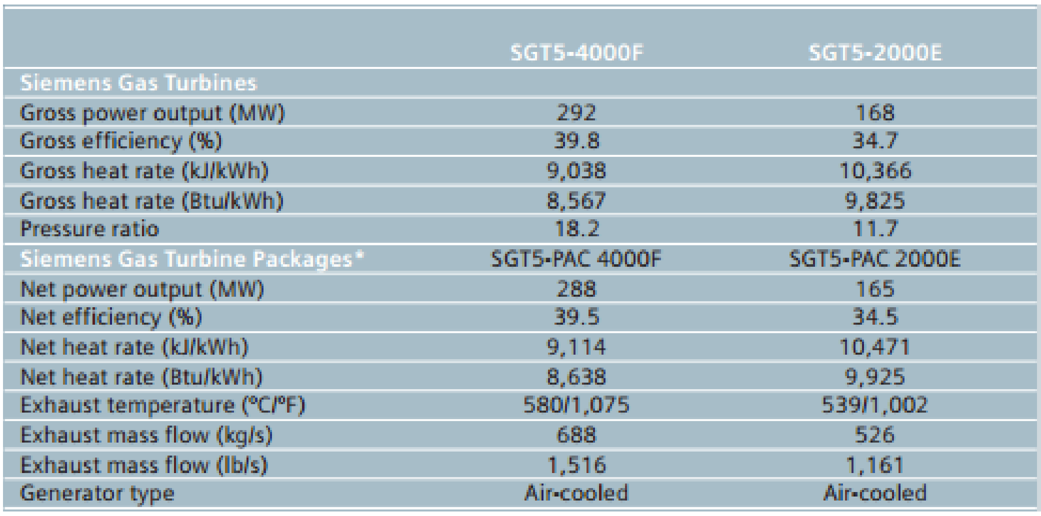
In the combustor the hot pressurized air or pure oxygen is combusted continuously with the fuel. The fuel in the 80 % of the cases is natural gas and the rest is divided in syngas, distillated oil and others. The exhaust temperature from the combustor can be over the 1500ºC [16]. This temperature usually is called turbine inlet temperature (TIT). The generated gases are expanded in the turbine slightly above atmospheric pressure. The energy contained in the gas is transformed into power in the turbine through different stages. Each stage is composed by two rows of blades, one row is fixed to the shaft and moves with it, it is called rotor. The other row, called stator is attached to casing and the blades do not move.

The TIT is as high as possible; the limitation in the temperature comes from materials and the cooling system of the gas turbine. The limitation in the TIT can be done in different methods, like increasing the excess air ratio (2.5-3.0), introduction of pure nitrogen comes from the air separation unit in the case of gasification with pure oxygen or the recirculation of the cooled exhaust or flue gas like is done in the Allam cycle [16].

The exhaust temperature of the gas turbine normally is in the range of 450-650ºC depending of the fuel and the technology used [16]. The energy contained in the flue gas can be taken by a steam cycle as will be explained in the next section.

The conversion of the fuel energy, LHV, to power is in the range of 35-40% for the large turbines used [16]. Other characteristics of the gas turbines are heat rate and the pressure ratio. In Table 3.4 it can be seen two examples of turbines with the classification.

Table 3.1 Siemens gas turbines for 50 Hz Grids (standard design, ISO ambient conditions) [17]



	SGT5-4000F	SGT5-2000E
Siemens Gas Turbines		
Gross power output (MW)	292	168
Gross efficiency (%)	39.8	34.7
Gross heat rate (kJ/kWh)	9,038	10,366
Gross heat rate (Btu/kWh)	8,567	9,825
Pressure ratio	18.2	11.7
Siemens Gas Turbine Packages*	SGT5-PAC 4000F	SGT5-PAC 2000E
Net power output (MW)	288	165
Net efficiency (%)	39.5	34.5
Net heat rate (kJ/kWh)	9,114	10,471
Net heat rate (Btu/kWh)	8,638	9,925
Exhaust temperature (°C/°F)	580/1,075	539/1,002
Exhaust mass flow (kg/s)	688	526
Exhaust mass flow (lb/s)	1,516	1,161
Generator type	Air-cooled	Air-cooled

For the gas turbines with high TIT require blade-cooling. The majority of the gas turbines are cooled using air extracted from the gas turbine compressor to flow through the blades, the cooling is realized by convection, the air exits the blade and it is mixed with the hot gas flowing through the turbine. An advanced model the air exits from the blades through a large number of strategically-placed small holes to form a film of spent cooling air, partially shielding the blades from the hot gases (Film air-cooling). For big power plant a new design is proved, from the steam cycle some of the steam is taken to cool the blades and then is recycled to the cycled with more temperature, it generate an increasing of the net power plant efficiency [16].

The cooling is going to permit increase the TIT, which will permit an increase in the gas turbine efficiency over the losses because the cooling. The cooling creates the following losses [16]:

1) The mix of hot gas and cooling fluid reduces the temperature of the expanding gas through the turbine, which reduces the turbine work.
2) Mixing of the cooling fluid in the hot gas path reduces the momentum of the hot gas as the cooling fluid has to be accelerated up to speed and direction of the hot gas.
3) Mixing of the cooling fluid causes disturbances to the flow profile around the blades and increases flow losses.

The TIT temperature has been increased every year since the creation of the technology. As can be seen in the Figure 3.6 the actual temperature is determined around 1500ºC for the first inlet temperature and1300ºC for the ISO definition of the TIT (mixing temperature of the flue gas and the cooling air).

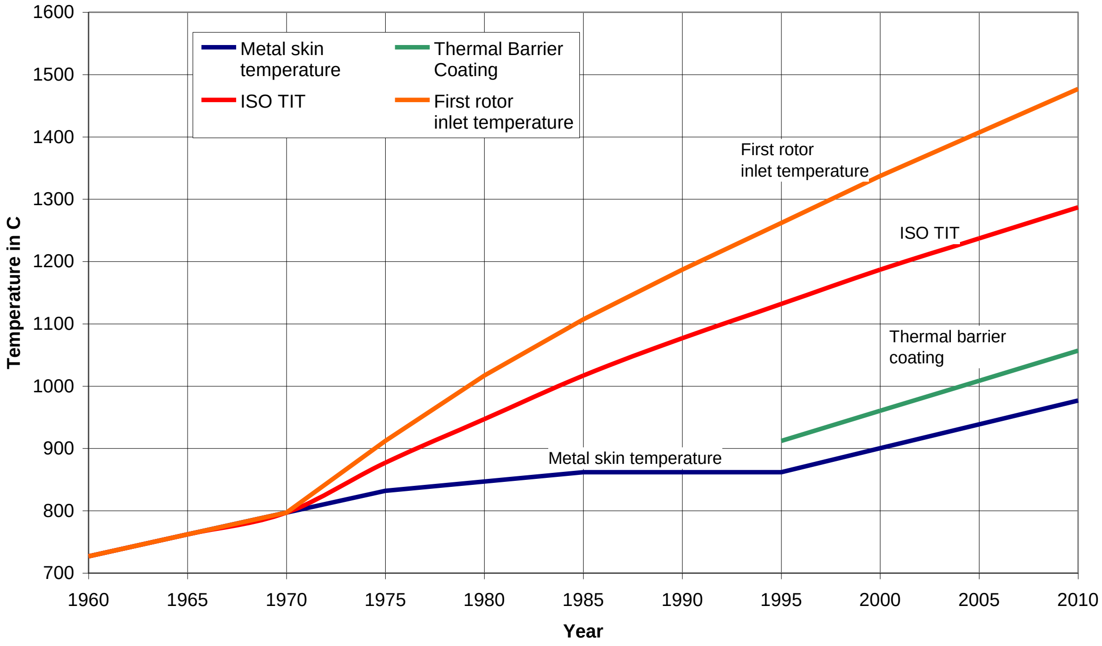


Figure 3.6 **Develop of turbine inlet temperature**

The efficiency lost can be calculated with a complex analysis stage by stage with heat transfer calculations. Different studies have been carried to calculated the lost of efficiency for different turbines and cooling methods as Bolland and Seather [18] and Fiaschi et al. [19].

3.1.6 Heat recovery steam generator

The HRSG unit is the connection between the steam cycle and the gas cycle. The HRSG takes the excess of heat from the flue gas of the gas turbine evaporating water. The evaporation is produced in different streams at different pressures. Each steam is divided in three steeps. First, condensed water is heated in an economizer, secondly enters in an evaporator where the water is vaporized at constant temperature. In the third the steam enters a super heater where the steam is heated to supercritical temperature. A simplified TQ-diagram of this process is given in Figure 3.7.

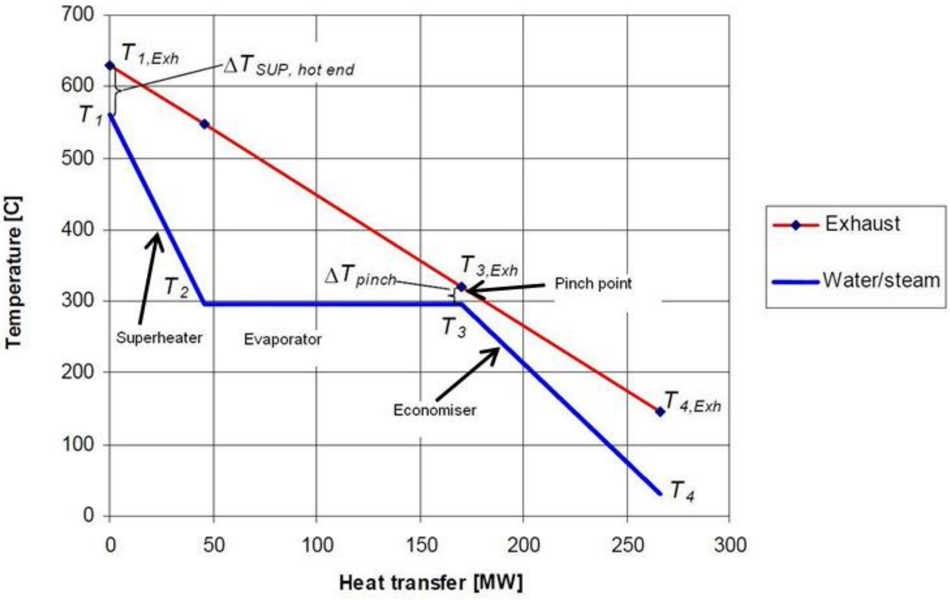


Figure 3.7 TQ-diagram for a HRSG [16]

The point where the minimum difference of temperatures between the flue gas and the water take place is called pinch point (ΔT_{pinch}). The pinch point can change according the operation conditions; normally it is found at the point where the water reaches its saturation temperature inside the evaporator. The pinch point temperature differences vary between 8-35K [16]. The efficiency and cost of the equipment depend of the peach point.

Different pressure streams are used in the steam cycle in order to obtain as much heat as possible. The saturation temperature change with the pressure and with it is possible fit the heating curve to the flue gas temperature.

3.1.7 Steam turbine cycle

The HRSG produce steam by heat exchange between condensed liquid in a steam cycle and hot flue gas from a gas turbine. The flue gas is at 450-560°C at the inlet of the HRSG and at 80-200 °C at the exit. For large combined cycles (larger than400MW) the configuration of the steam turbine is commonly made with three pressure levels. The three levels where expanded in different steam turbines, high pressure (HP) turbine, intermediate pressure (IP) turbine and low pressure (LP) turbine.

The combined cycle selected in the simulation of the report is a dual-pressure reheat steam cycle. An example of configuration is given Figure 3.8. The “Cold Reheat” stream is taken from the HP turbine and reheated to enter in the IP pressure to be further expanded. This configuration increases the steam quality leaving the LP turbine, and enables higher steam pressure to be used.

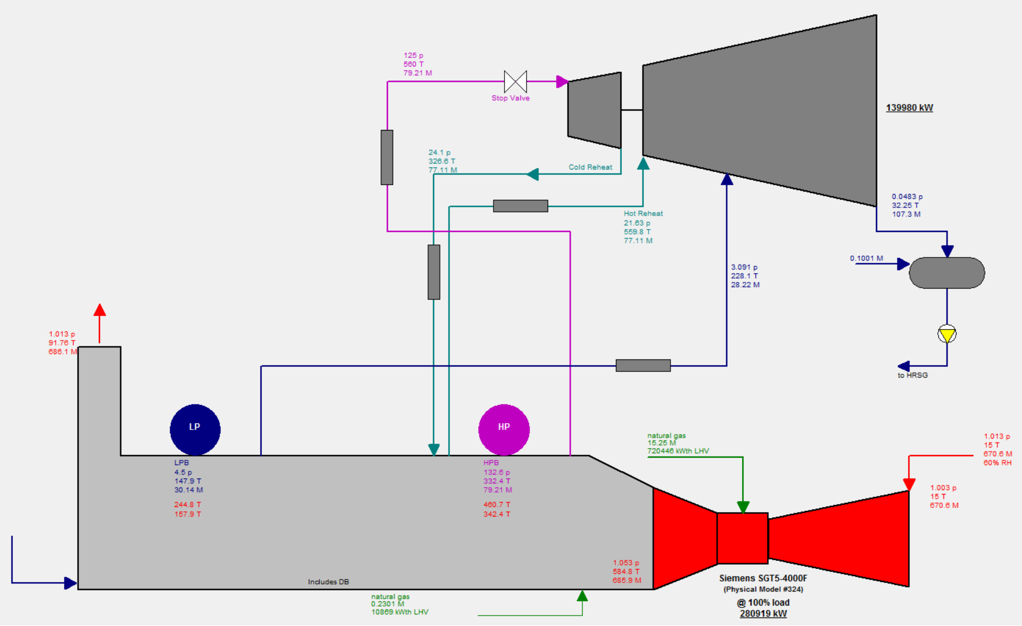


Figure 3.8 Scheme of a dual-pressure reheat steam cycle

The steam cycle is classified as Rankine type. In the cycle the condensed water is pumped until the heat exchanger where is preheated, evaporated and superheated. The superheated steam is expanded in a turbine to produce power until the saturation conditions. The expanded stream is transported back to condenser where is fully condensed. The process can be seen in the Figure 3.9.

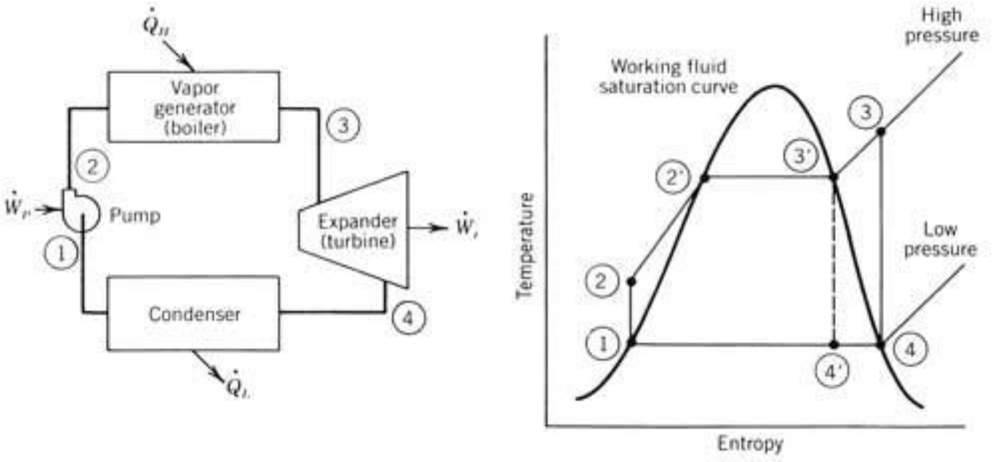


Figure 3.9 Simple Rankine cycle with corresponding TS-diagram [20]

Most steam cycles in the power plants have a deaerator before the steam production. The purpose of a dearator is to remove dissolved gases such as oxygen and carbon dioxide from the feedwater and makeup water. With the elimination of those gases the corrosion is avoided in the boiler tubes, heat exchangers, and other process equipment. In the upper side of the dearator feedwater is sprayed in a thin. Dearation steam is supplied at a lower level. This causes a rapid heating of the feedwater film and the solubility of the dissolved gases is reduced, liberating them from the feedwater. Finally the gases are vented and the feedwater is extracted ready to be used. A deaerator is shown in Figure 3.10.

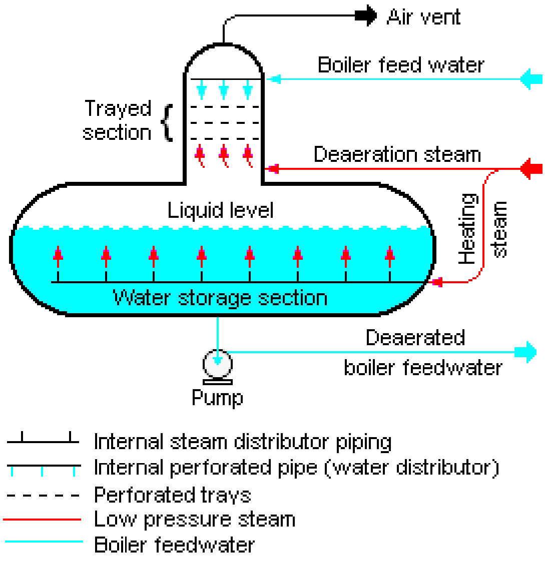


Figure 3.10 Deaerator designs [16]

3.1.8 Pre-combustion

The capture of CO_2 in the pre-combustion method is made before the gas turbine. To make the capture the fuel first has to be gasified for the coal and reformed for the natural gas. In this first steep it is produced the syngas. The production of syngas from coal is explained in section 3.1.3.

The syngas is composed mainly for CO and H_2, the CO reacts with steam in a catalytic reactor (water-gas shift reactor) to produce CO_2 and H_2. The water-gas shift reactor is slightly exothermic; this means that the exhaust temperature of the gas is higher than at the inlet. The increasing of the temperature depends of the amount of CO transformed. The higher temperature that is accepted at the exit is 450 ºC [5]. If the H_2/CO ratio of the stream is low it may be split in various reactors with intercooling. The intercooling can be used to produce steam in a combine cycle.

There are different options of catalysts to be used in the water- gas shift reactors. It depends of the temperature of the stream and if the sulfur is removed or not. For a sour shift reactor operating between 250-500ºC the catalyst used is CoMoS (sulfide Co and Mo) [5].

The water-gas shift (WGS) reactor is placed after the scrubber and particles filter. Before the water gas shift reactor the syngas is heated. The gas after the reactor will be cooled to be cleaned up in an absorption process. For the actual state of the art a capture of 90% of CO_2 and 99% of H_2S is possible to obtain.

For coal gasification like the used in this work for the absorption process the most of the times physical absorption is chosen. The manufactures of GE and Shell gasifier recommend the Selexol process for the plant using their technologies [5].

The desulfurization and capture of CO_2 is made in a physical absorption process using Selexol, the Figure 3.11 gives a flow diagram of the process. First the stream is cleaned of H_2S in an absorber. The reach solvent is sent to the stripper where the absorbent is regenerated and the sulfur is extracted. The gas clean of sulphur is sent to the second column of absorption where the CO_2 is removed. The reach Selexol is then split in two streams, one is flashed in levels of pressure and the solvent is semi-regenerated and the pure CO_2 is ready to the pipeline. The regenerated solvent is sent back to the CO_2 absorber. The other rich solvent steam is sent to the H_2S absorber.

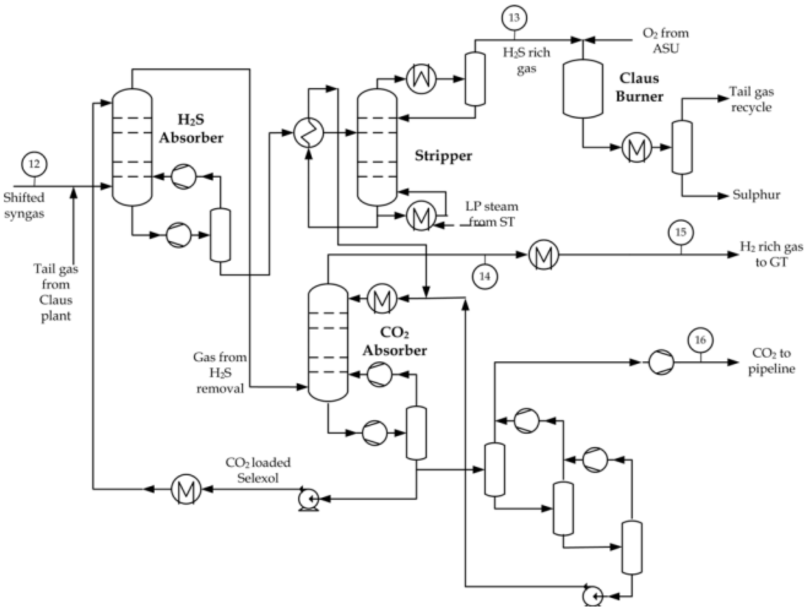


Figure 3.11 Flow diagram for Acid Gas Removal and Sulphur Recovery Unit [21]

3.2 NGCC

The NGCC is a combine cycle which fuel is natural gas. The components of the plant are the same that for an IGCC except for the gasification section. The gas turbine and the steam cycle have the same characteristics. The newest natural gas power plants have an output of 350-500 MW and a thermal efficiency up to 57-60%. The capture method chosen for a NGCC is the post-combustion method based in amine absorption.

3.2.1 Post-combustion

The post combustion capture method is based in absorption, as mentioned it can be done by physical or chemical absorption. The process is carried in to columns, one where the solvent (liquid which absorbs the CO_2) called absorber column and other where the solvent is regenerated by temperature or pressure swing called desorber column or stripper.

The absorption process is well known in the natural industry for the removal of CO_2 in natural gas sweetening. The difference is that in the power plant the flue gas at 1.013 bar while the natural gas is supplied at 60 bar. The low pressure difficult the separation because of the CO_2 low partial pressure. The better conditions are low temperature in the absorber to increase the loading capacity of the solvent and high temperature and low pressure in the stripper. A scheme of an absorption plant is given in Figure

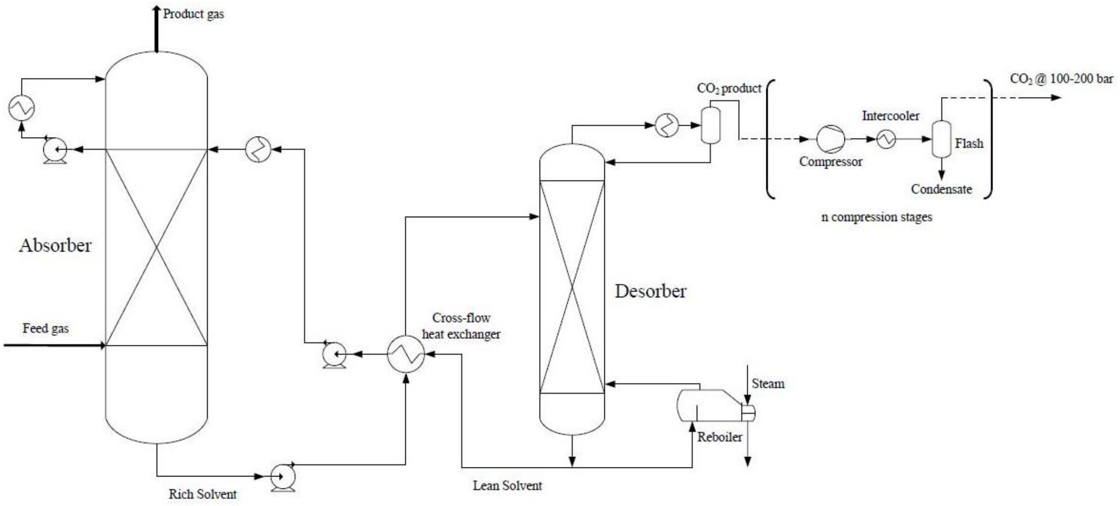


Figure 3.3 Standard absorption process utilizing temperature swing [22]

The most common solvent is an aqueous mixture that includes an amine. An amine consists of ammonia, hydrogen and one or more organic group. The most common amine used in the pos-combustion capture is the primary amine monoethanolamine (MEA). The reasons why MEA is preferred are the low heat of absorption (e heat necessary to break chemical bonds between the solvent and the CO_2 and to drive out the CO2 from the liquid) needed and because can capture the CO_2 at low partial pressure, typical in the area of 0.03-0.15 wt. %[5].

The amount of MEA being used may vary from 15-30 wt. %[13]. Due to the high corrosiveness of MEA only low wt. % can be used, but with effective corrosion inhibitors in the system the wt. % of MEA may come up to 30. If the flue gas contains SO2, NO2 or high levels of O2degradation of the MEA may occur. Degradation of the solvent reduces its loading ability, and may even destroy it completely. To avoid the corrosion a desulfurization unit has to be installed if the flue gas content SO_2. To avoid the degradation of the solvent the temperature should be below the 120 ºC.

3.2.1.1 *Absorption Process*

The flue gas at the exit of the HRSG is at 80-100 °C [5] and in a variable pressure depending of the plant. This flue gas from a natural gas power plant normally contains 3-4 mol. % of CO2[22]. The flue gas mainly is composed by N_2 and also O_2 and H_2O. If NO_x and SO_2 are found, these components need to be removed before the entrance of the absorption column. The flue gas needs to be cooled down up to 40-60 °C. The condensed water produced is removed, the water can content some traces of CO_2. A fan is installed before the column to prevent the pressure drop.

The flue gas enters at the lower part of the column and the lean solvent do it at the upper part. The liquid solvent will travel down the column while the gas goes up. To increase the surface of contact inside the column there are plates or random packing. In the contact between the streams there are a mass transfer, the solvent takes the CO_2 of the gas. The rich-solvent (with CO_2) leaves at the bottom of the column and the clean gas leaves at the top. Depending on the conditions and design the capture can achieve the 90% [22].

The rich- solvent at I bar and 40-50 ºC is pumped to the stripper. Before enter the stripper it through a heat exchanger with the lean solvent, the objective is preheat the reach solvent taking the heat from the 120 ºC of the lean-solvent. The reach solvent is heated until the 100-110 ºC. Another benefit from having this rich/lean heat exchanger is the reduction of water for cooling of the lean solution.

3.2.1.2 Stripper

Desorption process works in the opposite way than the absorption process. In this case heat is added to release the CO2 from the amine. The stripper is operated as a distillation column and it is important to have a high gas/liquid ratio, in order to have a good contact between the rich solution and the warm gas. As in the absorption column the rich solution flows downward in the column and the steam rises up. The steam has to be heated to take the CO_2 from the solvent; the heat is produced in the reboiler taking if from the superheated steam coming from the HRSG. The warm rich solution comes into the boiler as liquid, and there it is boiled and the CO2 is therefore released from the amine. Part of the lean-solvent is heated in the reboiler and it is sent back into the separator to heat up the rich solution. The part of the lean solvent taken from the bottom of the stripper is transported back to the absorption column. As mentioned the lean solvent levees the stripper at 120ºC and it will be cooled down before enters the absorber.

4 CO2 compression

The CO_2 captured have to be compressed to be transported and finally storaged. The cool stream of CO_2 at a low pressure is in a gaseous state. Actually the economical and technically way to transport the carbon stream is in a dense phase or a supercritical state. For the pure CO_2 the critical point is at 73 bar and 31 ºC but the stream that we obtain have other element in it composition, typically for pre-combustion the CO_2 concentration is >95.6%, >90% for oxy-combustion and >99% for the pos-combustion[23-24]. Typically the transport conditions can be obtained at 80 bar or higher. The transport conditions have to be maintained the entire pipe along until the storaged. The CO_2 has been transported for more than 30 year in USA. There are in operation pipelines from 90 km until the 808 km with different diameters and capacity [5]. Typically the pressure ranging rom85 to 200 bar and a temperatures between 4 to 43ºC, but in any case the supercritical state have to be maintenance until the end [5].

The compression can be divided in the sections. First the stream is compressed until the supercritical state with a compressors train with intercooling and a draining of the liquid water. The second section takes the liquefied stream at low temperature to be pumped until the needed pressure of transportation.

The energy consumption can be estimated in 0.365 MJ/kg CO_2. Examples made for ENCAP calculate the work requirement in the compression. The Figure 4.1 represents the consumption for a standard Soave-Redlich-Kwong-equation and a Peng-Robinson-equation in PRO/II. The calculation includes water vapor in phase-equilibrium with the CO_2. The presence of non-condensable gases like N_2, H_2, Ar and O_2 is not taken into account. In Figure 4.2 the CO_2 feed pressure is varied [25].

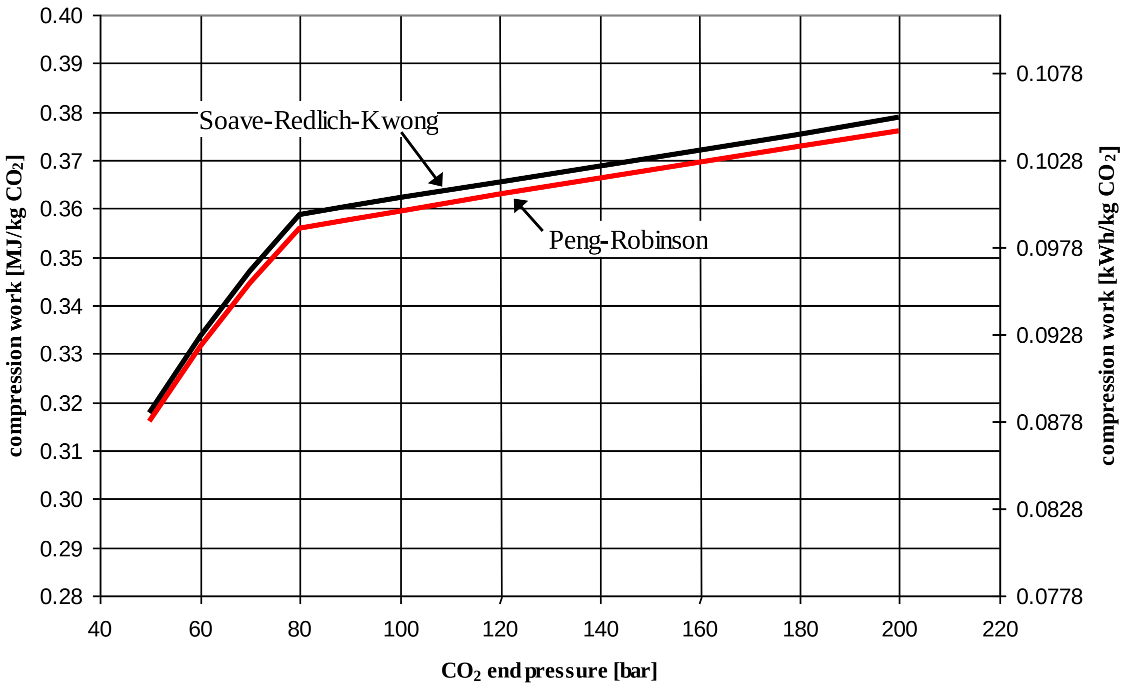


Figure 4.1 Work for compression CO2 from 1.013 bar [25]

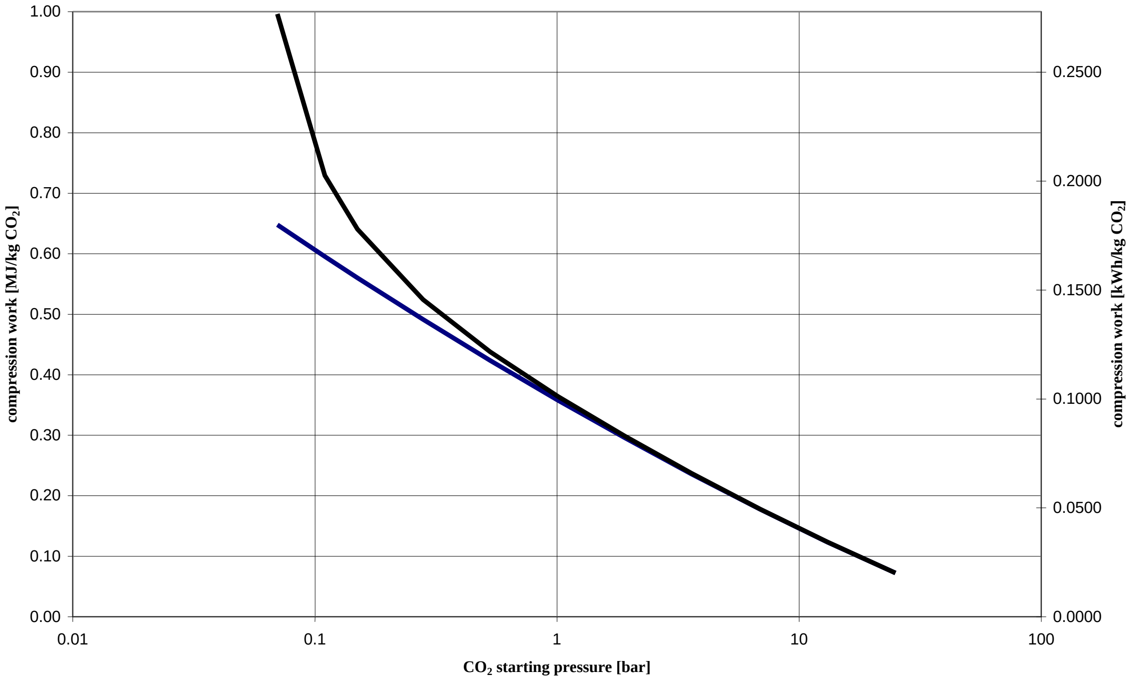


Figure 4.2 **Work for compression CO2 from a given inlet pressure and 30 °C to a fixed end pressure of 110 bar.**

5 State of the art oxy-combustion

Oxy-combustion is one of the methods for a zero emissions technology. The idea is have combustion of the fossil fuel with almost pure oxygen in a near stequeometric conditions. The uses of pure oxygen avoid the combustions product of the nitrogen, which are very contaminant. The reduction in nitrogen and inert gases permit a lower size of the boiler and the control of NO_x can be avoided. The combustion products are mainly CO2 and water, they can be easily separated cooling and condensation the water.

The expression zero emissions is not entirely true, a better term to refer the oxy-combustion can be near zero emissions. There are two main reasons to explain it, the first is that in some cycles convert the liquid water back to water vapor and emit it into the atmosphere, the water vapor is not a pollutant or greenhouse gas but it made it not strictly zero emissions. Second is that some cycles intend for the carbon dioxide to be of high purity, that imply a purification process that can have some escapes of the contaminants. If the carbon dioxide is destined for storage not very high purity is needed and the contaminants can be stored along with the carbon dioxide.

A brief overview of the history of oxy-combustion is going to be presented. The first mention of a zero emissions power unit was made by Degtiarev and Gribovsky (1967). The objective in a time when greenhouse effect was ignored was the coproduction of power and CO2. The cycle burn the fuel with oxygen and CO2. The only emission is the cold nitrogen from the ASU. The first time sequestration was proposed by Marchetti (1979), the combustion of fuel is made with a CO2/O2 mixture, followed by CO2 sequestration in the ocean. Steinberg (1981) described the concept of total emission control combined with enhanced oil recovery. The concept of total emission control combined with enhanced oil recovery was described by Steinberg (1981). Yantovsky and Degtiarev (1993) presented various zero emissions cycles for both CO2 and water recirculation, they demonstrated much higher efficiency using CO2 recirculation as opposed to H2O recirculation. Different methods have been proposed in that time and with the improvement of the technology they are closer to become an economical source for CO2 in the enhanced oil recovery.

The different oxy-combustion methods can be classified according three levels of technology characteristic. The fist level is the separation of the oxygen, according if it is separated in an external device, like the cryogenics distillation, or if it is separated inside the cycle. The internal separation can be done using metal oxide as an oxygen carrier or oxygen selective metal which are loaded and regenerated in a cycled operation

The second level refers to the main cycle type, a Rankine cycle or a Brayton cycle. For the Brayton cycle the working fluid is always in a gaseous estate along the expansion, compression, cooling, heat addition and rejection. On the other hand in the Rankine cycle the working fluid change from the gaseous estate in the expansion to a liquid state in the compression along closed loop. Normally the Rankine cycle use water as working fluid and is used in coal fired power plant and the Brayton is used in conventional gas turbines cycles. In oxy-combustion are used the pure Brayton cycle, the pure Rankine cycle and a mixture of both cycles.

Finally the third level refers to the composition of the flue gas that is recycled for the control of the combustion temperature and the cool of the turbine in the gas turbine cycles. There are three possibilities for the recycled, it can be pure water that have been condensed and separated of the flue gas, the pure CO2 after the separation of the water or the flue gas without separation, water and CO2 together. In that level it can be made a separation between the internally fired power cycles which use the flue gas as a working fluid and the externally fired power cycles which use the flue gas to heat an external working fluid. The three level and some examples are given in Figure 5.1.

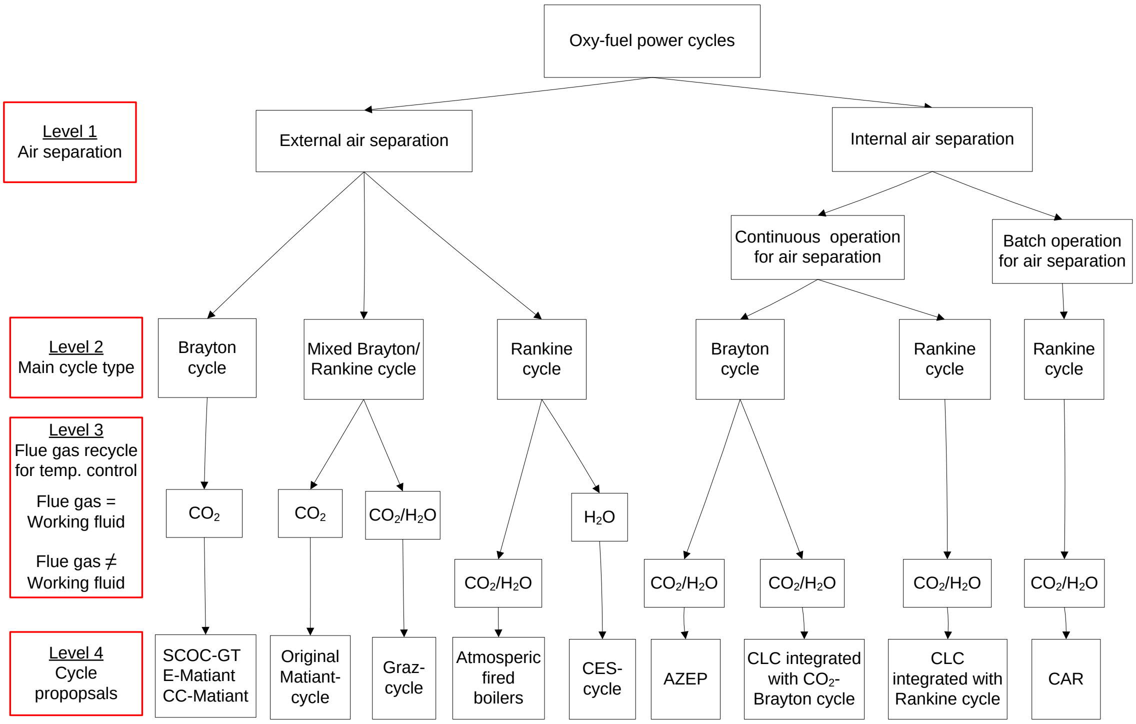


Figure 5.1 Classification of oxy-combustion cycles and some examples [5]

Some oxy-combustion cycles are explained below to see how the different element are combined and the specifications that are need to run them in the most efficiency way. The different cycles are taken from different articles and books so the initial conditions and specification of the equipment are not the same, it made the comparison difficult to do. Any way different efficiencies are given for some of the cycles taken from different sources or a comparison with a base case is given.

5.1 Steam-moderated oxy-coal combustion (SMOC) process

That technology is based in its simplicity, the use of steam to moderate the flame eliminate the need to recycle the flue gas. The ASU concentrate the oxygen between 95 and 99.99%. The pure oxygen is mixed with a preheated steam at 120 ºC before goes to the pulverized coal (PC) boiler. The composition of the flue gas is mainly water, and the components are CO_2, exceed of O_2, N_2 and impurities. The flu gas is cooled in a HRSG to produce power in the steam cycle. The flue gas will be cleaned in an electrostatic precipitator and the water condensed will be recalculated to be used in the boiler. Finally the flue gas, mainly composed of CO_2 will be compressed. A flow diagram is given in Figure 5.2.

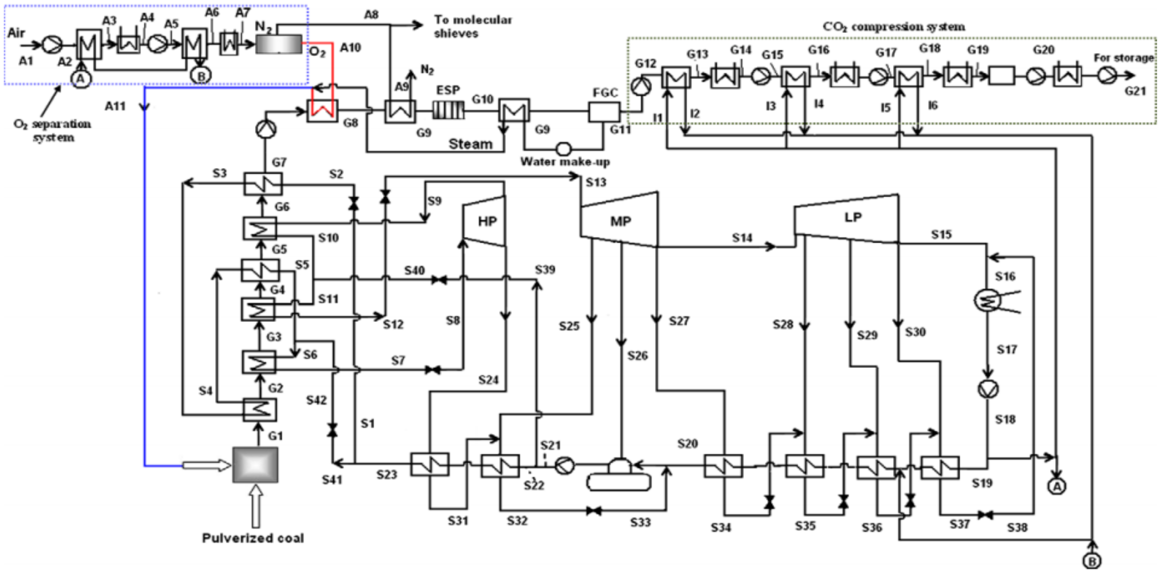


Figure 5.2 Flow diagram of a power plant operating under Steam-moderated oxy-coal combustion (SMOC) process [27]

For this technology the composition of CO_2 in the final flue gas is between an 80% and 88% for a 98% O_2 depending of the temperature used. A SMOC plant has a gross efficiency of 44.04 and a net efficiency of 29.57% [27]

In a comparison between SMOC and an air-fired power plant without CO_2 sequestration the gross efficiency is a 3.7% higher in the SMOC but the net efficiency is 8.1% lower. The penalty in the efficiency comes from the ASU and the CO_2 compression. [27]

5.2 Pressurized oxy-fuel combustion power cycle

The cycle is based in the suggestion of ENEL that oxy-fuel combustion at high pressure may increase the burning rate of char and the rate of the heating values. The pressurized coal combustor is fed by a coal water slurry, steam, oxygen and recycled flue gas. The combustor rise high temperatures, between 1400-1600ºC, at high pressures. The flue gas at the exit of the combustor is mixed with the recycled exhaust HRSG flue gas to cool the gas at the entrance of the HRSG. The flue gas is cooled by the condensed water stream and then purified and compressed. In the steam cycle the condensed steam is heated in the acid condenser and in the combustor before enters in the deaerator. The steam which feed the combustor is taken from the HP turbine in order to atomize the slurry particles. The Figure 5.3 gives the flow diagram for the process.

This cycle for coal combustion have a gross efficiency of 48.2% and a net efficiency 34.9 %. If we compare the cycle with a similar one at atmospheric pressure the improvement of net efficiency is in a 3.4% [28]

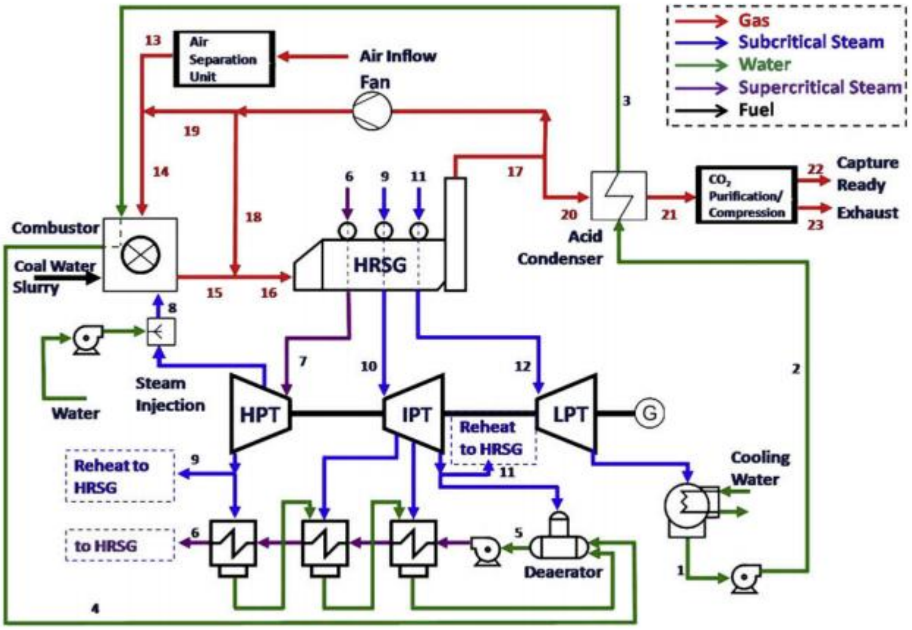


Fig. 1. Overall process layout for an oxy-fuel combustion power cycle utilizing a pressurized coal combustor (edited from Ref. [12]).

Figure 5.3 flow diagram for a pressurized oxy-fuel combustion system [28]

5.3 CES or water cycle

The CES or water cycle is one of the most representative cycles with the MATIANT and the GRAZ cycles. The CES cycle can be included in the category of the Rankine power cycles. The working fluid is around 90% water, which is compressed in the liquid phase and expanded in the gaseous phase to produce work. As can be seen in the Figure 5.4, the model works with two combustors at different pressures. The first combustor is fed with the fuel, oxygen and the recycled water. It work at a pressure around 100bar and a temperature around 800-900ºC. The exhaust gas is expanded in a steam turbine to produce work. The second combustor is feed with flue gas, fuel and oxygen; the temperatures can rice the 1400-1500ºC and the pressure is determines by the pressure ratio in the steam turbine. The agentive of the second combustor is to reheat the flue gas and optimize the process. The final flue gas is expanded in a gas turbine producing power. Before the water condensation of the flue gas it is cooled in a recuperator with the water that is recycled. The CO_2 steam is compressed with intercooling to the pressure of transportation.

In different simulations of that cycle the result of net efficiency are different. The net efficiency results vary from 39.5% [29] to 56% [30]. As a comparative efficiency the CES cycle have a similar efficiency to the CC-MATIANT [31] and a penalty of an 11 % in comparison with the GRAZ cycle.

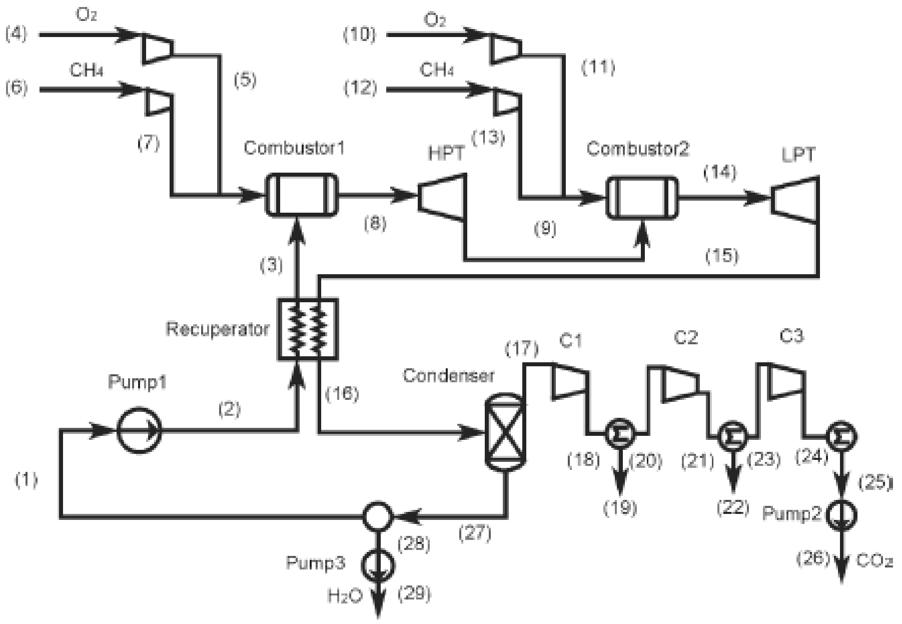
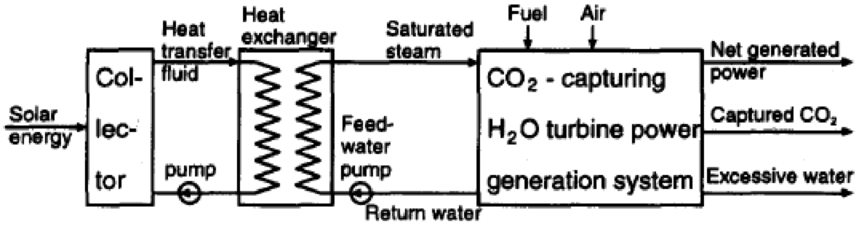


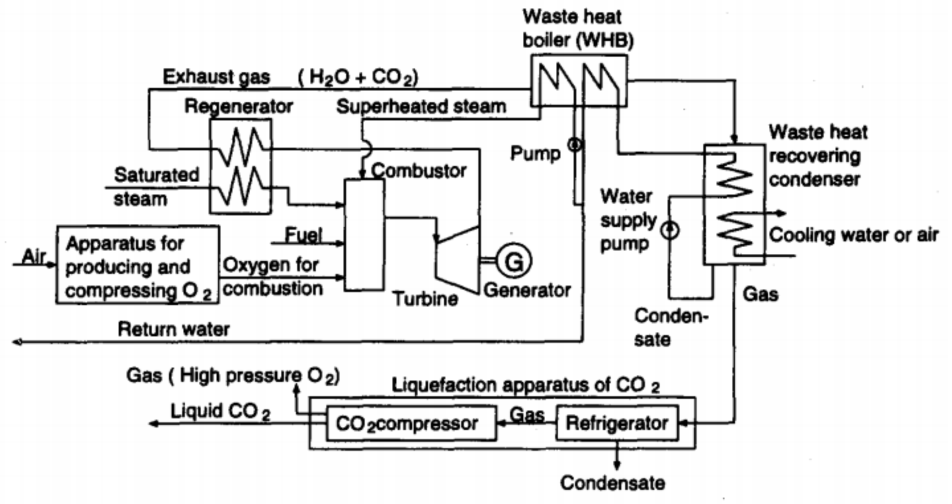
Figure 5.4 Flow diagram of a CES or water cycle [31]

5.4 STHS (solar thermal hybrid H_2O turbine power generation system)

The STHS combine the renewable energy sources with the conventional ones to reduce the emission of CO_2. It is a quasi-closed gas-turbine power-generation cycle. A solar collector is used to produce saturated steam as the working fluid. The use of the saturated steam eliminates the inefficient compression of the working fluid gas. The fuel is combusted with 0_2 and steam. As a result, almost all of the turbine-exhaust gas is condensed. The pressure at the turbine outlet becomes much lower than the atmospheric pressure. The flue gas cooled in a regenerator with the saturated steam and in waste heat boiler. The H_2O will be condensates and the CO_2 compressed until the liquid phase. The condensed water is recycled to the collector heat exchanger to be evaporated. Based on consumed fuel, the net thermal efficiency of the system is 63.7%, which is 46% higher than the conventional power plant [32]. Figure 5.5 shows the STHS cycle.



(a) Total structure



(b) Construction of CO_2-capturing H_2O turbine power generation system

Figure 5.5 **Construction of a CO_2 capturing, H_2O turbine, power generation system**

5.5 S-Graz cycle

The Graz cycle was presented in 1985 by Jericha and after some modifications and studies the cycle was renamed as S-Graz cycle [32]. The Graz Cycle is classified as mixture of a high temperature Brayton cycle and a low temperature Rankine cycle. There are two streams recycled, the steam which is heated in a HRSG and expanded in a high pressure turbine and the flue gas after the HRSG which is compressed before enter the combustor chamber. In Figure 5.6 gives a flow diagram for the S-GRAZ cycle.

The combustion chamber operate at 40 bar, it is fed with the fuel and oxygen near stoichiometric conditions. The recycled streams of steam and flue gas are used to cool down the burners and the liner.

The exhaust gas lives the combustor at 1400 ºC and with a composition of mainly water (74% steam, 25.3% CO2). In the HTT the fluid is expanded until near ambient pressure and a temperature around 580ºC. The turbine cooling is done with steam from the HPT and it makes that the steam contain up to 77 %.

The flue gas is cooled in the HRSG and part of the stream is further expanded until the 0.043 bar (the optimums pressure for condensation at 18 ºC) [34]. In the condenser the water and CO2 are segregated, the CO2, with a concentration 94%v in the stream, is compressed in C3 and C4 for the sequestration. The water is compressed in a pump until the 180 bar and is preheated, vaporized, and superheated in the HRSG. After expand the heated water part is used to cool the turbine and other part goes to the combustor chamber. The flue gas that is not sent to the condenser is compressed, with a maximum exit temperature of 600ºC, in the compressors C1 and C2 before enters the combustor.

The net efficiencies obtained for a power plant using this cycle are 52.5% [33], 50.4% [29] and 50.3% [34]. These results represent a good efficiency in the power plant with carbon capture.

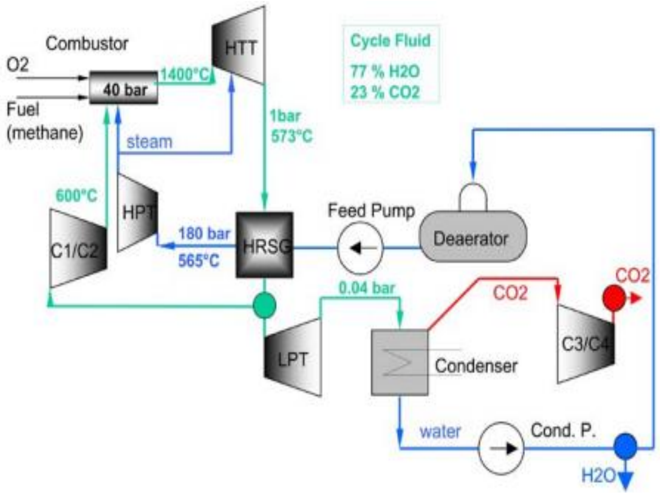
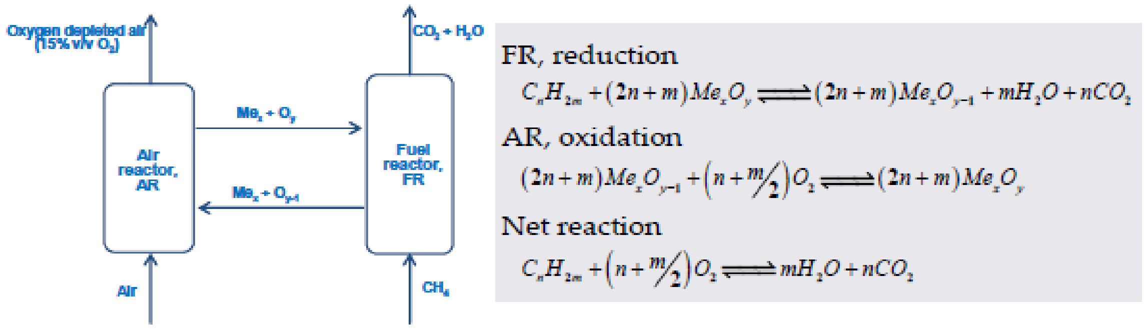


Figure 5.6 **Flow diagram for a S-GRAZ cycle [34]**

5.6 CLC (chemical looping combustion)

The chemical looping combustion (CLC) consists in a combustion without direct contact between the fuel and the air. The combustor chamber disappears in that cycle. The combustion process is split up into intermediate oxidation and reduction reactions near a thermodynamic equilibrium. It is made with a metal oxide which transports the oxygen from one reactor to the other. In Figure 5.7 the reactions and the configurations of the reactors are given.



FR, reduction

$$C_nH_{2m} + (2n+m)Me_xO_y \rightleftharpoons (2n+m)Me_xO_{y-1} + mH_2O + nCO_2$$

AR, oxidation

$$(2n+m)Me_xO_{y-1} + \left(n + {}^{m}\!/_{2}\right)O_2 \rightleftharpoons (2n+m)Me_xO_y$$

Net reaction

$$C_nH_{2m} + \left(n + {}^{m}\!/_{2}\right)O_2 \rightleftharpoons mH_2O + nCO_2$$

Figure 5.7 Configuration of the CLC unit and the chemical reactions [32]

Air at atmospheric condition is introduced in the air or oxidizing reactor, there the metal is oxidized. The oxidized metal then goes to the fuel reactor to react with the fuel and produce CO_2 and H_2O. The designee of the reactor is similar to fluidized beds. For the metal used in the transportation of oxygen nickel, iron and manganese have been proposed.

In the Figure 5.8 a CLC cycle is proposed. The air is compressed before enter the air reactor and the fuel feed the fuel reactor. Not all the fuel is burnt, a 2% is lost. The air ratio gives the outlet temperature of the air and fuel reactors, 1200 and 930ºC respectively. These temperatures are the TIT in GT1 and GT2. For the inlet temperature of the GT2 has been recommended a low temperature of 900°C, it is done to increase the conversion of the fuel in the fuel reactor and the energy available for oxidation of the metal in the air reactor.

The CO_2 stream after the expansion is cooled in a secondary HRSG to produce additional steam. Finally is condensed and after remove the water is compressed for the sequestration. The depleted air is expanded in the GT1 is cooled in a HSRG where extra power is produced. Finally the depleted air is released to the atmosphere.

The cycle described before has a net efficiency of 53.9% [32]. According to Bolland [5] the temperature of the air reactor has a large influence in the efficiency of the CLC cycles integrated in gas turbines cycles. For CLC with simple reheat a TIT of 900 ºC has the same efficiency that a similar power plant with post-combustion. If the TIT is 1000 ºC the efficiency is 51.2% while for a temperature of 1200ºC is 53% [5].

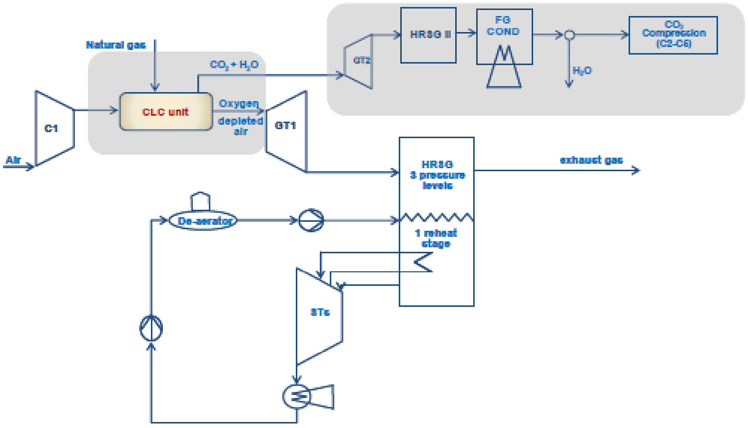


Figure 5.8 **Flow diagram of a CLC plant [32]**

5.7 MATIANT cycle

The MATIANT cycle was presented by Mathieu [35] as a solution to the CO_2 Prevented Emission Recuperative Advanced Turbine Energy (COOPERATE) cycle, the new cycle avoid the condensation of CO_2 compressing the CO_2 flow immediately after the exit of the cooling tower. Along the years three different models based in the same concept have been developed, these cycles are the E-MATIANT, CC-MATIANT and IGCC-MATIANT.

In all the cycles proposed the working fluid is the flue gas and the CO_2, the oxidizer is almost pure oxygen and the nitrogen of the air has been replaced for the CO_2 stream to control the flame temperature. The combustion products will be mainly H_2O and CO_2

5.7.1 E-MATIANT

The design is similar to a regenerative Ericsson-like cycle with two nearly isothermal processes (compression with intercoolers and expansion with a reheat) and two nearly isobaric processes (the regenerator, the two combustion chambers.

The Figure 5.9 shows a flow diagram of the E-MATIANT cycle. At point 1 the cooled flue gas has been condensed and the liquid water removed. The produced CO2 stream then is compressed with intercooling above the 73 bar and 30 ºC (supercritical conditions). (2)The CO2 produced (the amount that is not recycled) is removed for the sequestration; normally it will be further compressed for piping.

(3)The CO2 recycled is heated in the recuperator until around 700ºC, and then in premixed with the oxygen stream to entre in the combustor chamber with the compressed fuel. The combustor chamber work at 60 bar and the temperature is controlled by the CO2 stream to have a TIT of 1300ºC. (4)The flue gas is then expanded in a HP turbine; the final pressure can vary between 12 and 36 bar, adapting it to an optimal pressure of reheat. The flue gas now is mixed again with a stream of oxygen and fuel pressurized until the reheat pressure. (5) The new flue gas is expanded again in a LP turbine until 1 bar. (6)The stream is cooled in the regenerator by the recycled stream of CO2. (9)Finally is further cooler until near ambient conditions to be condensed and separate the water from the CO2. In Figure 5.10 a representative T-S diagram is given for the E-MATIANT cycle.

The efficiency of the cycle varies according the pressure of the reheating, for a pressure of 36 bar an efficiency of 46.5% is given [36].

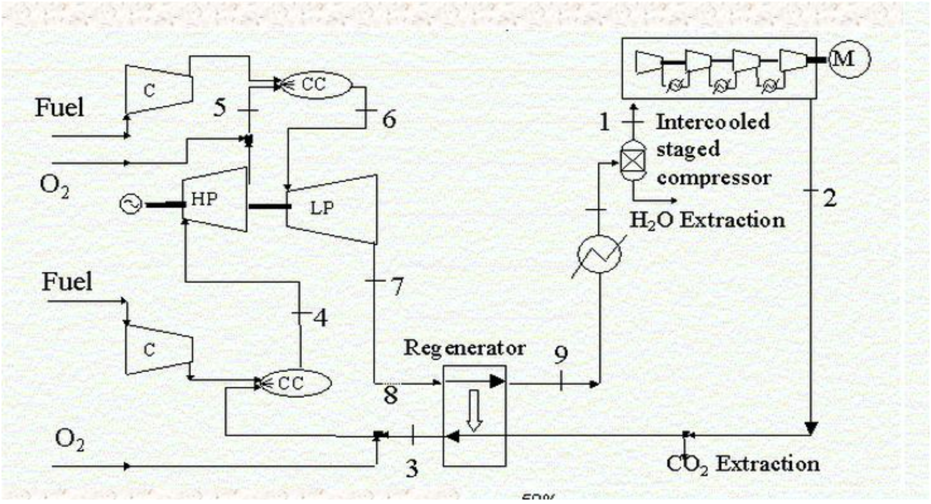


Figure 5.9 Flow diagram for an E-MATIANT cycle [36]

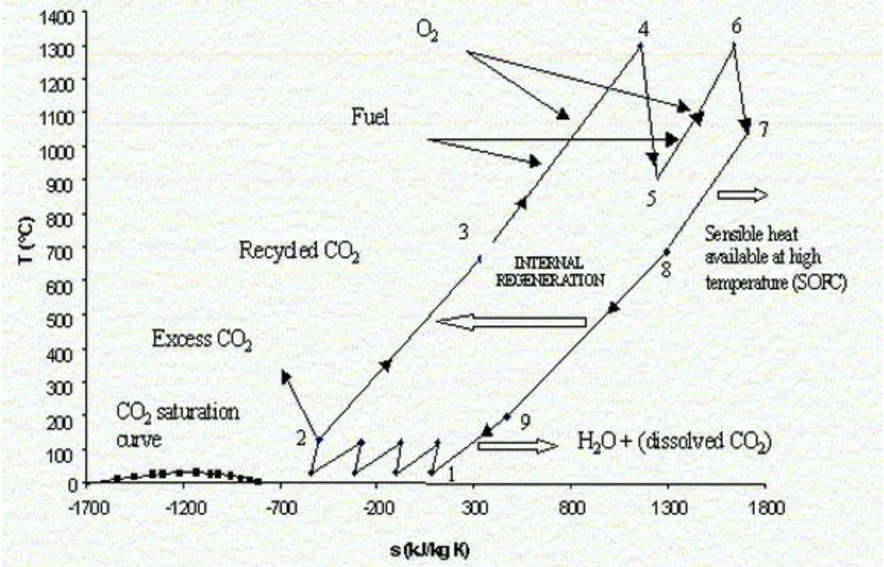


Figure 5.10 T-S Diagram for an E-MATIANT cycle [36]

5.7.2 CC-MATIANT

The new cycle represent an improvement respect the E-MATIANT. The improvement in this cycle is the incorporation of a new expander for the CO2 stream, here the maximum pressure is higher than before and achieves the 300 bar.

Figure 5.11 and Figure 5.12 show a flow diagram and a T-S diagram for the cycle.

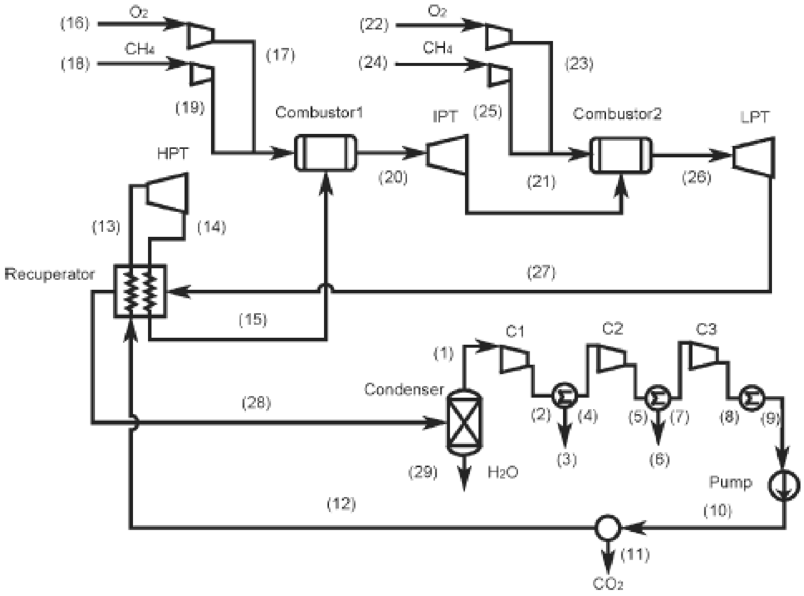


Figure 5.11 Flow diagram for a CC-MATIANT cycle [31]

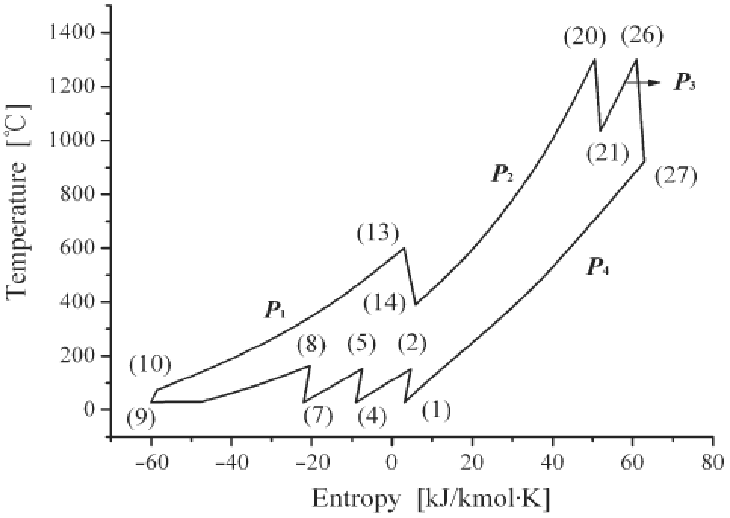


Figure 5.12 T-S Diagram for a CC-MATIANT cycle [31]

Starting from the CO_2 stream at the outlet of the condenser it is compressed in a chain of compressors with intercooling until the supercritical state. The stream is further compressed in pump until the 300 bar. After remove the produced CO_2, the recycled stream is heated in the recuperator en expanded in a HP turbine to produce electricity. The outlet pressure of the turbine will be around 40 bar, the work pressure for the first combustor chamber. The CO_2 stream is reheated again in the recuperator until around 700 °C to feed the combustor.

The combustor, which works at 40 bar, is fed with the CO_2 stream and the pressurized fuel and O2 from the ASU. The oxygen is pre-mixed with the fuel [31] or with the CO_2 [37]. The TIT for the IP turbine is set in 1300 °C and whit an outlet pressure around the 9 bar. The flue gas is reheated in a second combustor chamber until 1300°C. Finally the flue gas is expanded in a LP turbine until atmospheric pressure. The flue gas is cooled in the recuperator before goes to the condenser to separate the water from the CO_2.

The net plant efficiency of the plant has been studied in several publications, some of the result of efficiency obtained are 44.4% [026], 44.2% [37] or a 47-49% [38].

5.7.3 IGCC-MATIANT

The Matiant cycle has been adapted to an IGCC plant. The plant has two closed cycles, a gas cycle and a steam cycle. The integration of both cycles can be seen in Figure 5.13.

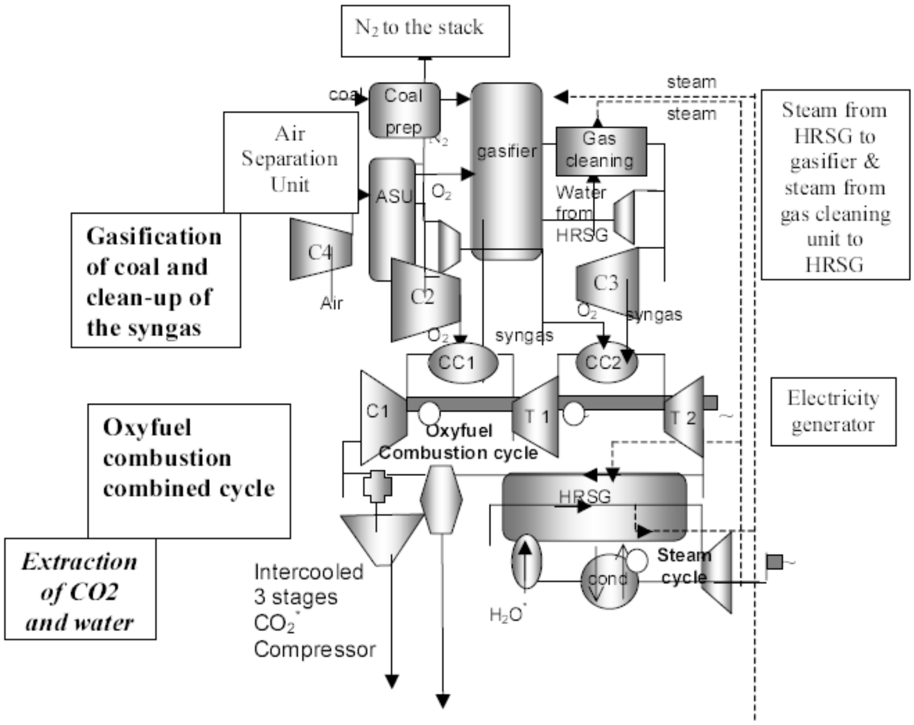


Figure 5.13 Flow diagram for an IGCC-MATIANT plant [39]

The coal is gasified with oxygen from coming from an ASU. The syngas produced is cooled with steam coming from the steam cycle. The syngas has to be clean up before be burnt in the combustor chamber. The syngas is sent to the combustor chambers at the operation pressure. In the first combustor chamber (CC1) it is burnt with oxygen from the ASU and the recycled CO_2. The combustor works at 120 bar and the exhaust temperature is around 1250°C. The flue gas is expanded until have 700°C for the exit stream. The flue gas is reheated in the second combustor chamber (CC2) until 1200°C and further expanded until 1 bar. The flue gas is then cooled in the HRSG where the steam cycle takes the heat to produce work. The water of the flue gas is then condensed near ambient temperature and removed in the condenser. The CO2 that is not recycled is removed and compressed for the sequestration. Finally the CO2 recycled is compressed until the pressure of the first combustor to be used there [39].

For that cycle using a Shell type gasifier an efficiency of 44.8% has been obtained [39]

6 Calculations

6.1 Plant efficiency

When the efficiency of a gas turbine is calculated there are some looses that have to be considered that looses decrease the real power generation respect the gross energy that is produced in the gas turbine. In a gas turbine there are mechanical looses created by the friction in the transmission of the mechanical energy from the turbine and the generator. The generator is not perfect engine an also have some lost of energy. That looses are estimated according the experience and are expressed as mechanical and generator efficiencies. The power island has some extra equipment like lights, control systems that have to be considered. The efficiency is the relation between the energy produced and the inlet energy contained in the fuel. The formula used to calculate the net power island efficiency is [5]:

$$\eta_{net,PI} = \frac{\left\lfloor (W_T + W_C)\eta_m \eta_g + W_{ST}\eta_m \eta_g + \sum W_{p,i} \right\rfloor \eta_{aux}}{\dot{m}_f \ LHV} \tag{6.1}$$

$\eta_{net,PI}$	Net efficiency for Power Island	-
$\dot{m}_f$	Fuel flow rate	kg/s
LHV	Lower heating value	kJ/kg
W_T	Turbine work, calculated as fluid enthalpy change	kW (>0)
W_C	Compressor work, calculated as fluid enthalpy change	kW (<0)
η_m	Mechanical efficiency	-
η_g	Generator efficiency	-
W_{ST}	Steam turbine work, calculated as fluid enthalpy change	kW (>0)
W_P	Pump work, feedwater pumps, cooling water pumps, etc.	kW (<0)
η_{AUX}	Auxiliary power efficiency (power island only)	-

For the calculation of the net efficiency for the plant the energy lost in the rest of processes have to be added to the calculation, it is calculated with the formula [5]:

$$\eta_{net,NPE} = \eta_{net,PI} + \frac{W_{CO_2} + W_{O_2} + W_{AUX}}{\dot{m}_f \ LHV} \tag{6.2}$$

$\eta_{net,NPE}$	Net Plant Efficiency	-
$\eta_{net,PI}$	Net efficiency for Power Island (6.1)	-
$\dot{m}_f$	Fuel flow rate	kg/s
LHV	lower heating value	kJ/kg
W_{CO_2}	Work for CO_2 compression	kW (<0)
W_{O2}	Work for O_2 separation and compression	kW (<0)
W_{AUX}	Work for any related auxiliary processes	kW (<0)

The efficiency quantifies the power to fuel energy ratio, $kJ_{power}/kJ_{fuelLHV}$. There is other way to express the amount of fuel consumed to produce energy, the heat ratio is the ratio between kJ_{LHV} and kWh_{power}. The heating value is calculated whit the formula 6.3 [5].

$$HR = \frac{3600}{\eta} \left[\frac{\mathrm{kJ}_{\mathrm{fuel\ LHV}}}{\mathrm{kWh}_{\mathrm{power}}}\right] \tag{6.3}$$

The heat rate is used in the calculation of the Specific Primary Energy Consumption for CO_2 Avoided (SPECCA), it express the energy cost for the capture of CO_2. The SPECCA formula is:

$$SPECCA = \frac{HR - HR_{REF}}{E_{REF} - E} \tag{6.4}$$

HR	Heat rate	kJ_{LHV}/kWh_{el}
E	CO2 emission rate	kg_{CO2}/kWh_{el}
η	net electrical efficiency	-
REF	value found for the same plant without carbon capture.	

6.2 CO_2 capture

For a power plant with carbon capture to produce the same amount of power than without capture is needed more fuel to produce power due the extra energy consumption in the carbon capture. To calculate that extra consumption of fuel it is used the efficiency [5]:

$$Aditional\ use\ of\ fuel\ per\ kWh_{power} = \frac{\eta_{without\ CO2\ capture}}{\eta_{with\ CO2\ capture}} \tag{6.5}$$

A term used in the carbon capture is the CO_2 emission index (χ), it is defined as the mass of CO_2 generated per LHV of fuel, and the formula used is [5]:

$$\chi = \frac{m_{CO2}}{Q} \left[\frac{kg_{CO2}}{MJ_{fuelLHV}}\right] \tag{6.6}$$

The CO_2 emission index varies between 0.205 and 0.230 for natural gas and between 0.320-0.370 for coal [5].

There is a difference of meaning between CO_2 capture and CO_2 avoided. The CO_2 captured refer to the amount of CO_2 that have been capture in the power plant while the CO_2 refers the amount of CO_2 that have not been emitted to the atmosphere because the use of a plant with CO_2 capture instance of other power plant with the same characteristic without capture. The Figure 6.1 illustrates the difference.

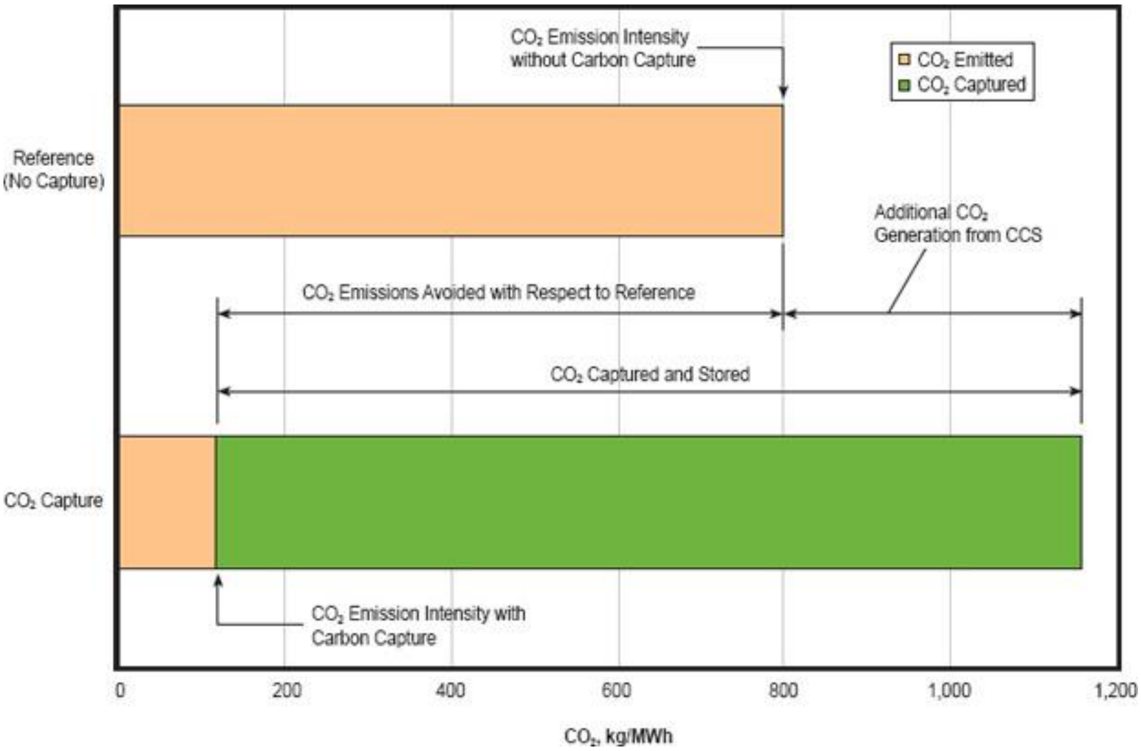


Figure 6.1 Difference between CO_2 capture and CO_2 avoided [40]

For the calculation of CO_2 capture and CO_2 avoided is needed to define the term CO_2 capture ratio (η_{cap}), it is the fraction of the formed CO_2 which is captured and stored. The CO_2 entering the system from others way than from the fuel can be negligible if they are small, like the amount of CO_2 coming with the air [5].

CO_2 capture is defined as “the amount of CO_2 captured per unit of the main product of the plant (in that case power)” [5]. The CO_2 capture has its complementary with the CO_2 emitted.

$$\mathrm{CO_2\ capture} = \frac{\chi}{\eta_{\mathrm{CO2}}}\eta_{\mathrm{cap}} \left[\frac{\mathrm{kg_{CO2}}}{\mathrm{kWh_{work}}}\right] \tag{6.7}$$

$$\mathrm{CO_2\ emitted} = \frac{\chi}{\eta_{\mathrm{CO2}}}(1-\eta_{\mathrm{cap}}) \left[\frac{\mathrm{kg_{CO2}}}{\mathrm{kWh_{work}}}\right] \tag{6.8}$$

CO_2 is defined as “the net reduction of CO_2 emission per unit of net power output comparing a reference power plant without CO_2 capture and that of a similar power plant with CO_2 capture”.

$$\mathrm{CO_2\ avoided} = \frac{\chi}{\eta_{ref}} - \frac{\chi}{\eta_{CO2}}(1-\eta_{cap}) \tag{6.9}$$

A final term referred to the carbon capture is the CO_2 capture efficiency, it is defined as “the ratio between the net reduction of CO_2 emission per unit of net power output comparing a reference power plant without CO_2 capture and that of a similar power plant with CO_2 capture, and the emission of CO_2 per unit of power output of the reference plant”, it is expressed as [5]:

$$\eta_{cap,e} = \frac{\frac{\chi}{\eta_{ref}} - \frac{\chi}{\eta_{CO2}}(1-\eta_{cap})}{\frac{\chi}{\eta_{ref}}} = 1 - \frac{\eta_{ref}}{\eta_{CO2}}(1-\eta_{cap}) \tag{6.1}$$

7 Technical specifications

To compare the result obtained in a simulation is important know the assumption in the specifications that have been done. In the present work the recommendations made in CAESAR, DECARBit and ENCAP [21, 25, 26] are followed.

7.1 Ambient conditions

No in everywhere the air is in the same conditions of pressure and temperature or has the same humidity and composition. The following conditions are used for the simulation. In the Table 7.1 the air composition is given

- Pressure: 1 bar
- Temperature:15ºC
- Relative humidity: 60%

Table 7.1 Air composition

Component	Volume fraction dry	Volume fraction at 60% Relative Humidity
N_2	78.09	77.30
CO_2	0.03	0.03
H_2O	-----	1.01
Ar	0.932	0.923
Oxygen	20.95	20.74
Gas constant [J/(kg K)]	287.06	288.16
Molecular weight	28.964	28.854

7.2 Fuel

The composition and characteristic of the fuel is fundamental in the study of the efficiency and mass rate for the simulations of the different cycles. The ENCAP recommend the use of bituminous Douglas premium coal, which is representative of different coals type. In many of the previous studies the coal used in the simulations is the Illinois nº6. The composition ad heating values for both coals are show in Table 7.2.

Table 7.2 Ultimate analysis and LHV of different coals

	Units	bituminous Douglas premium coal	Illinois nº6
LHV	kJ/kg	25,174	22325
Moisture	%	8.00	12
Ash	%	14.15	16
C	%	66.52	55.35
H	%	3.78	4
N	%	1.56	1.08
O	%	5.47	7.47
S	%	0.52	4

The ENCAP also recommend a composition for the natural gas. The composition varies depending of the place of origin and the process of cleaning used. The supply conditions of the NG are at 10ºC and 70 bar. For the Allam cycle pure CH_4 at 40 bar is used to simulate the natural gas conditions [41].The natural gas compositions given in Table 7.3.

Table 7.3 Natural gas composition and LHV

	Units	bituminous Douglas premium coal
LHV (25ºC)	kJ/kg	46503
N_2	$\%_v$	0.86
CO_2	$\%_v$	2.0
Methane	$\%_v$	89.0
Ethane	$\%_v$	7.0
propane	$\%_v$	1,0
Iso-butane	$\%_v$	0,05
n- butane	$\%_v$	0,05
Iso-pentane	$\%_v$	0,005
n-pentane	$\%_v$	0,004
Exhale	$\%_v$	0,001

7.3 Air Separation Unit

The simulation of the Air Separation Unit is out of this project. The energy consumption of the ASU can be estimated in different ways, it can be assumed a fix energy cost per kilogram of pure oxygen generated or a variable cost depending of the size of the plant, if more oxygen is generated, cheaper is produced it per kg of O2.

7.3.1 Gas stream conditions

For the conditions of streams of the Oxygen and Nitrogen we will use the following specification obtained from DECARBit.

- Oxygen purity: 95% or 99,5%
- Oxygen temperature: 10ºC

7.3.2 Energy requirements

To calculate the energy required for the production of an oxygen-rich stream at 2.38 bars and a pure nitrogen stream and a waste nitrogen stream at 1 atm we use the Figure 7.1. The Figure 7.1 shows the energy requirement for production of an oxygen-rich stream at 2.379 bar, a pure nitrogen stream at atmospheric pressure and a waste nitrogen stream at atmospheric pressure. A linear decrease can be used between 230 kWh/ton O_2 for 1000 tons O_2/day to 200 kWh/ton O_2 for 5000 tons O_2/day for the 95% O_2 and between 251 kWh/ton O_2 for 1000 tons O_2/day to 221 kWh/ton O_2 for 5000 tons O_2/day for the 99.5% O_2. In all the calculations when it said O_2 it is referred to the pure amount of oxygen in the stream.

If the oxygen is delivered to the power plant at a pressure higher that the 2.38 bar the stream have to be compressed. To calculate the energy consumed in that compression is used the Figure 7.2. The delivery temperature for the oxygen-rich stream is 15 °C for delivery pressures up to 75 bar The Figure 7.2 is the illustration of the equations 7.1 and 7.2 (pressure in bars):

$$\text{Power}(\text{kWh/tonm } O_2) = 697 * 0.11 * \log10(P/2.38) \quad (7.1)$$

$$\text{Power}(\text{kWh/tonm } O_2) = 687 * 0.11 * \log10(P/2.38) \quad (7.2)$$

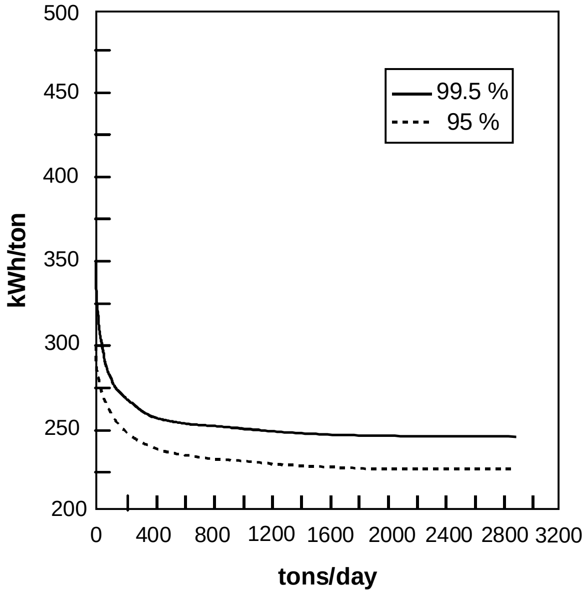


Figure 7.1 Energy requirement for production of an oxygen-rich stream at 2.379 bar [26]

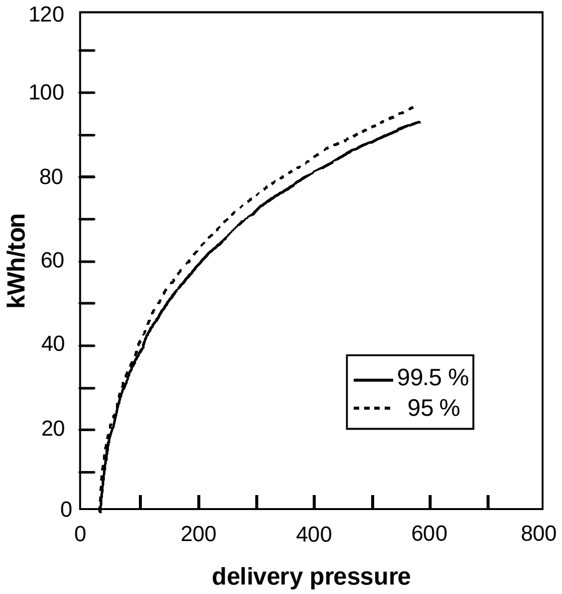


Figure 7.2 **Additional energy requirement for pressurizing the oxygen-rich stream from 2.379 bar to an specific pressure [26]**

7.4 Combustor

In the PRO/II simulations is define a pressure drop of 3% and that it operate at isentropic conditions [42].

7.5 Gas Turbine

In the simulation with PRO/II the adiabatic efficiency is fixed in 85% and the pressure ratio is defined depending the cycle [31].

In the simulation in GT PRO the gas turbine used is Siemens SGT5-4000F the characteristic of the turbine are defined for GTPRO [15].

For the calculation of the efficiency the mechanical efficiency ($\eta_{m)}$ is set in 99.6%, generator efficiency (η_g) in 98.5% and the auxiliary power efficiency ($\eta_{aux)}$ in 98.5% of net plant output for natural gas as fuel and 94.5% of plant output for coal.

7.6 Steam cycle

7.6.1 HRSG

The steam cycle is defined as a triple pressure with single reheat, the 3three pressure levels are 125 bar, 30 bar, 4.5 bar. The temperature of reheat and superheating is 560 °C. The cold reheat steam is mix with superheated. The circulation is natural.

Pressure losses considerate are:

- $\Delta p_{HRSG, hot} = 4$ kPa
- $\Delta p_{cold} = 3$ % for each heat exchanger
- $\Delta p_{reheat, cold, tot} = 10$ %

- $\Delta p_{\text{"steam pipe+valve"}}$ =
    - HP 7 %
    - IP 9 % (when steam flows directly to IP turbine)
    - IP 9 % for Reheat/IP-steam mixing (assuming pressure loss of 2% from HP turbine exit to HRSG, 3% in HRSG Reheater, and 5% from HRSG to IP turbine inlet)

LP 12 % Temperature differences inside the HRSG are:

- $\Delta T_{\text{steam/gas}} = 25$ K
- $\Delta T_{\text{pinch point, gas/boiling liquid}} = 10$ K
- $\Delta T_{\text{gas/liquid}} = 10$ K
- $\Delta T_{\text{approach, ECO}} = 5$ K

7.6.2 Condenser

The conditions for the condenser are:

- Condenser pressure: Pcond = 0.048 bar (Tsat = 32.2 °C)
- Cooling water pump work: 0.5% of steam turbine power
- Cooling water pressure: 2-2.5 bara

7.6.3 Steam turbines

The isentropic efficiency of the steam turbines change with the pressure:

- $\eta_{HP} = 90\%$
- $\eta_{IP} = 92\%$
- $\eta_{LP} = 88\%$

The pressure losses for steam extraction from the turbine are:

- HP-extraction pipe + preheater, $\Delta p = 3$ %
- LP-extraction pipe + preheater, $\Delta p = 5$ %

7.6.4 Feedwater preheating

The feedwater is not preheating with steam from the turbine, it is with exhaust gas heat up to 95 °C. The daerator operate at 1.2 bar and 105 ºC

7.7 Heat exchanger

- Pressure lost: 3%
- Pinch point gas/gas:25ºC
- Pinch point gas/boiling or liquid phase:10ºC
- Pinch point liquid/liquid:10ºC
- Pinch point condensing/liquid:3ºC

7.8 Flash

In PRO/II it operate at isentropic conditions and there is not pressure drop

7.9 Compressors

- Adiabatic efficiency for O_2 and fuel: 75%
- Adiabatic efficiency for first CO_2: 85%
- Adiabatic efficiency for the last CO_2 compressor: 80%
- Electrical efficiency: 75%

7.10 CO_2 pump

- Adiabatic efficiency: 75%
- Electrical efficiency: 75%

7.11 Gasifier

The gasifier selected is a GE with total water quench.

- Temperature: 1370ºC
- Pressure: 60 bar for the Allam cycle and 41.7 bar for the rest of cases.
- Water in the slurry: 33%

7.12 Gas clean up

- H_2S removal: 99%
- COS conversion: 98 %
- Scrubber water temperature 100ºC
- Reboiler heat input: 20952 kJ/kg_{H2S}

7.13 Splitters and mixers

There is not pressure drop.

7.14 Prost-combustion conditions

The inputs selected for the pre-combustion capture in GTPRO are shows in the Table 7.4. The Rich solvent flow/ CO2 flow is set in 20 to simulate a MEA solvent [15]

Table 7.4 GTPRO inputs for post-combustion capture

Flue gas processed	100%	**Nominal heat input per unit CO_2 in reboiler**	3700 kJ/kg [21]
CO_2 captured efficiency	90%	**Steam condensing pressure**	4
Flue gas exit temperature	35ºC	**Flue gas in temperature**	45ºC
Total gas pressure drop	100 mbar	**Rich solvent flow/ CO_2 flow**	20
CO_2 delivery compression	151 bar	**Pumping head solvent circulation**	10.34 bar

7.15 Pre-combustion conditions

The pre-combustion capture is simulated in GTPRO using a Selexol process and the main inputs selected are given in Table 7.5.

Table 7.5 GTPRO inputs for pre-combustion capture

<table>
<tr><td>H_2S removal efficiency</td><td>99%</td><td colspan="2">Nominal heat input per unit CO_2 in reboiler</td><td colspan="3">2700 kJ/kg$_{H_2S}$ [21]</td></tr>
<tr><td>CO_2 captured efficiency</td><td>90%</td><td colspan="2">Steam condensing pressure</td><td colspan="3">3</td></tr>
<tr><td>Flue gas exit temperature</td><td>35ºC</td><td colspan="2">Max absorber inlet temperature</td><td colspan="3">57.78 ºC</td></tr>
<tr><td>COS conversion</td><td>98%</td><td colspan="2">Rich solvent flow/ CO_2 flow</td><td colspan="3">20</td></tr>
<tr><td>CO_2 delivery compression</td><td>151 bar</td><td colspan="2">Pumping head solvent circulation</td><td colspan="3">10.34 bar</td></tr>
<tr><td rowspan="4">Acid gas outlet</td><td>1.52 bar</td><td rowspan="4">Flash pressure and CO_2 production</td><td></td><td>Flash 1</td><td>Flash 2</td><td>Flash 3</td></tr>
<tr><td>50ºC</td><td>CO_2 partial pres.</td><td>0.075</td><td>0.5</td><td>0.85</td></tr>
<tr><td>100% relative humidity</td><td>CO_2 production</td><td>35%</td><td>25%</td><td>40%</td></tr>
<tr><td>Mole CO_2/ moleH_2S=1</td><td></td><td></td><td></td><td></td></tr>
</table>

7.16 CO_2 stream

The recommended emissions for the CO_2 stream are show in the following Table. If any of the specifications is not kept in the acceptance level a purification system is need to clean the gas until the composition reach can be transported and sequestrated.

Table 7.6 Adopted limits in the CO_2 stream

	Recommended for EBTF	Aquifer	EOR
CO2	>90%v	>90%v	>90%v
H2O	<0.05%v	<0.05%v	<0.005%v
H2S	<0.02%v	<1.5%v	<0.005%v
NOX	<0.01%v	NA	NA
SOX	<0.01%v	NA	<0.005%v
HCN	<0.0005%v	NA	NA
COS	<0.005%v	NA	<0.005%v
RSH	<0.005%v	NA	NA
N2	<4%v	<4%v	<4%v
Ar	<4%v	<4%v	<4%v
CH4	<2%v	<4%v	<2%v
CO	<0.2%v	<4%v	<4%v
O2	<0.01%v	<4%v	<0.01%v

8 Simulation models

8.1 Simulation software

For the simulations made in this report different simulation programs have been used. Each program has its own limitations, advantages and disadvantages. The combination of all the programs allow the generation of different processes in the most efficient way. The inputs in each case have to be the same, to allow the correct comparison of results.

The SimSci simulation software PRO/II is designed as a steady-state simulator to improve process design and operational analysis. It is capable to perform rigorous heat and material balance calculations for a wide range of chemical processes. It is a very flexible program which permit simulates novel process without the rigid inputs of other simulation programs.

The other program used is Thermoflow. That simulation software has different software to work with: GTPRO, THERMOFLEX, and GT MASTER. The GTPRO is used to modeling combined cycles; the operator can select the equipment and its specifications to generate a complete report with all the mass and heat results. It is a simple tool but the distribution of equipment is set, to modify the distribution, add or delete something the operator has to use THERMOFLEX, with allow a free combination of equipment. For an off-design the models in GTPRO and THERMOFLEX can be exported to GT MASTER.

The number of inputs that can be carried in PROII is more limited that in Thermoflow, which can make the result in PROII more optimistic than in the other software but, assuming that the normal conditions of operation taken in both will be similar, the comparison can be made without an appreciable mistake.

The gasification of the coal is simulated in THERMOFLEX because PROII does not accept solids gasification and the GTPRO uses a cleanup syngas unit that is not uses by Allam et al. [41]. The rest of the model is computed with GTPRO.

8.2 Allam cycle

8.2.1 General cycle description

The Allam cycle is classified as a low pressure ratio Brayton cycle using CO_2 as working fluid in a high pressure, a scheme is show in Figure 8.1. It operates with a single turbine that has an inlet pressure between 200 and 400 bar and a pressure ratio between 6 and 12. The cycle runs with a high pressure oxy-fuel combustor that burns a fossil fuel with stream of oxygen with a 99.5 % of purity, it provides a high pressure feed stream to a power turbine. The oxygen is diluted with a fraction of the CO_2 recycled stream to enter to the combustor in order to moderate the adiabatic flame temperature. The oxygen concentrations of the stream vary between15% and 30% by mole-fraction. As the ASU supply the oxygen stream at 75 bar a separate O_2/CO_2 compressor compress the oxidant mixture at the required high pressure of the combustor. The oxidant mixture is preheated in the recuperator before entering the combustor.

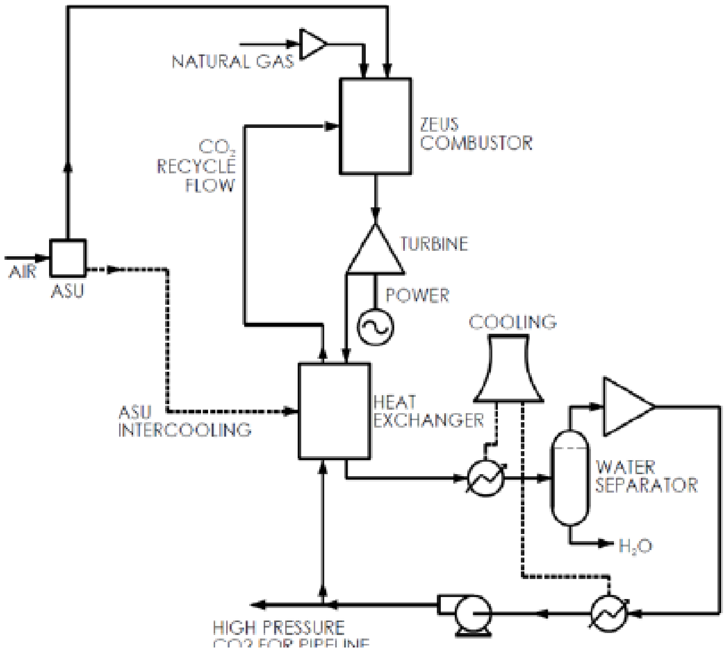


Figure 8.1 **Flow diagram of the Allam cycle for natural gas [42]**

A recuperator transfers heat from the high temperature turbine exhaust flow to a high pressure CO_2 recycle stream that feed the combustor, diluting the combustion products and lowering the turbine inlet temperature to an acceptable level. The recycled CO_2 must be heated to a temperature in the range 675°C to 750°C.

The turbine flue gas flow is cooled to a temperature below 70°C in the recuperator and then recooled to near ambient temperature. The CO_2 stream is now compressed because it is under the critical pressure at 73.9 bar. A conventional single- or two-stage compressor first raises the pressure near 80 bar, it makes the stream achieve the critical state. The supercritical CO_2 is cooled to near ambient temperature. The density of the stream will be above 700kg/m3. The CO_2 is now pumped to the high pressure required; for it a multi-stage centrifugal pump is used.

There is a very significant imbalance between the heat required to raise the temperature of the high pressure recycle stream and the heat liberated by the low pressure turbine flue gas. The imbalance is consequence of the very large increase in the specific heat of CO_2 in the high pressure recycled stream at the low temperature end of the recuperator. The imbalance is corrected raising the recycle CO_2 temperature at the low temperature end of the heat exchanger in a temperature range of 100°C to 400°C. The heat is added to a portion of the recycle CO_2; the heat can be taken from the ASU.

A high turbine inlet temperature gives better net cycle efficiencies but this temperature is limited by the maximum temperature permitted at the inlet of the recuperator. This maximum temperature depends on the operating pressure selected and the materials of the recuperator. The operating temperature at the hot end of the heat exchanger is in the range of 700°C to 750°C. As a consequence of this the typical turbine inlet temperature varies in the range of 1100°C to 1200°C.

For a configuration where the fuel is coal, it must be gasified first using a conventional partial oxidation water quench gasifier with a water/coal slurry feed. The Figure 8.2 represents the coal cycle. The impurities will be present in a reduced form in the synthesis gas, the major component of the syngas will be steam and it will be in the temperature range of 250°C to 300°C. In addition to the water quench, a water scrub and a final fine particle filtration will remove all slag and inorganic material formed in the gasification. The syngas is then cooled to near ambient temperature in a heat exchanger, where the condensed water is removed. The extracted heat is transferred to the low temperature region of the high pressure CO_2 recycle stream. The use of a direct water quench gasifier gives a very little heat loss. The syngas has to be compressed until the high pressure conditions of the combustor. The syngas is combusted and the impurities (H_2S, COS, CS_2, NH_3, HCN), are converted into their oxidized forms (SO_2, NO, H_2O, N_2). The main impurities after the combustion are SO_2 and NO/NO_2. These impurities will be converted into H_2SO_4 and HNO_3, it is made in the cold-end passages of the heat exchanger reacting with liquid water and the excess of oxygen. The concentration of H_2SO_4 depends on the cooling temperature and the sulfur content of the original fuel. The nitric acid present will largely remove mercury contaminant.

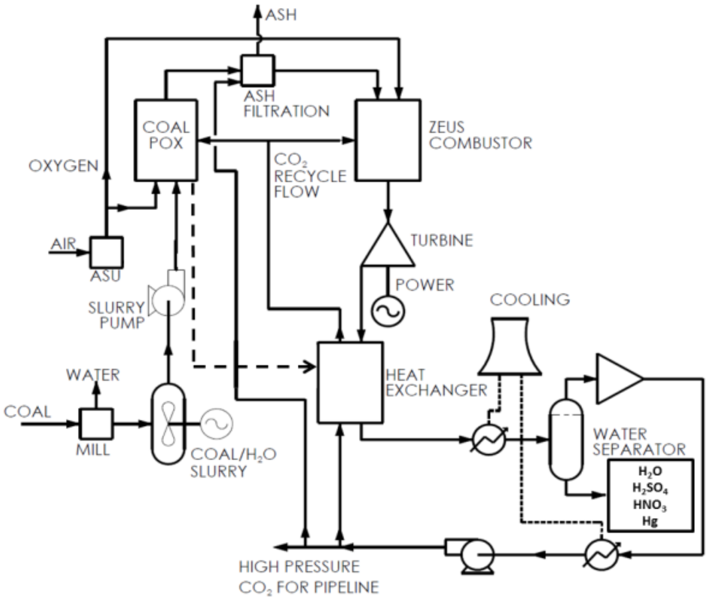


Figure 8.2 **Flow diagram of the Allam cycle using coal [42]**

8.2.2 Process design and specifications

The fuels input have been set in 15.5Kg/s for the gaseous fuel. This fuel generates a power output of the plant near to 400MW, which is a big plant to reproduce a real plant where the capture of CO_2 really worth the extra investment.

The specifications of the plant are the same that are indicated in the section 7. The case studied for Allam et al. (2012) [42] uses as fuel pure methane at 40 bar for the natural gas plant and the composition of natural gas recommended by the ENCAP. For the coal case, Illinois nº6 and the bituminous Douglass coal recommended for the ECCAP will be compared.

The heat required to reheat part of the CO_2 stream is calculated to minimize the temperature of the hot stream exhaust in the plant. In order to simplify the model all the CO_2 and O_2 stream is heated in the middle of the recuperator.

The recuperator is considered as unique heat exchanger, so even when in the simulation it is recreated with three of them, only one have a pressure lost of the 3%. The first heat exchange which the flue gas passed through has an approach of 25ºC as correspond for a heat exchanger with two gas stream; the second pass for the flue gas only have an approach of 10ªC because there is a change of state, part of the steam is condensed.

In the simulation, the CO_2 produced is compressed in a pump up to 151 bar and, using a different pump, the recycled CO_2 is compressed up to 320 bar. This reduces the work required for the compression.

8.3 Base case without CO_2 capture

For the base case GTPRO is used for the simulation. The specifications are the recommended by the ENCAP for the NGCC and IGCC. The turbine selected is the Siemens SGT5-4000F and the oxidant fluid is air. The gasification process is the same used for the Allam cycle in order to compare the CO_2 cycle efficiency. In a normal IGCC plant others gasifiers can generate more efficiency with a better gasification and cooling system.

The gas clean up system used after the gasifier use a stream of steam coming from the intermediate pressure steam after the superheating and from the reheat steam. The specifications used are specified in the section 7.

8.4 Post-combustion capture using amine absorption

The GTPRO is used to simulate that cycle. An amine based configuration is chosen for the carbon capture. For the simulation the fuel used and the steam cycle specifications are showed in the section7. The turbine selected is the Siemens SGT5-4000F and the oxidant fluid is air.

The heat need in the reboiler of the stripper in the capture section is taken from the low pressure steam at the end of the superheating section. The condensate comes back to the steam cycle in the condenser.

8.5 Pre-combustion capture

For the simulation GTPRO has been used. For the capture of CO_2 the method used is a sour shift conversion. For the simulation the fuel used is Illinois nº6, the coal and the steam cycle specifications are showed in the section 7. The turbine selected is the Siemens SGT5-4000F and the oxidant fluid is air.

The heat need in the reboiler of the stripper in the capture section is taken from the IP steam turbine. The condensate comes back to the steam cycle into the condenser.

9 Result and discursions

9.1 Natural gas

9.1.1 Allam cycle

For the simulation of the Allam cycle using 15.5 kg of pure CH4, the fuel enters at 220 ºC and 310 bar to the combustor with 63 kg/s of O_2 and 1264 kg/s of the CO_2 stream, both at 310 ºC. The TIT is set at 1150ºC, the turbine expands the flue gas from 300 bar until 30 bar with an exhaust temperature of 795ºC. That temperature is 20ºC higher than the maximum specify by NET power for the recuperator, set in 775ºC. That can be explained with the increasing of the isentropic efficiency until 90%, this represent an important advantage in the turbines technology. For that simulation the efficiency used is the given in the actual state of the art for gas turbines at high pressures and temperatures.

As have been mentioned, the TIT is 1150ºC, at that temperature is necessary cool the turbine .The simulated turbine is not cooled, the cooling of the gas turbine have some lost of the net efficiency. Different studies have been done to determinate the reduction of efficiency, a study made for the blade cooling in the MATIANT cycle determined it in a 1.4% of the LHV input [19].

In the recuperator 51 kJ/kg are added to the CO_2 stream, this represent an increase of the temperature in 35 º C. The exhaust temperatures of the recuperator are 738ºC and 79ºC with inlet temperatures of 795ºC and 63ºC.

Finally, the compression chain of CO_2 compress the flue gas up to 320 bar, the needed 1563 kg/s to be recycled and 55 kg/s to be sequestrated. The water extracted from the cycle can be used in the cooling system or just throw it after be cleaned.

The net efficiency of the power island and the net efficiency of the power are calculated according the indications given in section 6. Table 9.1 shows that the net efficiencies obtained in the simulations are lower than the obtained for the NET power simulation. That reduction in the efficiency can be assumed for the different assumptions taken for the simulation.

Especial importance in the results has the difference in the CO_2 compression consumption, which is smaller in the NET simulation, and also the ASU consumption. The consumption of the ASU can be determined by a set value according to the pressure of delivery or can be done as mentioned in section 6, where the consumption of energy also depends on the size of the plant. The more oxygen is produced, the lower is the cost per kg of O2. As for this plant size we need two ASU units the energy penalty is higher. The plant can be designed according the ASU, with a maximum of 5000 tonm/day.

Table 9.1 Energy consumptions and efficiencies for Allam cycle

		Natural gas		CH4		NET power
			$\%_{LHV}$		$\%_{LHV}$	$\%_{LHV}$
fuel flow rate	kg/s	15.50		15.50		
lower heating value	kJ/kg	46500		50047.00		
fuel LHV	KW	720896.50	100.00%	775728.50	100.00%	
turbine work	kW (>0)	595900	82.67%	640400	82.55%	82.70%
mechanical efficiency	%	99.60%		99.60%		
generator efficiency	%	98.50%		98.50%		
auxiliary power efficiency	%	98.50%		98.50%		
net efficiency of the Power Island	%	79.88%	79.88%	79.77%	79.775%	
compressors electrical efficiencies	%	95.00%		95.00%		
pump mechanical efficiencies	%	95.00%		95.00%		
ASU	kW (<0)	-61870	-8.58%	-69560	-8.97%	- 12.20%
Fuel compression	kW (<0)	-4421	-0.61%	-7967	-1.03%	
O_2 compression	kW (<0)	-10710	-1.49%	-11560	-1.49%	
Coolers	kW (<0)	-1372	-0.19%	-1684	-0.22%	
1ºCO_2 compressor	kW (<0)	-43210	-5.99%	-46440	-5.99%	- 11.60%
2º CO_2 compressor	kW (<0)	-33070	-4.59%	-36320	-4.68%	
CO_2 pump	kW (<0)	-47540	-6.60%	-51351	-6.62%	
Net plant efficiency		51.83%	51.83%	50.78%	50.78%	58.90%
net plant output	kW	373610		393900		
net island output	kW	575800		618800		

Using the same quantity of fuel, the results of efficiency obtained for the two types of fuel used in the simulation are different. The LHV for the CH_4 and the work produced in the turbine are higher than the obtained for the natural gas but if we compare the $\%_{LHV}$ for the work of the turbine, the efficiency is higher for the natural gas fuel. It can be explained for the amount of CO_2 recycled that is need in each case. For the natural gas fewer amounts of oxygen and CO_2 is need per MJ of fuel that is translated in a better efficiency. In Table9.2 the results obtained are show. The result are really similar, this demonstrate the assumption made for NET POWER [41] that to simulate the natural condition used methane at 40 bar.

Table 9.2 Fuel comparisons

	Units	Natural gas	CH4
O_2 stream	kg$_{O2steam}$/MJ$_{fuel}$	8.08E-02	8.10E-02
CO_2 stream	Kg$_{CO2steam}$/MJ$_{fue}$	1.62	1.63
turbine work	%$_{LHV}$	82.67	82.55

A reduction in the flow of oxygen means a reduction in the energy consumed for the ASU and in the %$_{LHV}$; also a reduction in the flue gas recycled represents a reduction in the energy consumed in the compression.

For the ENCAP natural gas case study can be done to study the variation in the efficiency with different combustor pressures. The ASU consumption has been set in 0.25 kWh/kg$_{O2}$ and the pressure ratio of the turbine set in 0.1. The maximum efficiency for the cycle is around 300 bar. The variation in the efficiency can be seen in Figure 9.1.

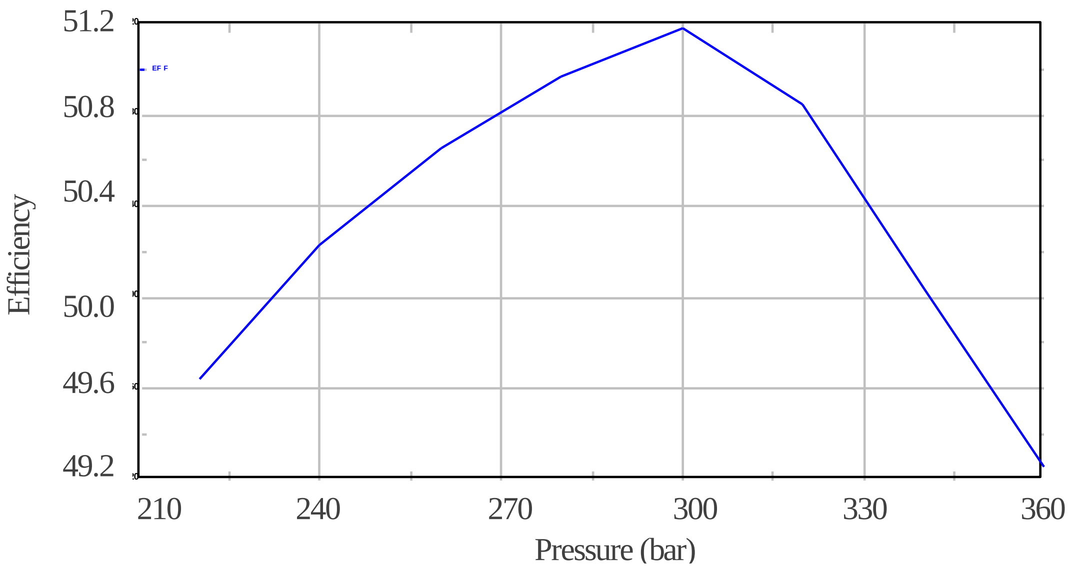


Figure 9.1 Effect of the pressure in the efficiency

9.1.2 NGCC without capture

The NGCC plant without capture operates with a net efficiency of 56.75% respect the LHV and generates 413 MW of power. In Table 9.3 the main results are exposed and in the Figure 9.2 show a flow diagram which summarizes the plant.

Table 9.3 Results for the NGCC without capture

parameters	Units	value
Fuel and air		
Flow rate fuel	kg/s	670.6
Flow rate air	kg/s	15.25
Flue gas		
Flow rate	kg/s	685.9
Temperature	ºC	91.76
pressure	bar	1.013
Flue gas composition		
N_2	mol.%	74.43
O_2	mol.%	12.56
CO_2	mol.%	3.882
H_2O	mol.%	8..237
Ar	mol.%	0.8964
Steam flow rates		
HP steam flow rate	kg/s	80.73
LP steam flow rate	kg/s	29.63
Overall performance		
Gross gas turbine output	MW	281
Gross steam turbine output	MW	142
Net electric power output	MW	415
Net electric efficiency	%LHV	56.75

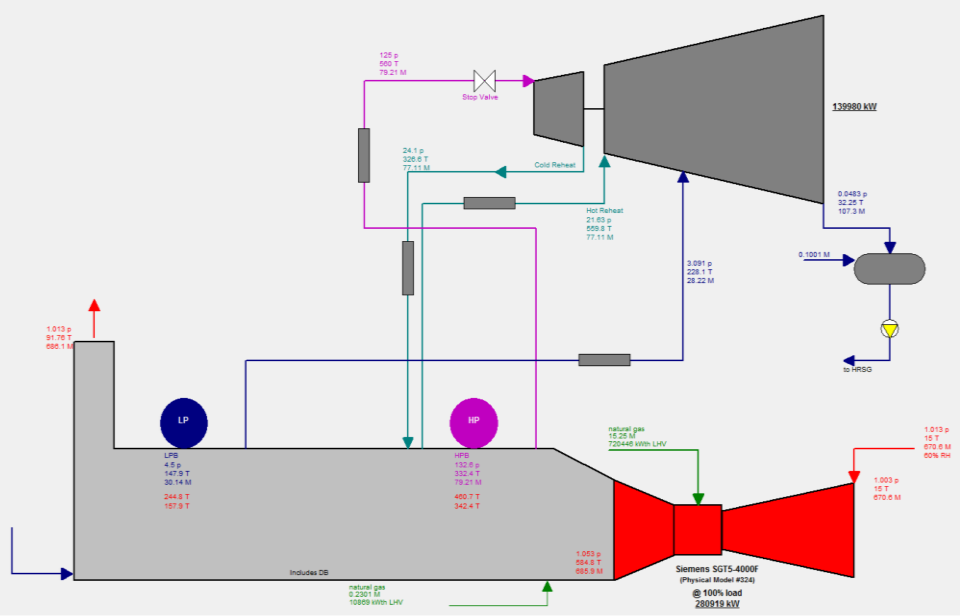


Figure 9.2 Simplified process diagram for the NGCC without capture

The gas turbine expands the flue gas to atmospheric pressure and the temperature is reduced from 1309 ºC to 585 ºC. In the HRSG the flue gas is cooled to a temperature of 92ºC. Figure 9.3 shows the temperature profile of the HRSG and how the three pressure stream are weaving together to optimize the heat exchange. There also can be appreciate the pinch point for the evaporation

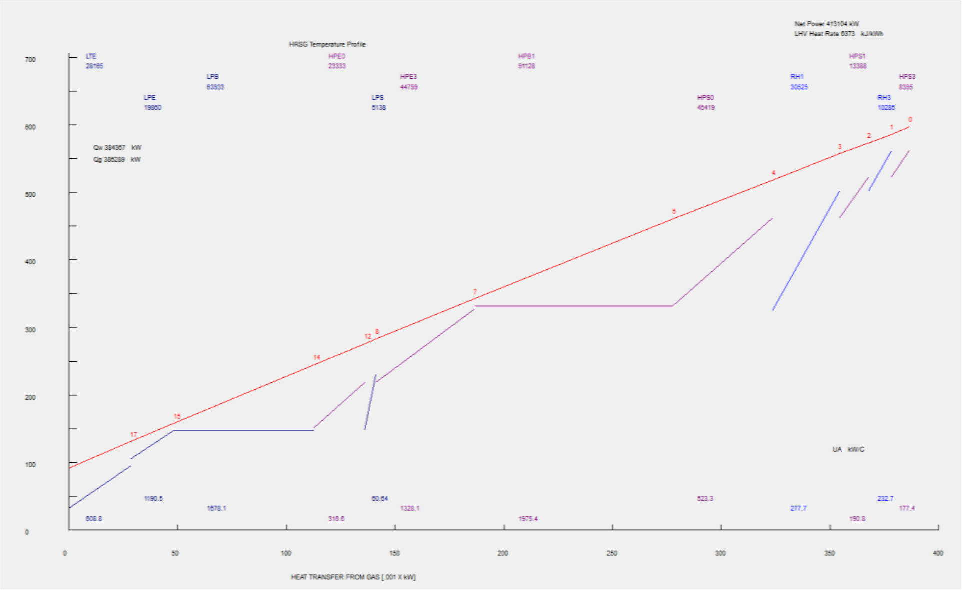


Figure 9.3 **TQ-diagram for the NGCC without capture**

9.1.3 NGCC with post-combustion capture

The main results of the NGCC with carbon capture based in amine absorption are given in the Table9.4. The net power efficiency is 49.93% with a power output of 365 MW. The TIT is 1309 ºC with an exit temperature and pressure of 585ºC and 1.05 bar. After the HRSG the flue gas temperature is 88ºC. After the absorber the flue gas is in a temperature of 35 ºC and the CO2 at until 151 bar and 25 ºC. In the Figure 9.4 a simplified process diagram of the plant is given.

Table 9.4 **Results for the NGCC with post-combustion capture**

Parameters	Units	Value
Fuel and air		
Flow rate fuel	kg/s	670.6
Flow rate air	kg/s	15.25
Flue gas		
Flow rate	kg/s	634.7
Temperature	ºC	35
pressure	bar	1.013
Flue gas composition		
N_2	mol.%	79.74
O_2	mol.%	13.33
CO_2	mol.%	0.4222
H_20	mol.%	5.548
Ar	mol.%	0.9603
CO2 stream composition		
CO_2	mol.%	100
H_2O	mol.%	0
Rich solvent		
Flow rate	kg/s	753.5
Reboiler heat	MW	139
Steam flow rate	kg/s	58.5
Steam flow rates		
HP steam flow rate	kg/s	79.23
LP steam flow rate	kg/s	27.48
Overall performance		
Gross gas turbine output	MW	281
Gross steam turbine output	MW	114
Net electric power output	MW	365
Net electric efficiency	%LHV	49.93

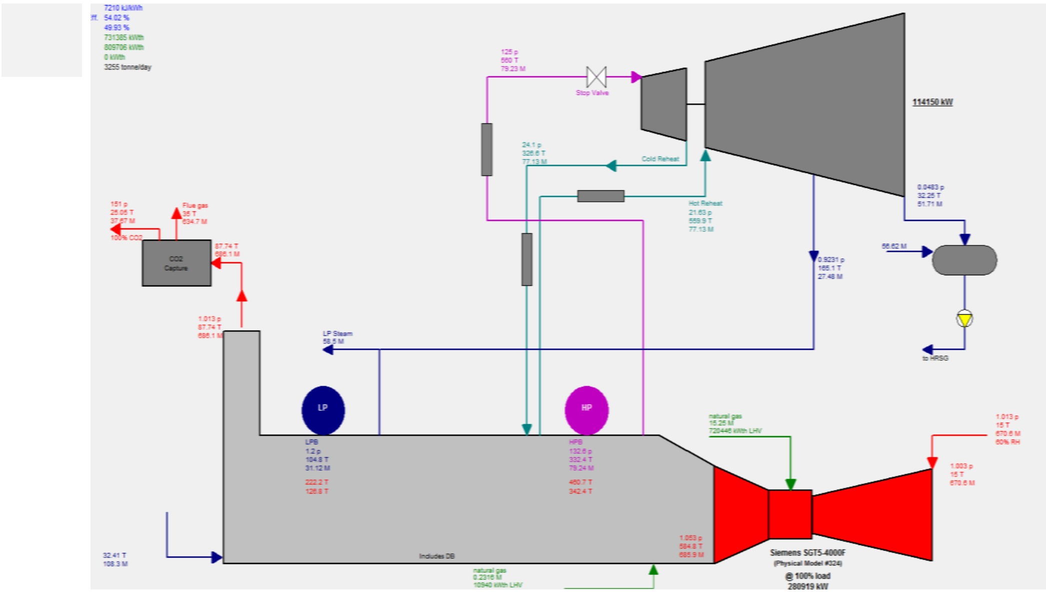


Figure 9.4 Simplified process diagram for the NGCC with post-combustion capture

9.1.4 Comparison of the cycles

The comparison with other cycles will allow us to determinate the quality of the cycle. The comparison will be made with a NGCC without CO_2 capture and a NGCC with post-combustion.

As it is indicated in the section 6 different parameters are calculated to compare the different power plants not only for the net power plant efficiency, also the efficiency in the carbon capture and the efficiency penalty for the capture.

Table 9.5 CO_2 capture results of different cycles

	Units	Allam cycle	Post-combustion	No capture
Fuel	kg/s	15.5	15.25	15.25
CO_2 produced	kg/s	41.13	41.56	41.56
CO_2 prod/fuel	kg_{co2}/kg_{fuel}	2.65	2.73	2.73
CO_2 lost	%	1.00%	0	0
CO_2 captured	kg/s	40.72	37.67	0
CO_2 captured ratio	%	99.00%	90.64%	0
Net efficiency	%LHV	51.83%	49.93%	56.75%
Net power	kW	373600	3652	415200
Power/fuel	kWh/kg_{fuel}	6.695	6.65	7.56
HR	kJ_{LHV}/kWh	6945	7210	6343
Additional fuel consumption	kJ_{fuel}/kWh	9.49%	13.66%	0.00%
SPECCA	MJ/kg_{CO2}	-16.75	-17.57	0
χ	kg_{CO2}/kWh_{fuel}	0.20543	0.20457	0.20452
CO_2 captured	kg_{CO2}/kWh	0.39	0.37	0
CO_2 emitted	kg_{CO2}/kWh	0.004	0.038	0.36
CO_2 avoided	kg_{CO2}/kWh	0.36	0.32	0

CO_2 capture efficiency	%	98.91%	89.36%	0.00%

The net power efficiency of the Allam cycle with 51.8% is in between the base case without capture with 56.5% and the 50% of the base case with post- combustion capture. The base cases correspond to the actual state of the art for each technology.

The quantity of CO_2 produced per kg of fuel for the Allam cycle, $2.65 kg_{CO2}/kg_{fuel}$, cycle is lower than for the bases cases, 2.70. This can be due to the use of different simulation programs. In each program the amount of CO and unburned fuel is different for the combustor and also the differences of pressure and temperature, all this generate the difference of CO_2 production.

For the oxy-combustion cycles a fraction of the CO_2 is diluted with the water extracted from the cycle, we consider that lost in a 1% of the bulk CO_2 [29]. The Allam cycle has 99% of CO_2 captured and 90% for the amine case. The CO_2 capture can be expressed also as 0.39 kg_{CO2}/kWh for Allam and 0.37 kgCO_2/kWh for the amine. It is important do not confuse the carbon capture with the CO_2 avoided, the last one express the CO_2 that is not emitted for use the capture technology instead of the normal technology. The CO_2 avoided is expressed as CO_2 capture efficiency with a very high value for the Allam cycle (99%) and a good one for the amine absorption with a 90%.

There is a significant difference between the CO_2 compression pressure for Allam and for the amine case. In the first one the final pressure is 320bar for the recycled gas, which represent the 90%vol of the flue gas, while in the other case the compression pressure is 152bar for the entire compress stream, which means an important reduction in the power consumption for the compression. In the Allam cycle it represents the 17% while for the post-combustion it represents only a 3.5%.

9.1.5 Comparison of the base cases

For the base case the same turbine is used and the same amount of fuel is burned, the difference is in the steam cycle. For the absorption of the CO_2 a steam stream is needed in the reboiler of the striper for the regeneration of the amine. The steam is taken from the low pressure turbine and from the end of the superheated section for the low pressure stream. The base case without capture produce 139980 kW with an efficiency of 31.63% while the amine base produce 114150 kW and a efficiency of 25.79%.

9.2 Coal

9.2.1 Allam cycle

The Allam cycle using coal as fuel follows the same scheme than the run with natural gas after the combustor. The Douglas coal is gasified in a GE water quench gasifier to produce the syngas burnt in the combustor boiler. The syngas out the gasifier is at 239ºC and go thought a stripper and fine particle filter before been cooled at 22 ºC, before the compression at 310 bar the condensed water is removed. In the combustor the syngas is burned in a proportion of 1.4 kg_{syngas}/kg_{O2} to obtain a 2% of O_2 excess. To control the temperature to 1150ºC, preheated flue gas is recycled in an amount of 18.8 times in weight the syngas. The flue gas is expanded from 300 bar to 30 bar to generate power. As in the case of natural gas the TIT is high and is needed a turbine cooling system, as it was mentioned before it has a penalty around the 1.5%. The exhaust temperature is 797 ºC and the turbine generates 698 MW without any penalties.

For a big power plant like the simulated, 359MW, it is necessary the use of two ASU, one is used for the gasification and the other is used in the combustion.

The flue gas leaving the turbine has still some energy that can be taken. The flue gas is cooled in a recuperator until 80ºC. In the recuperator some extra heat has to be added to optimize the process. It is done taken away the mixture of O2 and CO_2 form the recuperator and heating it with 86.3 MJ/s taken from the cooler of the syngas. The hot end of the recuperator is 770ºC and is added to the combustor. The stream from the cool end is further cooled until 22ºC and the condensed water is separated. Finally the flue gas is compressed in a compressor chain with intercooling until the 80 bar and the later it is separated into the flue gas generated and the CO2 that is recycled. The CO2 that is recycled is compressed up to 320 bar and the gas that is going to be sequestrated is compressed up to 110 bar.

The simulations of the Allam cycle have been realized with two types of coal, the Illinois nº6 and the Bituminous Douglas. Depending of the type of coal, the efficiency of the plant is different. In Table 9.6 can be seen the calculations of efficiency based in the section 6.

The results obtained are very far from the obtained by NET power, it is due the compression energy used in the compression of the flue gas and the cold gas efficiency for the gasification.

In the simulation in TERMOFLEX for the Illinois and Douglas coal the cold gas efficiency are respectively 74.5 and 76.6%. The normal efficiency of the gasifier is between 70 and 80% [11]. If we increase the gasification efficiency the amount of coal needed is reduced and the efficiency is increased. With the decreasing of fuel the amount of oxygen used in the gasification is also reduced.

Table 9.6 Energy consumption and efficiency for the Allam cycle using coal.

		Illinois nº6		Bituminous Douglas		NET power
			$\%_{LHV}$		$\%_{LHV}$	$\%_{LHV}$
Fuel flow rate	kg/s	45.91		41.91		
LHV fuel	kJ/kg	22325		25633.84		
Energy in fuel	KW	1024940.75	100.00%	1074314.23	100.00%	
Cold gas efficiency	%	74.51		75.61		
LHV syngas	kJ/kg	5262		5595		
Syngas flow	kJ/s	145.2		145.20		
Syngas energy	kW	764042.40		812394.00		
Turbine work	kW(>0)	661800	64.57%	697600	64.94%	74.91%

		Illinois n°6		Bituminous Douglas		NET power
			$\%_{LHV}$		$\%_{LHV}$	$\%_{LHV}$
Mechanical efficiency	%	99.60		99.60		
Generator efficiency	%	98.50		98.50		
Auxiliary power efficiency	%	94.50		94.50		
Net efficiency of the Power Island	%	59.86	59.86%	60.20	60.20%	
Compressors electrical efficiencies	%	95.00		95.00		
Fans, blowers mechanical efficiencies	%	95.00		95.00		
ASU	kW(<0)	- 80420	-7.85%	-80870	-7.53%	-12.69%
Syngas compression	kW(<0)	- 24400	-2.38%	-25860	-2.41%	
O2 compression combustor	kW(<0)	- 36930	-3.60%	-38130	-3.55%	
Coolers	kW(<0)	- 2445	-0.24%	-2445	-0.23%	-10.78%
1ºCO2 compressor	kW(<0)	- 45530	-4.44%	-48370	-4.50%	
2º CO2 compressor	kW(<0)	- 34300	-3.35%	-36870	-3.43%	
CO2 pump	kW(<0)	- 52110	-5.08%	-55300	-5.15%	
Net plant efficiency	kW	32.92	32.92%	33.41	33.41%	58.90%
Net plant output	kW	337400		359000		
Net island output	kW	613500		646800		

With a cold gas efficiency of 80% for the Illinois coal the reduction of the fuel flow is 6.8% in weight and an incensement in a 5.84% for the net power plant efficiency. The final net plant efficiency is 38.75 and 39.69 % for the Illinois and Douglas coal respectively. This results show that an increasing in the gasifier efficiency means a better plant efficiency. The results are given in Table 9.7.

Table 9.7 Plant efficiency using gasifier with cold gas efficiency of 80%

		Illinois nº6		Bituminous Douglas		NET power
	Units		$\%_{LHV}$		$\%_{LHV}$	$\%_{LHV}$
Fuel flow rate	kg/s	42.78	6.82	39.62	5.48	
LHV fuel	kJ/kg	22325.00		25633.84		
Energy in fuel	KW	955053.00	100.00	1015492.50	100.00	
Cold gas efficiency	%	80.00		80.00		
LHV syngas	kJ/kg	5262.00		5595.00		
Syngas flow	kJ/s	145.2		145.20		
Syngas energy	kW	764000		812400		
Turbine work	kW(>0)	661800	69.29	697600	68.70	82.70
Net efficiency of the Power Island	%	64.24	64.24	63.69	63.69	
Net plant efficiency	kW	38.75	38.75	39.69	39.69	58.90
Net plant output	kW	370100		403000		
Net island output	kW	613500		646700		

If we compare the coal used, the Douglas has more heating value and the gasification efficiency is better but for the production of power it gives worst results. If the gross efficiency of the turbine is compared it is 0.4 point higher that the Illinois and 0.5 points in the net power plant efficiency. In the simulation the same syngas production is set but the composition of each one is different due the initial composition of the coal. The different composition of the syngas means that different amount of O_2 is needed and it generate different temperatures of combustion, so different recycled flow is need to control the temperature. If the amount of O_2 or CO_2 increases, it makes increase the power generated by the turbine but it also makes increase the energy used in the compression of the streams. The variations in the inlet streams of the combustor are show in the Table 9.8. The different of efficiency is very low, that means that both coals are comparable for the different simulations.

Table 9.8 Variations in the inlet streams of the combustor

	Units	Illinois nº6	Bituminous Douglas
O_2 stream	kg_{O2st}/kg_{Syngas}	0.70	0.69
CO_2 stream	$kg_{fluega}s/kg_{Syngas}$	18.73	18.83
Turbine work	$\%_{LHV}$	64.57	64.94
$kgO_2/MWfuel$	kg_{O2}/MW_{fuel}	0.0790	0.0782

9.2.2 IGCC without capture

The main results obtained in the simulation of the IGCC without capture using Illinois nº6 coal are given in the Table 9.9. The net plant efficiency obtained is a 35.1%. The result can be compared with the found in the literature, the net efficiency vary from the 32.6% [43], 35%[44] to 41,2[45]

Table 9.9 Results for the IGCC without capture

Parameters	Units	Value
Gasifier		
Fuel	kg/s	47.05
Oxygen	kg/s	33.4
Cold gas efficiency	$\%_{LHV}$	74.92
Water for the slurry	kg/s	14.75
Raw syngas		
Flow rate	kg/s	150
Temperature	ºC	223.8
pressure	Bar	41.71
Raw syngas composition		
CO	mol.%	22.19
CO_2	mol.%	5.386
CH_4	mol.%	0.0032
H_2	mol.%	14.58
H_2S	mol.%	0.7255
O_2	mol.%	0
H_2O	mol.%	56.78
COS	mol.%	0.0373
N_2	mol.%	0.2751
Ar	mol.%	0.0271
Flue gas		
Flow rate	Kg/s	736.4
Temperature	ºC	585.7
pressure	Bar	1.05
Flue gas composition		
N_2	mol.%	71.89
O_2	mol.%	13.68
CO_2	mol.%	8.179

Parameters	Units	Value
H_2O	mol.%	5.371
Ar	mol.%	0.873
SO_2	mol.%	0.0025
Steam flow rates		
HP steam flow rate	kg/s	85.67
IP steam flow rate	kg/s	102.92
Overall performance		
Gross gas turbine output	MW	300890
Gross gas turbine output	MW	127828
Net electric power output	MW	368636
Net electric efficiency	$\%_{LHV}$	35.1

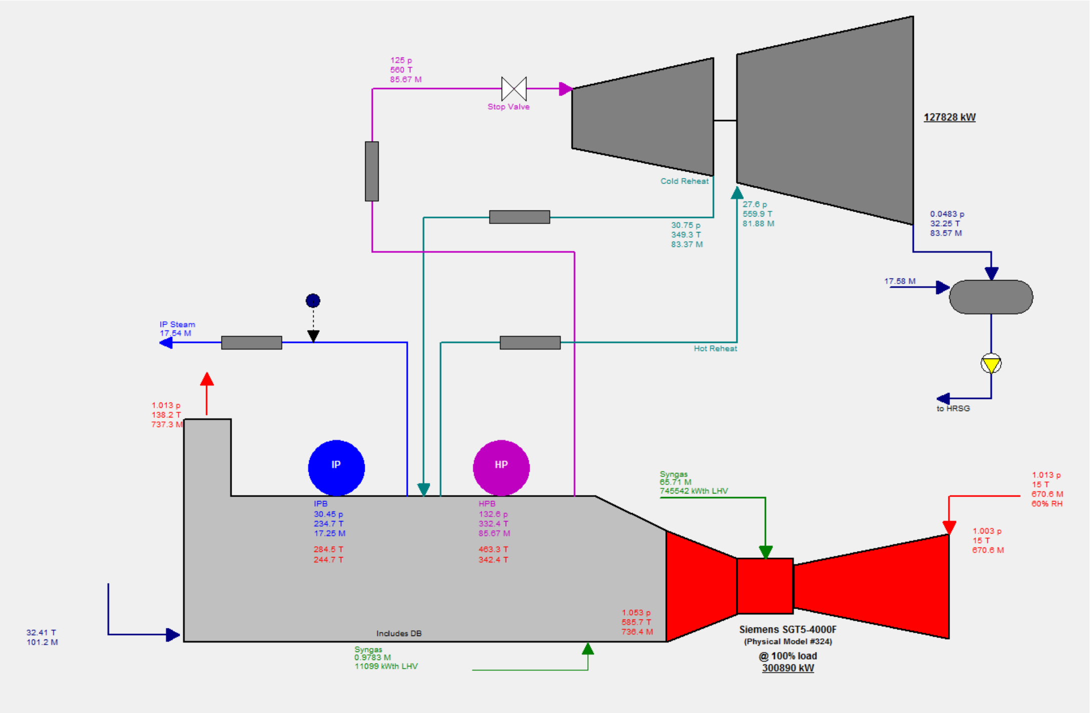


Figure 9.5 Simplified process diagram for the IGCC without capture

9.2.3 IGCC with pre-combustion capture

The main results of the IGCC with pre-combustion capture are in the Table 9.10 and a simplified process diagram is in Figure 9.6.

Table 9.10 Results of the IGCC with pre-combustion capture

Parameters	Units	Value
Gasifier		
Fuel	kg/s	50.32
Oxygen	kg/s	35.73
Cold gas efficiency	%LHV	74.92
Water for the slurry	Kg/s	15.77

Parameters	Units	Value
Raw syngas		
Flow rate	Kg/s	160.4
Temperature	ºC	223.8
pressure	Bar	41.71
Raw syngas composition		
CO	mol.%	22.19
CO_2	mol.%	5.386
CH_4	mol.%	0.0032
H_2	mol.%	14.58
H_2S	mol.%	0.7255
O_2	mol.%	0
H_2O	mol.%	56.78
COS	mol.%	0.0373
N_2	mol.%	0.2751
Ar	mol.%	0.0271
Flue gas		
Flow rate	Kg/s	680.3
Temperature	ºC	591.4
pressure	Bar	1.053
Flue gas composition		
N_2	mol.%	72.11
O_2	mol.%	13.24
CO_2	mol.%	1.023
H_20	mol.%	12.75
Ar	mol.%	0.8764
SO_2	mol.%	0.0028
Steam flow rates		
HP steam flow rate	kg/s	87.13
LP steam flow rate	kg/s	31.48
Overall performance		
Gross gas turbine output	MW	301
Gross gas turbine output	MW	152
Net electric power output	MW	453
Net electric efficiency	$\%_{LHV}$	32.17

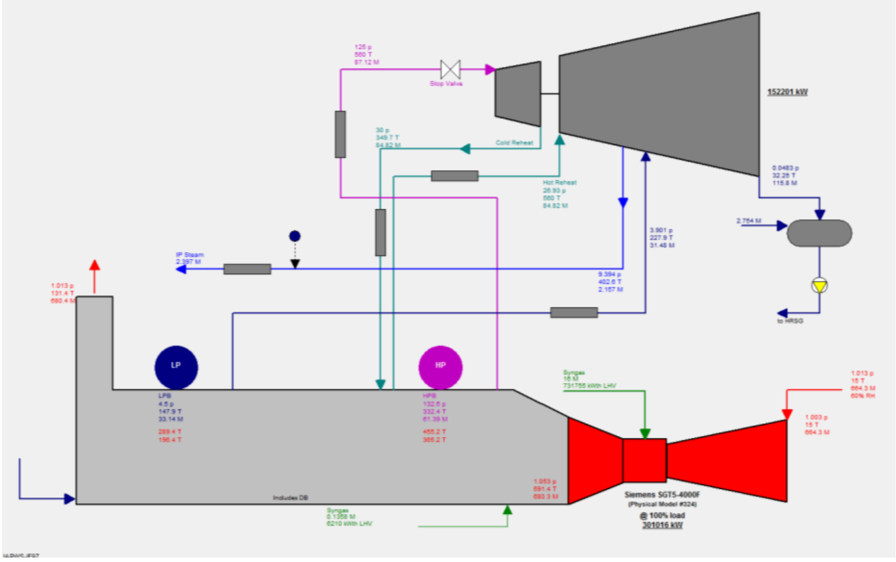


Figure 9.6 Simplified process diagram for the IGCC without capture

9.2.4 Comparison with other cycles

The Allam cycle is going to be compared with an IGCC plant without capture and with another that use pre-combustion absorption. There are two comparisons that are going to be made, in one case it is compared the Illinois coal with gasifier efficiency of 74.5% with a combine cycle simulated in GTPRO using the same gasifier and a pre-combustion capture plant. In the other comparison we are going to compare the gasification with an 80% of efficiency with results obtained in the literature.

In the project CAESAR [21] an IGCC power plant without capture and with pre-combustion capture are simulated. In this project they use very similar conditions that the recommended for the ENCAP. They use the Bituminous Douglas Premium Coal and a Shell gasifier. For the comparisons we are going to take the penalty in the efficiency for the capture and apply it to the power plant without capture. The efficiency with capture is reduced from 46.88% to 36.66%, 10.22 points. This results are compared with the obtained by Maurstad (2006) [43] where he obtain similar result for dry feed gasifier similar to the Shell used for the ENCAP. Using as coal the Illinois nº6 the reduction in the efficiency is in 10.5 points. The similar result indicate that the assumptions are comparable, with conclusion Maurstad estimate that for a GE gasifier with total water quench using the coal Illinois nº6 the efficiency is 34% without capture and 29.1% with pre-combustion capture.

Based in the comparisons made between the literatures a reduction of 5 point in the efficiency for the capture of CO2 in an IGCC power plant is obtained. This result is higher than the 3 point of efficiency reduction obtained in the simulation made here.

The pressure of gasification in the Allam cycle is higher than in the others because we want to avoid the compression of the syngas at the inlet of the combustor as much as possible. This difference of pressure and the use of different simulation tools give different production of CO2 per Kg of fuel. The differences affect the results but still are comparable between then.

The net power plant efficiency of the power plant for the Allam cycle is in between the plant without capture and with capture. This result makes the oxy combustion a technology that can compete with the pre-combustion capture for the coal gasification with a wet feed. The efficiency of the cycle also can be seen in the power produced per unit of fuel, for the plant without capture 2.2 kWh/kg$_{fuel}$ are produced while for the Allam cycle only 2 KWh/kg$_{fuel}$ are produced. The additional fuel consumption for the capture is a 6.62% for the Allam cycle and 9.11% for the pre-combustion one.

Table 9.11 CO_2 capture for various power plants

	units	Allam cycle 77%	Pre-combustion	no capture
fuel	kg/s	45.91	50.32	47.05
CO2 produced	kg/s	91.43	97.42	91.075
CO2 prod/fuel	kg$_{co2}$/kg$_{fuel}$	1.99	1.94	1.94
CO2 lost	%	1.00%	0	0
CO2 captured	kg/s	90.52	86.51	0
CO2 captured ratio	%	99.00%	88.80%	0
net efficiency	%LHV	32.92%	32.17%	35.10%
net power	kW	337400	361400	368600
power/fuel	kWh/kg$_{fuel}$	2.041	2	2.18
HR	kJ$_{LHV}$/kWh	10935	11190	10256
additional fuel consumption	kJ$_{fuel}$/kWh	6.62%	9.11%	0.00%
SPECCA	MJ/kg$_{CO2}$	-7.88	-11.54	0
χ	kg$_{CO2}$/kWh$_{fuel}$	0.32	0.31	0.31
co2 captured	kg$_{CO2}$/kWh	0.97	0.86	0
co2 emitted	kg$_{CO2}$/kWh	0.0098	0.11	0.89
co2 avoided	kg$_{CO2}$/kWh	0.88	0.78	0
CO2 capture efficiency	%	98.93%	87.78%	0.00%

As was explained in the case of natural gas the oxy-combustion cycle has a loss of CO_2 due its dilution with the liquid water that is extracted from the stream. The dilution can be quantify in a 1% of the CO_2 produced [29]. This make the percentage of CO_2 captured in a 99% of the produced, it is higher than the obtained in the pre-combustion capture with an 88.8%.

The Allam cycle need add less fuel to the process to generate the same power that without capture than the pre-combustion system and in addition the capture of carbon is higher. The better result in the capture and use of fuel for the Allam cycle are expressed also in other parameters that will be explained in the next paragraph.

The SPECCA express energy cost related with the CO_2 capture, the energy cost for the Allam cycle is 7.9 MJ per kilogram of $_{CO2}$ captured while for the pre-combustion method it represent 11.5MJ/kg$_{CO2}$.

For the carbon capture is usual the use of the terms CO_2 capture and CO_2 avoided. The fist one gives the amount of CO_2 that is captured per kWh, 0.97 kg$_{CO2}$/kWh in the Allam cycle. The CO_2 avoided gives the amount of CO_2 that is not emitted if that plant is used instead of a power plant without capture, for the Allam cycle it represent 0.88 kg$_{CO2}$/kWh and 0.78 kg$_{CO2}$/kWh for the pre-combustion case.

Finally the expression that can summarize the carbon captured is the CO_2 capture efficiency, the oxy-combustion cycle has a high value of 98.9% and for the pre-combustion cycle the capture efficiency obtained is 87.8 %.

9.3 Equipment used.

9.3.1 Compressors

The recirculation of the flue gas needed in the Allam cycle is very high; in the case of the natural gas plant with a size of 374 MW the flow recycled is 658 sm^3/s. The total flow to be compressed in the compressors is 687 sm^3/s. In the conditions of work the inlet stream to the compressor is at 28 bar and 22ºC, which means that the actual volume is 20.26m3/s or 72929 m3/h.

Siemens indicate for the carbon compression the following models: STC-GV, STC-SV and STC-SH. [46] to the comparison the model STC-SX that is the one with the biggest flow rate made by the company.

Table 9.12 flow rate for different models of compressors

	Allam	STC-GV	STC-SV	STC-SH	STC-SX
Flow rate m3/s	20.26 (28 bar)	133	133	167	361
Final pressure bar	80/320	Up 200	Up1000	Up 50	NA

As can be seen in the Table 9.12 the flow rate at standard conditions of the CO2 stream that is needed to compress is between 2 and 5 times higher that the technology we have at the moment. In the operation conditions the volume of the stream is reduced 34 times, this makes the compared turbines to be able to be used. Other question that can be posed is the weight of the stream, for the Allam cycle it is 1215.778 kg/s. For the same composition at 1 bar (normal exhaust pressure of a gas turbine) and 133 m3/s the mass flow is 258.116 kg/s, much less weight than the 1215kg/s the compressor have to support. The biggest gas turbine compressor in the market support 800 kg/s [42], meaning a volume of air of 960m3/s.

In the conditions of the Net power cycle the compression of the fuel have to be done very carefully because of the high flow rates that have to support the compressors.

9.3.2 Gas turbine

For a gas turbine one of the characteristic that is used to compare different models is the specific work. Normally the specific work is related to the mass flow of air used in the compressor of the gas turbine but as the Net power cycle work with pure oxygen instead of air the specific work will be calculated related to the exhaust flue gas of the turbine. For a normal gas turbine like the used in the simulation with GTPRO, the SGT5-4000F, the specific work is estimated in 418.6 kJ/kg_{gas} or in 414.63 kJ/kg_{gas} for the biggest model made by Siemens, the SGT5-8000H [17]. In the turbine used for the simulation of the Allam cycle the specific work is calculated in 461 kJ/kggas.

The work that produces our turbine is higher than a regular one used in other power plants. That is translated to a better efficiency of the turbine and for the plant.

9.3.3 CO2 stream impurities composition

The steam of CO2 to be piped and sequestrated needs to meet certain conditions of composition; the composition can vary according the final destination and use of the stream. In case any component of the stream is outside the range accepted the stream should be processed until it achieve the conditions required. The Table 9.13 gives the different values recommended by the ENCAP and the obtained in the simulation.

Table 9.13 Delivery specifications of composition for the CO_2 stream

	Recommended for EBTF	Aquifer	EOR	Allam natural gas	Allam Illinois
CO_2	>90%v	>90%v	>90%v	96%v	93.9%v
H_2O	<0.05%v	<0.05%v	<0.005%v	0.054%v	0.053%v
H_2S	<0.02%v	<1.5%v	<0.005%v	NA	6.57E-13%v
NO_X	<0.01%v	NA	NA	3.975E-3%v	1.54E-4%v
SO_X	<0.01%v	NA	<0.005%v	NA	2.59%v
HCN	<0.0005%v	NA	NA	NA	NA
COS	<0.005%v	NA	<0.005%v	NA	3.73E-13%v
RSH	<0.005%v	NA	NA	NA	NA
N_2	<4%v	<4%v	<4%v	1.3%v	1.14%v
Ar	<4%v	<4%v	<4%v	0.38%v	0.23%v
CH_4	<2%v	<4%v	<2%v	1.39E-12%v	1.4E-12%v
CO	<0.2%v	<4%v	<4%v	5.53E-5%v	5.4E-5%v
O_2	<0.01%v	<4%v	<0.01%v	2.1%v	2.08%v

For the Allam cycle using natural gas the CO_2 stream meets the conditions set in the three cases except for the O_2 composition for the EOR and EBTF and for the water to be used the stream for EOR. For the Allam cycle using Illinois nº6 as fuel the problems are the same that with natural gas plus the composition of SO_x.

The composition of SO_x cannot be a problem in the real operation condition as was mentioned in section 6. The SO_2, NO and NO_2 will converted to H_2SO_4 and HNO_3 mostly at the cold-end passages of the heat exchanger reacting with the condensed water and oxygen. The pressure of 30 bar of the flue gas ensures that the reaction kinetics is fast. If it is necessary the H_2SO_4 produced can be removed with the addition of limestone slurry in a stirred tank reactor, the H_2SO_4 is converted into $CaSO_4$ to be removed [41].

10 Conclusions

This report shows an overview of the oxy- combustion as a technology for the capture of CO_2 for plant working both for natural gas and coal. The report has simulated the novel cycle proposed for NET POWER that is called in the report as Allam cycle.

The net power plant efficiencies obtained for the Allam cycle are lower than the proposed from NET POWER. In the case of using natural gas this reduction goes from 60% to 51-52%. The efficiency proposed is closed to the efficiency of a NGCC without capture; this high result can be due to some optimistic assumptions from the creators and there was not found other studies to compare with. In the simulation with coal the reduction of efficiency is considerable; proposed 51% is reduced to 33% in the simulation. An increase on the efficiency can be obtained if the cold gas efficiency of the gasifier is increased. Whit an increase from 75 to 80% the efficiency obtained is around the 39%, with is still far from the proposed.

In the comparisons with other cycles, the oxy-combustion cycle obtains a better result than the pre-combustion capture for coal and better also than the post-combustion for coal. In any case the energy penalties for the capture are produced and have lower efficiency than the power plants without capture.

The size of the plant can have an important impact in the consumption of energy, if the plant is as big as the simulated, around 400 MW, it will be necessary the use of two ASU. The use of more than one ASU means more investment. To optimize the production of oxygen the plant can be sized according the maximum flow coming from the ASU, that in the actually is 5000 tonn/day.

The optimal pressure for the combustor is 300 bar, lower or higher pressures represent a loose in efficiency. The influence in the efficiency is not really high, it represent a loss of 0.4% of efficiency every 30 bar.

In the case of using a gaseous fuel, the natural gas composition recommended for the ENCAP, CEASAR and DECARBit at 70 bar and 10ºC and the use of pure methane at 40 bar and 10ºC gives similar result in the efficiency of the plant. The same occurs in the case on the bituminous Douglas premium recommended and the Illinois nº6 that is used in many studies of power plants.

The high recirculation of CO_2 can cause some problems in the CO_2 compressors. The high flow rate does not create problems related to the volume due to the high pressure of the flue gas (30bar), the problems can come with the high mass flow that has to supper the CO_2 compressors. In a natural gas power plant of 374 MW using the Allam cycle the compressors support 1200 kg/s while the biggest gas turbine compressor supports 258 kg/s.

The specific work (calculated with the exhaust turbine gas) obtained for the simulated turbine in the Allam cycle, 461 kJ/kg_{gas}, is higher than the obtained for the SGT5-4000F, 418 kJ/kg_{gas}. It means a smaller size of turbine and better efficiency for the simulated.

The flue gas obtained in the Allam cycle for natural gas and coal can be directly storaged in an aquifer. In the case of the coal the SO_x needs to be converted in H_2SO_4 in the cooler of the cycle.

11 Further work

A comparison of the Allam cycle with other plants without CO_2 capture and with CO_2 captured has been realized. Further work that can be done is the optimization in the condition of pressure and temperature in the cycle. The effect in the cooling of the turbine can be further studied for the specific conditions of the cycle, in the present report only an estimation of the efficiency loses has been done.

The Allam cycle uses energy coming from the ASU in the case of a natural gas plant and from the gasifier in a plant using coal. Further work can be directed in the optimization of the needed energy in the Allam cycle and the effects that in the ASU has the use of heat from its cycle.

As mentioned in the conclusions, the CO2 compressors have a very high mass flow, much higher than the normal for that type of engines. Further work can be done to study the effect of that high mass flow and the selection of the better compressors for the cycle. Ones the compressors have been chosen the Cycle can be re-simulated with the new conditions for the compressors.

In the present report, the turbine used in the production of the power is a general type. As mentioned for NET POWER they are developing a new type of turbine, a mixture between a gas turbine and a steam turbine. With the datum of the new turbine the cycle can be improved.

The economical aspects have not been included in the report. For a power plant is not only important the power efficiency or the capture efficiency, in the development and construction of a new plant, economical aspect as CAPEX and OPEX have to be considered.

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