IGCC State-of-the-art report

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Low Emission Gas Turbine Technology for Hydrogen-rich Syngas

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SUMMARY

The aim of this report is to perform a screening of the available IGCC technologies and give a brief overview of existing coal fed IGCC power plants currently in operation. The intention is to give an overview of current state of the art-technologies within the field of Internal Gasification Combined Cycle (IGCC) power stations in order to provide basis for technology selection for future modelling and simulation studies. The report comprises descriptions of oxygen production processes, different types of gasifiers, gas cleaning units including CO_2 capture, gas turbines and conventional steam cycle technologies.

From the information gathered it was found that cryogenic air distillation, which has been practiced for more than 100 years is currently the most economically method for production of large amounts of oxygen required for IGCC power stations. Ion transport membranes represent a promising alternative to the cryogenic technology bit their long term efficiency, performance and reliability is still to be demonstrated. The gasification technology screening showed that there are numerous types of gasifiers used with different properties, such as operation, - pressure and temperature, and imbedded features that lead to variation in outlet gas composition. In IGCC power stations with electricity generation as the final goal, the downstream components e.g. gas turbine has a major impact on the selection of gasifier type. The facilities for gas cleaning and syngas conversion have undergone rapid advances the last years with new methods, solvents and catalysts being developed. Selection of a proper process for separation of H_2S and CO_2 depends on some key parameters and demands. The power block of an IGCC power station consists of a gas turbine and a steam cycle and looks the same as in conventional combined cycle plants. However the interaction with the gasifier block results in several key differences for which special attention has be given during conditions with variable load. It was also found that significantly higher efficiency, reduced emissions and lower cost for gas turbine operation on hydrogen rich syngas will require advances in combustor technology.

There are currently six IGCC power stations operating on coal as main feedstock. The operational experience from these has proven the viability of the IGCC technology and provided valuable knowledge for the future potential of this technology in a world which most likely will have more stringent environmental regulations for greenhouse gas emissions. The IGCC is the most advanced technology for generating electricity from coal cleanly and offer a major advantage to control and reduce CO_2 at high pressure to facilitate sequestration cost efficiently.

The work has been carried out at University of Stavanger, Department of Mechanical & Structural Engineering & Material Science with valuable input from Nuon and Ansaldo Energia.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

ABBREVIATIONS AND ACRONYMS

AFR	Air/fuel ratio
AGR	Acid gas removal
Ar	Argon
ASU	Air separation unit
atm	atmosphere
AZEP	Advanced zero emission power
BFW	Boiler feed water
C	Coal
CH_4	Methane
CO	Carbon oxide
CO_2	Carbon dioxide
COS	Carbonyl sulphide
DC	Direct current
DEA	Diethanolamine
DIPA	diisopropanolamine
DLE	Dry low emission
DOE	Department of Energy
FT	Fisher Tropsch
GE	General Electric
GFERC	Grand Forks Energy Research Center
GT	Gas turbine
GTCC	Gas turbine combined cycle
IGCC	Internal gasification combined cycle
IP	Intermediate pressure
ISO	International organization for standardization
ITM	Ion transport membranes
H_2	Hydrogen
H_2O	Water/steam
H_2S	Hydrogen sulphide
HCN	Hydro cyanide
HHV	Higher heating value
HP	High pressure
HRSG	Heat recovery steam alternator
HTS	High temperature shift
IGV	Inlet guide vane
LHV	Lower heating value
LP	Low pressure
LTS	Low temperature shift
MEA	Monoethanolamine
MDEA	Methyldiethanolamine
MHI	Mitsubishi Heavy Industries
NGCC	Natural gas combined cycle

N_2	Nitrogen
N_2O	Nitrous oxide
NH_3	Ammonia
NO	Nitrogen oxide
O_2	Oxygen
O&M	Operation and maintenance
OTM	Oxygen transport membrane
PC	Pulverized coal
PSA	Pressure swing adsorption
S	Sulphide
SCOT	Shell off-gas treating
SCR	Selective catalytic reduction
SEWGS	Sorption enhanced water gas shift
ST	Steam turbine
TBC	Thermal barrier coating
TIT	Turbine inlet temperature
TOT	Turbine outlet temperature
VPSA	Vacuum swing adsorption
wt	weight

1 INTRODUCTION

1.1 BACKGROUND

The world's electricity generation is dominated by fossil fuels out of which about 40% is generated using coal. At the same time the electricity generation stands alone for approximately a third of the global CO_2 emissions. The use of coal as primary fuel is expected to increase by approximately 30% the next 20 years and the worldwide capacity of coal fired power stations is expected to increase by over 40% between 2010 and 2030. In order to protect the environment and prevent climate change by reducing greenhouse gas emissions there is currently a growing political willingness to develop and bring carbon capture and storage (CCS) technologies to the market.

The integrated gasification combined cycle (IGCC) technology has during the last 20 years being promoted as the leading choice for electric power utilities planning to construct new coal-fired power stations due to their high thermal efficiency, low environmental impact and ability to produce power as well as synthetic fuels, chemicals and marketable by-products. Even though IGCC offer significant advantages over pulverized coal (PC) plants in terms of cost effective reduction of CO_2 emissions, the technology has been facing several major challenges for wide commercialisation. The main concerns include cost, compatibility with alternative technologies and the insecurity of the implementation of any future CCS.

One of the main drawbacks with existing IGCC power stations have been their high operational costs compared to conventional natural gas combined cycle -, (NGCC) and PC power stations. Although the power block of an IGCC appears same as those in NGCC plants there are several important differences due to the combination with the gasification unit. The composition and properties of the syngas burnt in the gas turbine combustion chamber is completely different compared to natural gas. Since current gas turbine combustion technology is not optimized for using hydrogen rich syngas deriving from the gasification of coal, cost-intensive dilution of the syngas with nitrogen and/steam is required for combustion stability and NOx control.

1.2 OBJECTIVES

This report has two key objectives. The first objective is to present current state-of-the-art of the five main components of an IGCC power station:

- Oxygen production unit
- Gasifier
- Gas cleaning
- Gas turbine
- Steam cycle

The second objective is to give an overview of the IGCC power stations at the moment in commercial operation throughout the world that are using pulverized coal as primary feedstock for the gasifier island.

1.3 REPORT OUTLINE

The first five chapters, 2-6, present the technology screening of the five main parts of the IGCC power station: oxygen production unit, gasifier, gas cleaning, gas turbine and steam cycle. In chapter 8 an overview of the six commercial coal fed IGCC power stations: Buggenum, Puertollano, Wabash River, Tampa Electric Polk, Nakoso and

Vresova is given. In addition the Negishi IGCC, which is not operating on coal as primary feedstock, is presented in chapter 7.7 as this was the first IGCC built with an F-class Gas turbine from Mitsubishi Heavy Industries.

2 OXYGEN PRODUCTION

2.1 INTRODUCTION

Oxygen supply to the gasifier is a key requirement and one of the most expensive parts of any IGCC power station. The technology currently used for oxygen separation from air is by distillation at cryogenic temperatures. This is a technology that has been known for over 100 years and at present the most cost-effective one with a number of international companies who are able to not only provide oxygen plants for third parties but, but are also willing to build and operate their own plants. Due to the high competitiveness within this industry characteristic data considering performance and detailed cost of cryogenic air separation plants are difficult to obtain. Data from these plants are generally regarded as confidential, but existing published system descriptions with pressure and temperature conditions available render the possibility to estimate the power requirement of the compressors. Continuous improvements of the technology have been made during the years and among the most recent and significant ones are increase in train size, the use of structured packing in distillation columns and more complex cycle designs which have lowered the power consumption [1], 0.

The development of mixed metallic oxide ceramic materials, which produce oxygen by the passage of oxygen ions through the ceramic crystal structure, has been an important breakthrough for oxygen production technology. These materials are known as Ion Transport Membranes (ITM) as well as Oxygen Transport Membranes (OTM). The membrane technology offers the possibility to significantly reduce the cost of oxygen production, but is at the present still in the early stages of development [1].

The two other existing methods of air separation used at present are the polymeric membranes operating at atmospheric temperatures and the use of natural and synthetic materials to preferentially adsorb nitrogen in pressure swing multi-bed adsorber systems. None of these methods are currently economically competitive for production of large amounts of oxygen required for an IGCC power station. Pressure and vacuum swing adsorption units (PSA and VPSA) are available up to a capacity of about 250 tonnes/day for a purity of about 93% O_2 [2], while the polymeric membrane systems are limited to small-scale production of oxygen enriched air of 20-50% O_2 [3].

2.2 CRYOGENIC AIR SEPARATION

Distillation of air to produce pure oxygen together with nitrogen and argon at cryogenic temperatures is the only technology available for large oxygen production rates required for fossil fuel gasification. The invention of the process by Carl von Linde in 1895 was the first effort of what further led to the founding of Linde, which together with Air Liquide are the oldest and largest companies in the world producing oxygen and various other industrial gases and whole plants for different gas recovery. In addition, several other companies represent an important share of the oxygen production market. The most important are Air Products, Praxair and Chemicals as well as the Chinese based Hangzhou Oxygen Company [1].

Production of pure oxygen by cryogenic distillation of air encompasses the separation of the less volatile component Oxygen from the more volatile components Nitrogen and Argon. This is achieved by using a vapour feed to the base of the counter-current separation column usually provided by a reboiler and a reflux liquid at the top of the column typically from an overhead condenser. The principle features of a cryogenic air separation plant (ASU) are shown in Figure 1. This double distillation column system is characterized through the combination of condenser and evaporator, dividing the separation into two separate areas with different pressures. The re-boil and reflux for the upper column in which the distillation of air into its main constituents takes place is generated by the lower column [1], [4].

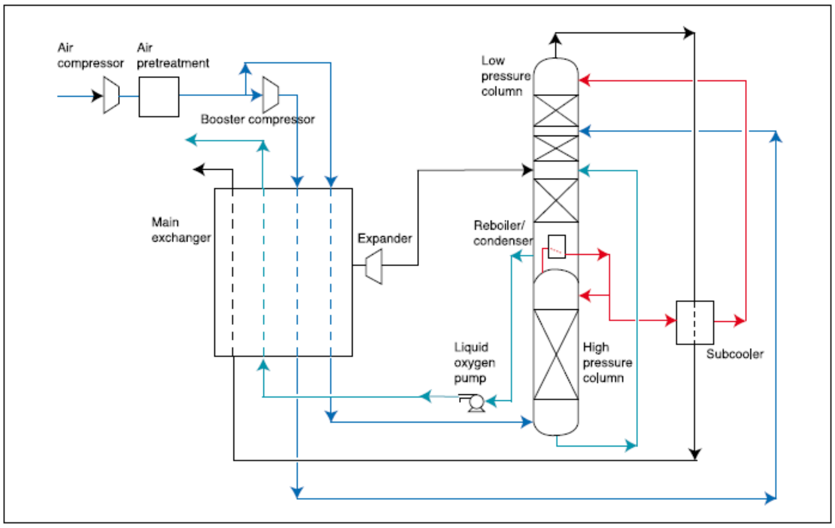


FIGURE 1 – AIR SEPARATION BY CRYOGENIC DISTILLATION [4]

The air is first compressed to a pressure of 5 to 6 bar and then purified to remove contaminants including water, CO_2, N_2O and trace hydrocarbons, which could accumulate to undesired levels in the oxygen-rich parts of the plants such as the reboiler condenser, causing safety issues for the plant operation. This is generally accomplished by multiple fixed bed adsorbers, using either temperature or pressure swing regeneration with a low pressure nitrogen stream. The air is then cooled to its liquefaction temperature against returning products (oxygen and nitrogen) in several heat exchangers and separated into oxygen, nitrogen, and, optionally, argon streams in the two structured packed columns. It should be noted that it is possible in any ASU to produce additional product streams of oxygen, nitrogen and argon at any purity level in gaseous and liquid form. The produced oxygen could be withdrawn at the base of the low pressure (LP) column either as a liquid or a gas. The most common approach in modern plants is to withdraw all the produced oxygen as a liquid and accomplish the delivery pressure by utilizing a multi-stage centrifugal oxygen pump whilst the evaporation [1].

2.2.1 FACTORS AFFECTING OXYGEN PRODUCTION COST

The main parameter controlling the power consumption of a cryogenic oxygen production plant is the air compressor discharge pressure, which is inherently affected by the pressure balance and re-boiler/condenser design. Consequently numerous possible alternatives for the configuration of heat exchange, distillation, compression and pumping exist. However, the power consumption is also dependent on the number of product streams produced and their purity; hence there is a trade-off between capital cost and power consumption and the degree of integration between the ASU and other units downstream [1].

Since the cost for produced oxygen in a cryogenic air separation plant consists mainly of the cost linked to the power consumption, developments to reduce the specific power consumption has been the main driving force for this industry since the introduction of the first Linde double column cycle. In addition to the improvements of the whole purification cycle the design of the basic components of the cryogenic oxygen plants such as compressors, air purifiers, the heat exchangers and columns has been of major importance. A further area of enhancement has been the integration of the ASU with other units in the power producing part of the power station. The subsequent sections 1.2.2 - 1.2.5 present some of the most relevant topics to IGCC power stations [1], [5].

2.2.2 INTEGRATION POSSIBILITIES OF THE ASU AND POWER GENERATION BLOCK

The air requirements of an ASU could be partially or fully provided by the gas turbine compressor. However, the ASU does not only deliver the required O_2 to the gasifier, but does also generally supply the GT with the necessary waste nitrogen for dilution of the H_2 rich syngas. The degree of integration of the ASU and the gas turbine combined cycle (GTCC) is an optimization parameter that has major impact on the gas turbine performance. As illustrated in

Figure 2 there are four major integration alternatives of the ASU with the gas- and steam cycle [5]:

a. Full, partial or no air supply to the ASU

b. Pressurized nitrogen supply to the gas turbine for dilution purposes in the combustor, for turbine cooling, and for power augmentation

c. Low pressure nitrogen for gas turbine inlet cooling, or heated to increase HRSG steam production

d. Chilled water for gas turbine inlet cooling, or heated for feed-water pre heating in the HRSG

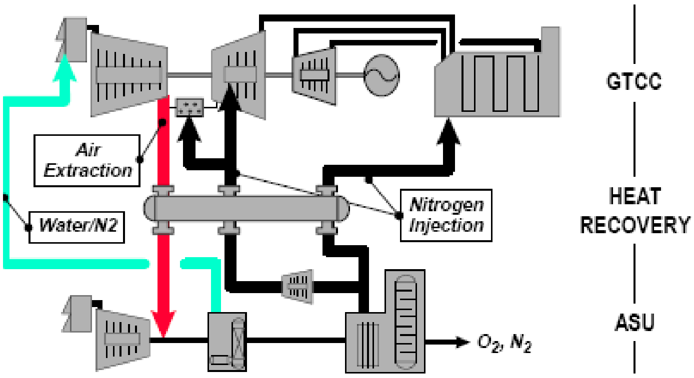


FIGURE 2 – INTEGRATION OPTIONS OF THE ASU AND THE POWER BLOCK [5]

2.2.2.1 FULL AIR INTEGRATION

This option means that all the feed air required by the ASU is supplied by the gas turbine air compressor. This configuration was chosen for the Buggenum IGCC power station in the Netherlands. The main difficulty with total air integration is the control of the ASU when the gas turbine is operated at variable load. An increase in the power output from the gas turbine results in an increased compressor discharge pressure which results in a pressure raise of the air delivered to the ASU. This causes an elevation of the boiling pressure and temperature of the liquids in the ASU meaning that liquids in the columns will be sub-cooled and the net vapour flows will be reduced while the gas turbine combustor requires an increased fuel flow to enhance for the increased power production. The opposite could occur if the load is reduced. The discharge pressure of the air will be reduced resulting in a surplus of flows will be generated from the ASU while at the same time less O_2 is required for the gasification process. The most suitable manner to deal with an ASU integrated with the gas turbine compressor is to reduce the air pressure delivered by the compressor to the required pressure of the cryogenic ASU and to control this pressure carefully.

This could be achieved efficiently by the use of a power producing expansion turbine. Another problem with the fully integrated option arises during start up of the ASU and the gasification system which calls for the gas turbine to run on natural gas or liquid hydrocarbon fuel to supply the initial amount of air or by having a supplementary air compressor for start-up of the ASU.

Industrial gas turbines installed until today have a compressor outlet pressure at about 18 bars and a temperature of about 435˚C. For integrated ASU systems an efficient heat exchange between the air delivered from the pressure expanding turbine to the ASU and the product streams leaving the ASU, O_2 and N_2, has to be considered in order to preserve the heat within the process streams generated by the gas turbine expander flow [1].

2.2.2.2 PARTIAL AIR INTEGRATION

When only a partial flow of the air from the gas turbine compressor is supplied to the ASU the integration is said to be partial. The amount provided by the GT compressor depends on two factors: the air flow required for plant start up, which is then supplied by a separate compressor and the amount of air available from the GT, which depends on both design and the prevailing atmospheric conditions. Generally the partial integration designs have a 50% air feed supply from the GT compressor section including a pressure reducing expander turbine and heat recovery of the air bleed. The additional amount of air required by the ASU is delivered by the separate inter-cooled compressor, driven by an electrical motor. However, the overall amount of the available air flow to be withdrawn from the GT depends on several parameters. The most optimal situation is to assure that the overall loading of the gas turbine expander part is first maximized (choked). Given that the syngas fuel has a lower heating value compared to the case with natural gas and the required thermal power of the GT dictates a substantial increase in fuel gas flow. This additional fuel flow results in a possible need to vent air from the compressor section in order to avoid an increase in flow rate after the combustion chamber to be expanded in the turbine, under the assumption that the turbine flow is already maximized. Consequently this is the available air feed which could be allocated to the ASU. It should be noted that this system has to be optimized for each plant location since the air bleed from the compressor varies with atmospheric temperature, pressure and humidity. Nonetheless, this configuration allows the gas turbine system to be started after the ASU-start-up and gasification processes and is also the one installed at the Elcogas IGCC power station a Puertollano in Spain [1].

2.2.2.3 NO AIR INTEGRATION

The zero supply option of air from the GT compressor to the ASU is usually only optimum under circumstances when the air flow from the compressor is limited due to the re-allocation of compressor air for cooling purposes in other parts of the gas turbine or where the expander design does not allow for added fuel gas flow. In the most recent developed gas turbines the margin allowing for extra fuel at ISO conditions is limited; hence dilution by nitrogen is most probably restricted to situations depending only on atmospheric conditions [1]

2.2.2.4 PRESSURIZED HOT NITROGEN INTEGRATION

Nitrogen is a by-product from the ASU and could be compressed and heated in cases with partial and full air integration by the extracted air feed stream from the gas turbine. The use of this nitrogen is first and foremost as diluent in the gas turbine combustor and could be injected separately into the combustor or mixed with the syngas. The most important benefits utilizing pressurized nitrogen are the improved operation of the gas turbine by the reduction of NOx and the increased power output from the turbine [5]. The amount and possibility could though be restricted by the GT vendors.

2.2.2.5 LOW PRESSURE NITROGEN INTEGRATION

The use of low pressure waste nitrogen is a common application in ASUs as a source to cool the compressed air feed stream. This is done by allowing water introduced at the top flow counter currently to the nitrogen flow in a humidification tower. After being saturated with water the cooled nitrogen exits the top of the tower. This slightly pressurized nitrogen and the chilled water produced within the ASU system could be fed to the inlet of the gas turbine compressor to reduce the bulk air temperature and thereby increase the air mass flow. Low pressure nitrogen for air cooling purposes in the gas turbine could also be produced by expanding high pressure nitrogen.

2.3 ION TRANSPORT MEMBRANES (ITM)

Ion transport membranes are made up by nonporous oxide ceramic materials, which unlike porous membranes have 100% selectivity for oxygen, in the absence of leaks, cracks, seals damages, etc. Materials used in these types of membranes are solid electrolytes possessing the ability to conduct both oxygen ions and electrons when operated at temperatures above 600°C; usually it is preferable to have temperatures in the range of 800 to 900°C.

The operation of ion transport membranes is either as an electrically driven device or as a concentration cell. The operation of the high temperature ITM as an electrically driven device encompasses the connection of its surfaces to a power source of DC type while air with atmospheric pressure or high pressure is supplied to the cathode side. Consequently, the oxygen molecules at the cathode side of the membrane will ionize and in order to sustain the electrical neutrality of the ITM, oxygen ions at the anode side will give up electrons and move towards the cathode side. The electro-chemical process is sustained by the continuous supply of DC power. In this way, the membrane is not only able to separate the oxygen from the air but also to deliver the oxygen with an increased pressure depending on the applied voltage 0.

If the heated ITM cell is exposed to a difference in activity at its two surfaces by means of difference in oxygen partial pressure a concentration cell will be activated with an electromotive force making the oxygen to diffuse through the lattice of the membrane [1].

Generally for separation of the amounts of oxygen required for large scale energy conversion processes the method of choice is by applying a solid electrolyte with both ionic and electrical conductivity also referred to as mixed conducting membranes [7]. In these membranes transmission of ions and electrons occurs simultaneously, but in reverse directions as a result of the internal oxygen chemical-potential gradient, as illustrated in Figure 3.

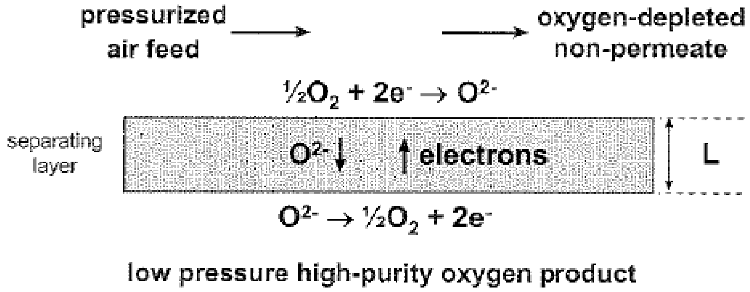


FIGURE 3 – OXYGEN SEPARATION BY ION TRANSPORT MEMBRANE [7]

The selectivity to oxygen and extreme high permeability is the main feature of high temperature mixed conducting ion transport membranes. The permeability of current ITM's is a factor 10^4 to 10^5 higher than for a typical polymeric membrane for oxygen diffusion 0. The oxygen can be separated as a pure product or by sweeping the permeate side of the membrane with an inert gas such as steam, or an oxygen depleted exhaust or recycle gas. If the last is utilized it is important to consider the possible existing impurities present in the sweep gas and their compatibility with the materials used in the high temperature membrane.

The development of oxygen transport membrane systems for oxygen production is still in the phase of research and considerable work has been done to scale-up and demonstrate the technology. The most well known example of the integration of a mixed conducting membrane into a gas turbine power cycle is the AZEP (Advanced Zero Emission Power) cycle [8]. The AZEP oxy-fuel concept uses hot exhaust gases from the GT combustor as a sweep gas and has demonstrated theoretically one of the lowest efficiency penalties for power stations with CO_2 capture (approximately 4.5% with a CO_2 capture rate of 85%). However, in order to achieve stabile operation of the membrane the temperature cannot be too high, which is in conflict with the combustion temperature which should occur at the highest possible. The limitation in membrane operation temperature has been one of the main reasons for the abandon of this project [9].

ITMs offer the possibility to separate oxygen with less adverse effect on the efficiency of power cycles requiring oxygen compared to cryogenic air separation units [9]. Nevertheless, cost targets, manufacturing procedures and performance targets for large scale ITM systems for integration into IGCC power stations has still not reached commercial development.

3 GASIFICATION

3.1 INTRODUCTION

Utilizing solid and liquid fuels in gas turbine based electricity generation units with low emissions requires gasification of the fuel prior to the combustion. Thermal gasification can be used to decompose organic materials to raw syngas, mainly consisting of CO, H_2 and CO_2. The syngas composition depends on selected gasification parameters such as temperature, pressure, oxidation agent, etc.

Gasifiers are currently in use at different industries such as chemical, petrochemical and utilities. In order to fulfill specific requirements of one and each of these industries, different types of gasifiers have been designed and developed [10].

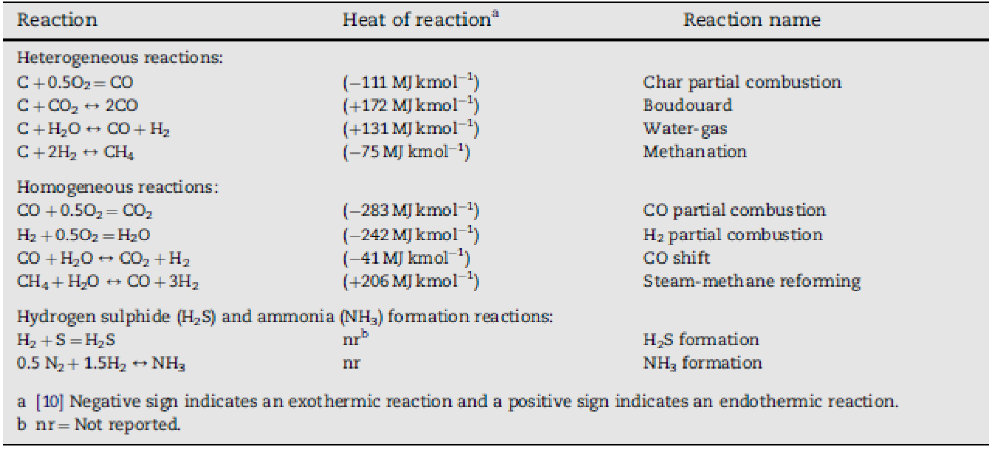
During gasification process three major reactions take place; namely pyrolysis, partial oxidation and hydrogenation. As these three groups of reactions are strongly temperature dependent, temperature control plays an important role in gasification process. Having detailed knowledge about the thermodynamic of gasification process is crucial for proper design of the gasifier, so that it provides the user with desired syngas properties.

3.2 THE THERMODYNAMICS OF GASIFICATION

Gasification temperature may range between 800°C and 1800°C. In this range only there are a few combinations of elements carbon, hydrogen and oxygen. These combinations are CO, CO_2, H_2O, H_2 and Methane. The concentration of them that will result at equilibrium can be calculated from equilibrium constants determined from thermodynamic properties and temperature and also pressure by an energy balance. Feedstock characteristics, in particular the softening and melting temperatures of the ash decides mainly gasification temperature. This criterion applies for all kind of gasifiers such as entrained-flow, fluidized bed and fixed bed. Reaction rates in this range of temperature are relatively high, so modeling based on thermodynamic equilibrium of main gaseous components and carbon give results which are so close to reality.

The reactions which are taking place during gasification also can be classified in heterogeneous, homogenous and H_2S and NH_3 formation reactions. Heterogeneous reactions take place in more than one phase such as carbon with oxygen in which two solid and gas phase reacts. In homogenous reactions, compounds are in one phase like CO and O_2 in gas phase. During these three groups of reactions, carbon, carbon monoxide, carbon dioxide, hydrogen, H_2S, NH_3 and methane are produced and consumed. These reactions are stated in Table 1 with their heat of reaction and industrial name [11].

TABLE 1 – COMMON GASIFIER REACTIONS [11]



Reaction	Heat of reaction[a]	Reaction name
Heterogeneous reactions:		
$C + 0.5O_2 = CO$	(-111 MJ kmol^{-1})	Char partial combustion
$C + CO_2 \leftrightarrow 2CO$	($+172$ MJ kmol^{-1})	Boudouard
$C + H_2O \leftrightarrow CO + H_2$	($+131$ MJ kmol^{-1})	Water-gas
$C + 2H_2 \leftrightarrow CH_4$	(-75 MJ kmol^{-1})	Methanation
Homogeneous reactions:		
$CO + 0.5O_2 = CO_2$	(-283 MJ kmol^{-1})	CO partial combustion
$H_2 + 0.5O_2 = H_2O$	(-242 MJ kmol^{-1})	H_2 partial combustion
$CO + H_2O \leftrightarrow CO_2 + H_2$	(-41 MJ kmol^{-1})	CO shift
$CH_4 + H_2O \leftrightarrow CO + 3H_2$	($+206$ MJ kmol^{-1})	Steam-methane reforming
Hydrogen sulphide (H_2S) and ammonia (NH_3) formation reactions:		
$H_2 + S = H_2S$	nr[b]	H_2S formation
$0.5\ N_2 + 1.5H_2 \leftrightarrow NH_3$	nr	NH_3 formation

a [10] Negative sign indicates an exothermic reaction and a positive sign indicates an endothermic reaction.
b nr = Not reported.

As the gasification takes place at temperatures between 800 and 1800°C, theoretically based on thermodynamic equilibrium constants in energy balance equations and also in practice with analysis of outlet gases from gasifiers, all hydrocarbons are converted to CO, CO_2 and H_2 at this range of temperature only methane may be available in this temperature range because methanation reaction takes place in 800 °C and for the gasifiers working in this temperature, methane will appear in outlet gas. Since some of the gasifiers are operating at temperatures above this limit, no hydrocarbons can be present in outlet gas.

These principles about thermodynamic of gasification would be useful for design and simulation of such unit operation. Different types of gasifiers can use different types of feed. Knowledge about various feedstock is necessary for selection of applicable gasifier type.

3.3 CHARACTERIZATION OF FEED IN GASIFIERS

3.3.1 COALS AND COKE

There are various types of coal and each coal type has its own properties. Therefore analysis for determination of coal composition and properties is an important task. There are three analysis methods for coal. One of them is used for analysis of coal is maceral analysis [2]. In this method, microscopic pictures from coal are analyzed and the number of macerals is counted. Macerals are a component of coal. This method is used to predict the strength and crushing behaviour of coal. Two other methods are Proximate and Ultimate analysis which are discussed in next section. Some important information for coal gasification are:

- age of the coal
- caking properties
- water content
- ash properties

Coal is classified based on the content of fixed carbon and volatile matters. Table 2 shows the four classes of coal with their own heating values [2].

TABLE 2 – CLASSIFICATION OF COAL [2]

Class	Volatile Matter (wt %)	Fixed carbon (wt %)	Heating value (HHV) (MJ/kg)
Anthracite	<8	>92	36-37
Bituminous	8-22	78-92	32-36
Sub-bituminous	22-27	73-78	28-32
Brown coal (lignite)	27-35	65-73	26-28

3.3.1.1 COAL ANALYSIS

Two methods are used for analysis of coal to determine existing components, moisture contents and volatiles by their weight percent; namely proximate and ultimate analysis.

PROXIMATE ANALYSIS

This analysis determines the amount of moisture content, volatile matter, ash and fixed carbon in the coal.

ULTIMATE ANALYSIS

In ultimate analysis, the percentages of carbon, hydrogen, oxygen, sulfur and nitrogen are measured.

Table 3 illustrates the proximate and ultimate analysis of different class of coals and the difference between these two methods is cleared in detail [2].

TABLE 3 – ULTIMATE AND PROXIMATE OF VARIOUS COALS [2]

Coal		Proximate analysis, % mass				Ultimate analysis, % mass					LHV
Country	**Class**	**Fixed Carbon**	**Volatile matter**	**Water**	**Ash**	**C**	**H**	**O**	**N**	**S**	**MJ/kg**
Germany	Brown coal	17.3	20.0	60.0	2.7	67.5	5.0	26.5	0.5	0.5	26.2
USA	Lignite	27.8	24.9	36.9	10.4	71.0	4.3	23.2	1.1	0.4	26.7
USA	Sub-bituminous	43.6	34.7	10.5	11.2	76.4	5.6	14.9	1.7	1.4	31.8
USA	Bituminous	39.3	37.0	13.0	10.7	78.4	5.4	9.9	1.4	4.9	33.7
Poland	Bituminous	54.9	35.6	5.3	4.2	82.8	5.1	10.1	1.4	0.6	36.1
S. Africa	Bituminous	51.3	32.7	2.2	13.8	83.8	4.8	8.4	2.0	1.0	34.0
China	Bituminous	50.9	28.1	11.9	9.1	84.4	4.4	9.5	0.9	0.8	33.4
India	Bituminous	30.0	23.0	7.0	40.0	75.5	6.4	15.2	1.5	1.4	32.1

Australia	Bituminous	44.9	41.1	4.5	9.5	81.3	5.8	10.0	2.0	0.9	33.8
Germany	Anthracite	81.8	7.7	4.5	6.0	91.8	3.6	2.5	1.4	0.7	36.2

3.3.1.2 HEATING VALUE

The heating value is usually determined experimentally by combustion of the sample in a calorimeter. Both higher and lower heating values are used for thermodynamic calculations. The lower heating value takes into account the amount of energy lost as water vapour in the exhaust gas stream. For determination of the higher heating value, one needs to condense out the water vapour in the exhaust gas to recover the steam formation heat.

There are two theoretical equations for estimation of the heating value. One is the Dulong formula [12]:

$$\text{HHV in MJ/kg} = 33.86 \cdot C + 144.4 \cdot (H - O/8) + 9.428 \cdot S \qquad (1)$$

Where C, H, O and S are the mass fractions of the elements obtained from the ultimate analysis.

Channiwala et al modified Dulong's equation for estimation of the heating value from the ultimate and/or proximate analyses [13].

$$\text{HHV in MJ/kg} = 34.91 \cdot C + 117.83 \cdot H - 10.34 \cdot O - 1.51 \cdot N + 10.05 \cdot S - 2.11 \cdot Ash \qquad (2)$$

These formulas and experimental method are very useful to calculate and determine the heating value. Using formula after determination by experiment is a cross-check to rely on the values. Also, these formulas can be used in simulators to calculate the heating value for coal.

3.3.2 LIQUID AND GASEOUS FEEDSTOCKS

Liquid feedstocks are another material which is used in gasification process as the gasifier feed. In 2002, about 154 million Nm^3/d of synthesis gas was produced by partial oxidation of liquid feeds [14] which in IGCC units can generate approximately 11 500 MW_e. Gaseous feed does not need gasification and they are used in some small units for production of a vast array of petrochemicals.

3.3.3 BIOMASS

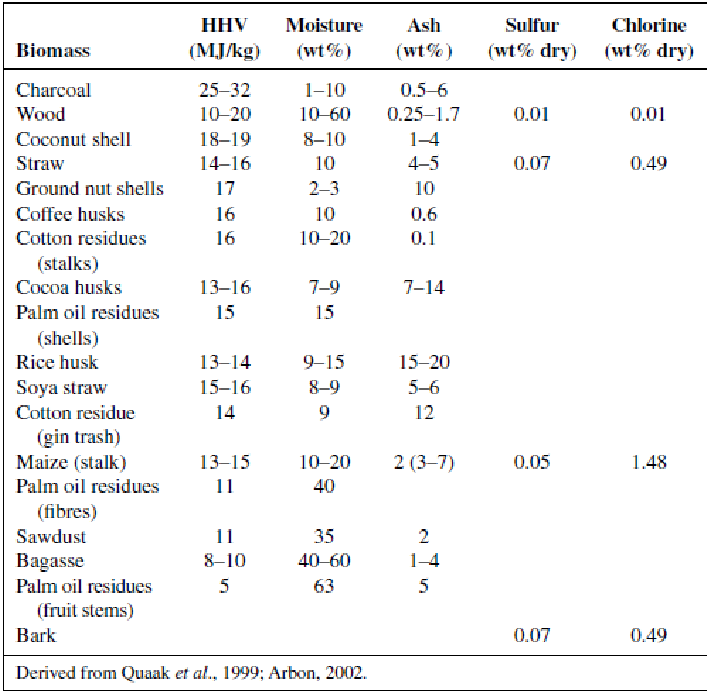
"The term " biomass " covers a broad range of materials that offer themselves as fuels or raw materials and which have in common that they are all derived from recently living organisms"[2]. This definition excludes fossil fuels because they produced from plants and animals million years ago. Biomass covers the materials which are produced by photosynthesis and they are produced everyday and everywhere. The basic overall chemical reaction which leads to biomass production is as follow [18]:

$$6CO_2 + 6H_2O + \text{Light} \rightarrow C_6H_{12}O_6 + 6O_2 \qquad (3)$$

3.3.3.1 PROPERTIES OF BIOMASS

The properties of biomass depend on its source. Table 4 shows the properties of different types of biomass.

TABLE 4 – PROPERTIES OF DIFFERENT TYPES OF BIOMASS [2]



Biomass	**HHV (MJ/kg)**	**Moisture (wt%)**	**Ash (wt%)**	**Sulfur (wt% dry)**	**Chlorine (wt% dry)**
Charcoal	25–32	1–10	0.5–6		
Wood	10–20	10–60	0.25–1.7	0.01	0.01
Coconut shell	18–19	8–10	1–4		
Straw	14–16	10	4–5	0.07	0.49
Ground nut shells	17	2–3	10		
Coffee husks	16	10	0.6		
Cotton residues (stalks)	16	10–20	0.1		
Cocoa husks	13–16	7–9	7–14		
Palm oil residues (shells)	15	15			
Rice husk	13–14	9–15	15–20		
Soya straw	15–16	8–9	5–6		
Cotton residue (gin trash)	14	9	12		
Maize (stalk)	13–15	10–20	2 (3–7)	0.05	1.48
Palm oil residues (fibres)	11	40			
Sawdust	11	35	2		
Bagasse	8–10	40–60	1–4		
Palm oil residues (fruit stems)	5	63	5		
Bark				0.07	0.49

Derived from Quaak *et al.*, 1999; Arbon, 2002.

3.3.4 WASTES

Waste as a gasification feedstock covers a wide range of materials. Due to its heterogeneous nature, it is rather difficult to provide an unambiguous property description of waste. Physical properties and composition of waste as well as presence of different components, such as sulfur, chlorides or metals, have impact on its utilization. Practical use of waste as a feedstock requires continuous adjustment of operating conditions to prevent losses and production of undesirable outlet gasses.

Each gasifier is designed to use specific material as feed according to its operating condition and ability to convert the feed to syngas. Four main groups of gasifiers are discussed in detail as follows to represent their operating conditions and capabilities of using different feeds. In Table 5, generally, it is cleared what feed is suitable for which type of gasifier [2].

TABLE 5 – SUITABLE FEED FOR DIFFERENT TYPES OF GASIFIERS [2]

Gasifier type	**Feed**
Fixed bed	(non-baking) Coal/Coke or Anthracite
Fluidized bed	Coal/Biomass/Waste
Entrained flow	Coal(hard)/ Black liquor
Molten bath	Coal

3.4 DIFFERENT TYPES OF GASIFICATION PROCESSES

Gasification is used to produce syngas which can be converted to a flow rich in hydrogen in a shift reactor and burned in various energy conversion technologies such as a gas turbine.

Different industries might select different gasifiers according to their specific requirements. Selection of gasifier type might be based on:

- The demanded rate of energy
- The heating value of the gas
- Operating temperature and pressure
- Required gas composition
- Gas purity (presence of tars, ash)
- Availability of feed, regarding to its type and cost
- Limitations related to gasifier size

Gasifiers can be divided into four main categories based on their construction and operating conditions. These four categories are presented and discussed in the following sections. More information about these gasifiers can be found in [10].

3.4.1 FIXED BED GASIFIERS

In fixed bed gasifiers, air or oxygen and occasionally steam are passed through feedstock such as coal and biomass. Fixed bed gasifiers are usually not suitable for coal gasification of those types of coal that agglomerate during the pyrolysis phase because of cake formation, but in recent designs some parts such as stirrers or rotating grates have been added resolving this problem. Depending on the flow direction of the oxidant and fuel these gasifiers can be classified as counter-current or updraft and co-current or downdraft.

In counter-current (updraft), air or oxygen flow through a fixed bed of carbonaceous fuel in a counter-current direction and ash can be removed in dry or slag form and gas leaves at the top of the gasifier. Complete combustion of char takes place at the bottom of the bed. In order to have a permeable fuel bed, updraft gasifiers require non-caking fuels with high mechanical strength. There are rather few gasifiers of this kind in operation. However, lower gas exit temperature leads to higher cold gas efficiency for these gasifiers.

Other advantages of updraft gasifiers are simplicity, high charcoal burn-out and internal heat exchange that lead to low gas exit temperatures and contribute to high cold gas efficiency.

The major drawbacks of the updraft fixed bed gasifier are that the syngas contains 10 to 20% tar by weight, which requires extensive syngas cleanup before engine, turbine or synthesis applications.

Co-current (downdraft) gasifiers are very similar to counter-current ones, with the main difference in direction of air flow through the gasifier. In this type, gasification agent flows co-currently with the fuel.

In conclusion, fixed bed gasifiers have the following characteristics or advantages and drawbacks compared with others gasifier types:

- Low oxidant requirements
- Relatively high methane content in the produced gas
- Production of by-product hydrocarbon liquids, such as tars and oils
- High cold gas thermal efficiency when the heating value of the hydrocarbon liquids are included
- Special requirements for handling caking coal
- Simple construction
- Low pressure drop
- High carbon conversion efficiency
- Bad temperature distribution
- Possible ash agglomeration and clinker formation on grate
- High residence time of solids
- Low residence time for gas

- Long time to heat up
- High investment for big plants

Some of the gasifiers which are constructed as fixed bed gasifiers are described in following sections, concerning their operating conditions and equipments. More information about following fixed bed gasifiers can be found in [10].

3.4.1.1 British Gas/Lurgi slagging process

This gasifier was designed as vertically orientated, cylindrical, water based jacketed with operating pressure of about 5 atm. Feed was entered to gasifier from the top using a lock hopper and steam and oxygen were premixed and fed to gasifier through a tube in the bottom. A tap on the side of gasifier was used to remove the slag. After some modifications, the operating pressure of this gasifier reached 26 atm and slag tap location changed to the bottom of gasifier. Operating conditions of this gasifier are stated in the Table 6.

TABLE 6 – OPERATING CONDITIONS OF THE BRITISH GAS/LURGI SLAGGING PROCESS [10]

Operating Conditions	
Temperature (°C)	
Comb. zone: 1260 to 1370	Effluent gas: 370 to 425
Pressure (atm)	
5 to 26	
Residence time	
Gas velocity: 0.75 m/s	Coal: 10 to 15 min
Reactants	
Coal, Oxidant, Steam	

Figure 4 illustrates the operating parts of the British gas/Lurgi slagging gasifier.

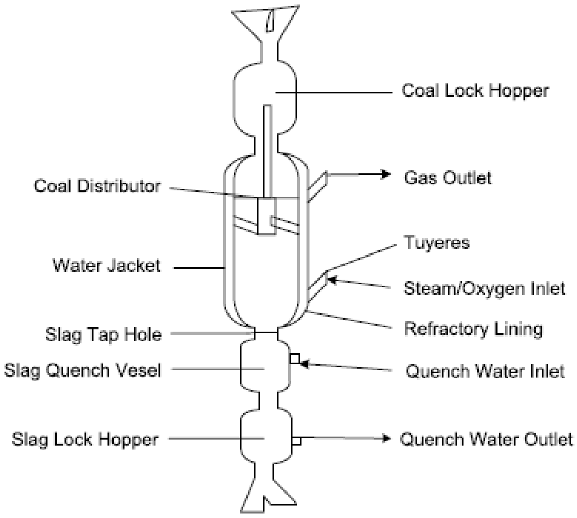


FIGURE 4 – BRITISH GAS/LURGI SLAGGING GASIFIER [15]

3.4.1.2 GFERC SLAGGING PROCESS

The Grand Forks Energy Research Center (GFERC) slagging gasifier was designed for improvement of the Lurgi fixed bed. It means this is a modified version of the Lurgi gasifier. This one is equipped with a bottom grate for ash disposal. To control the temperature and prevent ash from melting, steam was also used as it is used in Lurgi gasifier. Figure 5 on the next page is a schematic of the GFERC gasifier.

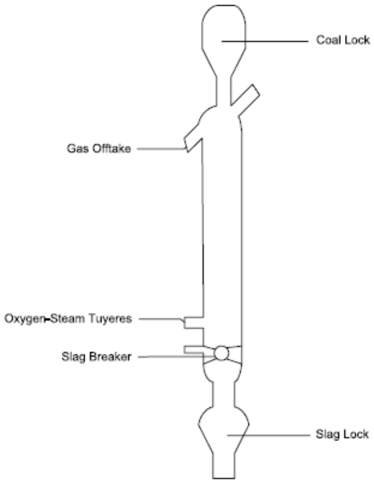


FIGURE 5 – GFERC SLAGGING GASIFIER [16]

3.4.1.3 LURGI, DRY ASH PROCESS

This is a vertical, cylindrical vessel constructed of two sections: a coal bunker and air lock at the top, gasification chamber and ash lock at the bottom.

For transportation of coal to coal bunker a conveyor belt is used. Before coal is fed to the combustion chamber, it is pressurized. The steam which is used in gasification chamber is produced utilizing the excess heat of gasification reactions.

Ash removal is controlled by a rotating grate which rotates at variable speeds. This is an important part which by changing speed the amount of ash is controlled and this procedure leads to control the height of reaction bed in gasification chamber. Operating conditions of this gasifier are stated in Table 7 below.

TABLE 7 – OPERATING CONDITIONS OF THE LURGI DRY ASH PROCESS [10]

Operating Conditions		
Temperature (^{o}C)		
Gasification zone: 620 to 815	Comb. zone: 980 to 1370	Effluent gas: 370 to 590
Pressure (MPa)		
2.4 to 3.1		
Residence time		
up to 1 hour		
Reactants		
Coal, Oxidant, Steam		

Figure 6 shows the schematic of this gasifier.

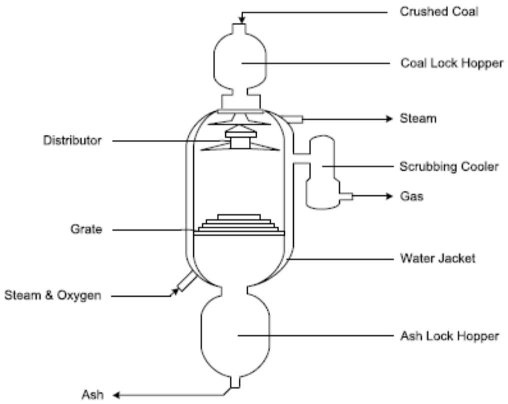


FIGURE 6 – LURGI, DRY ASH GASIFIER [15]

3.4.1.4 WELLMAN-GALUSHA PROCESS

This gasifier exists in two types: standard and agitated. The agitated has a larger rated capacity (about 25 %) than the standard one of same size. The agitated is also capable of processing volatile caking bituminous coals. The agitator is equipped with a horizontal rotating arm which agitates the coal bed as well as with a vertical spiralling movement into the coal bed that prevent the channelling of steam or air into the coal. A rotating grate is used to remove the ash from coal bed to the bottom of the vessel. The continuous inflow of coal from the top of gasifier causes the stabilization of the coal bed and gas quality. The amount of steam is controlled by the temperature of water jackets. Operating conditions of this gasifier are stated in Table 8 below.

TABLE 8 – OPERATING CONDITIONS OF THE WELLMAN-GALUSHA PROCESS [10]

Operating Conditions	
Temperature (°C)	
Combustion zone: 1315	Effluent gas: 590 to 650
Pressure	
atmospheric	
Residence time	
Gas velocity: --	Coal : 4 hours
Reactants	
Coal, Oxidant, Steam	

Figure 7 shows the different parts of Wellman-Galusha gasifier.

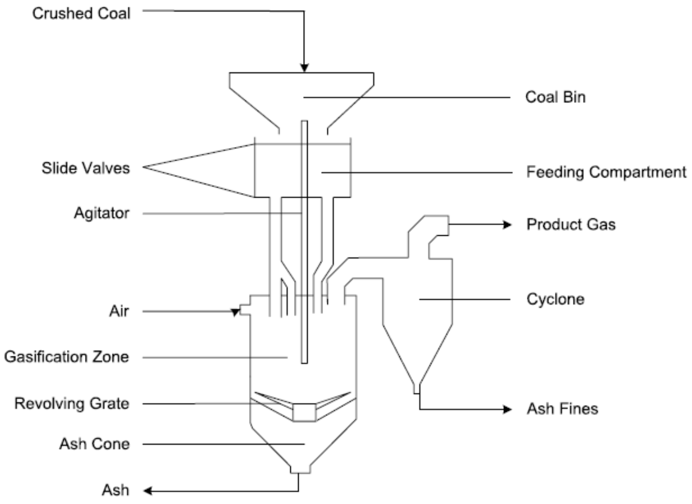


FIGURE 7 – WELLMAN-GALUSHA GASIFIER [15]

3.4.1.5 WOODALL-DUCKHAM/GAS INTEGRALE PROCESS

This cylindrical, vertical vessel is equipped with a rotating grate which distributes the air stream at the bottom and also disposed ash formed by the gasification reaction. This gasifier has two main parts: drying and distillation, water-jacketed gasification. Wet coal will dry after passing through the drying zone and get in contact with hot gas stream from gasification zone counter-currently. The distillation zone is located after the drying zone, where the temperature is higher than in the drying zone, causing distillation of the volatile matter contained in the coal. Temperature of the gasification zone is close to the ash fusion temperature (an indication of the melting and softening behavior of ash). In the gasification zone, carbon reacts with oxygen and steam in counter-current flow. The quality of ash can be controlled in this gasifier by controlling the air to steam ratio. High ratio means low steam rate, which causes high reaction temperature leading to clinker ash formation. Low ratios have negative impact on temperature increase and will lead to production of very fluffy ash. Operating conditions of this gasifier are stated in Table 9.

TABLE 9 – OPERATING CONDITIONS OF THE WOODALL-DUCKHAM/GAS INTEGRALE PROCESS [10]

Operating Conditions		
Temperature (°C)		
Gasification zone: 1200	Clear gas (bottom off-take): 650	Effluent gas (top off-take): 120
Pressure		
atmospheric		
Residence time		
Gas velocity: --	Coal: several hours	
Reactants		
Coal, Air, Steam		

Figure 8 is a schematic of some parts of Woodall-Duckham/gas integrale gasifier.

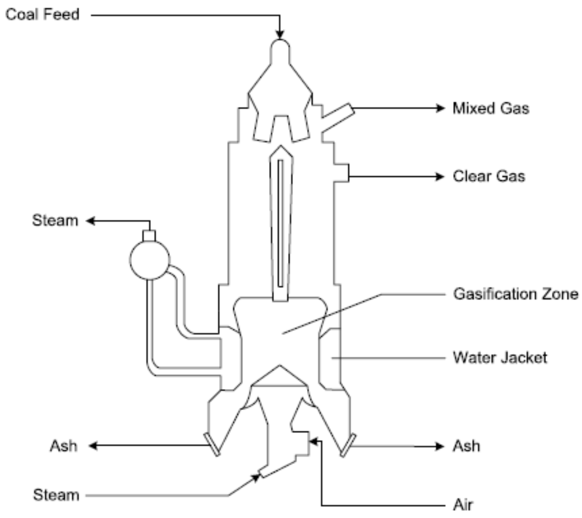


FIGURE 8 – WOODALL-DUCKHAM/GAS INTEGRALE [15]

3.4.2 FLUIDIZED BED GASIFIERS

A fluidized bed gasifier is a well-mixed reactor containing a mixture of un-reacted coals which enters the gasifier with gasified particles of coals in the gasifier. Mixing results in rather uniform temperature distribution throughout the bed. The flow of gas (oxidant, steam, and recycled syngas) which enters the vessel must be sufficient in order to keep the particles floating. But not so high that entrains them out of the bed. However, during gasification of particles, they will become lighter and be entrained out of the gasifier. The important issue is the temperature control of the vessel and to set to a value lower than the initial ash fusion temperature to prevent particle agglomeration. A cyclone in employed to collect the entrained particle in outlet gas and recycles them back to the bed. Overall, the residence time of coal particles in a fluidized bed gasifier is shorter than that of a fixed bed gasifier.

Some characteristics of these kinds of gasifiers which could be their advantages or drawbacks are as follow:

- Extensive solid recycling
- Uniform and moderate temperature
- Moderate oxygen and steam requirements
- Good temperature distribution
- Good heat exchange
- Good gas solid contact and mixing
- Short residence time for solids and gas
- High reaction rate
- Fast change of different fuels
- Operation is more difficult than with fixed bed gasifiers
- Pressure drop is higher than for the fixed bed
- High energy requirement for fans (fluidizing air)
- Ash is not molten

Several kinds of fluidized bed gasifiers are summarized below. More information about these gasifiers is available in [10].

3.4.2.1 Battelle ash agglomerating process

The gasifier used in this process is a vertical, cylindrical vessel consisting of three sections; with different diameters that are increasing upwards. Coal is transported by an inert gas pneumatically to lock hoppers. To convey the coal from lock hoppers to the gasifier, recycled product gas is used. The nozzles which are located above the ash entrance zone pass the coal to the gasifier. Superheated steam, which enters the gasifier through a distributor, is used for fluidization of the bed. The two zones are separated by an inner section.

There is also a burner in this process. This burner is fed with coal (carried by air), recycled char and ash from the gasifier as well as additional air. Operating conditions of this gasifier are stated in Table 10.

TABLE 10 – OPERATING CONDITIONS OF THE BATTELLE ASH AGGLOMERATING PROCESS [10]

Operating Conditions		
Temperature (°C)		
Burner: 1100 to 1150	Gasifier: 870 to 890	Effluent gas: 870 to 890
Pressure (kPa)		
Pretreater: Atmospheric	Burner: 690 to 860	Gasifier: 690 to 860
Reactants		
Coal, Oxidant(Air), Steam		

Figure 9 demonstrates the schematic of battle ash agglomerating gasifier.

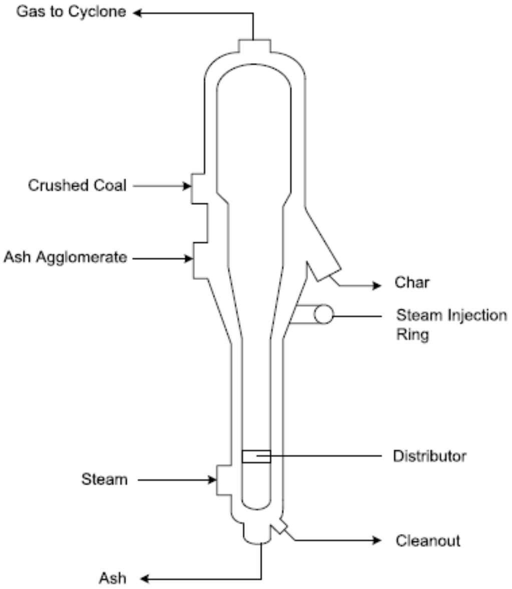


FIGURE 9 – BATTELLE ASH AGGLOMERATING GASIFIER [15]

3.4.2.2 CARBON DIOXIDE ACCEPTOR PROCESS

In this process coal is fed to the bottom of the gasifier from a lock hopper. Before this, coal is reduced to its standard size for this gasifier and its water content is reduced by preheating and drying. Steam is also injected from the bottom and the acceptor materials (calcinated limestone or dolomite) are injected at the top of the vessel. The coal in the gasifier is gasified with steam. Released gas is sent out from the top by passing through the pipes. Acceptors are regenerated in a vessel with heat from oxidation of char which is produced in the gasifier.

CO_2 acceptor reaction which takes place in this process is [19]:

$$CaO+CO_2 \rightarrow CaCO_3+176.784\ KJ/kmol \qquad (4)$$

The major part of the required heat for the gasification reaction is provided by this exothermic reaction. Another advantage of this gasifier is the low concentration of CO_2 in outlet gas which is the direct consequence of this reaction. A disadvantage is the fact that the production of CaO or MgO is very energy consuming.

Operating conditions of this gasifier are stated in Table 11.

TABLE 11 – OPERATING CONDITIONS OF THE CARBON DIOXIDE ACCEPTOR PROCESS [10]

Operating Conditions	
Temperature (°C)	
Gasifier: 815	Realternator: 1000
Pressure (kPa)	
1030	
Residence time	
Fluidizing velocity: 0.35 m/s	Empty gasifier: 0.5 m/s to 0.7 m/s
Reactants	
Coal, Oxidant, Steam	

Figure 10 is a carbon dioxide acceptor gasifier. The important parts of this gasifier are shown in Figure 10.

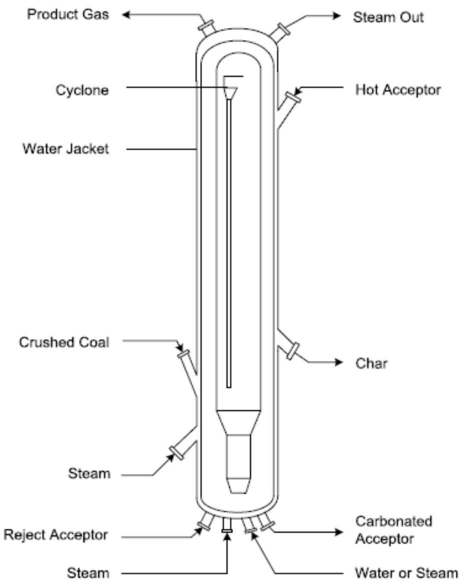


FIGURE 10 – CARBON DIOXIDE ACCEPTOR GASIFIER [15]

3.4.2.3 HYGAS PROCESS

This gasifier consists of four internal gas/solid sections. These sections are (from top to the bottom):

- Slurry drying/solids extrication
- 1st stage hydrogasification
- 2nd stage hydrogasification
- Steam/gasification

Slurry Coal is injected at the top of the slurry drying section. The oil which is mixed to coal is vaporized in this section and coal is passed through internal pipe line to the 1st stage hydrogasification and brought in contact with the hot gases from the zone below counter-currently. These pipes serve as the first hydrogasification zone. In the second hydrogasification zone contact between the descending gasified char and the hydrogen rich gas from the gasification section takes place directly.

The steam/gasification section is located below the second stage hydrogasification. In this zone, the residual coal from the section above and steam and oxygen from the section below reacts. Some methane is formed by reaction between excess hydrogen with carbon and carbon monoxide. This process is exothermic and supplies the energy needed for the carbon-steam reaction. Operating conditions of this gasifier are stated in Table 12.

TABLE 12 – OPERATING CONDITIONS OF THE HYGAS PROCESS [10]

Operating Conditions			
Temperature (°C)			
Slurry dryer zone: 315	1st Hydrogasification zone: 540 to 690	2nd Hydrogasification zone: 940	Gasification zone: 1000
Pressure kPa)			
Slurry dryer zone: 7960	1st Hydrogasification zone: 8000	2nd Hydrogasification zone: 8030	Gasification zone: 8100
Reactants			
Coal, Oxidant, Steam			

3.4.2.4 SYNTHANE PROCESS

Crushed coal, high pressure steam and oxygen are transported into the fluidized bed. In pre-treater zone, coal is dried and pressurized to almost 40 atm, entering the gisifier. In pre-treater section, coal surface is oxidized slightly, preventing coal from agglomeration.

Steam which flows from the bottom of the vessel is brought in contact with char counter-currently. The residual char is removed through a valve. Gasification product exits at the top of the vessel, passing through scrubbers to remove impurities and remaining ash particles. Operating conditions of this gasifier are stated in Table 13 below.

TABLE 13 – OPERATING CONDITIONS OF THE SYNTHANE PROCESS [10]

Operating Conditions	
Temperature (°C)	
Fluidized bed: 815 to 980	Effluent gas: 425 to 870
Pressure (kPa)	
4135 to 6900	
Reactants	
Coal, Oxidant, Steam	

A schematic of the Synthane gasifier can be seen in Figure 11.

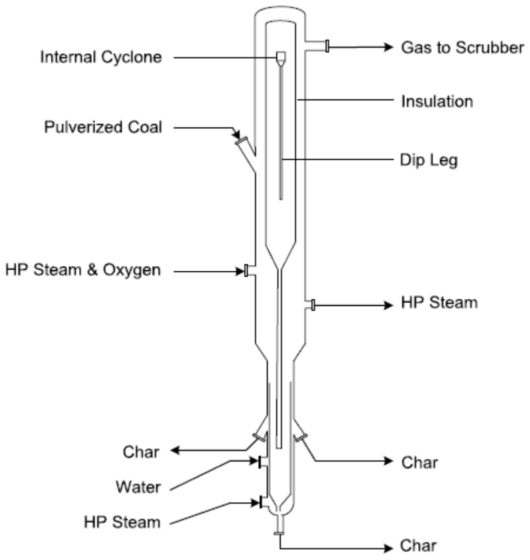


FIGURE 11 – SYNTHANE GASIFIER [15]

3.4.2.5 WINKLER PROCESS

The gasifier in this process consists of a cylindrical, vertical, refractory lined gasifier (Figure 12). Coal enters at the bottom of gasifier and gas streams (steam, air/oxygen) enter at various places along the vessel. Coal is crushed and dried in a series of unit operations prior to gasification. The bed for fluidization fills almost one third of the gasifier capacity. The rest of the volume is used as separation zone. To ensure all heavy hydrocarbons and tars are gasified, the vessel is kept at high temperature between 980 and 1150 °C. Ash particles in the product gas are removed in ash discharge chamber. Operating conditions of this gasifier are stated in Table 14.

TABLE 14 – OPERATING CONDITIONS OF THE WINKLER PROCESS [10]

Operating Conditions	
Temperature (°C)	
Fluidized bed: 980 to 1150	Effluent gas: 790 to 1150
Pressure (kPa)	
100 to 400	
Residence time	
20 to 30 minutes	
Reactants	
Coal, Oxidant, Steam	

Winkler gasifier is shown in Figure 12 with some entrances and exit flows at different parts of the gasifier.

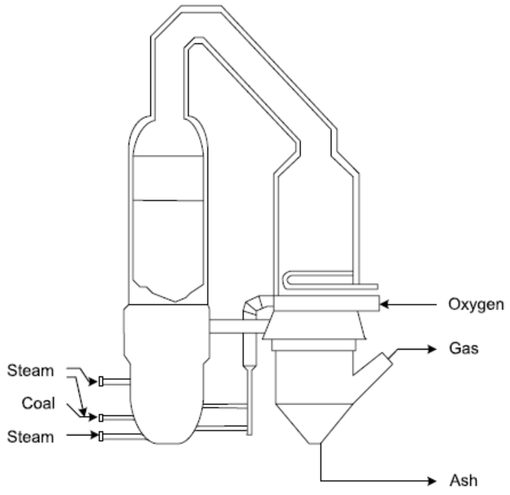


FIGURE 12 – WINKLER GASIFIER [15]

3.4.3 ENTRAINED BED GASIFIERS

In this kind of gasifiers, crushed coal and oxidant are injected to gasifier concurrently. Coal and oxidant are reacted after heating in gasifier. As the residence time of these kinds of gasifiers are short (order of seconds), entrained gasifiers temperature must be sufficiently high (1500°C) to achieve high carbon conversion. Oxygen is more common as oxidant than air. Operating temperatures are well above the slagging temperature of the coal.

Some characteristics of entrained flow gasifiers are listed below covering both advantages and drawbacks of this group. These attributes are:

- High temperature slagging operation
- Entrainment of some molten slag in the raw syngas
- Relatively large oxidant requirements
- Large amount of sensible heat in the raw syngas
- Ability to gasify all kind of coal regardless of rank, caking characteristics or amount of fines
- Less technical complexity compared to pneumatic feeders
- less electricity is needed to compress the inert pressurizing gas
- the gasifier efficiency increases due to less dilution

This group is heavily used in some industries such as IGCC and FT synthesis. The most significant and widely available entrained bed gasifiers are presented in the following sections 3.4.3.1-3.4.3.3. More details can be found in [2] and [10].

3.4.3.1 SHELL COAL GASIFICATION PROCESS (SCGP)

This entrained flow gasifier works with dry feed such as coal and petroleum coke and converts them to syngas. This gasifier uses recycled syngas or pressurized nitrogen to carry the feed to the gasifier. The feed reacts with oxygen at a temperature of about 815°C. In order to keep the mineral matter in coal molten the gasification temperature is maintained high. Slag forms a layer on a inner water/steam cooled so called membrane walls in the gasifier. The gasifier exit gases are quenched cooled and dedusted syngas which causes a temperature drop of the raw syngas which causes solidification of the molten materials contained in the raw syngas. The slag is removed by a slag sluicing system after having been quenched in a (luke warm) water bath. Upon quenching this slag will solidify as a granular, vitreous material. Ceramic candle filters reduce the fly ash concentration to less than 1 [mg/Nm^3] The generated heat in gasifier is used to produce HP and IP-steam used for additional power generation in the steam turbine. The produced gas consist roughly of about 30 % H_2 and 60% CO [2]. This gasifier is optimized to achieve high cold gas efficiency. Operating conditions of this gasifier are stated in Table 15.

TABLE 15 – OPERATING CONDITIONS OF THE SHELL COAL GASIFICATION PROCESS [10]

Operating Conditions
Temperature (°C)
815
Pressure (bar)
30–40
Residence time
0.5–4 seconds

Figure 13 shows the Shell coal gasification process with a joint steam alternator unit.

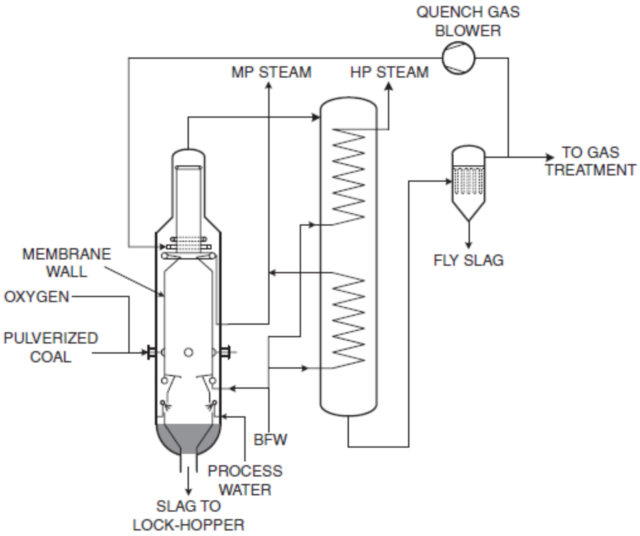


FIGURE 13 – SHELL COAL GASIFICATION PROCESS [17]

3.4.3.2 Babcock and Wilcox process

This gasifier is cylindrical, vertical with two shells (Figure 14). The burners are located near the bottom of gasifier in two rows. The coal is pre-pulverized and dried in a tank. The coal and air enter the coal burners simultaneously. The operating temperature is above the melting point of the ash. This temperature causes formation of slag (molten ash), which is continually removed into a molten slag tank. The slag is mitigated and released to slag disposal lock hoppers. The cyclones capture the char particles which are exiting from gasifier and recycle them back to the gasifier reaction zone [10].

Operating conditions of this gasifier are stated in Table 16.

TABLE 16 – OPERATING CONDITIONS OF THE BABCOCK AND WILCOX PROCESS [10]

Operating Conditions	
Temperature (°C)	
Combustion zone: 1870	Effluent gas: 980
Pressure (kPa)	
100 to 2000	
Gas Velocity Residence time	
4.5 m/s and 9 m/s, residence time 1 second.	
Reactants	
Coal, Oxidant, Steam	

Figure 14 is a schematic of this gasifier.

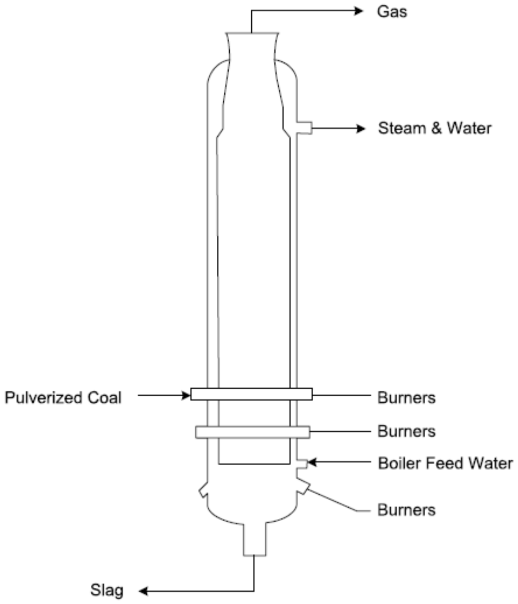


FIGURE 14 – THE BABCOCK AND WILCOX GASIFIER [15]

3.4.3.3 KOPPERS-TOTZEK PROCESS

In this gasifier, pulverized coal is used as feed with the particle size of about 74 micrometers in mean diameter. The feed is mixed with steam and oxygen and sent to the gasifier. The operating pressure is below atmospheric and the temperature is between 1600 to 1900 °C. The coal dust allows short residence time in the gasifier which is approximately one second. High temperature and small particle size lead to high reaction rates such that carbon conversion efficiency is almost unity. Because the temperature is high all ash is molten. A slag quench tank is used to accommodate a part of molten ash and send it out of the gasifier. The rest of the molten ash is entrained with the gas and is solidified in a water spray section [10]. Operating conditions of this gasifier are stated in Table 17 below and the layout of the gasifier is shown in Figure 15.

TABLE 17 – OPERATING CONDITIONS OF THE KOPPERS-TOTZEK PROCESS [10]

Operating Conditions	
Temperature (°C)	
Combustion zone: 1925	Effluent gas: 1500
Pressure (kPa)	
3.5 / 35 / 50	
Residence time	
under a second	
Reactants	
Coal, Oxidant, Steam	

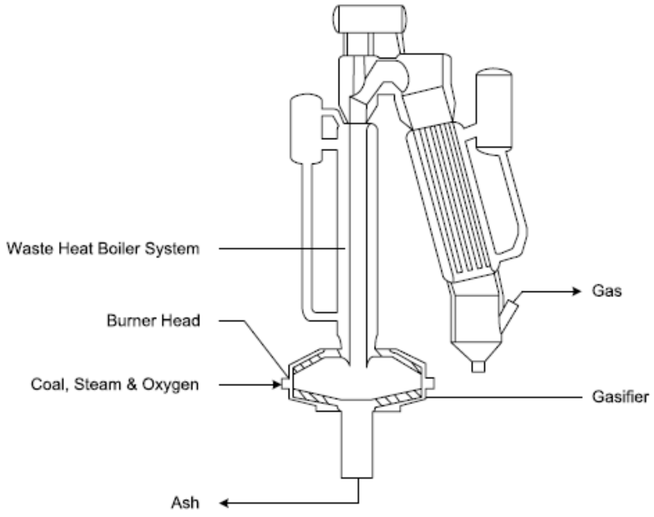


FIGURE 15 – KOPPERS-TOTZEK GASIFIER [15]

3.4.4 MOLTEN BATH GASIFIERS

This generation of gasifiers operates based on bath temperature of some molten materials such as molten salts. Crushed feed is mixed with air and steam and injected into the molten liquid. The carbon contained in the coal dissolves in the hot liquid and react with oxygen. Carbon monoxide is produced and passed through the top of the vessel. The rest of carbon moves up on the surface of bath and passes through pipelines into a liquid bath regeneration section [10].

Some advantages and drawbacks of these gasifiers are:

- Handling of both caking and non-caking coals
- High oxidation rate
- limitation on inlet temperature to the gas turbine
- possibility of carryover of alkalis
- loss of sodium carbonate as sulphates, sulphites and alumina-silicates
- complicated regeneration system

Two molten bath gasifiers are discussed as follows

3.4.4.1 ROCKWELL INTERNATIONAL

This gasifier is a vertical, cylindrical vessel. The walls are prevented of corrosion from molten salt by using alumina refractory bricks. Four nozzles are used to inject air and solid reagents to vessel. Coal and sodium carbonate are fed to molten bath by air.

Produced gas is escaped from top of the vessel and the un-reacted materials with ash will remain in molten liquid. The produced gas does not require any cleaning because there are not any coal, ash and sulphur particles in it. Operating conditions of this gasifier are stated in Table 18 below [10].

TABLE 18 – OPERATING CONDITIONS OF THE ROCKWELL INTERNATIONAL PROCESS [10]

Operating Conditions	
Temperature (°C)	
Melt bed: 980	Effluent gas: 980
Pressure (kPa)	
100 to 1930	
Gas Velocity	
0.5 m/s to 0.7 m/s.	
Reactants	
Coal, Oxidant, Steam	

Figure 16 shows the Rockwell international gasifier.

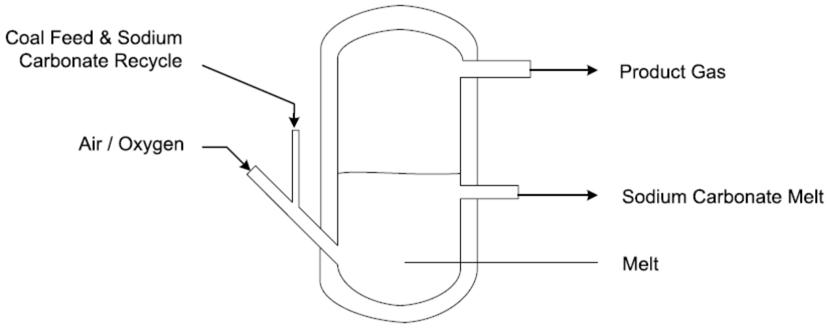


FIGURE 16 – THE ROCKWELL INTERNATIONAL GASIFIER [15]

3.4.4.2 SAARBERG/OTTO

This gasifier is made up of three sections from bottom to top:

1. Molten slag whirlpool
2. Reaction zone
3. Gas cooling

To prevent heat loss a tubular wall surrounds the sections 1 and 2. Side nozzles in molten slag whirlpool inject coal, ash, char as well as air and steam to the vessel. The nozzles are stranded in a downward direction, toward the molten slag bath's surface.

Reaction rates are enhanced by rotating the slag bath. All of the coal dust is gasified in the molten slag whirlpool and some entrained coal particles and ash with produced gas will go to the reaction zone and because of centrifugal forces in this section, some particles will be removed and fall back into the slag bath. The rest of the char particles are gasified in the reaction zone.

Produced gas moves to gas cooling section and liquid slag droplets are solidify mixing with cold recycled gas. Char and entrained particles are recovered in cyclones and recycled to the gasifier. The deposited slag in section 1 is sent out to a water bath for granulation purpose and disposal. Operating conditions of this gasifier are stated in Table 19.

TABLE 19 – OPERATING CONDITIONS OF THE SAARBERG/OTTO PROCESS [10]

Operating Conditions	
Temperature (°C)	
Gasifier: 1500 to 1700	Effluent gas: 815 to 925
Pressure (kPa)	
2500	
Gas Velocity	
1.8 m/s	
Reactants	
Coal, Oxidant, Steam	

Figure 17 below is a schematic of a Saarberg/Otto gasifier.

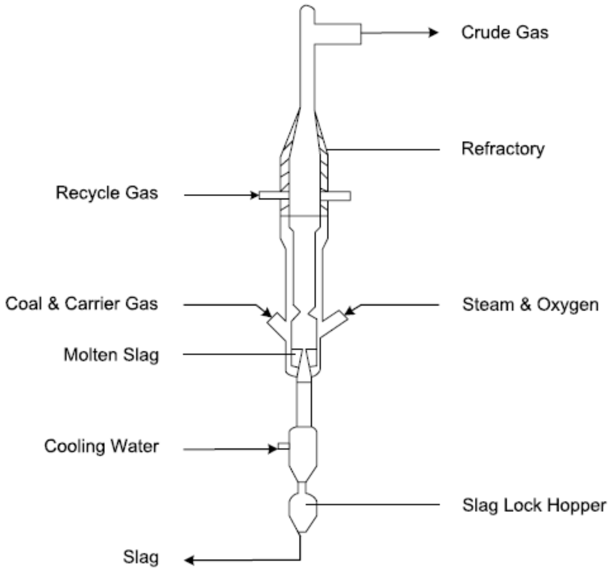


FIGURE 17 – SAARBERG/OTTO GASIFIER [15]

4 GAS CLEANING AND CONVERSION

4.1 INTRODUCTION

Produced gases from gasification units are constituted of various raw gases that need to be cleaned. Dedusting and selective removal of gaseous contaminants are essential tasks before this outlet gas can be used in the final application, such as IGCC power stations.

In conventional gas cleaning processes, the gas flow is usually cooled to low temperatures which result in condensation of water vapour and (semi-) volatile material. The gas stream is then sent to an absorber in order to remove soluble contaminants from the condensate and prepare a dry gas which is purified from water, ammonia, and halides. Subsequently, the dry gas is sent to a gas absorption tower to remove sulphur from the bulk [20]. After that, the dry gas must be converted to a gas which is replete from H_2 and CO_2. So, a series of shift reactors will convert CO to CO_2 and produce H_2. Then CO_2 will be separated from the gas flow in absorption unit and concentrated H_2 flow will be sent to the power generation section.

Figure 18 shows a schematic of a pre-combustion CO_2 capture which has a complete gas cleaning and purification units for removing solids, H_2S and CO_2.

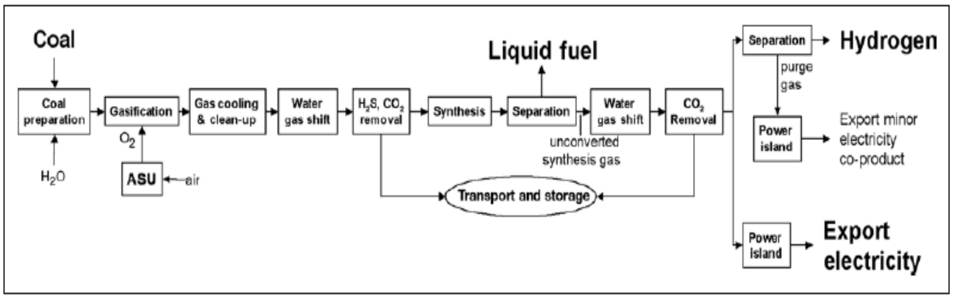


FIGURE 18 – SCHEMATIC OF A PRE-COMBUSTION CO2 CAPTURE [5]

4.2 H_2S REMOVAL

In purification of biogas and syngas, some techniques are used which are completely similar to natural gas purification. The reason is similarity of these mixed materials to natural gas in composition and physical properties.

The contaminating compounds in the gas phase are listed in Table 20. There is a wide range of impurities in gas phase which it must be treated before using it in gas turbine combustor. To achieve this goal, various types of separation processes must be used. These separation methods are described in the next section.

TABLE 20 – GAS PHASE IMPURITIES [21]

1. Hydrogen sulfide
2. Carbon dioxide
3. Water vapor
4. Sulfur dioxide
5. Nitrogen oxides
6. Volatile organic compounds (VOC's)
7. Volatile chlorine compounds (e.g., HCl, Cl_2)
8. Volatile fluorine compounds (e.g., HF, SiF_4)
9. Basic nitrogen compounds
10. Carbon monoxide
11. Carbonyl sulfide
12. Carbon disulfide
13. Organic sulfur compounds
14. Hydrogen cyanide

Source:Kohl and Neilsen (1997), pg 3

4.2.1 DIFFERENT TYPES OF SEPARATION PROCESSES

Gas purification processes generally can be categorized in five groups as follows [21]:

a) Absorption into a liquid

b) Adsorption on a solid

c) Permeation through a membrane

d) Chemical conversion to another compound

e) Condensation

4.2.1.1 ABSORPTION INTO A LIQUID

Gas-liquid absorbers form part of the gas clean-up unit operation which can provide suitable conditions for mass transfer between liquid and gas. They can increase the contact surface and optimize the gas/liquid contact time. If a reversible mass transfer would be possible (which is very often the case), stripper columns can be operated in association with the absorber in a continuous process. An absorber/stripper flow scheme is presented in Figure 19.

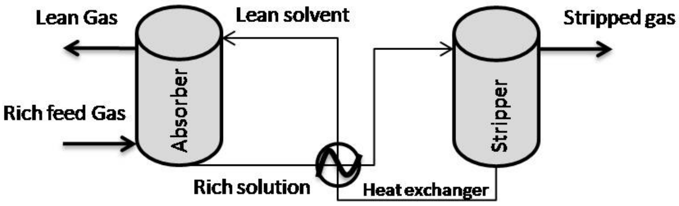


FIGURE 19 – GENERIC ABSORBER/STRIPPER SCHEMATIC

There are various solvents which are used for gas purification process. Since amine based solvents are most common in industrial applications, some of these are presented in the following sections.

AMINE SOLUTIONS

Amines can solve H_2S and CO_2 in two different ways depending on the properties of the solvent and the ability of building a chemical bond with the amines. These solvents are divided into two types viz. chemical and physical solvents [21]. These two types of solvents and their solution mechanisms are discussed in the following two subsections.

CHEMICAL SOLVENTS

Alkanolamines contain a hydroxyl functional group on one end and an amino functional group at the other. The hydroxyl group will lower the vapour pressure and increase water solubility, while the amine group provides the alkalinity required for absorption of acid gases. The main ionic chemical reactions taking place in liquid phase are as shown in following equations [21].

$$H_2O = H^+ + OH^- \tag{5}$$

$$H_2S = H^+ + HS^- \tag{6}$$

$$CO_2 + H_2O = HCO_3^- + H^+ \tag{7}$$

$$RNH_2 + H^+ = RNH_3^+ \tag{8}$$

$$RNH_2 + CO_2 = RNHCOO^- + H^+ \tag{9}$$

Typical amines, used for separation are monoethanolamine (MEA), diethanolamine (DEA), methyldiethanolamine (MDEA), and diisopropanolamine (DIPA). Absorption takes place at high pressures with heat-driven regeneration in the stripper. The basic process flow diagram for an alkanolamine acid-gas removal process is illustrated in Figure 20.

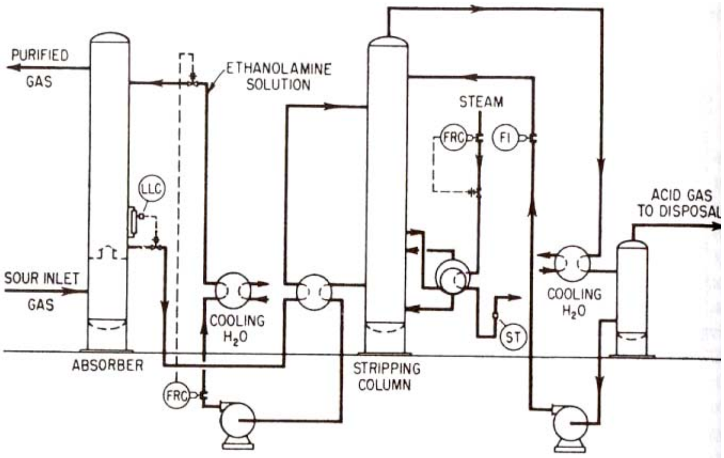


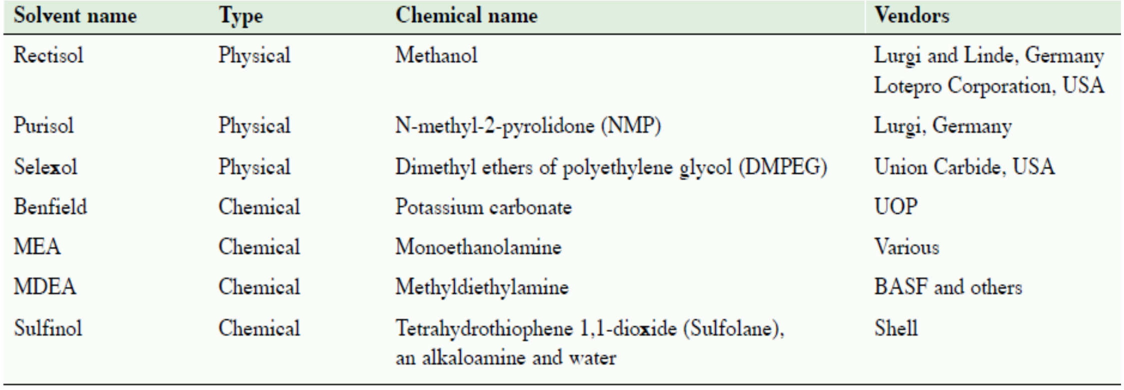
Figure 20 – Basic flow-scheme for an alkanolamine acid-gas removal process [21]

PHYSICAL SOLVENTS

Using physical solvents is another way to separate acid gas components from gas stream. These solvents work based on partial pressure difference between two phases and they will regenerate with a proper pressure drop. The dominant driving force in these systems is partial pressure difference.

Table 21 illustrates both physical and chemical industrial solvents which are used for H_2S and also CO_2 removal.

TABLE 21 – PHYSICAL AND CHEMICAL INDUSTRIAL SOLVENTS USED FOR H2S AND CO2 REMOVAL [5]

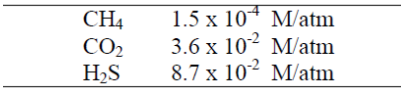


Solvent name	**Type**	**Chemical name**	**Vendors**
Rectisol	Physical	Methanol	Lurgi and Linde, Germany Lotepro Corporation, USA
Purisol	Physical	N-methyl-2-pyrolidone (NMP)	Lurgi, Germany
Selexol	Physical	Dimethyl ethers of polyethylene glycol (DMPEG)	Union Carbide, USA
Benfield	Chemical	Potassium carbonate	UOP
MEA	Chemical	Monoethanolamine	Various
MDEA	Chemical	Methyldiethylamine	BASF and others
Sulfinol	Chemical	Tetrahydrothiophene 1,1-dioxide (Sulfolane), an alkaloamine and water	Shell

WATER SCRUBBING

Water as a rather poor solvent for H_2S and CO_2, is not typically chosen in high concentration of these two components but the advantages of this solvent compared with others is its availability and low cost. CO_2 and H_2S solubility in water can be calculated based on Henry’s law. Table 22 illustrates Henry’s law constants for biogas components in water.

TABLE 22 – HENRY’S LAW CONSTANTS AT 25° C AND 1-ATMOSPHERE [21]



CH_4	1.5×10^{-4} M/atm
CO_2	3.6×10^{-2} M/atm
H_2S	8.7×10^{-2} M/atm

As it can be seen in the table above, H_2S has a higher solubility in water than CO_2 but this difference in solubility is not sufficiently high to allow a selective separation between these two components in water. For this reason, water washing results in a simultaneous separation of these two compounds from bulk flow.

Methanol, Propylene Carbonate, and Ethers of Polyethylene Glycol, are some of the commonly available solvents [21]. The main parameters that must be considered for solvent selection are:

- high absorption capacity
- low reactivity with equipment
- gas constituents
- low viscosity

Also methods of regeneration of these solvents are important to prevent solvent loss, product loss in purged solvent, and solvent degradation.

THE SELEXOL SOLVENT

Selexol is the commercial name of dimethyl ether of polyethylene glycol which is commonly used as a physical solvent. The chemical formula of Selexol is:

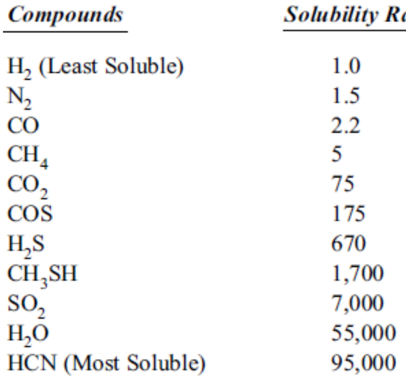
CH_3-O-(CH_2-CH_2-O)N -CH_3

Where N = 2 to 9

One of the advantages of Selexol compared to other solvents is a high H_2S to CO_2 selectivity in the absorption process compare to the commonly used amine based systems This solvent tends to dissolve acid gas compounds better than other gaseous compounds of comparable volatility [26].

A list of the relative solubility for Selexol solvent is presented in Table 23.

TABLE 23 – SELEXOL RELATIVE SOLUBILITY OF GASES [26]



Compounds	*Solubility Ratio*
H_2 (Least Soluble)	1.0
N_2	1.5
CO	2.2
CH_4	5
CO_2	75
COS	175
H_2S	670
CH_3SH	1,700
SO_2	7,000
H_2O	55,000
HCN (Most Soluble)	95,000

A typical scheme of H_2S removal unit with Selexol in IGCC applications is shown in Figure 21 on the next page.

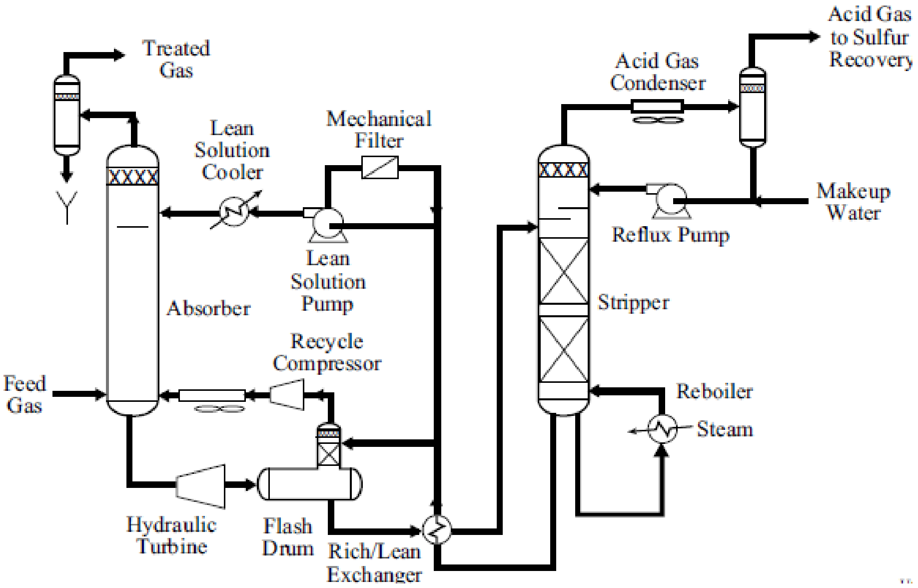


FIGURE 21 – H_2S REMOVAL UNIT WITH SELEXOL [26]

4.2.1.2 Adsorption on a solid

Solid adsorbents have a large surface for adsorption of particles from gas phase to solid phase. During a physical adsorption, particles adhere to the surface of the solid till the surface saturate. Subsequently, the solid must be regenerated to renew its surface activity. Regeneration of an adsorbent is achieved by using one of the following processes:

- Temperature Swing Adsorption
- Pressure swing Adsorption
- Inert Purge
- Displacement Purge

During regeneration process, gases such as H_2S are released from the surface and must be gathered appropriately.

Two kinds of adsorbents which are commonly used in industries are:

- Molecular Sieves (Zeolites)

  Compounds such as water, H_2S, SO_2, NH_3, carbonyl sulfide, and mercaptans are very strongly adsorbed and can be removed from such polar type systems [26].

- Activated Carbon

  It can adsorb compounds such as H_2S but its adsorption potential is lower than zeolites. Activated carbon is commonly used in industries with low H_2S concentration such as drinking water industries [26].

4.2.1.3 PERMEATION THROUGH A MEMBRANE

This separation process is based on transfer of mass through a permeable membrane. Mass transfer takes place on microscopic levels. This implies that molecules which are smaller than the pores of the membrane pass through, while bigger molecules remain on the surface of membrane. Polymers are the most common material used for production of these membranes. Membranes are generally divided into two types:

- High pressure with gas phase on both sides
- Low pressure with a liquid adsorbent on one side

Since the mass transfer rate through the membrane is rather low, they are not suitable for use in large scale power generation units. However, they have some advantages such as ease of operation and high reliability which is important for the operation of small scale units [8].

4.3 GAS CONVERSION AND CO_2 CAPTURE

In pre-combustion capture, the syngas which consists mainly of CO and H_2 can be produced by coal gasification. The syngas is then passed through one or more water-gas shift reactors to convert the CO and steam to CO_2 and H_2. Produced hydrogen is the used in power stations for the sake of electricity generation.

4.3.1 WATER GAS SHIFT REACTION

This reaction was discovered about two centuries ago and is used for industrial production of ammonia, methanol and FT liquids [22]. In an equilibrium reaction, CO and H_2O react with each other to produce CO_2, H_2, and heat.

$$CO + H_2O \leftrightarrow CO_2 + H_2 \qquad \Delta H^0 = -41 kJ/mol' \tag{10}$$

The shift reaction given above, which is carried out catalytically, is an exothermic reaction. Therefore the equilibrium composition is rather sensitive to temperature such that higher temperature leads to decrease in equilibrium conversion of CO. On the other hand, catalysts are more active at high temperatures. So the temperature must be optimized in these reactors to yield the optimum conversion. The temperature is usually controlled by controlling the stream flow and steam/CO ratio, which is one of the controversial topics in CO shift reactors discussed in [24]. Using staged shift reactors is one of the methods for CO conversion control discussed in [24]. Figure 22 illustrates an advanced staged shift reactor unit.

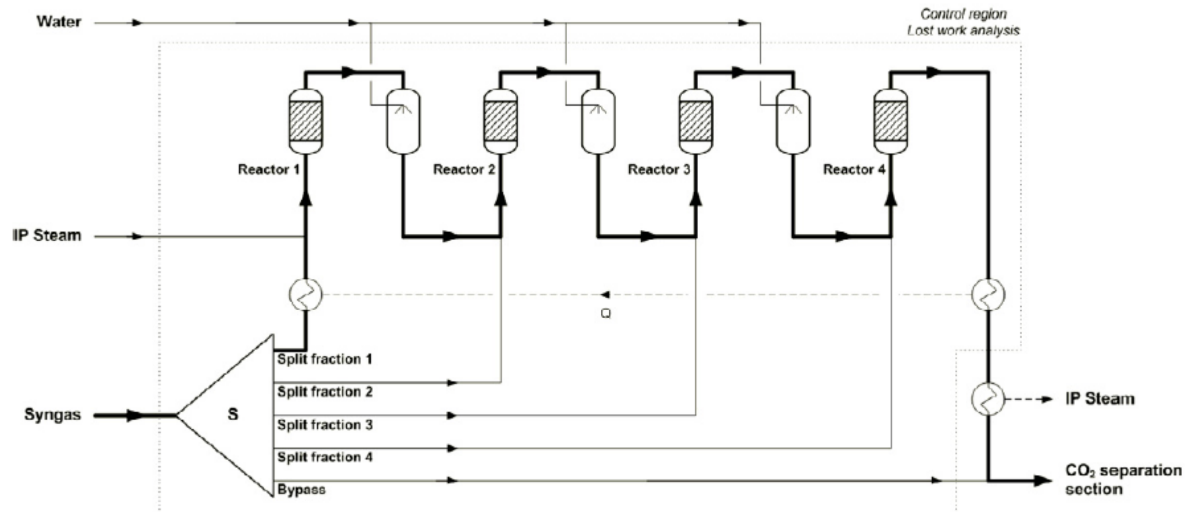


FIGURE 22 – THE ADVANCED SHIFT REACTOR UNIT [24]

There are several types of water-gas shift catalysts available for shift reaction. The three most important groups are listed below [23]:

- High-temperature shift (HTS) catalysts:
    - Active compound: Fe_3O_4 with Cr_2O_3 as stabilizer, working at: 350 – 500 ºC; sulphur content limitation in syngas < 20 ppm
- Low-temperature shift (LTS) catalysts:
    - Active compound: Cu supported by ZnO and Al_2O_3, working at 185 – 275 ºC; sulphur content limitation in syngas < 0.1 ppm
- Sour shift catalysts:
    - Active compound: Sulphided Co and Mo (CoMoS), working at 250 – 500 ºC; sulphur content limitation in syngas > 1000 ppm

At least two reactors with high and low temperature must be used. The high temperature reactor converts the bulk of CO to CO_2 and the low temperature one reduces the CO concentration to ppm level. So, HTS and sour shift catalysts are used for bulk conversion of CO and LTS catalyst is used for reducing concentration of carbon monoxide to ppm level. It must be kept in mind that reduction of CO to ppm levels is not required when the shifted and CO2 depleted syngas is to be fired in a gas turbine (IGCC application).

4.3.2 CO2 CAPTURE METHODS

Existing CO_2 capture systems utilize many of technologies used for gas separation and treating. These technologies are based on different separation methods. A summary of these separation methods is given below.

4.3.2.1 SEPARATION WITH SORBENT/SOLVENT

The separation is achieved by bringing the CO_2-rich stream in contact with a liquid absorbent or solid sorbent which is able to solve the CO_2. In Figure 23, section (a), the sorbent saturated with the CO_2 is transported to a regeneration unit and by heating or changing the pressure the sorbent/solvent is regenerated. Regenerated solvent is then sent back to the absorption unit. As the solvent loss takes place in regeneration unit, a make-up stream of fresh solvent is injected to the recycled solvent [5].

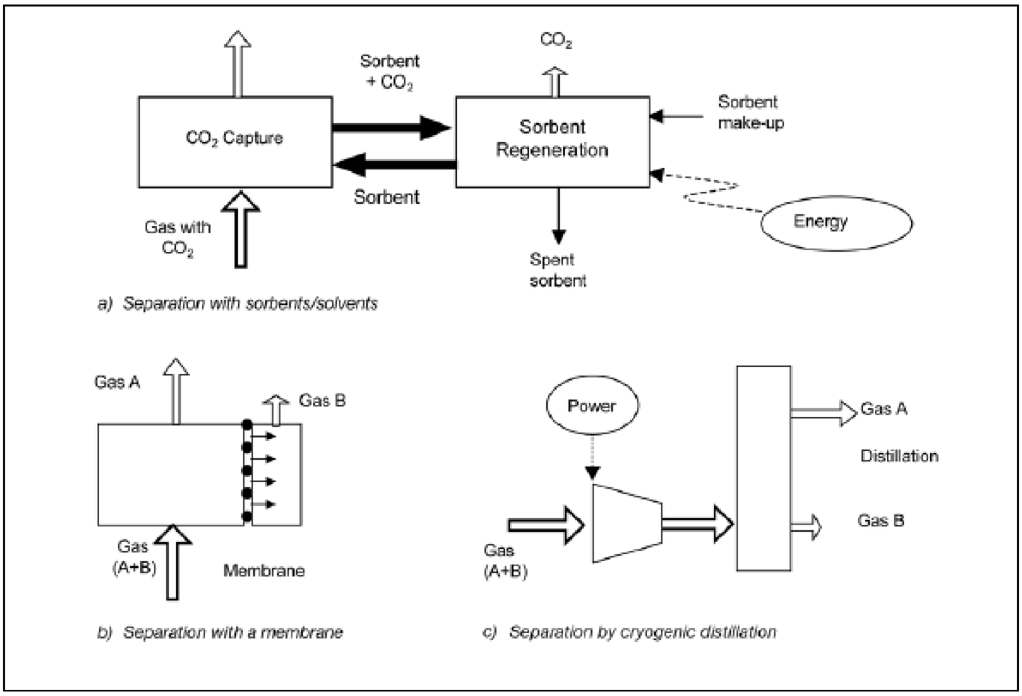


FIGURE 23 – CO_2 CAPTURE SYSTEMS

Some of the solvents which are used commercially in CO_2 capture processes are listed in Table 24.

TABLE 24 – MOST COMMON SOLVENTS FOR CO2 CAPTURE PROCESS [5]

Solvent Name	**Type**	**Chemical Name**
Rectisol	Physical	Methanol
Purisol	Physical	N-methyl-2-pyrolidone (NMP)
Selexol	Physical	Dimethyl ether of polyethylene glycol (DMPEG)
Benfield	Chemical	Potassium carbonate
MEA	Chemical	Monoethanolamine
MDEA	Chemical	Methyldiethylamine
Sulfinol	Chemical	Tetrahydrothiophene 1,1-dioxide, alkanolamine, water

4.3.2.2 SEPARATION WITH MEMBRANES

“Membranes (Figure 23 (b)) are specially manufactured materials that allow the selective permeation of a gas through them”. [5] As the pores on membrane are in microscopic scale, the stream which passes through the membrane usually subject to pressure drop. Therefore it is far better to use membrane in high pressure streams. Different types of membrane materials (polymeric, metallic, ceramic) are used in separation purposes such as air separation units and food industries. But as they are expensive and cannot handle high flow rates, they are not used commercially in large scale CO_2 capture units [5]. Membranes have some advantages and drawbacks which are discussed in section 3.1.1.3.

4.3.2.3 DISTILLATION OF LIQUEFIED GAS STREAM AND REFRIGERATED SEPARATION

A gas can be converted to liquid by increasing its pressure and decreasing its temperature. A series of compression, cooling and expansion steps can be applied for this purpose. In liquid state, the desired components are separated in a distillation tower (Figure 23 (c)). This technique is used in air separation units (ASU). The method can be used for the separation of CO_2 from natural gas or outlet gases from syngas water-gas shift reactors as well. But this method is rather expensive and therefore not economically feasible for most of the industries [5].

4.3.3 SEWGS (SORPTION-ENHANCED WATER-GAS-SHIFT) PROCESS

The sorption-enhanced water-gas shift (SEWGS) is a process which can be used for CO_2 capture in pre-combustion technology. This process can capture more CO_2 and can lead to larger CO conversion efficiency than the other common processes with lower efficiency penalties and costs [25].

The main equipment in this process is a chemical reactor which is packed with a mixture of CO_2 sorbent (solid) and water-gas shift catalyst. CO_2 is adsorbed on solid sorbents and CO in converted to CO_2 by WGS reaction. CO_2 concentration is decreased by sorbent in reactor so that CO conversion is enhanced. Steam is used to regenerate the sorbent. The operation temperature in this process is 400 ^{o}C. This process has two outlet streams:

- Hot and pressurized fuel gas replete with H_2
- Relatively pure CO_2 mixed with steam

As the SEWGS process can operate at high temperature and pressure, it does not require large cooling operation. According to [25] this process is able to convert CO to CO_2 and capture CO_2 simultaneously which leads to increase CO_2 production and capture rates. The sorbents which are suitable for this process are potassium promoted hydrotalcite-based materials. These materials can operate at 400 °C for capturing the CO_2 [25].

5 GAS TURBINE

5. 1 INTRODUCTION

The applications of gas turbines have been numerous since their introduction in aviation by the jet engine flight of Heinkel and in power generation by Brown Boweri & Cie's 4 MW power generation plant in Neuchtel, Switzerland in 1939. One of the biggest developments in the field of heavy-duty industrial gas turbines occurred after the Second World War with the transfer of the technological successes accomplished until that time within jet propulsion for military aircrafts. For a long time during the 1970's and 80's the use of gas turbines for power generation was relatively unattractive due to low efficiencies and their requirement of high quality fuel. However, once natural gas became abundant and regulations in many countries were altered allowing natural gas to be burned for electricity production a growth which has continued ever since and has turned the gas turbine into one of the most important technologies for thermal power conversion. The leading force for this growth has been the development of better materials for turbine blades and the introduction of sophisticated methods for blade cooling which have made possible a significant increase in turbine inlet temperature (TIT). In this regard coating of turbine blades has been a significant factor which have risen the GT firing temperature considerably the last two decades, as illustrated in Figure 24. This, in conjunction with elevated compressor pressure ratio, has contributed to increased gas turbine thermal efficiency from 15% to over 45% [27].

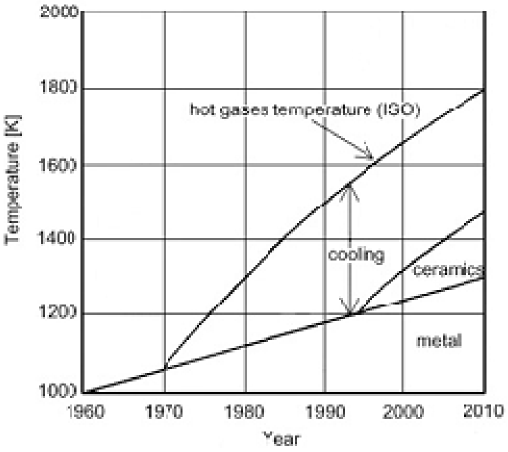


FIGURE 24 – DEVELOPMENT OF GAS TURBINE FIRING TEMPERATURE [28]

At the same time the increase in TIT has called for the need to develop new combustor designs in order to limit NOx emissions within permissible limits. These have included the replacement of stable diffusion burners in side-can arrangement with the more efficient annular combustors utilizing Dry Low Emission (DLE) NOx technology. The DLE combustors utilize a pre-mixed flame in which the flame temperature is considerably lower compared to diffusion flame burners for the same TIT leading to reduced NOx emission. This is because of the release of heat, in the primary combustion zone, in pre-mixed burners is conducted with an excess of air compared to diffusion burners where the heat is released at stoichiometric condition.

Increased firing temperature requires increased cooling air flow for cooling of the hot combustor and turbine inlet surfaces. In addition, a higher TIT implies that less air is available for cooling, since the air fuel ratio is decreased, for a certain engine type. This is due to the fact that for a given air fuel ratio and at the same time higher TIT less air is available for dilution and profiling at combustor outlet, as illustrated in Figure 25.

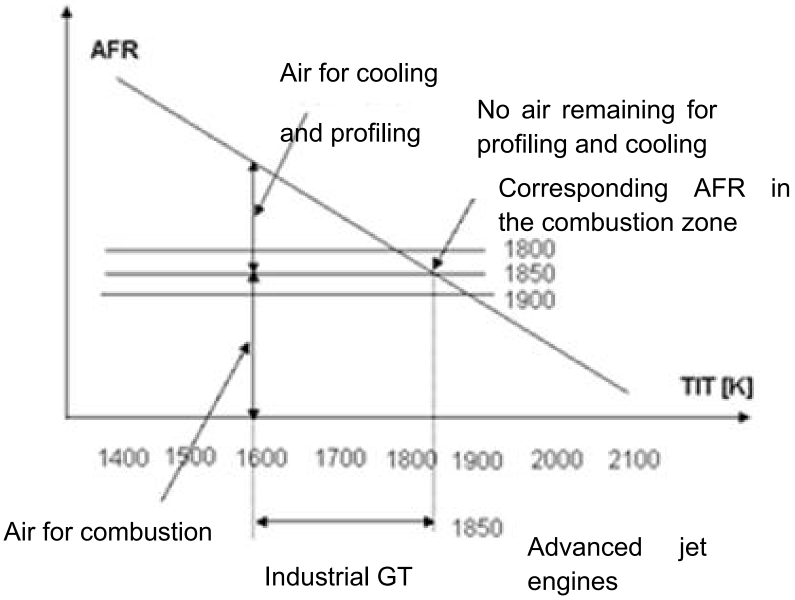


FIGURE 25 – AIR/FUEL RATIO (AFR) AS A FUNCTION OF TURBINE INLET TEMPERATURE

An approach to deal with this problem has thus been to develop cooling techniques utilizing steam instead of air. In such system, steam is used in a closed loop to cool the gas turbine by a number of tubes embedded in the turbine nozzle or blades, as well as in the transition piece of the combustion chamber. Usually the steam is bled from the HP steam turbine of a combined cycle power station and returned back to the IP steam turbine after being used for cooling and consequently heated up, as shown in Figure 26. The main advantages with convective steam cooling system is the elimination of losses emerging when cold air is mixed with the hot exhausts and the omission of secondary losses around the blades [28]. Cooling of the turbine by means of steam could be found in the H-system technology of General Electric (GE). Formerly Westinghouse, currently Siemens-Westinghouse as well as MHI have been utilizing steam cooling, but only of non rotating GT parts.

An alternative strategy to minimize consumption of cooling air has been presented by Mitsubishi Heavy Industries (MHI). Their cooling technology is based on a combination of air and steam as coolant. The H-technology from MHI was utilizing a combination of air and steam cooling of both rotating and stationary parts; however the G-technology with steam cooling of only stationary parts is the one currently available at the market [28].

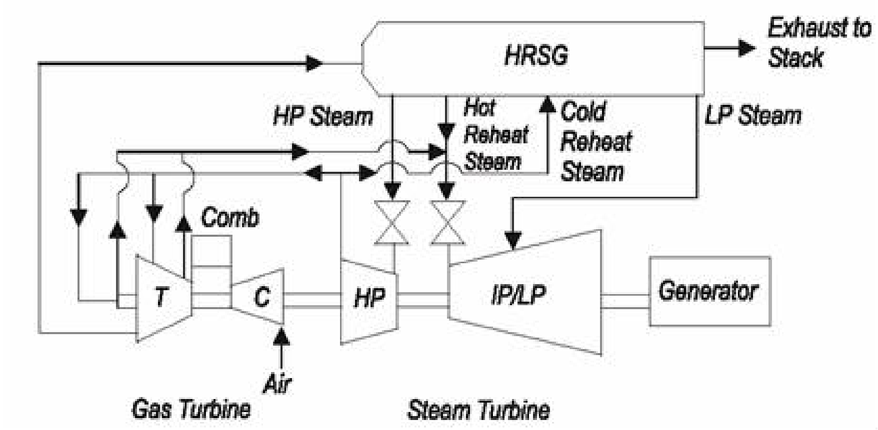


FIGURE 26 – OVERVIEW OF GES STEAM COOLED GT USED IN THE COMBINED CYCLE POWER STATION IN BAGLAN BAY [28]

A third option to solve the problem of minimizing the effects of increased air cooling requirements has been by increasing the air flow through the compressor without changing the inner and outer compressor chasing. This has been achieved by utilizing 3D-design of the compressor blades and by reducing the air leakage between the blades and the housing through better sealings. In Alstoms GT26 these changes in the compressor configuration resulted in an increase of the air flow by about 5%, which enabled both power and efficiency increase [28].

5.2 COMPRESSOR

Compressors used in large industrial applications such as power generation are axial flow compressors. In axial flow compressors the fluid enters and leaves in the axial direction. The compression of the fluid is accomplished by acceleration of the fluid in the rotating part called rotor, followed by diffusion in the stationary part also known as stator. The diffusion process in the stator converts the velocity gained in the rotor into a pressure increase. The acceleration and diffusion is repeated in several stages in a compressor, where one stage is generally defined as one blade row on a rotor disk followed by one blade row of stator. The pressure increase in each stage has the magnitude of 1.1:1 to 1.4:1, which by the multiple use permits overall pressure increases to approximately 30:1 [27], [29].

The gas turbine efficiency is dependent on the two basic parameters in combination: pressure ratio and firing temperature. Since the compressor consumes between 55-65% of the power produced by the turbine an improvement of the compressor performance has thus a positive impact on both gas turbine efficiency and power output [9]. The compressor together with the combustion chamber is the subsystem governing the area of stable operation of the gas turbine cycle. The high pressure ratio of the new industrial units has lead to very narrow operational margins, thus making the turbine very susceptible to compressor fouling. Accordingly, changes in the compressor design are limited in order to sustain safe operation, without reducing the surge margin [27], [28].

In order to increase stable range/window of operation of gas turbines during periods with varying load and maintaining high efficiency under part load operation all modern units are utilizing one or more additional row of variable vanes, also known as Inlet Guide Vanes (IGV) at the compressor inlet controlling the total air mass flow through the machine, as seen Figure 27. Since most modern industrial gas turbines are built as single shaft units the variable geometry at the inlet provides the flexibility for fast start up and variable load control, which have become crucial instruments for the de-regulated power production industry [27], [28].

FIGURE 27 – INLET GUIDE VANES AT THE COMPRESSOR INLET IN ALSTOMS GT 26 [28]

An important aspect to increase compressor efficiency is by reducing the losses by controlling the leakages through better seals as well as reducing the clearance between the compressor blades and the housing. Seals used in modern GTs are based on the “brush sealing” principle, which are comprised of thousands of densely packed wire filaments combined between two metallic plates. Unlike traditional seals such as labyrinth, the brush seal is designed to come into contact with the rotor in order to provide a positive seal and thereby reducing leakages during small displaces and eccentricities in the compressor. Losses also occur due to the small free space between the blade shroud and the compressor housing, thus active tip clearance control by cooling the compressor housing from the outside with a cooling flow to reduce the clearance between the blades and the housing is generally considered in modern compressors. However, in order to maintain the free space as small as possible an extensive control and measurement system is required to prevent damage of the compressor blades and contact with the housing [27],[28].

5.3 COMBUSTOR

The combustor, sometimes referred to as the burner, provides the heat input to the gas turbine cycle. The combustion process is a steady-state flow process in which a hydrocarbon rich fuel is burned with the compressed air to achieve a desired combustor firing temperature.

The first industrial gas turbines had combustors arranged as a silo can, offering the advantage of simple design and long life due to low heat-release rates. These combustors were very large and required large amount of cooling air in order to keep the material temperature sufficiently low. Another drawback was the difficulty of providing a homogenous temperature profile at the turbine inlet due to the side arrangement. This uneven temperature distribution at the turbine inlet resulted in thermal stresses reducing the blades operational life. Consequently the transition to annular combustors with better temperature distribution and eased maintenance has been important for the further development of the gas turbine technology. The two different arrangements of combustors can be seen in Figure 28 [28].

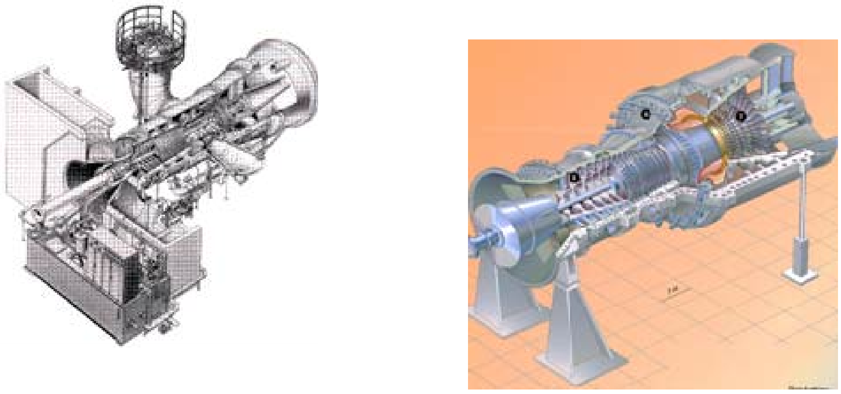


FIGURE 28 – SILO CAN AND ANNULAR COMBUSTORS RESPECTIVELY IN SIEMENS GAS TURBINES [28]

Emissions deriving from gas turbines are a function of residence time and temperature, which is directly related to the fuel air ratio. As illustrated in Figure 29, formation of NOx increases exponentially with the temperature while CO and unburned hydrocarbons are decreased. The challenge in combustor design has thus been to lower the NOx without degradation in combustion stability. This has been achieved by the DLE approach where most of the fuel (at least 75%) is burnt at cool, fuel-lean conditions to minimize the production of NOx. The principal feature of controlling the flame temperature is the premixing of the fuel and air before the mixture enters the combustion chamber. In order to stabilize the flame in DLE combustors, swirlers are used to create the necessary flow conditions. The DLE fuel nozzles are more complicated and larger in number than in conventional diffusion burners, because the fuel injector contains the fuel/air mixing chamber in which approximately 50-60% of the combustion air flow is premixed with fuel. The main difficulty with DLE combustors is the flashback problem in which the flame moves back from the combustor outlet towards the premix chambers. This results in the burn out of those chambers and will cause undesired damage to the main section of the combustor can. An additional unfortunate side effect of lean premixed combustors is that the heat release and local pressure variations can result in oscillations also known as humming. These can cause vibrations strong enough to initiate mechanical damage to the engine [27].

There are a number of technologies used to protect the combustor liner from excessive temperatures. The cooling air could be introduced either to serve as blanket between the combustion gas and the metal surface or to remove heat from the liner by cooling its backside. In connection with the first mentioned effusion air cooling has been an important technique in order to reduce air cooling requirements while extending the combustor liner life. Effusion cooling is based on the concept of introducing the cooling air trough small holes in the combustor wall that will emerge as small jets on the hot gas side. The jets are united and form a protective layer of coolant over the entire surface. In this way the convective heat transfer to the combustor wall is reduced [27].

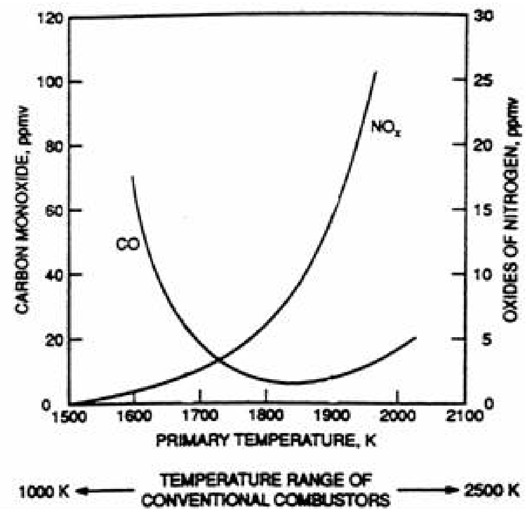


FIGURE 29 – THE EFFECT OF FLAME TEMPERATURE ON EMISSIONS [28]

In modern gas turbines the development has been towards the use of backside-cooled liners by the convective cooling of the liner's outer surface, as illustrated in Figure 30. This is to avoid cold spots on the liner wall, which have the potential of increasing CO production and is associated with liner cooling through air jets introduced through louvers [27], [28], [29].

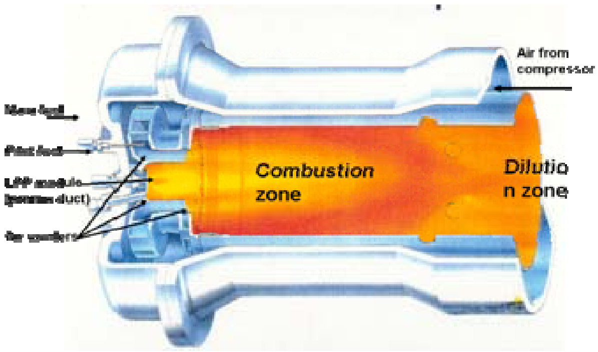


FIGURE 30 – CONVECTIVE COOLING OF A PRE-MIXED COMBUSTOR LINER [28]

5.4 TURBINE

In the turbine being of axial-flow type, the flow like in its counterpart the axial flow compressor, enters and leaves in the axial direction. Similar to the compressor, the turbine consists of a number of stages, each stage consisting of a row of nozzle (stator) blades followed by a row of rotor blades. The working fluid is first expanded and accelerated in the nozzle and then usually further expanded and deflected in the rotor. Contrarily to a compressor rotor in which work is supplied, work is extracted in the turbine rotor. An additional difference between the compressor and the turbine is that the turbine works with a positive pressure gradient and accelerating flow, which results in the turbine having fewer stages than the compressor. The degree of reaction is used to describe the fraction of the stage expansion taking place in the rotor. Most axial flow turbines are designed with zero reaction (impulse) of the front stages and with about 50% reaction in the later stages. The work output from an impulse stage is about twice the output from a comparable 50% reaction stage, whilst the efficiency of an impulse stage is lower than that of a 50% reaction stage [27], [29]

The turbine has for a long time been considered as the technically most advanced component of the GT due to the high interaction of mechanical and aerodynamical stresses, temperature and corrosion. The high temperatures that are now available in the turbine section would not have been possible without the improvements in metallurgy of the turbine blades as well as the development of new cooling schemes. The first stage blades in the turbine must withstand the harshest combination of temperature, stress, and environment. This is generally also the limiting component of the unit in terms of life time, performance, etc. The turbine blades of modern GTs are made up by a single-crystal i.e. without any grain boundaries. With the elimination of grain boundaries and the addition of grain boundary strengthening stabilizers, a considerable increase of the melting point of the alloy is achieved, and in turn gives rise to a corresponding increase in high temperature strength of the blade [27], [28].

The trend with increasing firing temperatures has also increased the need for blade coatings in order to protect the blade from corrosion, oxidation and thermal fatigue resistance. With the increased complexity of super alloys used in modern turbine blades it has been difficult to obtain both high strength levels that are required as well as maintaining a satisfactory level of corrosion and oxidation resistance without the use of coatings. The development of ceramic thermal barrier coatings (TBC) has been essential in the context of protecting the blade base metal at high temperatures while reducing cooling requirements due to their low thermal conductivity. A typical TBC system contains two layers: an oxidant-resistant metallic bond coat and a ceramic top coating. However, the durability of the thermal barrier coatings under high temperature cyclic conditions has been a major concern since the coating does not condition as long as the blade itself. As the cost of single-crystal TBC blades is very high the general practice is to renew the coating after delamination [27], [30].

Cooling of the turbine components such as blades, vanes, endwalls, shrouds, etc is not only required but essential in order to meet metal temperature limits. This is usually accomplished by extracting air from the compressor and direct it to the turbine components to provide adequate cooling. The aerodynamic effects of the cooling depend on several factors: type of cooling used, temperature of the coolant compared to the working fluid temperature, the location and direction of the coolant injection and the amount of coolant. Nevertheless, the use of cooling results in losses [31]:

1. Temperature reduction of the working fluid as a direct effect of the mixing of hot gas and cooling fluid, which consequently reduces the turbine work output.

2. Reduction in momentum of the hot gas as the cooling fluid has to be accelerated to the speed and direction of the hot gas, as an effect of the mixing of the cooling fluid in the hot gas path.

3. Disturbances of the flow around the blade profiles leads to increased flow losses as the cooling fluid is introduced.

There are several methods used for turbine cooling deriving from the five basic air-cooling schemes, also presented in Figure 31 [27], [29] and [31]:

I. Convection cooling - The cooling air flows in channels inside the turbine blade or vanes and thereby removes the heat through the walls (first blade in Figure 31). Convection cooling has been the most widely used cooling method in gas turbines until today.

II. Impingement cooling - Is a form of high intensity convective cooling in which the heat transfer from the metal surface is increased by blasting the cooling air on the inner surface of the blade through high velocity jets. This is a commonly used cooling method for maintaining even temperature distribution on sections with high temperature gradients.

III. Film cooling - Is a type of cooling achieved by allowing the cooling air to flow through small holes in the blade wall and thus form an insulating layer between the hot gas stream and the walls of the blade (second blade in Figure 31). The film of cooling air protects the blade, but increases the profile losses around the blade due to disturbances in the gas flow path.

IV. Transpiration cooling - This cooling method is a further development of film cooling aiming at transpiration of the cooling air through the blade wall. This is achieved by increasing the number of holes and reducing their cross sectional area or by the use of porous materials having the capability of transpiring the cooling air (Third blade in Figure 31). The successful application of this method awaits further development of suitable porous materials and manufacturing blade techniques.

V. Water/steam cooling - Air has relatively low heat capacity limiting the heat transfer from the hot gases. Steam has almost twice as much heat capacity as air; while water has four times higher heat capacity as air. Nevertheless, the use of water for cooling of the gas turbine blades is problematic due to vibrations as the water is set into motion in combination and the eventual generation of bubbles deriving from local areas with boiling. Another problem is the high temperature gradients at the turbine blades. For these reasons water cooling is not used in modern gas turbines. The use of steam as cooling medium was introduced by GE in the mid 90s. This technique has gained increasing attention the last years and is further described in the gas turbine introductory section 5.1.

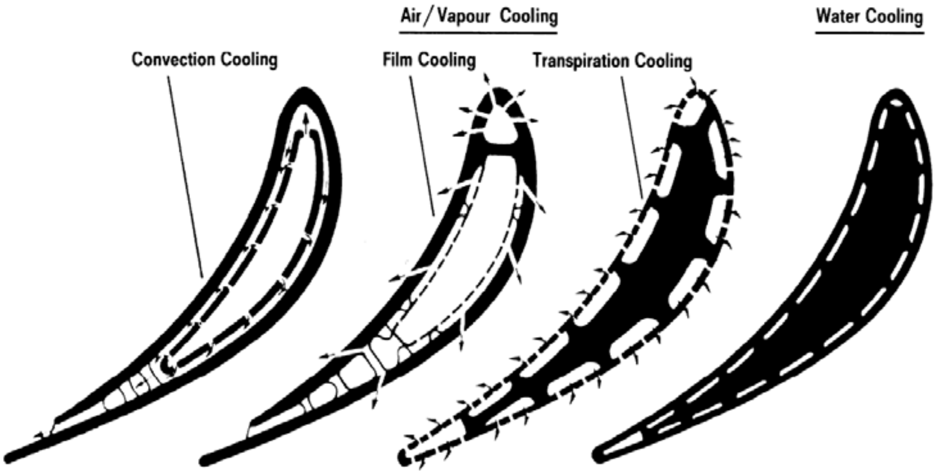


FIGURE 31 – VARIOUS METHODS OF TURBINE BLADE COOLING [31]

Generally in modern gas turbines a combination of several of the cooling principles presented above are utilized. Nevertheless, cooling of the turbine blades makes it possible to increase TIT resulting in elevated gas turbine efficiency, but there is a point where the gain from an increased TIT is outbalanced by the losses caused by the cooling fluid for a given level of cooling technology.

6 STEAM CYCLE

6.1 INTRODUCTION

Modern heavy duty gas turbines have thermal efficiencies around 35-40% in simple cycle configuration. Hence for electrical power production purposes gas turbines are generally used in combination with a steam bottoming cycle allowing for efficiencies near 60%. The exhaust gas leaving the gas turbine has a temperature within the range of 450-650˚C, depending on the gas turbine efficiency, TIT and pressure ratio [32] . This energy correspond to the fraction of the fuel energy not converted to power by the gas turbine and has thus the potential to raise steam to produce power by a steam turbine.

The steam cycle consists of the main units:

- Heat recovery steam alternator (HRSG)
- Steam turbine with alternator
- Cooling system
- Auxiliary system

In addition, depending on the fuel composition and the type of gas turbine combustor a selective catalytic reduction (SCR) system to control emissions of NOx is sometimes required to be integrated in the HRSG in order to fulfil environmental regulations. Since the SCR catalyst could be positioned in an optimal temperature window within the HRSG it offers an attractive solution for emission control.

A variety of complex configurations of the steam cycle are possible. However an important improvement of the steam cycle efficiency has been achieved by the increased firing temperature in modern GTs and thus a higher gas turbine outlet temperature (TOT). This has enabled the application of multiple pressure levels and reheat steam cycles. Consequently the triple-pressure reheated steam cycle has become the most common combined cycle layout in present days.

6.2 HEAT RECOVERY STEAM ALTERNATOR (HRSG)

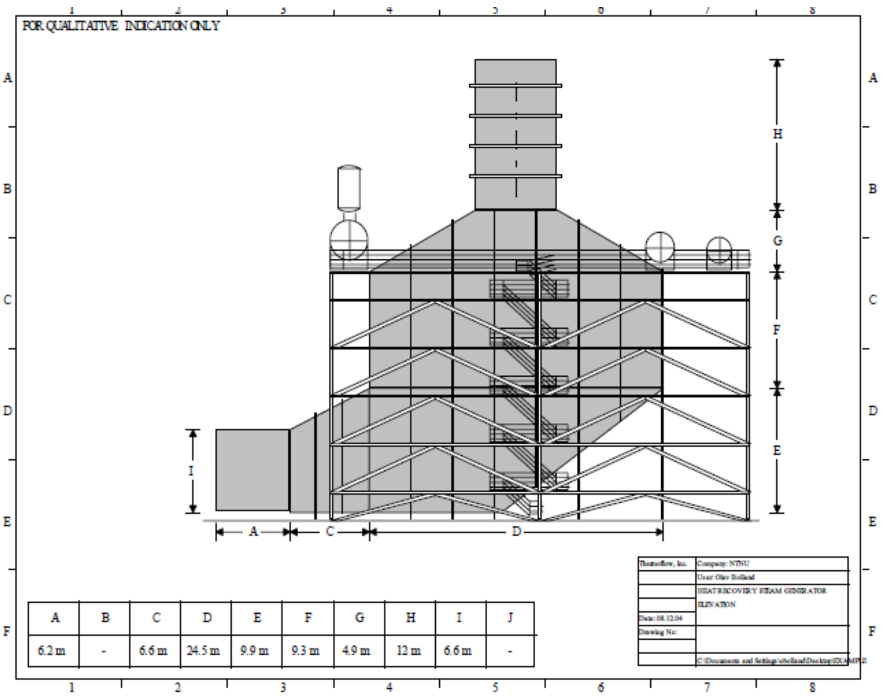
In combined cycle plants the HRSG is the connection between the gas topping cycle and the steam bottoming cycle. In this way, the steam conditions are defined by the steam turbine requirements and by the multifaceted trade-off between efficiency and cost of the plant. Given that the necessities at every plant site are exclusive to that site, each application is unique and requires customized HRSG design [31].

HRSG designs could be divided into two main categories: with and without supplementary firing. Supplementary firing could be applied to produce additional steam using the flue gas as combustion oxidizer, as it has a content of oxygen of about 12-13% by volume. However, supplementary firing is not thermodynamically optimal in modern combined cycle power stations intended for production of electricity only; hence for further reading please see reference [32].

The function of the HRSG is to recover the energy from the gas turbine exhaust and convert it into steam. The HRSG is an entirely convective heat exchanger package, consisting of tubes with pressurized water or steam on the inside and with the exhaust gas on the outside. The process is based on heating of water in an economizer, which is then supplied to a drum, slightly sub-cooled. The water leaving the drum is circulated through the evaporator and is returned to the drum as a water/steam mixture where the water is separated from the steam. The saturated steam leaving the drum is then supplied to the super-heater where it is heat-exchanged against the hottest exhaust gas leaving the gas turbine [32].

The pinch-point, i.e. the smallest temperature difference between the flue gas and the evaporator outlet temperature on the steam/water side, is an important factor defining the amount of steam being produced. Nevertheless, a smaller pinch-point gives a better efficiency but does also require a larger heat transferring area and thus a higher investment cost [32].

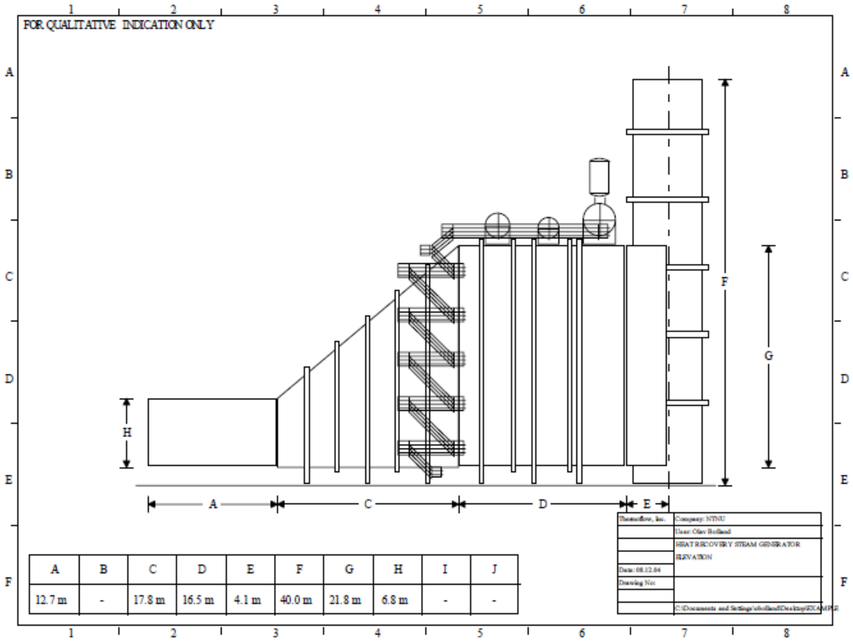
The HRSG could be built either as a vertical- or as a horizontal unit, depending on the flow direction of the exhaust gas trough the boiler. Vertical HRSGs are also known as forced-circulation systems because of their use of a pump to maintain circulation in the tubes of the evaporator section. In this type of boilers the tubes are positioned horizontally. It is though, possible to design vertical HRSGs with evaporators that do not use circulating pumps A vertical HRSG is shown in Figure 32 [31], [32].



A	B	C	D	E	F	G	H	I	J
6.2 m	-	6.6 m	24.5 m	9.9 m	9.3 m	4.9 m	12 m	6.6 m	-

FIGURE 32 – VERTICAL HRSG WITH DIMENSIONS RELEVANT FOR A 270 MW GAS TURBINE [31]

Horizontal type of HRSGs is usually called a natural-circulation HRSG, which means that the tube boundles circulating the water and the steam/water mixture are arranged in a way that the two phase mixture in the steam generating tubes is risen to the steam drum based on the difference in density and is replaced by water from the drum due to gravity. Figure 33 illustrates a horizontal HRSG. As it can be seen the exhaust gas from the turbine flows in horizontal direction. The difference between forced- and naturally circulated drum type HRSG are presented in Figure 34. Previously the vertical HRSG design offered several advantages relatively the horizontal layout such as lower foot print, smaller boiler volumes, and lower sensitivity to steam blockage in economizers during start-up while the main advantage for the horizontal HRSG was that it did not require any circulation pump. Today most of the disadvantages against horizontal boilers have been overcome and the same pinch-point could be achieved in the HP and IP- evaporator by both technologies. The exception is for large HRSGs having a very small pinch-point in the low pressure evaporator, a difference in steam performance is present [31], [32].

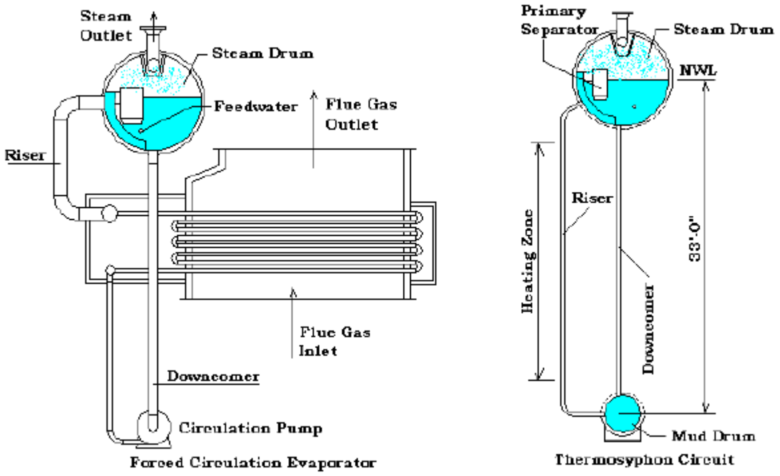


A	B	C	D	E	F	G	H	I	J
12.7 m	-	17.8 m	16.5 m	4.1 m	40.0 m	21.8 m	6.8 m	-	-

FIGURE 33 – HORIZONTAL HRSG WITH DIMENSIONS RELEVANT FOR A 270 MW GAS TURBINE [31]

It has become more common to operate combined cycles with frequent load changes and many start-ups and shut downs compared to other base load power units. However, many combined cycle power stations are still used as base load units. The HRSG designs described above are utilizing a steam drum in order to separate water and steam as well as for water preservation. A HRSG with a designed high pressure drum of a 100 bar and beyond enforce limitations on the cyclic operations required by modern combined cycle plants. Accordingly, both horizontal and vertical HRSGs are often built with a once-trough system, which means that the economizer, evaporator and super-heater are basically several tubes arranged in parallel, in which water enters at one end and steam leaves at the other end. The different sections of the tube i.e. economizer, evaporator and super-heater are characterized by different tube material. This design eliminates the need for the drum and the circulation pumps and thus provides flexibility for fast start-up and load changes [32].

To limit losses in the gas turbine power output and reduction in gas turbine efficiency it is important to maintain a low pressure drop on the exhaust gas side of the HRSG. At the same time in order to fulfil the requirement of an efficient HRSG the heat recovery rate has to be high, which require large heat transfer surfaces. These are two contradictory conditions, but to increase the heat transfer coefficient between the hot and cold side it is common to use tubes with fins on the hot side. The fins could be either solid or serrated as illustrated in Figure 35. In some applications tubes without fins (bare tubes) are preferred [31] , [32].



Forced Circulation Evaporator

Thermosyphon Circuit

FIGURE 34 – STEAM DRUM SYSTEM IN A HRSG. FORCED CIRCULATION (LEFT) AND NATURAL CIRCULATION (RIGHT) [31]

In addition to reducing the pinch-point a common way to improve the efficiency of the HRSG today is by using several pressure levels. Combined cycle with three pressure levels and reheat of the steam after the first expansion in the HP turbine has become normal practice. The use of several pressure levels also gives rise to optimization of the heat transfer because the super-heater and the economizers could be divided into different segments.

The removal of permanent gases (non-condensables) from the feedwater is essential in a steam system. The presence of oxygen in the feedwater could cause rapid corrosion in the tubes of the HRSG. Carbon dioxide will, if it dissolves in water, lower the pH value and form carbonic acid, leading to wastage of carbon steel constructional parts. Wastage is a corrosion phenomenon characterised by a large uniform corrosion rate. Removal of dissolved gases in the feedwater could be performed either by adding chemicals or by stripping. For large systems the most economical and thermally efficient option is by stripping better known as deaeration. Deaeration takes place either in the feedwater tank or in the condenser. Besides preventing corrosion, removal of non-condensable gases improves the heat transfer in the HRSG because gases in the feedwater will form a thermal blanket, which will reduce the heat transfer across the tube wall [31].

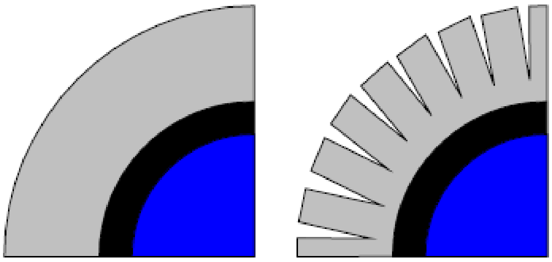


FIGURE 35 – SOLID TUBE FINS (LEFT) AND SERRATED TUBE FINS RESPECTIVELY (RIGHT) [31]

6.3 COOLING SYSTEM

Since the steam cycle is a closed cycle it is possible to expand the steam to a pressure that is below atmospheric. The lowest possible pressure is determined by the saturation pressure in the condenser, which is dependent on the temperature of the cooling medium. A lower temperature allows a lower pressure in the condenser which will result in a higher enthalpy drop over the LP turbine and will in turn result in a higher power output. The best cooling is generally achieved with direct water cooling using river or sea water, since water has a high specific thermal capacity and good heat transfer properties. In places where water is a shortage cooling by a wet cooling tower can be used and in areas with no water available the options are an air cooled condenser or a dry cooing tower [32].

6.4 STEAM TURBINE

The steam turbine is similar to the expander of a gas turbine but with the two main differences: the working fluid is steam and the steam turbine is not cooled. In a steam turbine high enthalpy (high pressure and temperature) steam is expanded in the nozzles (vanes) where the kinetic energy is increased at the expense of pressure, i.e. an increase in velocity due to decrease in pressure. The expansion of the steam is performed in several stages where one stage is a combination of nozzle and rotor.

The most usual configuration in combined cycle plant is to mount the gas turbine and the steam turbine on one single shaft, driving the same alternator. The alternator can either be placed between the gas turbine and the steam turbine, each turbine driving one end of the alternator, or the alternator is placed at one end, driven by both turbines from the same side. The first option with the alternator in between has several advantages such as the gas turbine could be operated independently of the steam turbine, continued plant operation during steam turbine failure (the produced steam is dumped in the condenser), shorter start-up times of the plant, etc [32].

7 EXISTING IGCC POWER STATIONS

7.1 INTRODUCTION

The Integrated Gasification Combined Cycle concept offers clear advantages in terms of environmental and economical considerations such as the gasification process contributes to feedstock and product flexibility and in combination with a combined cycle achieves higher efficiency compared to conventional thermal power stations. There are currently five commercial IGCC power stations in operation using coal as primary feedstock. An overview of these five is presented in sections 7.2-7.6. In addition the Nippon Petroleum Refining Co.'s Negishi Plant in Yokohama, Japan, is presented in chapter 7.7 as this is the largest IGCC plant in operation today and the first built with an F-class gas turbine from MHI, although it uses vacuum residual oil as its main fuel. In the following section 7.8 the Vresova IGCC plant situated in the Czech Republic is described. This plant was initially built as a natural gas plant, but was converted to a coal fed IGCC in 1996.

7.2 BUGGENUM IGCC POWER STATION

Nuon's Buggenom power station located in the Netherlands was the world's first IGCC plant of commercial size and was first built as a demonstration plant for a test period of 4 years in the beginning of 1994. The plant has been in commercial operation since 1998 and has accumulated approximately 80 000 hours of syngas operation [32], [34].

The plant configuration consists of a fully integrated high pressure ASU, coal pre-conditioning system, a dry pulverized coal fed oxygen blown gasifier from Shell as illustrated in Figure 36, a two step gas cooling system with recycle gas bringing the temperature of the syngas down to approximately 800 ˚C followed by a convective cooler where high- and intermediate pressure steam is generated, a fly ash removal section including a cyclone and a ceramic candle filter, a wet scrubbing unit for halogenides removal, sulphur removal and recovery featuring carbonyl sulphide/hydrocyanic acid (COS/HCN) hydrolysis and Claus plant, sulfinol wash, gas saturator and water cleanup system [32],[34],[35]. A simplified process flow diagram of the plant is shown in Figure 37.

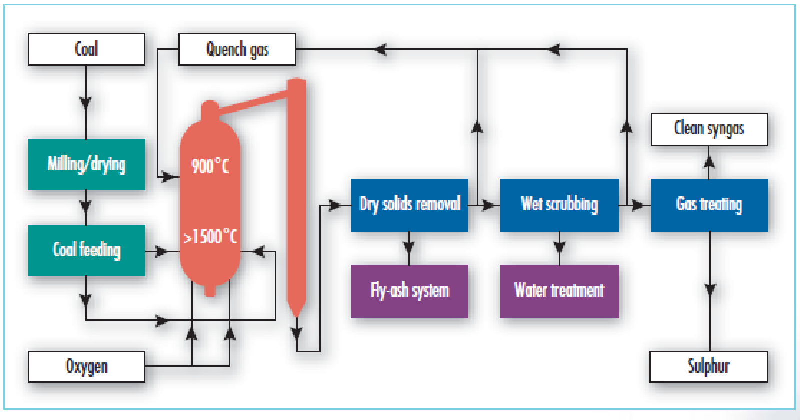


FIGURE 36 – SIMPLIFIED SCHEME OF THE SHELL COAL GASIFICATION PROCESS [35]

The power cycle is based on a Siemens V94.2 gas turbine, combined cycle with a net electrical output of 253 MW along with a turbine inlet temperature of 1060 ˚C at ISO conditions. The installed turbine was the first field test for Siemens syngas combustion system and the burner design has been adjusted to enable easy transition to different syngases having large variation in both composition and lower heating value (LHV). Since all air needed for the ASU is extracted downstream the GT compressor, waste nitrogen from the ASU is compressed and reintroduced to the gas turbine by mixing with the undiluted syngas. In this way the extracted air compensates the increased fuel mass flow, which is an effect of lower heating value of the syngas in comparison with natural gas. The low NOx emissions, 6-30 ppm(vol) (15%O_2) are controlled trough water saturation and nitrogen dilution from the ASU upstream the saturator. A typical syngas composition of the Buggenum plant is presented in Table 25, which reveals the high nitrogen content followed by the other main components hydrogen, carbon monoxide and water vapour. The H2/CO ratio is approximately 0.50 [32], [34].

TABLE 25 –TYPICAL SYNGAS COMPOSITION USED IN BUGGENOM (VOL%) [32]

H_2	12.3
CO	24.8
H_2O	19.1
N_2	42
Ar	0.6
CO_2	0.8
CH_4	0
O_2	0.4

After solving the initial problems with the gas turbine encountered during the test period the IGCC plant has had an overall availability of approximately 80% and an overall plant efficiency of 43% [32],[36].

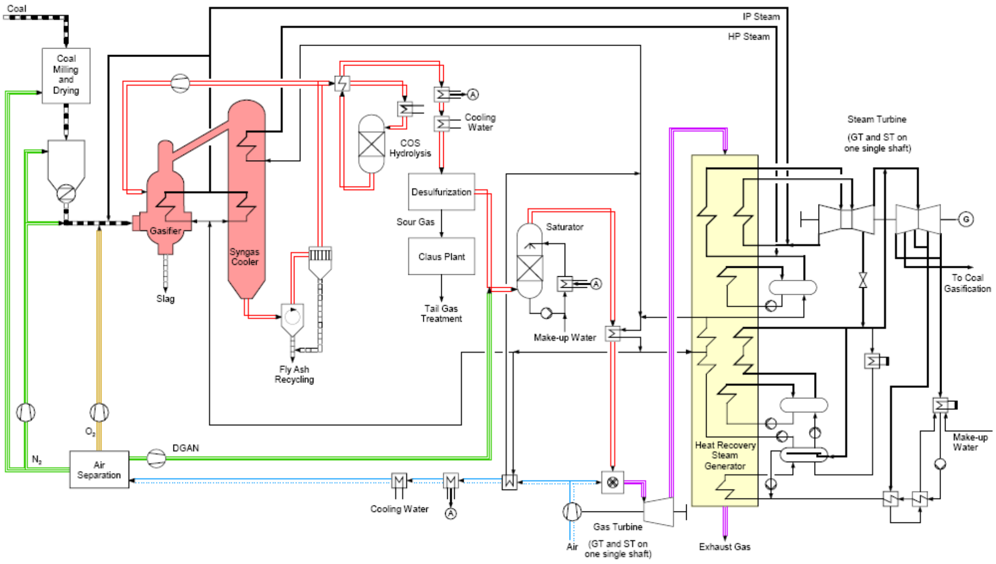


FIGURE 37 – SIMPLIFIED PROCESS FLOW DIAGRAM OF THE BUGGENUM IGCC PLANT [36]

In order to achieve CO_2 emission reductions targets, the plant has successfully been operated with co-gasification of biomass mounting up to 30 wt%. A demo CO_2 capture is currently being commissioned [37].

7.3 PUERTOLLANO IGCC POWER STATION

The Puertollano IGCC power station located in the central south part of Spain was launched as a demonstration project in 1992 and was selected as a target project by the European Commission under the funding of the THERMIE program to assure reliable clean coal technology for the future power generation [38].

The power station was taken into commercial operation in March 1998 and was designed with a targeted net electrical output of 300 MW and an electrical efficiency of 45% at ISO conditions. The plant is, like the Buggenum one, fully integrated with the ASU. It uses a coal blend based on sub-bituminous coal and petroleum coke with a normal weight proportion of 50:50 [38].

The IGCC power station, as illustrated in Figure 38, consists of the main units:

- ASU
- Coal pre-conditioning
- PRENFLO gasifier
- Gas cleaning
- Sulphur recovery (Claus)
- Gas conditioning
- Power island

The coal feed is first mixed with limestone to reduce the ash melting point and milled in two grinding roller mills. The coal is then fed to the drying system for achieving the specified 2% moisture for the gasifier feeding and then pressurized to 30 bars in a lock hopper system before entering the gasifier. Nitrogen from the ASU is used both for pressurization and as carrier gas. The gasifier is of entrained oxygen blown type also known as the PRENFLO technology, developed by Krupp Koppers. Coal dust is burnt together with oxygen, having a purity of 85% provided by the ASU, inside the gasifier where it is also mixed with steam produced in the gasifier itself. The operating pressure and temperature are 25 bar and 1200-1600 ˚C respectively. The ash, except or a small part entrained by the gas, is removed from the bottom of the gasifier in liquid form (slag). The raw gas leaving the gasifier is immediately cooled down to 800˚C (the point at which ash becomes solid) using recycled cool gas of a temperature of 235 ˚C. The syngas is then further cooled in two steps using convection boilers. In the first boiler the gas is cooled to 400 ˚C while producing HP steam (127 bars) and further cooled to 235 ˚C in the second boiler whilst IP steam is generated. The generated HP- and IP steam is sent to the HRSG for re-heating and expansion in the STs [39].

The syngas is filtered through ceramic candle filters, where the fly ash is retained. The syngas is then sent through the gas cleaning system consisting of wet scrubbing and desulphurization units. The desulphurization is accomplished in an absorption column using MDEA as the active alkaline solvent compound. Before the gas is sent to the gas turbine it is first saturated and diluted with waste nitrogen from the ASU. Since the oxygen content in the residual nitrogen is higher compared to the Buggenum plant, the admixing of waste nitrogen to the syngas takes place as close as possible to the gas turbine to minimize the risk of auto-ignition. The saturation and nitrogen dilution in combination with the low NOx burners in the GT results in a contamination level of NOx of less than 60 mg/Nm^3 (15% O_2) [32],[38].

The recovery of sulphur is completed in the Claus unit where conversion of H_2S to elementary sulphur is fulfilled [38].

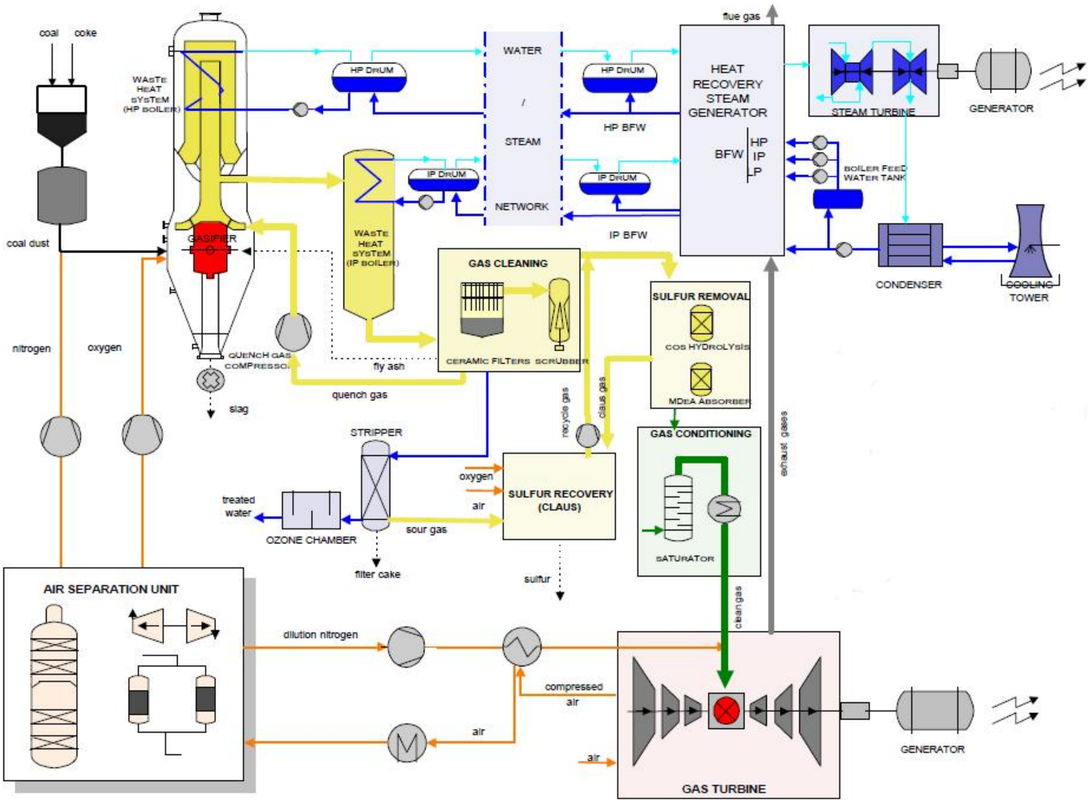


FIGURE 38 – SIMPLIFIED PROCESS FLOW DIAGRAM OF THE PUERTOLLANO IGCC PLANT [39]

The power cycle at Puertollano is similar to the Buggenum plant with a Siemens V94.3 gas turbine having two external hopper combustion chambers which allows for burning both natural gas and syngas. Natural gas is used during start-up and syngas for medium to high load operational regimes. The GT burners are designed with special syngas nozzles for diffusion flame combustion [32], [38].

The composition of a typical syngas used at Puertollano is presented in Table 26 on the next page. The hydrogen content is slightly lower than for the syngas used at Buggenum, hence the H2/CO value is also lower in this case, 0.36.

TABLE 26 – TYPICAL SYNGAS COMPOSITION USED IN PUERTOLLANO (VOL %) [32]

H_2	10.67
CO	29.24
H_2O	4.18
N_2	53.08
Ar	0.62
CO_2	1.89
CH_4	0.07
O_2	0.25

7.4 WABASH RIVER IGCC POWER STATION

The Wabash River IGCC Power station was selected 1991 by DOE as a Clean Coal Technology (CCT) demonstration project aiming at enhancing the utilization of coal as a major energy source. Construction of the gasification facility was started in 1993 and commercial operation began in the end of 1995. The demonstration period lasted until December 1999 [40].

The plant is located in Indiana, USA and has a net electrical power output of 262 MW and an overall thermal efficiency of approximately 40%. The gasification process used in Wabash River is Global Energy´s two stage E-GAS^{TM} technology featuring an oxygen-blown, entrained-flow, refractory lined gasifier with continuous slag removal. The plant was designed to use a range of local coals, but the sulphur content should not exceed 5.9%, nevertheless the main coal used was a bituminous Illinois Basin coal, but operation also included Petroleum coke. In contrary to Buggenum and Puertollano the ASU at Wabash River is not integrated with the power station [34], [40].

As shown in the process flow diagram in Figure 39, the coal is first slurried with water and fed to the first stage of the gasifier. Oxygen with a purity of 95% is provided from the ASU and the coal is partially combusted to maintain a temperature of 1370 ˚C. Raw fuel gas is produced as the coal chemically reacts with oxygen and steam. The melted ash at the bottom of the vessel is removed while the raw gas is further fed to the second gasification stage where the gas with additional coal/water slurry undergoes devolatilization, pyrolysis and partial gasification in order to enhance the raw gas heating value and cool it down as the evaporation of water and endothermic reactions cause the temperature to be reduced. The raw syngas exits the second stage of the gasifier at temperature of 1038 ˚C and is further cooled in a fire tube boiler, producing high pressure (110 bar) saturated steam [34], [40] .

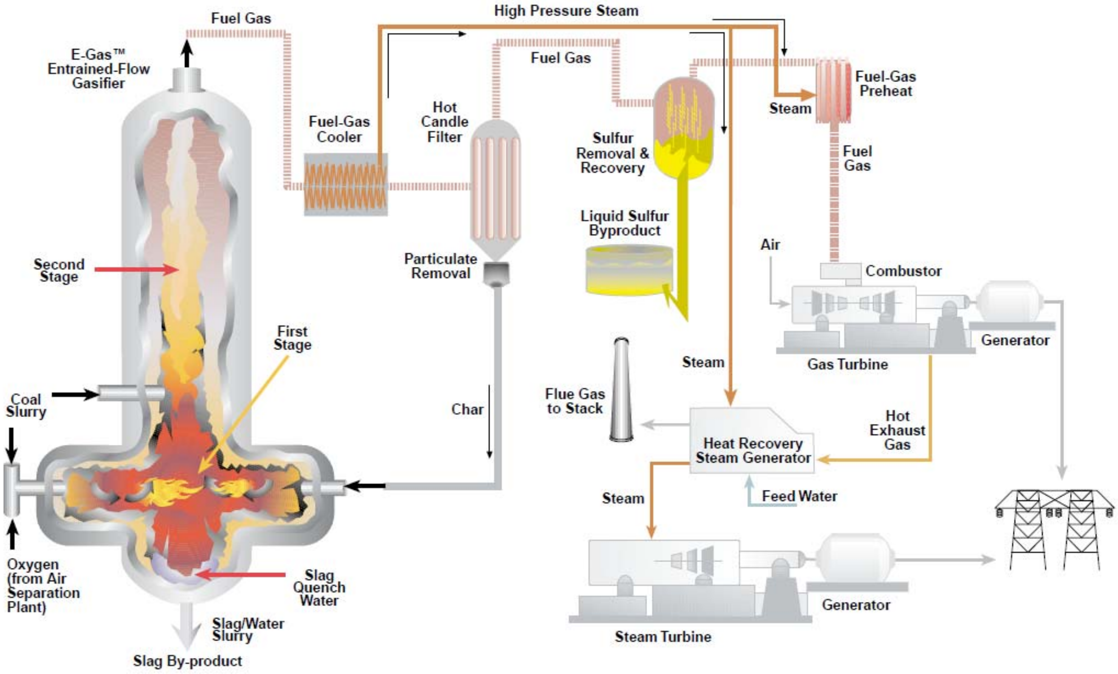


FIGURE 39 – SIMPLIFIED PROCESS FLOW DIAGRAM OF THE WABASH RIVER IGCC PLANT [40]

The gas cleanup system consists of a metallic candle filter system for the removal of fly ash and remaining char particles that are recycled back to the first stage of the gasifier for gasification of residual carbon. In order to achieve the low design values of SO_2 emissions high degree of H_2S and COS removal are required in the acid gas removal system (AGR Unit). Implying the necessity to hydrolyse COS. Before the removal of H_2S the sour gas is cooled to approximately 38 ˚C in several heat exchangers and then passed through the conventional H_2S removal unit consisting of an absorber column with MDEA solvent. Sulphur is recovered to a purity of 99.99% in a Claus plant [34], [40].

For NOx emission control purposes the syngas is pre-heated and saturated before it enters the power block, which is based on General Electric's MS 7001 FA gas turbine unit. The combustor allows for dual fuel operation, syngas and oil, where oil is used during start-up. The gas turbine allows for a firing temperature of 1222 ˚C, which is significantly higher than previously demonstrated in Buggenum. The installed GT at Wabash River was also the first F-class machine operating on syngas. The HRSG provided by Foster Wheeler is of single drum design with a maximum super-heating and re-heating temperature of 543˚C. The installed Westinghouse steam turbine was repowered to accept the increased steam flow rates and pressures related with combined cycle operation. The steam turbine had been previously de-rated as a necessity to reduce stack emissions due to reduced coal consumption.

Typical syngas compositions obtained at Wabash River IGCC power station is provided in Table 27 on the next page. It can be seen that irrespective of coal type the syngas consists mainly of hydrogen, carbon monoxide and carbon dioxide. The H_2/CO ratio is approximately 0.68 [34], [40].

TABLE 27 – TYPICAL SYNGAS COMPOSITION USED IN WABASH RIVER (VOL %) [34]

	Typical coal	Petroleum coke
H_2	34.4	33.2
CO	45.3	48.6
N_2	1.9	1.9
Ar	0.6	0.6
CO_2	15.8	15.4
CH_4	1.9	0.5

7.5 TAMPA ELECTRIC POLK POWER IGCC

The Polk power station in Tampa, Florida, USA was built and is operated by the Tampa Electric Company (TECO). The IGCC power station was partially funded under DOE’s clean coal technology program [41], [42].

The Tampa Polk power station consists of three units, the 250 MWe IGCC plant and two 180 MW simple cycle combustion turbines utilizing natural gas commercially operated since 2000 and 2002 respectively. The IGCC facility began commercial operation in 1996 and uses an oxygen-blown, entrained-flow, slurry-fed gasification technology licensed by Texaco. The IGCC plant has an outline similar to the previous presented IGCC projects, as shown in the simplified process flow diagram in Figure 40 [41],[42].

The non-integrated ASU separates air cryogenically into its main components nitrogen and oxygen (95% purity). The coal pre-handling unit consists of a wet rod mill in which the coal feed, medium bituminous coal (the gasifier is able to handle other feedstocks such as petroleum coke or biomass), is crushed and mixed with recycled water, fines and ground into a viscous slurry. The coal slurry containing about 60-70% solids is then pumped to the gasifier by means of high pressure charge pumps. The gasification unit is designed to handle about 2200 tons of coal (dry basis) per day. In the gasifier process feed injector the coal/water slurry is mixed with the oxygen. The water in the slurry acts as a temperature moderator and as a hydrogen source in the gasification process. The gasifier operates at a temperature of 1315-1430 °C and produces a raw syngas mainly composed of hydrogen, carbon monoxide and carbon dioxide. The gasifier is designed to achieve a carbon conversion rate above 95% in one single pass. The raw syngas leaving the reactor is first cooled in a radiant syngas cooler producing high pressure steam and then further cooled in two parallel fire tube convective syngas coolers where more high pressure steam is generated. The syngas leaves the convective cooler at a temperature of approximately 430 °C and flows to a scrubbing unit, where fine particles and halogenides are removed with water. The scrubbed gas enters the COS hydrolysis section where COS is converted to H_2S, the latter compound being more easily removed from the syngas. The syngas then enters various heat exchangers in the low temperature gas cooling section where the heat is recovered for preheating clean syngas and heating steam turbine condensate. Before the gas enters the final cold gas cleanup it is cooled to 40 °C in a small trim cooler [41], [42].

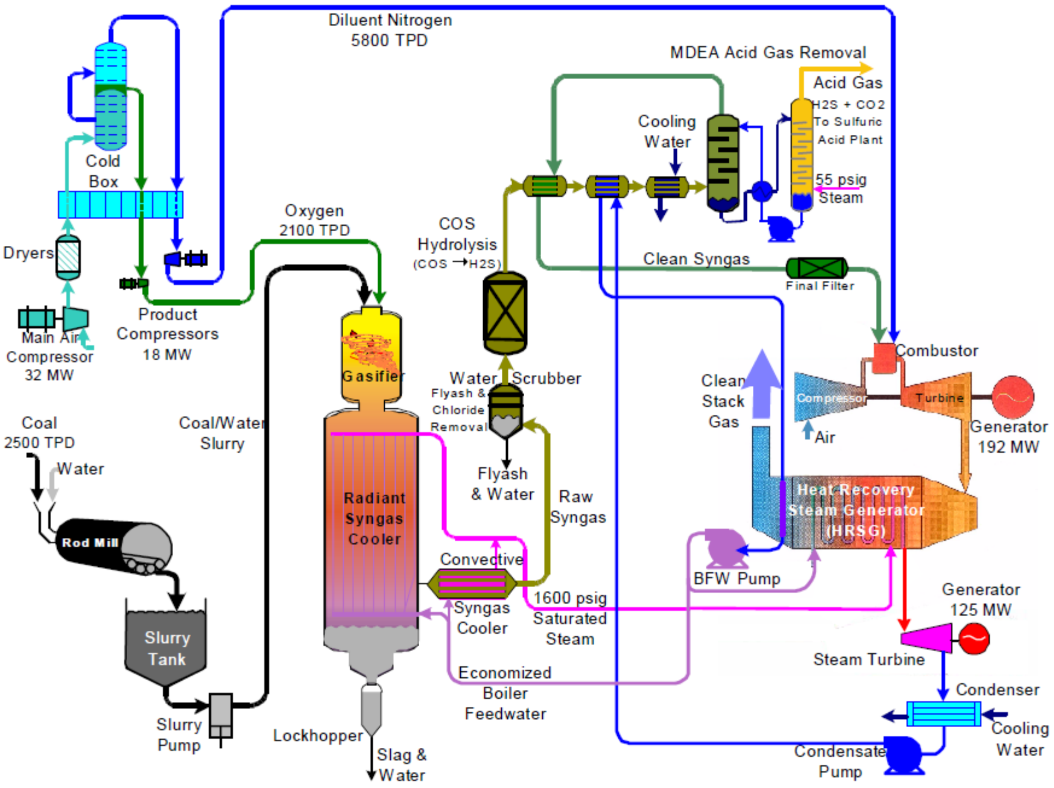


FIGURE 40 – SIMPLIFIED PROCESS FLOW DIAGRAM OF THE TAMPA POLK IGCC PLANT [41]

The cold gas cleaning up system also known as the acid gas removal section of the plant consists of a traditional amine scrubber absorber, which removes sulphur from the syngas by a circulating MDEA solution. The clean syngas is reheated, filtered, saturated and delivered to the gas turbine combustor. A typical syngas composition used in Tampa Polk IGCC power station is given in Table 28. The removed sulphur together with the sour gas from the process water treatment unit is sent to the Claus sulphur plant for recovery of elemental sulphur. The Claus plant produces steam and 200 tons of 98% sulphuric acid, which has a market in the phosphate industry in the central Florida area. Most of the ungasified carbon separated from the slag and water in the lockhopper at the radiant syngas cooler exit are recycled to the slurry preparation section. This slurry is saleable for blasting, grit, roofing tiles and construction building products [41], [42].

Since all of the water used in the gasification process is cleaned and recycled there is no need for discharging process water from the gasification system. The chlorides build up in the process water system is prevented by letting the water pass through a brine concentration unit where the chlorides are removed in the form of marketable salts [41], [42].

The power block at Tampa Polk is a General Electric combined cycle which has been slightly modified for IGCC. The gas turbine is a GE 7FA (GE MS7001FA) machine, adapted for syngas and distillate fuel combustion. The low sulphur fuel oil is used for establishment of syngas production from the gasification plant. The gas turbine generates 192

MWe (gross) on syngas with N_2 dilution or 160 MWe (gross) on distillate fuel. The TOT is approximately 570 °C. GT waste heat is recovered for boiler feed water- and steam production in a conventional HRSG. In order to abate NOx emissions and lower peak-flame temperatures the maximum amount of nitrogen from the ASU is injected after moisturizing the syngas. During operation with back-up distillate fuel oil, NOx emissions are abated by water injection [41], [42], [43].

The HRSG has medium and high pressure steam production and all superheating and reheating to a temperature of about 540°C, is carried out in the HRSG before the steam is delivered to the ST.

The ST is a double-flow reheat turbine with low pressure crossover extraction with a nominal production of 123 MWe (gross) [41], [42].

TABLE 28 – TYPICAL SYNGAS COMPOSITION USED IN TAMPA POLK (VOL %) [34]

	Typical coal	Petroleum coke
H_2	37.95	34.02
CO	44.06	48.29
N_2 + others	2.38	3.08
Ar	0.88	1
CO_2	14.73	13.61

7.6 NAKOSO IGCC POWER STATION

The Nakoso power station located in Nakoso, Japan, is a 250 MW IGCC demonstration project which have completed a series of tests since the start in 2007. The plant logged more than 2000 hours of long term continuous operation at rate load at the end of year 2008. The aim is to build a commercial IGCC with twice the capacity of the demonstration plant with a targeted earliest start of operation in 2014 [44].

The demonstration IGCC power station uses an air-blown, dry-feed, entrained-flow gasifier which was adopted as it was expected to have higher efficiency, capacity and reliability than the oxygen-blown gasifiers originally developed for the application to chemical plants and used in IGCC applications in Europe and USA. The air-blown gasifier at Nakoso developed by MHI industries, has a two stage configuration including a combustor and redactor, as illustrated in Figure 41, which enables smooth molten slag discharge and high carbon conversion rate at the same time [45],[46].

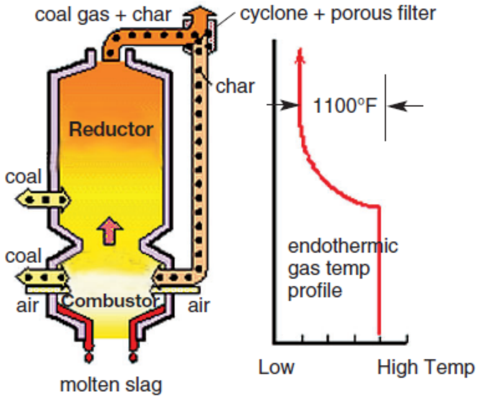


FIGURE 41 – MHI TWO-STAGE AIR-BLOWN GASIFIER [47]

As shown in the simplified process flow scheme in Figure 42, the IGCC plant is integrated in similar to so-called partial integration of oxygen-blown systems. This means that part of the oxidizer used for gasification is extracted from the gas turbine compressor and the rest from an auxiliary compressor. However the small ASU in the Nakoso plant is included in the gasification system to provide nitrogen, used as an inert pressurized gas for coal transport. The ASU is 75-80% smaller than a corresponding unit typically used for oxygen-blown gasifier where the ASU is consuming about 10% of the gross plant power output [45], [46].

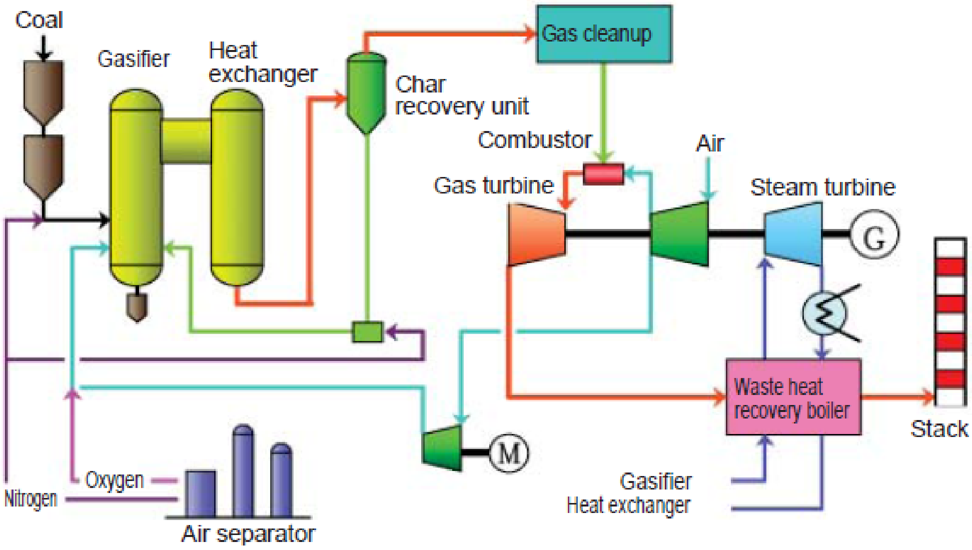


FIGURE 42 – SIMPLIFIED PROCESS FLOW DIAGRAM OF THE NIKOSO IGCC DEMONSTRATION PLANT [47]

The oxygen by-product from the ASU is mixed with the extracted air from the GT compressor and supplied as an enriched air stream to the gasifier. The gasification system allows for the use of a wide variety of coal including low-grade coal such as high-moisture, sub-bituminous. The pulverized coal feed and recycled char along with the enriched air are delivered to the first stage of the gasifier, the combustion chamber, under relatively high air/coal ratio. A mixture of gases is generated consisting of mainly carbon monoxide and carbon dioxide during both full and partial oxidation. During the intense heating of the hydrocarbons water vapour is generated, which is needed for the water shift reactions in the second stage. The temperature inside the combustor is kept very high enabling the coal ash to separate from the gas stream in the form of molten slag. The molten slag flows down to the bottom of the combustion chamber, where it is quenched with water. The slag, containing less than 0.2% unburned carbon and virtually free from trace elements has a potential commercial application in road paving materials or as aggregate concrete [45], [46].

The oxygen enriched air fed do the first stage of the gasifier does not only ensure operational flexibility, but does also increase the heating value of the syngas at last delivered to the gas turbine.

After leaving the first stage the gas enters stage two, the reductor, where more coal is fed to the hot gas stream flowing upwards the upper path, but no additional air is supplied. In this section the endothermic gasification reactions take place, where the necessary heat is provided by the hot gas stream from the combustor. The raw hot gas produced by the gasifier at a temperature of about 1200 °C is then cooled down in the integrated gas-cooler/steam alternator and char removal system. The reduction in temperature ensures that the solid particles containing char or ash solidify. This prevents plugging and fouling of downstream heat exchanger surfaces. The char trapped at the cyclones and ceramic filter units are recycled back to the combustor thus allowing for very high carbon conversion rates, above 99.8%. The steam generated during the raw gas cooling process is sent to the HRSG for superheating and expansion in the ST. The syngas leaving the combined char/dust removal and initial cooling unit is then further cooled in several heat exchangers against clean syngas fuel on its way to the gas turbine. Before ending up at the combustor inlet the fully cooled syngas is passed through a conventional COS converter system and the chemical absorber unit for H_2S removal using MDEA solvent. The sulphur recovery system consists of a limestone-gypsum unit converting the H_2S in the usable by-product Gypsum, widely used as building material in Japan. The clean syngas is reheated against the hot raw syngas and delivered to the specially designed syngas fuel nozzles downstream the gas turbine fuel control valve [45], [46].

The power block at Nakoso consists of a modified Mitsubishi M701DA gas turbine with air extraction to the gasifier. The TIT is around 1200 °C, and with an electrical output of 142 MW at ISO conditions. The GT combustors have a basic diffusion flame design with dual fuel capability allowing for operation on syngas and to burn kerosene during start-up [45], [46].

The bottoming cycle consists of a conventional HRSG with a condensing oversized steam turbine. The steam turbine is rated at more than 110 MW in order to make use of the steam generated by the gasifier. The plant uses seawater for cooling purposes and has a net thermal efficiency of 42% (LHV basis). It has been indicated that with an F-class gas turbine such as the M701F, the same plant would be able to produce 450 MW (50 Hz) and achieve an efficiency of 45-46% (LHV). With a G-class gas turbine, which has been assumed for the commercial IGCC power station the corresponding electrical output is predicted to be 650 MW (50 Hz) and efficiencies in the range of 48-50% are expected [46].

A typical syngas composition used in Nakoso IGCC power station is shown in Table 29, revealing the high nitrogen content and a H2/CO ratio similar to Puertollano, about 0.34 [34] .

TABLE 29 – TYPICAL SYNGAS COMPOSITION USED IN NAKOSO (VOL %) [34]

H_2	10.5
CO	30.5
N_2 + others	55.5
CO_2	2.8
CH_4	0.07

7.7 NEGISHI IGCC POWER STATION

Contrary to the other plants presented in this report Negishi IGCC power station located outside Yokohama is not fed with coal. The Negishi IGCC built and owned by the Nippon Petroleum Refining Company is gasifying residual oil. The plant was put into commercial operation in 2003 and was the first IGCC in Japan. The plant has a net electrical output of 342 MW and is many times considered as the world's largest IGCC currently in operation [48].

The Negishi plant has, as presented in Figure 43, an ASU providing oxygen of amount of 2300 tons/day. The ASU has no integration with gas turbine on the air side. The gasification section consists of two General Electric Energy oil gasifiers with integrated water quench. The gasifier is designed to use a variety of fuels but the main feedstock asphalt is supplied directly from an upstream unit. The operational pressure and temperature of the gasifier is 70barg and 1300 °C respectively. The carbon conversion rate is approximately 99.5%. Unconverted carbon together with ash, which is rich in vanadium, is removed from the gas in the quench and in the subsequent syngas scrubber. The unconverted carbon is recycled back to the gasifier by extracting it from the soot water and mixing it with the gasifier feed. The syngas leaving the quench section of the gasifier is cooled down to about 240 °C and further cleaned in the acid gas removal section, consisting of a COS/HCN hydrolysis followed by an ammonia scrubber [48], [49], [50].

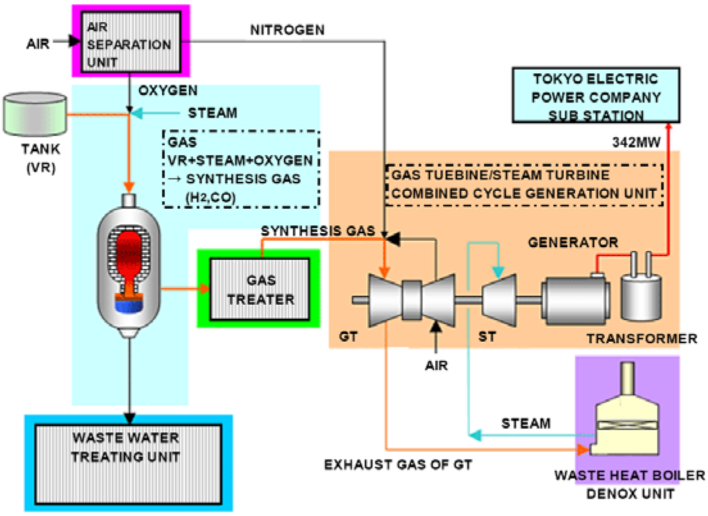


FIGURE 43 – SIMPLIFIED PROCESS FLOW DIAGRAM OF THE NEGISHI IGCC POWER STATION [49]

The desulphurization is completed by a conventional amine absorption column, leaving the syngas with a residual content of sulphur of about 15 ppmv. The recovery of sulphur from the sour gas is achieved in the dedicated oxygen-blown Claus unit. Before the gas is discharged to the atmosphere the Claus tail gas is hydrogenated and washed in a SCOT unit. In this way a sulphur recovery of 99.8% is attained [48].

The power block in Negishi is based on Mitsubishi 701F gas turbine with HRSG and steam turbine. The syngas is diluted with nitrogen for NOx reduction purposes. Similarly to the gas turbine at the Nikoso IGCC plant the gas turbine combustor has dual fuel capabilities i.e. kerosene may be used during start up. In order to limit NOx and SOx to 2 ppm the HRSG his equipped with a selective catalytic reduction (SCR) stage [48].

7.8 VRESOVA IGCC POWER STATION

The Vresova IGCC power station located in the Czech Republic is many times overlooked when lists considering currently operating coal fired IGCC units are compiled. This is probably due to the fact that it was not originally designed as an IGCC. The 400 MWe (gross) plant is operated by Sokolov Coal Corporation (SUAS) and has been the world's largest coal fired IGCC during the last 14 years. The Vresova plant has been an important centre for demonstration of clean coal technology and a continuous development of the plant has been undertaken [51], [52]

The IGCC power station consists of twenty-six Lurgi type fixed bed gasifiers, using brown coal from SUAS own local mines and a recent installed liquid gasifier from Siemens, (formerly Future Energy) which provides additional syngas from tars produced by the fixed-bed gasifiers. However, the possibility to replace the fixed bed gasifiers with more modern technology has been investigated; one of the options that have been considered is the High Temperature Winkler (HTW) process, which is based on the fluidized bed technology. A block-flow diagram of the IGCC power station is provided in Figure 44 [51], [52].

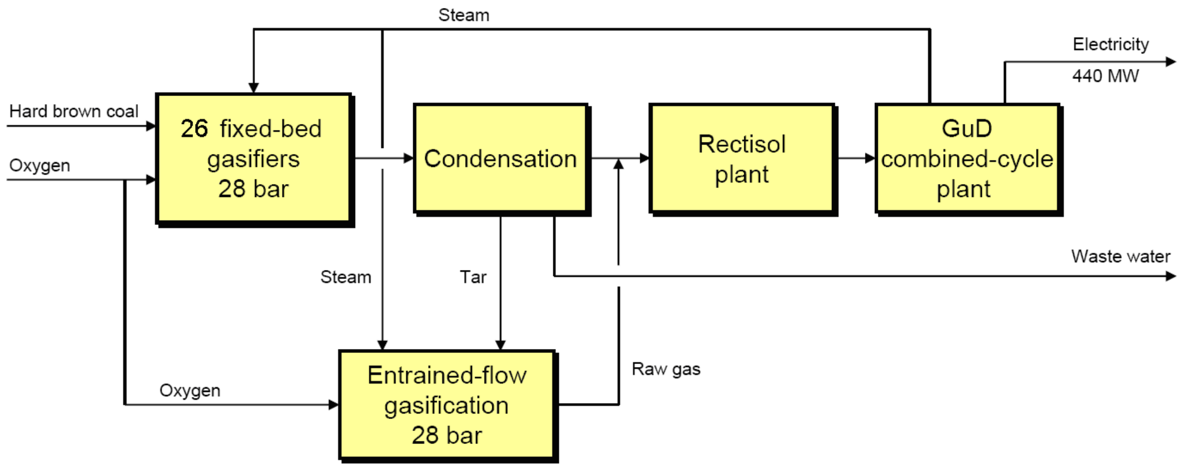


FIGURE 44 – BLOCK FLOW DIAGRAM OF THE VRESOVA IGCC POWER STATION [34]

The existing 26 water-jacketed fixed-bed gasifiers are arranged in counter-current arrangement with gasification occurring in several stages. The coal is prepared to fine particles having size of 3 to 25 mm, evenly distributed and introduced at the top of the gasifier. The oxygen and steam are introduced into the gasifier vessel by means of lances mounted at the sidewalls at the height where combustion and slag formation occur. The coal descends and is transformed into char before it enters the gasification zone. Below this zone, any residual carbon is oxidized and the ash gets molten. The collected slag in the slag pool is removed by an opening in the bottom of the gasifier vessel. The slag flows then into a quench chamber followed by a lock hopper. The pressure difference between the quench chamber and the gasifier regulates the flow of slag between the two vessels. The raw gas exits through an opening near the gasifier top with a temperature of approximately 570 °C and passes into a water quench vessel and a boiler feed water preheater in which the gas is pre-cooled to about 200 °C. Entrained solids and soluble compounds mixed with the liquid at the gasifier exit are sent to a gas-liquor separation unit. Soluble compounds such as tars, oils and naphtha are recovered and recycled to the top of the gasifier and/or reinjected at the lances [52], [53].

The raw gas exiting the gasifier is further cooled to 30 °C before it enters the Rectisol unit for removal of various impurities. The Rectisol process consists of an initial wash of the gas by a mixture of water and hydrocarbons removing crude naphtha, ammonia, HCN and any remaining ash that could have abrasive effects in the following process. The gas is then washed with cold methanol during which H_2S and COS is removed. The total sulphur content of the clean gas is approximately 13 mg/m^3. The clean syngas leaving the Rectisol unit has a pressure of 2.1-2.5 bar and is compressed before delivered to the gas turbine [52].

The sulphur recovery consists of a wet sulphuric acid (WSA) plant where the sulphur compounds are burnt and converted to SO_3 in a catalytic process. The sulphur trioxide is then reacted with water vapour for producing H_2SO_4 that condenses as a 95% purity azeotropic sulphuric acid, a marketable product.

The power block at Vresova consists of two identical combined cycles composed of [52]:

- A Frame 9E (9171E) gas turbine, made and supplied by EGT under license of General Electric.
- A double pressure HRSG without supplementary firing and a steam turbine, supplied by ABB.

Syngas is used as primary fuel in the gas turbine with natural gas as back-up fuel. In order to reduce flame temperature steam injection is utilized. The steam cycle is closely integrated with the rest of the plant, thus providing the possibility to both extract and supply steam to the HRSG, which results in high flexibility and reliability. The thermal efficiency of the GT is 34.8% while the overall combined cycle efficiency is 50.5% (without district heating) [52].

7.9 SUMMARY

TABLE 30 – RESUMED PRINCIPLE CHARACTERISTICS OF THE PRESENTED IGCC POWER STATIONS [34]

	Buggenum	**Puertollano**	**Wabash River**	**Polk Power**	**Nakoso**	**Negishi**	**Vresova**
Owner	NUON	ELCOGAS	Cinergy/Conoco Philips	Tampa Electric	Clean Coal Power R&D Co.	Nippon Petroleum Refining Co.	Sokolovská Uhelná
Location	Netherlands	Spain	Indiana, U.S.	Florida, U.S.	Japan	Japan	Czech Republic
Gasifier	Shell	Prenflo	Conoco Philips	GE Energy-Chevron Texaco	Pilot Plant	GE Energy-Chevron Texaco	Lurgi & FE
GT	Siemens V94.2	Siemens V94.2	GE MS7001FA	GE MS7001FA	Mitsubishi M 701DA	Mitsubishi M 701F	GE 9E
Fuel Feedstock	Bit. Coal	Bit. Coal/Pet. Coke	Bit. Coal/Pet. Coke	Bit. Coal/Pet. Coke	Pulverized coal	Refinery Residue (Asphalt)	Brown coal

TABLE 31 – RESUMED PERFORMANCE CHARACTERISTICS OF THE PRESENTED IGCC POWER STATIONS [34]

	Buggenum	**Puertollano**	**Wabash River**	**Polk Power**	**Nakoso**	**Negishi**	**Vresova**
Power [MW]	253	300	262	250	250	342	400
η_{net} (LHV) [%]	43.2	45	n.a.	n.a.	42.5	n.a.	50.5
η_{net} (HHV) [%]	41.4	41.5	39.7	37.5	40.5	46	n.a.
ISO TG Power [MW]	168	200/182.3[1]	171/192[1]	171	130	270	n.a.
TIT [˚C]	1100	1120	n.a.	n.a.	1200	1350	n.a.
Sulphur Recovery [%]	99	99	99	98	n.a.	99.8	n.a.

[1] At site conditions

8 CONCLUSIONS

From the literature study completed, an overview of the existing technologies concerning air separation, gasification, gas cleaning, gas turbine, and steam cycle has been covered. The most important findings are:

ASU

Cryogenic distillation of air is currently the most preferred technology for the supply of oxygen and other industrial gases to large facilities such as IGCC power stations. The main drawback with this technology is the high power consumption hence optimizing the integration of the ASU with the gasification unit and the gas turbine has a significant importance for efficiency improvement and increased power production. The main integration options of the ASU with the gas turbine are: no integration, nitrogen injection from the ASU, and full gas turbine air and nitrogen injection integration. The feasibility and potential degree of integration of an ASU with the gas turbine is determined by the design and performance characteristics of the gas turbine unit. However, the ASU process could be customized to the integration needs of the gas turbine and IGCC power station considered.

ITM are foreseen as a promising alternative to cryogenic ASU for the production of high-purity and large-quantity oxygen. The technology does though have limitations regarding production of pure by-products and liquids for storage and backup. The technology is still in the early stages of development, but the potential of improvement is extensive.

GASIFICATION

There are numerous types of gasifiers used with different properties, such as operation, - pressure and temperature, and imbedded features that lead to variation in outlet gas composition.

- For IGCC applications, the selection of a gasifier depends on different criteria such as:
    - Application
        - Hydrogen production
        - Electricity production
        - Both
    - Feedstock type
    - Cost of electricity
    - Efficiency
    - CO_2 capture rate
    - Emission issues

In IGCC power stations with electricity generation as the final goal, the downstream components e.g. gas turbine has a major impact on the selection of gasifier type.

GAS CLEANING

Gas cleaning and syngas conversion technologies are advancing rapidly these days and new methods are being developed. New solvents and also new catalysts for cleaning and conversion of gas are introduced. Selection of a proper process for separation of H_2S and CO_2 depends on some key parameters and demands.

In H_2S and CO_2 removal, selection of amine solutions, water washing or adsorption depends on the desired composition of H_2S and CO_2 in the outlet gas as well as criteria concerning corrosion and investment costs. Physical solvents may be efficient for acid gas removal, but it must be considered that separation potential of these solvents is lower than chemical solvents. On the other hand chemical solvents show a higher energy demand for solvent regeneration. Trade-off between the types of separation process must be considered in two economical and operational aspects.

In gas conversion, number of reactors, type of catalyst and type of adsorber in SEWGS process are the major key points which affect the process efficiency directly or indirectly. The number of reactors affects the cost because more catalyst is required and also temperature control will be more complex.

Overall, gas cleaning and conversion for the sake of CO_2 -capture must be done in a way that the configuration of unit operations that is selected offer the best trade-off between the lowest cost and highest performance of the system.

GAS TURBINE

In order to achieve significantly higher efficiency, reduced emissions and lower cost for operation of GTs on hydrogen rich fuel, advances in combustion technology are required. In this context the adaptation of combustion technologies already used for burning natural gas, in particular, lean premix technology is of major interest. The lean premix technology allows for the adiabatic combustion temperature to be lowered while the NOx emissions could be maintained at acceptable levels. In this way the expensive dilution by nitrogen and steam could be avoided and less complex layout of the IGCC power station could be attained, which reduces both installation and operational costs.

As for conventional natural gas fuelled gas turbines the improvement in performance for syngas fuelled gas turbines by increased pressure-ratio and a slightly higher mass throughput than for current F-class gas turbines have a favourable effect on the overall IGCC process efficiency. The increased efficiency will result in a decreased cost of electricity since the cost for the advanced turbine and the increased O&M and fuel costs due to increased coal throughput are offset the additional power output.

STEAM CYCLE

The steam cycle in an IGCC power station consist of a conventional HRSG, steam turbine with alternator, cooling system and axillaries. The main difference between conventional NGCC and an IGCC power station is the high interaction between the steam cycle and the upstream gas cleaning units and the gasifier. This interaction causes the plant to be more sensitive to operational variables such as part load operation. However, their high complexity does also provide for higher efficiencies and lower emissions compared to conventional PC plants which in turn make them more economically attractive.

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