A COMPARATIVE ENVIRONMENTAL ANALYSIS OF FOSSIL FUEL ELECTRICITY GENERATION OPTIONS FOR SOUTH AFRICA

BY

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THIS STUDY IS DEDICATED TO MY PARENTS

Whom have always been there to support me in all my endeavours. May God bless bless them with improved health for the years to come.

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AFBC:	Atmospheric Fluidised Bed Combustion
ASU:	Air Separation Unit
BFBC:	Bubbling Fluidised Bed Combustion
CCGT:	Combined Cycle Gas Turbine
CDM:	Clean Development Mechanism
CFBC:	Circulating Fluidised Bed Combustion
CHP:	Combined Heat and Power
DME:	Department of Minerals and Energy
EPA:	Environmental Protection Agency
EPRI:	Electric Power Research Institute
ESP:	Electrostatic Precipitators
FBC:	Fluidised Bed Combustion
FGD:	Flue Gas Desulphurisation
GHG:	Greenhouse Gas
HRSG:	Heat Recovery Steam Generator
IGCC:	Integrated Gasification Combined Cycle
NER:	National Electricity Regulator
PF:	Pulverised Fuel
PFBC:	Pressurised Fluidised Bed Combustion
SCR:	Selective Catalytic Reduction
UNFCCC:	United Nations Framework Convention on Climate Change
ZLED:	Zero Liquid Effluent Discharge

SUMMARY

The increased demand for electricity in South Africa is expected to exceed supply between 2004 and 2007. Electricity supply options in the country would be further complicated by the fact that older power stations would reach the end of their design life beyond the year 2025. In light of this and considering the long lead times required for the commissioning of new plants, new power supply options need to be proactively investigated.

The environmental impacts associated with coal-fired generation of electricity have resulted in increased global concern over the past decade. To reduce these impacts, new technologies have been identified to help provide electricity from fossil fuels. The alternatives considered are gas-fired generation technologies and the Integrated Gasification Combined Cycle (IGCC).

This study attempts to document and understand the environmental aspects related to gas-fired and IGCC electricity generation and evaluate their advantages in comparison to conventional pulverised coal fired power generation. The options that could be utilised to make fossil fuel electricity generation more environmentally friendly, whilst remaining economically feasible, were also evaluated.

Gas-fired electricity generation is extremely successful as electricity generation systems in the world due to inherently low levels of emissions, high efficiencies, fuel flexibility and reduced demand on finite resources. Associated benefits of a Combined Cycle Gas Turbine (CCGT) are lower operating costs due to the reduced water consumption, smaller equipment size and a reduction in the wastewater that has to be treated before being returned to the environment. A CCGT plant requires less cooling water and can be located on a smaller area than a conventional Pulverised Fuel (PF) power station of the same capacity. All these factors reduce the burden on the environment.

A CCGT also employs processes that utilises the energy of the fuel more efficiently, with the current efficiencies approaching 60%. Instead of simply being discharged into the atmosphere, the gas turbines' exhaust gas heat is used to produce additional output in combination with a Heat Recovery Steam Generator (HRSG) and a steam turbine. Furthermore, as finite resources become increasingly scarce and energy has to be used as wisely as possible, generating electricity economically and in an ecologically sound manner is of the utmost importance. The clean, reliable operation of gas-fired generation systems with significantly reduced noise levels and their compact design makes their operation feasible in heavily populated areas, where electricity is needed most. At the same time, energy can be consumed in whatever form needed, i.e. as electricity, heat or steam.

The dependence of the South African economy on cheap coal ensures that it will remain a vital component of future electricity generation options in the country. This dominance of coal-fired generation in the country is responsible for South Africa's title as the largest generator of carbon dioxide (CO_2) emissions on the continent and the country could possibly be requested to reduce its CO_2 emissions at the next international meeting of signatories to the Kyoto Protocol.

Carbon dioxide emissions can be reduced by utilising gas-fired generation technologies. However, the uncertainty and costs associated with natural gas in South Africa hampers the implementation of this technology. There are currently a number of initiatives surrounding the development of natural gas in the country, viz. the Pande and Temane projects in Mozambique and the Kudu project in Namibia, and this is likely to positively influence the choice of fuel utilised for electricity generation in the future. The economic viability of these projects would be further enhanced through the obtaining of Clean Development Mechanism (CDM) credits for greenhouse gases (GHG) emissions reduction.

Alternatively, more efficient methods of generating electricity from coal must be developed and implemented. IGCC is capable of achieving this because of the high efficiencies associated with the combined cycle component of the technology. These higher efficiencies result in reduced emissions to the atmosphere for an equivalent unit of electricity generated from a PF station.

An IGCC system can be successful in South Africa in that it combines the benefits of utilising gas-fired electricity generation systems whilst utilising economically feasible fuel, i.e. coal. IGCC systems can economically meet strict air pollution emission standards, produce water effluent within environmental limits, produce an environmentally benign slag, with good potential as a saleable by-product, and recover a valuable sulphur commodity by-product. Life-cycle analyses performed on IGCC power plants have identified CO_2 release and natural resource depletion as their most significant positive lifecycle impacts, which testifies to the IGCC's low pollutant releases and benign by-products. Recent studies have also shown that these plants can be built to efficiently accommodate future CO_2 capture technology that could further reduce environmental impacts.

The outstanding environmental performance of IGCC makes it an excellent technology for the clean production of electricity. IGCC systems also provide flexibility in the production of a wide range of products including electricity, fuels, chemicals, hydrogen, and steam, while utilizing low-cost, widely available feedstocks. Coal-based gasification systems provide an energy production alternative that is more efficient and environmentally friendly than competing coal-fuelled technologies. The obstacle to the large-scale implementation of this technology in the country is the high costs associated with the technology. CDM credits and by-products sales could possible enhance the viability of implementing these technologies in South Africa.

OPSOMMING

Die toenemende aanvraag na elektristeit in Suid-Afrika sal na verwagting die produksie daavan teen 2004/2007 oorskry. Elektrisiteitsvoorsieningsopsies in die land sal moontlik verder gekompliseerd word weens die feit dat die ouer kragstasies die einde van hul beplande lewensduur na die jaar 2025 sal bereik. In die lig hiervan en met inagneming van die lang beplanningsfases benodig voor die ingebruikneming van nuwe aanlegte, moet nuwe kragvoorsieningsopsies proaktief ondersoek word.

Die omgewingsimpakte verbonde aan die steenkool- opwekking van elektrisiteit het in die laaste dekade tot toenemende internasionale kommer gelei. Om hierdie omgewingsimpakte te verminder, is nuwe tegnologieë geïndetifiseer om te help met die voorsiening van elektrisiteit uit fossielbrandstowwe. Die alternatiewe wat oorweeg word, is aardgastegnologie en Geïntegreerde Vergassing Gekombineerde Siklus (GVGS).

Die doel van hierdie studie is om die omgewingsaspekte verbonde aan aardgastegnologie en GVGS te dokumenteer en te verstaan en om hierdie tegnologieë se voordele te evalueer en te vergelyk met steenkoolkragopwekking. Die moontlikhede om fossielbranstofopwekking meer omgewingsvriendelik te maak, terwyl dit steeds ekonomies-lewensvatbaar bly, is ook geëvalueer.

Die gaselektrisiteitsopwekking is uiters suksesvol as elektrisiteitsopwekkingsisteem dwarsoor die wêreld, as gevolg van inherente lae emissievlakke, hoogsdoeltreffendheid, brandstofaanpasbaarheid en die verminderde aanvraag na beperkte ondergrondse fossielbrandstowwe. Ander voordele van GVGS sluit in: ‘n verlaagde bedryfskoste a.g.v. verminderde waterverbruik, kleiner masjinerie en ‘n vermindering in afvalwater wat behandel moet word alvorens dit in die omgewing vrygelaat kan word. ‘n GVGS-aanleg benodig minder afkoelwater en kan gevolglik ook op ‘n kleiner oppervlak geïnstalleer word as ‘n konvensionele steenkoolkragstasie met dieselfde kapasiteit. Al hierdie faktore lei tot ‘n vermindering in negatiewe omgewingsimpakte.

Die GVGS gebruik ook prosesse wat die energie van die brandstof meer effektief benut, met ‘n huidige doeltreffendheidsfaktor van byna 60%. In plaas daarvan dat die gas in die atmosfeer vrygelaat word, word die uitlaatgashitte van die gasturbines, gekombineer met ‘n Hitte Terugwinning van Stoom Opwekker (HTSO) en ‘n stoomturbine, gebruik om die totale opwekking te verhoog. Bowendien, namate grondstowwe toenemend skaars word en energie so verstandig as moontlik aangewend moet word, is dit uiters belangrik dat elektrisiteitsopwekking op ’n ekonomies - en ekologiesvriendelike wyse geskied. Die skoon, betroubare werkverrigting van aardgaskragopwekkers met hul beduidend verminderde

geraasvlakke en kompakte ontwerp, maak hul bedryf moonlik in digbevolkte gebiede, waar elektrisiteit meer benodig word. Terselfdetyd kan energie gebruik word in welke vorm dit benodig word, d.w.s. as elektrisiteit, hitte of stoom.

Die Suid-Afrikaanse ekonomie se afhanklikheid van goedkoop steenkool waarborg dat dit steeds ‘n essensiële komponent van toekomstige elektrisiteitsopwekkingsopsies in die land sal bly. Die oorheersing van steenkoolopweking in die land is die hoofrede waarom Suid-Afrika as die grootste koolstofdioksied (CO_2) besoedelaar op die vasteland van Afrika bekend staan. By die volgende internasionale vergadering van die Ondertekenaars van die Protokol van Kyoto, kan die land moontlik versoek word om sy koolstofdioksied-emissies te verminder.

Koolstofdioksied-emissies kan verminder word deur ‘n opwekkingstegnologie met gas as die verkose brandstof te gebruik. Die onsekerheid en koste verbonde aan aardgas in Suid-Afrika bemoeilik egter die implementering van hierdie tegnologie. Daar is tans ‘n aantal inisiatiewe rondom die ontwikkeling van aardgas in die land, naamlik die Pande en Temane Projekte in Mosambiek en die Kudu Projek in Namibië. Hierdie projekte sal waarskynlik in die toekoms die keuse van gas as brandstof vir elektrisiteitsopwekking positief beïnvloed. Die ekonomiese uitvoerbaarheid van hierdie projekte sal verder verhoog word deur die verkryging van Kweekhuis Gas Krediete vir die “Skoon Ontwikkeling Meganisme” of CDM (Clean Development Mechanism).

As alternatief moet meer effektiewe metodes om elektrisiteit uit steenkool te produseer, ontwikkel en geïmplementeer word. GVGS kan dit vermag, as gevolg van die hoë doeltreffendheid verbonde aan die gekombineerde sikluskomponent van hierdie tegnologie. Hierdie verhoogde doeltreffendheid lei tot verminderde emissies in die atmosfeer vir die verkryging van ‘n gelykwaardige eenheid elektrisiteit wat deur ‘n normale steenkoolkragstasie geproduseer word.

‘n GVGS-sisteem kan in Suid-Afrika sukesvol wees, aangesien dit die voordele verbonde aan die gebruik van gaselektrisiteitsopwekkingsisteme met ‘n ekonomies-bekostigbare brandstof, d.w.s. steenkool, kombineer. GVGS-sisteme kan streng lugbesoedelingstandaarde ekonomies nakom, afvalwater binne aanvaarbare ekologiese grense produseer, omgewingsvriendelike afval met goeie potensiaal as ‘n verkoopbare byproduk produseer en ‘n waardevolle sulfaatkommoditeit as byproduk herwin.

Lewenssiklusanalises van GVGS-kragstasies het koolstofdioksiedvrylating en natuurlike grondstofuitputting as hul mees betekenisvolle positiewe lewenssiklusimpakte geïdentifiseer, wat getuig van die GVGS se lae besoedingvrylatings en goedaardige byprodukte. Onlangse studies het ook bewys dat hierdie aanlegte gebou kan word om toekomstig CO_2-opvangtegnologie doeltreffend te akkommodeer, wat omgewingsimpakte verder kan verminder.

Die GVGS se uitstaande omgewingsprestasie maak dit ‘n uitstekende tegnologie vir die skoon opwekking van elektrisiteit. GVGS-sisteme verleen ook buigsaamheid in die produksie van ‘n wye verskeidenheid produkte, insluitend, elektrisiteit, brandstof, chemiese produkte, waterstof en stoom, terwyl dit lae-koste geredelik-beskikbare grondstowwe benut. Steenkool-gebaseerde gasvormingsisteme bied ‘n energieproduserende alternatief wat meer doeltreffend en omgewingsvriendelik is as mededingende steenkool brandstof tegnologieë. Die struikelblok vir die grootskaalse implementasie van hierdie tegnologie in die land is die hoë koste verbonde aan dié tipe tegnologie. CDM-krediete en byprodukte-verkope kan moontlik die lewensvatbaarheid in die implementering van hierdie tegnologieë in Suid-Afrika verhoog.

CHAPTER 1

1. INTRODUCTION

The environmental impacts associated with coal-fired generation of electricity have resulted in increased global concern over the past decade. To reduce these impacts, new technologies have been identified to help provide electricity at lower costs and higher efficiencies. The first alternative that is being implemented at rapid pace is gas-fired generation technologies. The successes of these technologies are due to the fact that natural gas contains very low concentrations of polluting components such as sulphur and heavy metals, it emits far less carbon dioxide per unit of energy than either the combustion of oil or coal and it has substantially higher efficiencies than coal-fired power stations. Hence it has become an attractive fuel for thermal power stations facing ever-stricter environmental regulation. However, a major limitation to the large-scale implementation of this technology in South Africa is the lack of an adequate supply of natural gas.

The second potential alternative technology to conventional coal-fired electricity generation is the Integrated Gasification Combined Cycle (IGCC). Both gasification of coal and combined cycle technologies, using mainly natural gas, have been in commercial use for many years, without any significant efforts made to integrate these processes. The main advantages of IGCC is its ability to utilize low-grade fuel supplies whilst delivering higher cycle efficiencies and reduced emissions to the environment when compared to conventional coal-fired power station. There are now a few IGCC plants across the world beginning to amass meaningful hours of operation, demonstrating high availabilities and able to conform with the much stricter emission standards that are enforced in developed countries.

1.1. MOTIVATION FOR THE STUDY

Eskom, the South African power utility, owns 24 power stations with a nominal capacity of 42011 megawatts (Eskom Annual Report, 2003:138). Eskom supplies an estimated 95% of the country's total electricity requirements, which equates to more than half of the electricity supplied on the African continent. The South African National Electricity Regulator (NER) assumes that demand will exceed supply by the year 2007 if the annual growth electricity demand is around 4%. A conservative estimate of 1.8% indicates that South Africa could run out of supply in 2011 (Infochain, 2004a). This increased demand for electricity and the constraints associated with the supply thereof would be further complicated by the fact that older power stations would reach the end of their design life beyond the year 2025.

In light of this and considering the long lead times required for the commissioning of new plants, new power supply options need to be proactively investigated. Legislation, international agreements, permits and environmental impact assessments are time consuming processes. In order to ensure timeous project implementation, an integrated planning approach should be adopted taking cognisance of all the additional environmental planning requirements for commissioning a power plant.

In order to reduce the concerns associated with generation of power from coal and their associated impacts, new technologies have been identified to help provide electricity at lower costs and higher efficiencies. However the fuel supply options and financial implications associated with certain technologies has severely limited the path that South Africa can follow. This study aims to compare the environmental impacts of gas turbines and IGCC with those from a PF plant, to briefly identify resource constraints and to provide a superficial evaluation of the economics of each technology.

1.2. OBJECTIVES

The objectives of this study are:

- To document and understand the environmental aspects related to gas-fired and IGCC power generation and evaluate their advantages in comparison to conventional pulverised coal fired power generation.
- To evaluation the options that could be utilised in order to make fossil fuel power generation more environmentally friendly whilst remaining economically feasible.

The following key research questions have been formulated:

- What are Conventional Coal-Fired, Gas-Fired and Integrated Gasification Combined Cycle (IGCC) Power Generation Technologies?
- What are the environmental impacts associated with a conventional coal–fired power station, a gas-fired power station and an IGCC power station?
- What are the some of the barriers to implementing the above-mentioned power generation technologies in South Africa?

CHAPTER 2

2. THE TECHNOLOGIES

This chapter details the technologies under consideration, viz. Pulverised Fuel Coal-Fired Electricity Generation, Gas-Fired Electricity Generation and Integrated Gasification Combined Cycle Generation Technologies.

2.1 PULVERISED FUEL (PF) COAL-FIRED ELECTRICITY GENERATION

The generation of electricity from coal is generally a simple process involving crushing coal into a fine powder which is fed into a combustion unit where it is burned. The heat generated from the burning coal is used to produce steam which spins one or more turbines to generate electricity.

Coal has played a major role in electricity production since the first power plants were built in the 1880's. These power plants utilised wood or coal, which were hand fed to heat a boiler and produce steam. This steam was used in reciprocating steam engines which turned generators to produce electricity. These steam turbines were based on the Rankine cycle, which is a thermodynamic cycle used to generate electricity in many power stations, and is the practical approach to the Carnot cycle. Superheated steam at a pressure of 16 MPa and a temperature of 535℃ is produced in a boiler, and then expanded in a steam turbine. The turbine drives a generator, to convert the work into electricity. The remaining steam is then condensed and recycled as feedwater to the boiler (Coal in a Sustainable Society, 2004).

A British engineer, Charles A. Parsons, developed a more efficient high-speed turbine in 1884 to replace the use of reciprocating steam engines to generate electricity. Pulverized coal firing, which was developed in the 1920's, brought advantages that included a higher combustion temperature, improved thermal efficiency and a lower requirement for excess air for combustion. The cyclone furnace was developed in the 1940's and this technology allowed for the combustion of inferior grade coals whilst achieving less ash production and greater overall efficiencies (Edmonton Power Historical Foundation, 2004).

2.1.1 The processes associated with Conventional PF Electricity Generation

The process of converting coal to electricity involves a collection of separate processes, as indicated in figure 1, which are all inter-linked. Pulverised fuel (PF) coal-fired generation generally comprises of the following processes:

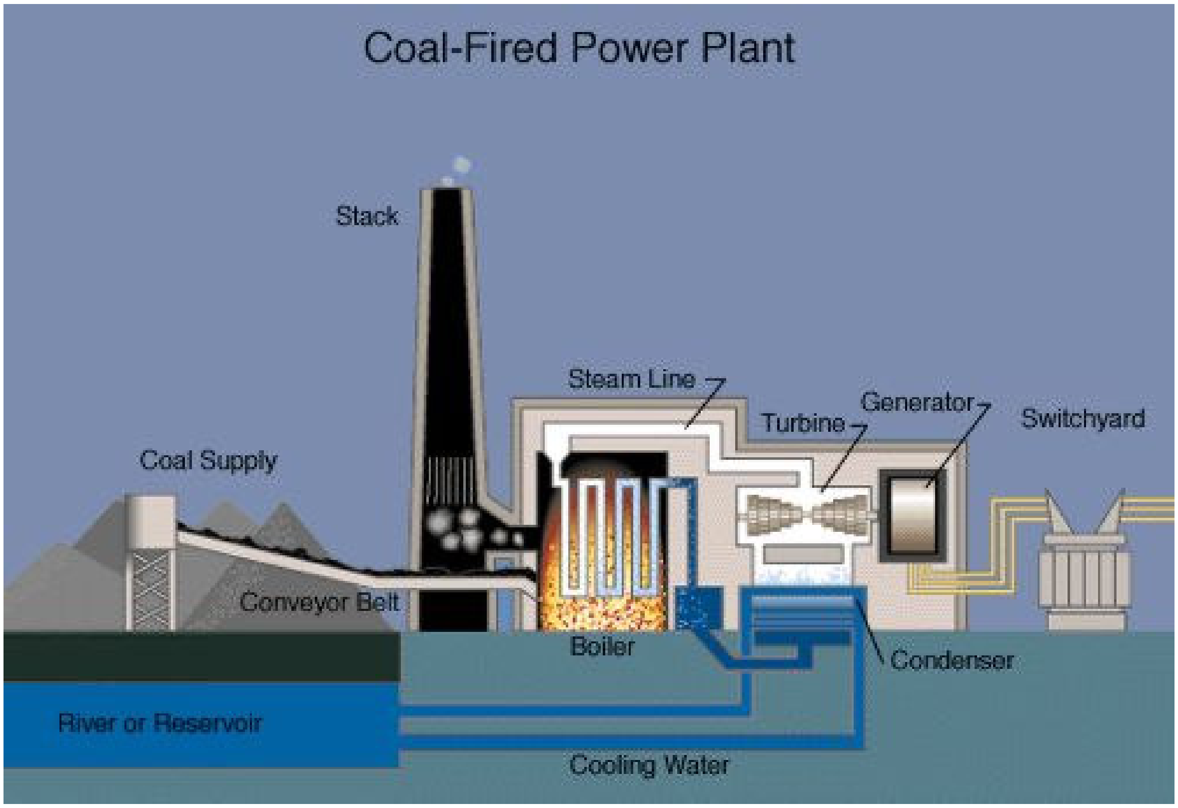

Figure 1: A coal-fired plant (Edmonton Power Historical Foundation, 2004)

2.1.1.1 Coal Handling

Coal from a mine is delivered in large trucks, by conveyer belts or via rail, and offloaded to storage bunkers at the power station. Coal from different parts of the mine are “blended” at the bunkers to ensure consistency before being conveyed to coal storage silos in the power plant. From here, it is fed to the pulverizers, which grind it to a fine powder, which is ultimately burned in the boiler.

2.1.1.2 The Boiler

The pulverised coal is blown into the boiler where it is ignited, creating a fireball. The intense heat generated from the fireball helps turn highly purified water, running through enclosed tubes in the boiler, to steam. This steam is collected in a steam drum at the top of the boiler before it is subsequently passed through another set of tubes in the boiler where it is superheated to extremely high temperatures. This steam, at high pressures (± 17MPa) and temperatures (510-535^{o}C), then flows via the enclosed tubing to the steam turbine which in turn is attached to the generator (Keir, 2004).

2.1.1.3 Ash Systems

The combustion of coal in the boilers results in the production of two types of ash. The heavier ash which collects in the bottom of the boiler is called "bottom ash". This ash is collected and disposed of at an ash disposal site.

The remaining lighter ash, known as "fly ash", is carried through the boiler with the exhaust gas. This fly ash is removed from the furnace exhaust by electrostatic precipitators or bag filters before the remaining flue gases, mainly nitrogen (N_2), sulphur (S), carbon dioxide (CO_2), and water vapour (H_2O) are discharged up the stack into the atmosphere. A percentage of the collected flyash is sold for use in the manufacture of concrete and the remainder are combined with the bottom ash and transported to an ash disposal site.

2.1.1.4 Turbine / Generator

The steam turbine is composed of hundreds of angled blades which are mounted in rows on a rotating shaft. Steam entering the turbine from the boiler hit these blades and causes the shaft to turn rapidly at 3000 revolutions per minute (rpm) (Eskom, 1995). Rows of stationary blades between each row of moving blades help redirect the steam flow onto the next row of moving blades. As the steam moves through the turbine, its energy is transferred to the turbines, resulting in a pressure and temperature reduction. The steam exits the turbine at low temperature and pressure and is condensed back into water in the condenser.

The generator comprises two major components: the rotor and the stator. The rotor carries a magnetic field which rotates as the rotor turns within the stator, which is fixed. This process generates an electrical current in copper coils in the stator. The electricity generated by this process flows from the generator to a transformer where its voltage is increased before sending it out on the transmission grid.

2.1.1.5 The Condenser

After the steam has passed through the turbine, it enters the condenser where it reaches low temperatures (35-40^{o}C) and pressures (4-8kPa). Removal of it's latent heat of condensation condenses it back into liquid water. This process is accomplished by allowing the wet steam to pass through thousands of small tubes surrounded by cold water. Cold water is usually utilised from nearby dams. The condensed steam is collected at the bottom of the condenser as water and returned to the boiler using feedwater pumps, where it begins the water-to-steam, steam-to-water cycle again.

2.1.1.6 Switchyard

Electricity produced by the generator is generally of too low a voltage to transmit efficiently over long distances via a transmission line. Therefore, transformers are utilised to step up the voltage before sending it out on a long distance transmission line. The voltages commonly used on transmission lines range from 132kV to 765kV. Upon reaching its destination area, it feeds into distribution substations that may range from 66kV to 132kV before it enters the reticulation networks/mini substations where the voltage is stepped down to 240 volts for domestic user consumption or levels appropriate for industrial consumption (Vrede, 2004).

2.1.2 Evolution of PF Electricity Generation

Coal-fired power generation is currently based on the same methods that started over a century ago. The technology has, however, evolved in all aspects thus allowing coal power to be the inexpensive power source used so widely today. Supercritical steam cycles were developed in the 1950's but wide-spread implementation of this technology has been restricted due to higher capital and maintenance costs. The combustion of each coal particle occurs in less than 2 seconds within large rectangular combustion chambers. The hot gases transfer heat by radiation to the water wall lined combustion chamber, and through a succession of tubular heat exchangers starting with the superheater, economiser (feed water heat) and air preheater. In this way steam that is raised and superheated to around 16 MPa and 535°C for a conventional steam cycle reaches pressures around 24-28 MPa and temperatures around 565-580 °C for a supercritical steam cycle. The overall thermal efficiency is 38% for a conventional steam cycle and varies between 41-44% for supercritical cycles. The main differences between a conventional and supercritical steam cycle are in the materials used for the construction of the combustion chambers. The higher temperatures and pressure with supercritical boilers require high alloy steel, both ferritic and austenitic to minimise corrosion and high temperature creep (Coal in a Sustainable Society, 2004).

Another technology that has been developed is Fluidised Bed Combustion (FBC). This technology is a successful clean coal technology, which offers two important advantages:

- a single FBC boiler design can burn a wide range of solid fuels efficiently, including very low grade coal, and
- produces integral low emission levels of both NO_x and SO_x (due to low combustion temperature and addition of limestone in the furnace respectively).

In a FBC, fuel and sorbent are fed into the lower part of the combustion chamber in the presence of fluidising air. The air is fed upwards through nozzles at the bottom of the bed upwards, causing a turbulent mixing of fuel, bed material (quartz sand and ash) and sorbent. Typical combustion temperatures are between 800°C and 900°C.

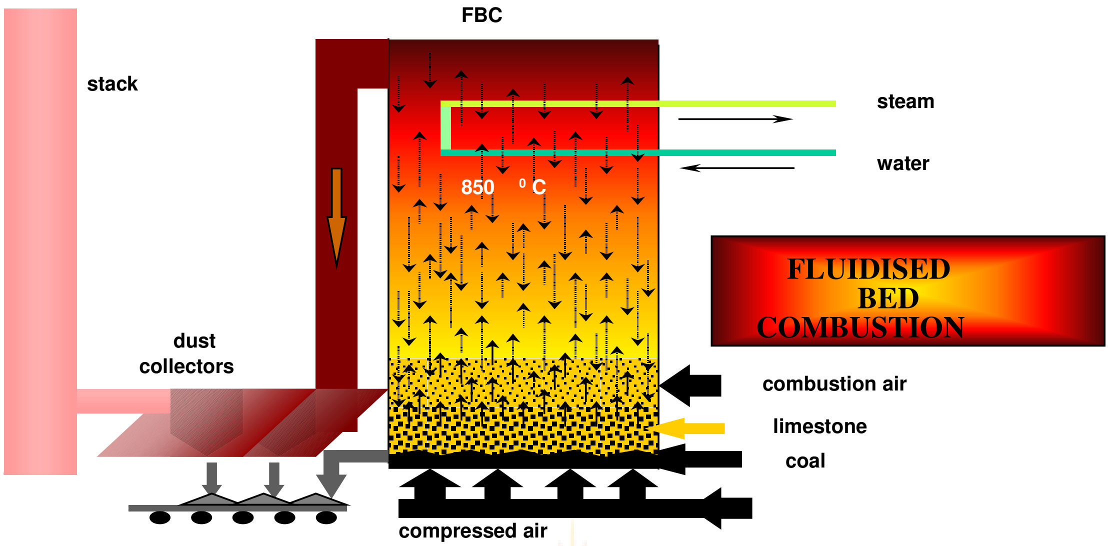

Figure 2: Fluidised Bed Combustion in a boiler (Haripersad, 2004)

FBC can be categorised as Atmospheric FBC (AFBC) or Pressurised FBC (PFBC). AFBC can be further categorised into Circulating Fluidised Bed Combustion (CFBC) and Bubbling Fluidised Bed Combustion (BFBC) with the essential difference being the recirculation of solids back into the bed of the former. Bubbling bed is essentially limited in size to 60 MWe, and hence finds greater application in the industrial market. Circulating bed is operational up to 300 MWe scale, with the most recent installations commissioned at Jacksonville Electric, USA (Lundqvist, *et al,* 2003).

Both circulating and bubbling fluidised beds can be operated with a high combustion chamber pressure, with the pressurised circulating bed being very experimental and the pressurised bubbling bed attempting to prove itself a commercially viable project.

On the CFBC steam side, all commercial installations have been sub-critical to date. However this is changing with the current 460 MWe once-through CFBC of Elektrownia Lagisza, in Bedzin, Poland, This plant is due to be commissioned in 2006, and represents not only the first super-critical CFBC installation, but will also be the largest operational CFBC (Lundqvist, *et al,* 2003).

Supercritical steam cycles and FBC technologies have been included in this chapter for information purposes. The lack of detailed environmental information and the large variations of these technologies make comparison highly complicated and therefore they have been excluded from detailed analysis in this study.

2.2 GAS-FIRED GENERATION

The gas turbine is relatively new in the history of energy conversion with the first practical application being carried out at Neuchatel, Swtitzerland in 1939 by the Brown Boveri Company. It is based on the Brayton cycle and comprises a compressor which draws in and compresses gas (most usually air); a combustor or burner which adds fuel to heat the compressed air; and a turbine which extracts power from the hot air flow. It is essentially an internal combustion (IC) engine employing a continuous combustion process.

A typical gas turbine can range in power output from 0.05 MW to as high as 240 MW. Although gas turbines are increasingly being used for base load electrical power generation, they are most frequently used to drive compressors for natural gas pipelines, to power ships and to provide peaking and intermittent power for electric utility applications.

2.2.1 The Single Gas Turbine.

The Brayton cycle, which the single gas turbine is based on, is a representation of the properties of a fixed amount of air as it passes through a gas turbine in operation. It describes what happens to air as it passes through a system and specifies the relationship between the volume (V) of the air in the system and its pressure (P).

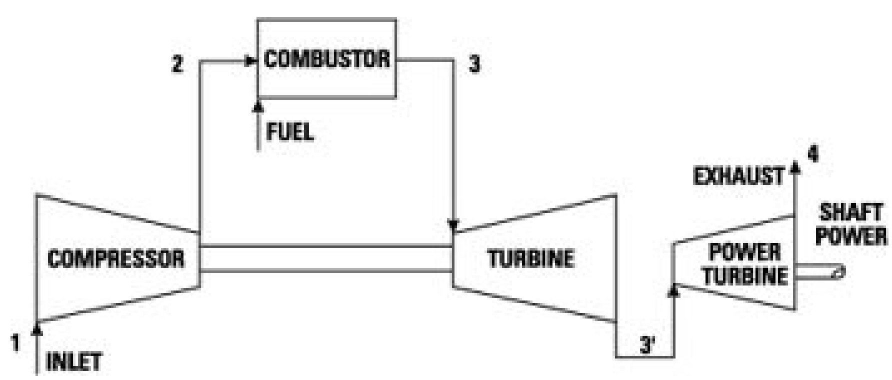

Figure 3: Schematic for a power generation gas turbine (Langston & Opdyke, Jr., 1997).

Figure 3 depicts a gas turbine, where air is initially compressed increasing its pressure, as the volume of space it occupies is reduced. This compressed air is then heated at constant pressure. Heat is added by injecting fuel into the combustor and igniting it on a continuous basis (reaching temperatures of over 1300°C). The hot compressed air is then allowed to expand reducing in pressure and temperature and increasing in volume. This expansion takes place in the turbine, where the expansion of the hot gases against the turbine blades turns a shaft. This shaft is connected to a generator, which produces electricity. The Brayton cycle is completed by a process in which the volume of air is decreased (temperature decrease) as heat is absorbed into the atmosphere. A gas turbine that is configured and operated to closely follow the Brayton cycle is called the single gas turbine (Langston & Opdyke, 1997).

A greater understanding of the single cycle gas turbine and its operation can be gained by considering its three major components: the compressor, the combustor and the turbine. Their features and characteristics are outlined below.

2.1.1.1 Compressors and Turbines.

The compressor components are connected to the turbine by a shaft in order to allow the turbine to turn the compressor. Gas turbine compressors are either centrifugal or axial, or can be a combination of both. The more efficient, higher capacity axial flow compressors are used in most gas turbines. An axial compressor is made up of a relatively large number of stages, each stage consisting of a row of rotating blades (airfoils) and a row of stationary blades (stators), arranged so that the air is compressed as it passes through each stage.

Turbine design and manufacture is hampered by the need to extend turbine component durability in the hot air flow. This problem is especially critical in the first turbine stage where temperatures are highest. Special materials and elaborate cooling systems must be used to allow turbine components to survive in airflows with temperatures as high as 1700°C.

2.1.1.2 Combustors

A combustor consists of at least three basic parts; a casing, a flame tube and a fuel injection system. The casing must withstand the cycle pressures and may be a part of the structure of the gas turbine. It encloses a relatively thin-walled flame tube, within which combustion takes place, and a fuel injection system.

A successful combustor design must satisfy many requirements and has been a major challenge from the earliest gas turbines. The relative importance of each requirement varies with the application of the gas turbine, with some requirements being of a conflicting nature. This necessitates design compromises to be made. The major design requirements reflect concerns over engine costs, efficiency and the environment, and include the following parameters:

- High combustion efficiency under all operating conditions.
- Low levels of unburned hydrocarbons and carbon monoxide, low oxides of nitrogen at high power output and no visible smoke. (Minimised pollutants and emissions.)
- Low-pressure drop, three to four percent is common.
- Combustion must be stable under all operating conditions.
- Consistently reliable ignition must be attained at very low temperatures.
- Smooth combustion, with no pulsations or rough burning.
- Minimal temperature fluctuations for good turbine life requirements.
- Long useful life (thousands of hours), particularly for industrial use.
- Multi-fuel use, characteristically natural gas and diesel fuels are used for industrial applications but they can operate on a range of other fuels.
- Designed for minimum cost, repair and maintenance.

In stationary applications, additional equipment can be added to the single gas turbine, leading to increases in efficiency and/or the output of a unit. Three such modifications are Regeneration, Intercooling and Reheating.

- *Regeneration* involves the installation of a heat exchanger through which the turbine exhaust gases pass. The compressed air is then heated in the exhaust gas heat exchanger, before the flow enters the combustor. A well designed regenerator that has a highly effective heat exchanger and small pressure drop increases the efficiency over the simple cycle value. However the relatively high cost of such a regenerator must also be taken into account. Regeneration gas turbines are 5-6% more efficient and are even more effective in part load applications.
- *Intercooling* involves the use of a heat exchanger that cools compressor gas during the compression process. If the compressor consists of a high and a low-pressure unit, the intercooler could be mounted between them to cool the flow and decrease the work required for compression in the high-pressure compressor. The cooling fluid could be atmospheric air or water.
- *Reheating* occurs in the turbine and is a way to increase turbine work output without changing compressor work or melting the materials from which the turbine is constructed. If a gas plant comprises a high-pressure turbine with a low-pressure turbine at the back end of the machine, a reheater (usually another combustor) can be used to "reheat" the flow between the two turbines. This can increase efficiency by 1-3% (Langston & Opdyke, Jr., 1997).

Some of the principal advantages of the gas turbine are:

- It can produce large amounts of electrical power for a unit of relatively small size and weight.
- Its mechanical life is long, due to the fact that motion of all its major components involve pure continuous rotation and not reciprocating motion as in a piston engine. In light of this the corresponding maintenance cost of a gas-fired turbine is relatively low.
- The start-up time for a gas turbine is measured in minutes. This is substantive when compared to a coal-fired unit for which the start up time is currently measured in hours. These fast start-up times enables its use for peak, standby and emergency power. The rapid startup of gas turbines also minimises the need for hot or spinning reserve in larger stations to cover peak or standby capacity, thereby increasing the overall efficiency of the grid.
- A wide variety of fuels can be utilised by a gas turbine. Natural gas is the preferable choice. However, diesel oil or specially treated residual oils, kerosene, combustible gases derived from blast furnaces, refineries and the gasification of solid fuels such as coal, wood chips and bagasse could also be utilised by a gas turbine.
- The general working fluid is atmospheric air and as a basic power supply unit, the gas turbines require no water for cooling purposes.

In the past, one of the major disadvantages of the gas turbine was its lower efficiency when compared to other internal combustion engines and power plants. However, during the last fifty years, continuous development has pushed the thermal efficiency from 18% for the 1939 Neuchatel gas turbine to present levels of about 40% for the single cycle operation. Current development work is predicting even more fuel-efficient gas turbines, with single cycle efficiencies as high as 45-47%.

2.2.2 The Combined Cycle Gas Turbine (CCGT).

A *combined cycle* gas turbine (CCGT) power plant is essentially an electrical power plant in which a gas turbine and a steam turbine are used in combination to achieve greater efficiency than would be possible independently. The gas turbine drives an electrical generator. The gas turbine exhaust heat is used to produce steam in a heat exchanger (called a heat recovery steam generator or HRSG) to supply a steam turbine whose output provides the means to generate more electricity. If the *steam* is used for heating buildings, the unit would be called a cogeneration plant or a CHP (Combined Heat and Power) plant. It comprises two power production systems, referred to as cycles, which complement each other to allow a very high utilisation of the fuel. It is either designed solely for electricity power generation or to provide both electricity and heat for industry or district heating (ABB Powergen, 1993).

Figure 4 illustrates a simplified representation of a CCGT and shows it to be two heat engines coupled in series. The "upper" engine is the gas turbine. It expels heat as the input to the "lower" engine (the steam turbine). The steam turbine then rejects heat by means of a *steam condenser.*

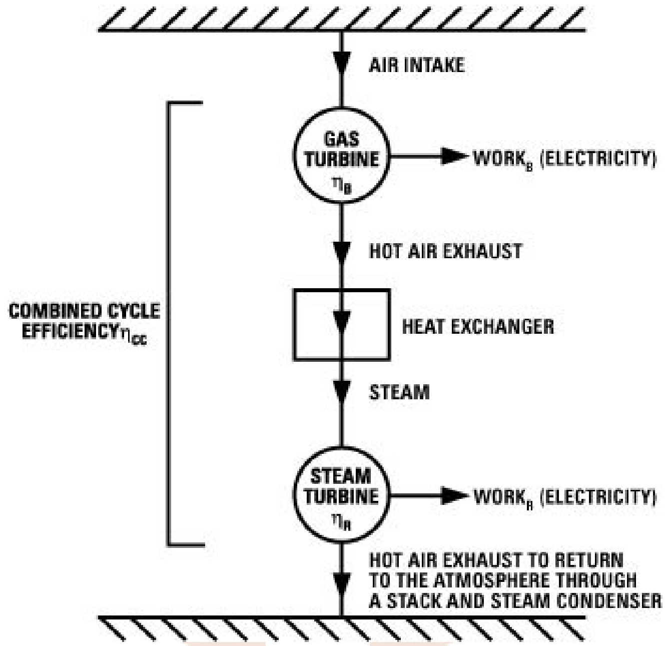

Figure 4: Schematic of Combined Cycle (CCGT) plant. (Langston & Opdyke, 1997)

The efficiency of a combined cycle plant is derived by the equation $\boldsymbol{\eta_{cc} = \eta_B + \eta_R - \eta_B\eta_R}$ or the sum of the individual efficiencies, minus their product. $\boldsymbol{\eta_{cc}}$ is the efficiency of the combined cycle plant. This equation provides an insight as to why CCGTs are so successful. Suppose the efficiency of high performance Brayton cycle gas turbines or single gas turbine is 40%. A moderate value for a Rankine cycle steam turbine operating at typical CCGT conditions would be 30%. Incorporating these values into the equation yields:

$$\begin{aligned}\eta_{cc} &= 0.40 + 0.30 - 0.12 \\ &= 0.58 \\ &= 58\%\end{aligned}$$

One can see that the combined efficiency of 58% is greater than the efficiency of either of the component engines taken separately. It must be however be noted that the values used represent the maximum on the actual CCGT efficiency and there are losses in the system that need to be considered.

Actual efficiencies of 52-58% have been attained with CCGT units during the last few years and the technology is particularly popular for new gas turbine power plants. In the last 5-6 years, the CCGT has experienced a remarkable breakthrough in sales. Current annual orders for the combined cycle facilities total more than one-third of the entire market of power stations. The reasons for their success are:

- Combined cycle plants today post efficiencies well above 50%, with best levels of 55% achievable. This is substantial if compared to 1980 when the best combined cycle power plant had efficiencies of 46 to 47%.
- The cost of a large size combined cycle plant is approximately half the cost of a modern coal-fired facility, with the same power output.
- Combined cycle plants can be commissioned much faster than other types of power plants since the gas turbine generator can be utilised to generate power before the steam turbine is fully operational.
- The greatest single factor contributing to the success of combined cycle plants is their superior environmental performance, and this has streamlined approval procedures. Not only do the plants' inherently low emission levels make it easier to obtain siting permission, they also make the plant's technology more readily acceptable than others.
- Combined cycle plants have an availability that is at least as good as that of steam power plants.

These attributes are the result of significant advances in the technology. Gas turbine development, in particular, has made a key contribution, with improved cooling technologies and materials allowing a sharp increase in turbine inlet temperature, which explains the high efficiency. In the combustion area, advanced technologies have reduced the NO_x emissions by a factor of 10. But improved steam cycles, such as the 3-pressure cycle and more compact, high efficiency steam turbines have also contributed to better utilisation of fuel energy.

The first combined cycle plant to be built by ABB went on stream in Luxembourg in 1956 (ABB, 1993). Despite this early start, it took another 20 years for the technology to achieve its global breakthrough. The reason for this being that the high temperature materials for the gas turbine and blade cooling technology were of unsatisfactory standards. Only after these two problems had been solved and appropriate materials developed, did combined cycle power generation begin to establish itself. Today, combined cycle plants are recognised as being exceptionally reliable, economical, and environmentally friendly.

2.3 INTEGRATED GASIFICATION COMBINED CYCLE

Integrated Gasification Combined Cycle (IGCC) is a potential alternative technology to conventional pulverised fuel (PF) combustion for generation of electricity from coal. Both gasification and combined cycle technologies have been in commercial use for many years, without significant steps taken to integrate the process. The technology itself is relatively new in power generation and passed through a critical stage in its development during the 1990's (IEA Clean Coal Centre, 2004). It basically involves gasification of coal in a reactor and the syngas that results is utilised in a combined cycle gas turbine as described in section 2.2.

The gasification of coal takes place in the presence of a controlled 'shortage' of oxygen, thus maintaining reducing conditions. It is carried out in an enclosed pressurized reactor, and a mixture of $CO + H_2$ (called synthesis gas, syngas or fuel gas) is produced (IEA Clean Coal Centre, 2004). This syngas is subsequently cleaned of pollutants such as hydrogen sulphide (H_2S), hydrogen cyanide (HCN) and ammonia (NH_3) and then fed to the CCGT where it is burned with either oxygen or air at high temperatures and pressures. There are generally three gasifier formats, viz. fixed beds (not normally used for power generation), fluidized beds and entrained flow. Fixed bed units use only lump coal, fluidized bed units a feed of 3-6 mm size, and entrained flow gasifiers use a pulverised feed, similar to that used in pulverised coal combustion (Tavoulareas, 1995).

The main advantages of the IGCC technology is its ability to utilise low-grade fuel supplies (depending on gasifier type) whilst delivering higher cycle efficiencies and reduced emissions to environment compared to conventional pulverised fuel plant. An IGCC process promotes better use of fuels by utilising combustion products that would have otherwise been emitted to the atmosphere. Heat energy that would normally be wasted during coal-fired generation is utilised in an IGCC to generate power in the HRSG (Rajoo, 2004). There are now a number of IGCC plants across the world beginning to amass significant hours of operation with high availability's and able to conform to the latest emissions legislation (Coal 21, 2004).

2.3.1 The Technology

A simplified process diagram for an IGCC process is outlined in Figure 5. The traditional coal combustor utilised in a pulverised coal fired power plant is replaced with a gasifier and a gas turbine (US Department of Energy, 2000). Gasification involves heating coal by partial combustion to 900-1600°C with oxygen and steam to produce syngas. There are various ways of gasifying coal and this is dependant on controlling the mix of coal, oxygen, and steam within the gasifier. There are also several options for controlling the flow of coal in the gasification section, e.g., fixed-bed, fluidized-bed, and entrained-flow systems (Tavoulareas, 1995).

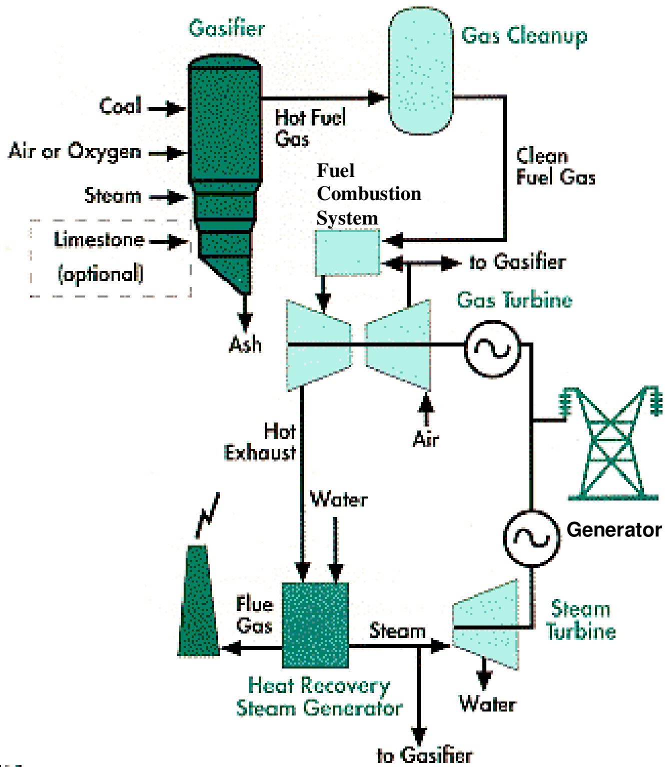

Figure 5: The IGCC Process (US Department of Energy, 2000)

Gasification may take place using either air, or more commonly in newer technologies, using oxygen from an Air Separation Unit (ASU). It should be noted that oxygen promotes the rate of gasification and produces a higher calorific value syngas, but oxygen does have numerous drawbacks compared to air (IEA Clean Coal Centre, 2004). In addition to the costs involved, there are technical concerns such as the effect on high ash/high ash fusion temperature coals in slagging gasifiers, explosion risks, etc.

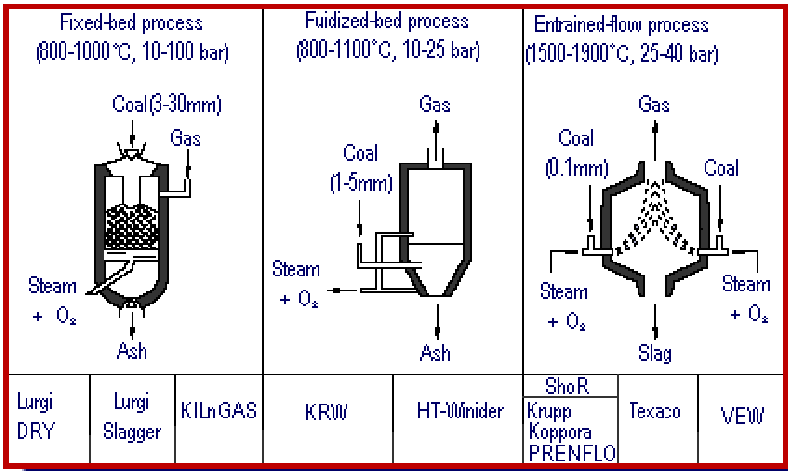

Figure 6: The main coal gasification processes: fixed bed, fluidized-bed, and entrained flow (Tavoulareas, 1995).

- Fixed Bed

This reactor utilises lump coal (3-30mm) which is distributed on a rotary grate at the bottom of a gasifier. The gasifying agents, viz. oxygen (or air), steam and fuel, are injected into the bed. Ash is removed from the rotary grate and exits the gasifier through the ash lock under the gasifier. In order to prevent slag formation, the gasifier temperature must be kept below the ash melting point. The syngas exits the gasifier at a temperature of approximately 800^{o}C at a pressure of 1-10 MPa (Wibberley, *et al,* 1999). Sasol operates over 90 such gasifiers, initially designed by Lurgi in the 1950's. Sasol has since optimised the design for local coals.

- Fluidised Bed

The fluidised bed is based on the principles of the fixed bed reactor but the gasifying agent flow is substantially higher. Crushed coal (1-5mm) is fed into a fluidised bed consisting of inert material such as sand. Oxygen (or air) and steam is passed through the bed as fluidising gases. A small amount of these gases are injected above the bed to increase the temperatures and assist with gasifying the elutriated material. The gas exits the gasifier at a temperature of approximately 1000^{o}C at a pressure of 1-2.5 MPa (Wibberley, *et al,* 1999). A high efficiency hot gas cyclone is utilised to remove particulates from the product stream and unreacted char is recycled and returned to the bed, thus increasing efficiency. Ash is extracted at the foot of the gasifier.

- Entrained Flow

  The entrained flow reactor utilises smaller sized coal particles than the fluidised bed (0.1mm) and higher velocity gas flows up through the bed. The pulverised coal is introduced into the gasifier via burner nozzles and is gasified as it flows, mostly suspended, though the gasifier. The process relies on high temperature operation to melt the coal ash, forming a liquid slag that may be tapped off from the bottom of the gasifier and fed to a water batch where it solidifies into dense, glassy granules which, following washing and dewatering, can be used by the road construction industry. The resulting gas has a negligible tar, oil and phenol content and an exit temperature of around 1500°C at a pressure of 2.5-4 MPa (Wibberley, *et al,* 1999). Fluxing agents (usually high Ca minerals such as limestone) are necessary for coals with high ash fusion temperatures, as is generally the case with South African coals. Coal sulphur can be reclaimed as elemental sulphur or sulphuric acid, and marketed to users. Coal ash, in the form of slag may be used in construction industries.

The fuel gas leaving the gasifier must be cleaned (to very high levels of removal efficiencies) of sulphur compounds and particulates. Cleanup occurs after the gas has been cooled, which reduces overall plant efficiency and increases capital costs, or under high pressure and temperature (hot-gas cleanup), which has higher efficiency. In older applications, syngas is usually cooled to around 250°C before entering the gas clean-up system. The thermal efficiency of the IGCC process, however, increases with higher gas turbine inlet temperatures. Therefore, the extent to which syngas from the gasifier is cooled during clean-up impacts heavily on the overall cycle performance. It must, however, be noted that hot-gas cleanup technologies are still in the early demonstration stage (Tavoulareas, 1995).

After the fuel gas has been cleaned, it is utilised in a CCGT to produce electricity. Depending on the level of integration of the various processes, IGCC may achieve efficiencies up to 50%. Plant efficiencies are improved by injecting nitrogen from the air separation unit into the fuel gas prior to the gas turbine and utilising air from the gas turbine/compressor in the air separation unit (Tavoulareas, 1995).

2.3.2 IGCC Advantages

The IGCC process offers several advantages over conventional coal fired plant

2.3.2.1 High Efficiency

Plants currently in commercial operation have demonstrated net thermal efficiencies approaching 50%. This figure compares favourably with current sub-critical pulverised fuel (PF) plants with efficiencies in the range of 34-37% and super-critical PF plant efficiencies of up to

40%. Using syngas in a gas turbine increases its output, especially when nitrogen from an oxygen blown unit is fed to the turbine. Thus a turbine rated at 170MW when fired on natural gas can yield 190MW or more on syngas. Furthermore, output is less dependent on ambient temperature than is the case with natural gas. With development of new gas turbine concepts and increased process temperatures efficiencies of more than 60% are being targeted (Coal 21, 2004).

2.3.2.2 Environment

IGCC produce extremely low emissions compared to a pulverised fuel fired plant. It is claimed that 99% of sulphur is removed after gasification, NOx is reduced by over 90% and CO_2 emissions are reduced by 35%, due to the increased efficiencies, compared to a conventional pulverised fuel coal plant equipped with scrubbers. Increasing efficiency from 35 to 40%, for example, reduces carbon dioxide emissions by over 10%. With efficiencies currently approaching 50%, IGCC power plants use less coal and produce much lower emissions of carbon dioxide than conventional power plants (Coal 21, 2004). This environmental performance matches or exceeds that of alternative energy sources.

2.3.2.3 IGCC Costs

The cost of IGCC generated electricity in the US is approximately 30% more than the cost of electricity produced by a conventional pulverised coal-plant (US Department of Energy, 2004). It should however be noted that IGCC plants internationally have generally been supported by government funding and incentives, making it difficult to derive a true indication of cost. Further, it should be noted that South African coals are relatively cheap, making efficiency gains less profitable. The country also has limited limestone resources (a major operational cost), and the viability of using low-grade dolomite still needs to be confirmed. However, if stricter emission limits were to be enforced by the authorities, IGCC could prove to be one of the most economical methods of generating electricity whilst meeting these environmental targets.

2.3.2.4 Fuel Flexibility

The combined-cycle portion of an IGCC plant can be fuelled by natural gas, oil, or coal. The implications of this are that a plant can switch between natural gas and coal in the event of a decreasing gas supply or increased prices. Conversely, it must be noted that the CCGT component of an IGCC plant can be fuelled by natural gas or oil in case of unplanned events such as disruption of coal supply or problems with the gasifier.

2.3.2.5 Reusable sorbents and marketable by-products

The gasification process in IGCC enables the production of not only electricity, but a range of chemicals, by-products for industrial use, and transport fuels (see diagram below). Coal sulphur is reclaimed as elemental sulphur or sulphuric acid, and marketed to users. Coal ash, in the form of slag may be used in the construction industry. It should be noted that the local market for sulphur/sulphuric acid is in over supply, so this opportunity may not be realised. Further, high ash coals already locally in use imply a possible saturation of the local market, leaving only niche ash products as a possible revenue source. Eskom currently dumps a significant amount of ash. The Fischer-Tropsch process utilised by Sasol for the production of synfuels from coal gasification has yielded a wide variety of by-products. Some that have a commercial value include ammonia, tars and sludge, toluene, napthalene, anthracene and phenols (Mbendi, 2004). The demand and higher value returns of chemicals such as phenols could possibly offset the higher costs associated with commissioning and operating an IGCC power station.

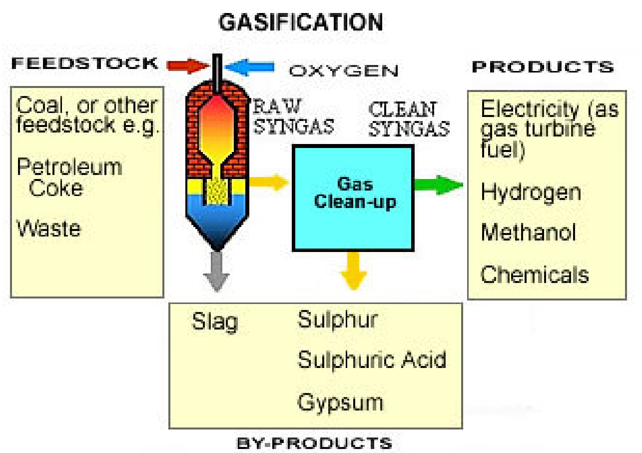

Figure 7: Products and by-products of coal gasification (Coal 21, 2004)

Carbon dioxide can be captured from the coal syngas (carbon monoxide and hydrogen) through a water/gas shift process. The CO_2 can be captured in a concentrated stream, making it easier to convert into other products, or to sequester it underground (Coal 21, 2004). An added advantage in this process is that there are low additional costs for carbon capture, particularly if the plant is oxygen driven.

2.3.2.6 Demonstrated success

IGCC systems are being operated commercially around the world although the plant elements of IGCC are the subject of ongoing research and development. In February 1997, nine IGCC plants were operating worldwide and a further 11 were in the final stages of planning. Some 50 more were under consideration. By 2000 nearly 4 GW were in use worldwide with a further 3 GW due to go online by 2004 (Coal 21, 2004).

A number of demonstration units, mainly around 250 MWe size are being operated in Europe and the USA. A majority utilise entrained flow gasification and are oxygen blown. The 235 MWe unit at Buggenum in the Netherlands, was commissioned in 1993. Three plants are in the USA at Wabash River in Indiana; Polk Power near Tampa in Florida and Piñon Pine in Nevada. The largest unit is that at Puertollano in Spain with a capacity of 330 MWe (IEA Clean Coal Centre, 2004).

CHAPTER 3

3. ENVIRONMENTAL IMPACTS ASSOCIATED WITH ELECTRICITY GENERATION

An overview of the environmental impacts associated with the different technologies studied, viz. conventional pulverised fuel (PF) coal-fired generation, gas-fired electricity generation and integrated gasification combined cycle technologies, are presented in this chapter. This chapter attempts to detail those impacts under the categories of emissions to air, emissions to water, noise impacts, water requirements, wastes generated and land and aesthetic impacts. The expected levels of impacts have been sourced from the New York State Environmental Externalities Cost Study (ESEERCO, 1995). The values are also based on the average emissions for technology specific facilities from the United States (US) and are available in pounds (lb)/Million British Thermal Units (MMBtu). These values were converted to kg/MWh utilising conversion factors provided by the International Energy Agency (2004).

3.1 CONVENTIONAL PULVERISED FUEL (PF) COAL-FIRED GENERATION

There are numerous environmental impacts that occur as a result of the generation of electricity from coal. This section attempts to detail those impacts and the values are based on a PF plant utilising flue gas desulphurisation (FGD) that removes 90% of SO_2 emissions, low NO_x burners that remove 40% of NO_x emissions and an electrostatic precipitator that removes 99% of particulate emissions. The values are based on average emissions for PF facilities from the US.

3.1.1 Emissions to Air

The combustion of coal for power generation releases several pollutants into the atmosphere viz. carbon monoxide (CO), carbon dioxide (CO_2) nitrogen oxides (NO_x), sulphur oxides (SO_x), hydrocarbons (HC), particulates, lead (Pb) and mercury compounds (Hg). These pollutants have major impacts on the environment and human health. They contribute substantially to global warming and increased respiratory problems in humans and animals (Institution of Electrical Engineers, 2002*)*, and also contribute to the formation of acid rain, which has a detrimental impact on plant and animal life.

3.1.1.1 The major atmospheric pollutants associated with electricity generation

Some of the major atmospheric pollutants generated by the combustion of coal for power generation are detailed below:

- Carbon monoxide (CO) is formed as a by-product during the incomplete combustion of all fossil fuels. Carbon monoxide can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues, leading to fatalities in certain circumstances (Union of Concerned Scientists, 2004). Conventional PF generation emits approximately 37.2g CO/MWh of electricity generated (ESEERCO, 1995).

- Carbon dioxide (CO_2) is a natural occurring gas in the atmosphere that is utilised in the process of photosynthesis, the process by which plants produce food. The production of CO_2 is inevitable when burning fossil fuels and this has led to a substantial increase in their levels in the atmosphere (Union of Concerned Scientists, 2004). These higher levels of CO_2 are largely blamed for climate change and global warming. Approximately 340.6kg CO_2 is emitted per MWh of electricity generated in conventional PF stations (ESEERCO, 1995).

- Nitrogen oxides (NO_x), is a generic term for a group of highly reactive gases, which contain nitrogen and oxygen in varying proportions. These oxides are largely colourless and odourless except for nitrogen dioxide (NO_2) which can be seen as a reddish-brown layer in the atmosphere. Combustion NO_x emissions arise from two separate sources by means of quite different mechanisms. One source is the oxidation of nitrogen compounds in the fuel and the other source is from the fixation of atmospheric nitrogen in the flame. This is known as thermal NO_x. The two major products that result from the combustion of coal are NO_2 and nitric oxide (NO_3). These pollutants can irritate the lungs, cause bronchitis and pneumonia, and decrease resistance to respiratory infections. The transportation sector is responsible for close to half of the emissions of NO_x in South Africa while power plants produce a large percentage of the remainder (Union of Concerned Scientists, 2004). According to ESEERCO (1995), conventional PF emits 650g NO_x/MWh of electricity generated.

- Oxides of sulphur (SO_x) are formed when fuel containing sulphur is burned and the available sulphur in the fuel is oxidised to produce SO_x. These gases dissolve easily in water. One of the major components of SO_x is sulphur dioxide (SO_2) which dissolves in water vapour to form an acid, and interacts with other gases and particles in the air to form sulphates and other products that can be harmful to people and their environment (Institution of Electrical Engineers, 2002*)*. PF electricity generation emits approximately 604g SO_2/MWh of electricity generated (ESEERCO, 1995).

- Hydrocarbons (HC's) are a broad class of pollutants made up of hundreds of specific compounds containing carbon and hydrogen. They are usually generated due to their presence in the fuel or as a result of incomplete combustion. Some hydrocarbons present a direct health hazard, e.g. benzene and 1,3 butadiene are carcinogens. The simplest hydrocarbon, methane (CH_4), does not readily react with NO_x to form smog, but most other hydrocarbons do. Most hydrocarbons generally do not present a health risk. However they are oxidised to form oxygenated organic products and carbon monoxide, some of which can be harmful to human health (Union of Concerned Scientists, 2004). In the presence of NO_x, hydrocarbon oxidation also leads to ozone formation. Pulverised fuel (PF) electricity generation emits approximately 2.3g CH_4 and 4.6g Volatile Organic Carbons (VOC's) per MWh generated.

- Particulate matter (PM), is the term for particles found in the air, including dust, dirt, smoke, and liquid droplets. The main chemical components of concern in PM are lead, nickel, arsenic, and other trace metals. These particles can remain suspended in the air for long periods of time and vary in size from minute to large. They are respiratory irritants and can cause lung damage and respiratory problems (Union of Concerned Scientists, 2004). In addition, particulates may contribute to acid rain formation as a result of the chemical change of the gases that are indirectly formed when gases from burning fuels react with sunlight and water vapour. Particulates can also affect the diversity of ecosystems by altering the acidity of waterbodies thus affecting all life therein. Other impacts include depletion of nutrients in soil and damage to sensitive flora and farm crops (Institution of Electrical Engineers, 2002*)*. Particle matter is most usually described in terms of PM_{10}, which covers all the particles less than 10 microns in diameter. Particles with a size greater than 10 microns are not easily inhaled thus limiting its impacts on human health. According to ESEERCO (1995), conventional PF emits 49.5g PM_{10}/MWh.

3.1.1.2 Impacts of atmospheric pollution associated with electricity generation

- Photochemical Smog

Electricity generation does not emit ozone (O_3) directly into the atmosphere. It however results from the reaction of nonmethane hydrocarbons and NO_2 in the presence of heat and sunlight. This O_3 forms a white haze that is clearly visible over many cities and is called tropospheric ozone or smog. Limited exposure of humans to O_3 can result in shortness of breath, however prolonged exposure could lead to permanent lung damage. Ozone can also lead to a reduction in crop yields (Institution of Electrical Engineers, 2002*)*.

- Acid Rain

Acid rain is the term used to describe rainfall that is more acidic than what can be expected from natural processes. It is generally caused by water droplets absorbing hydrogen chloride (HCl), SO_x and NO_x from the atmosphere. Rain water is naturally acidic due to the fact that CO_2 in the atmosphere dissolves in water to form carbonic acid (H_2CO_3), however the anthropogenic emissions of sulphur and nitrogen adds substantially to these levels of acidity. They combine with water in the atmosphere to form sulphuric (H_2SO_4) and nitric (HNO_3) acids (Institution of Electrical Engineers, 2002*)*.

Acidic deposition occurs in two ways. Wet deposition occurs when water droplets in the atmosphere absorb gases and solid particles before falling to the earth as any form of precipitation, viz. rain, hail or fog. Dry deposition occurs when gases and solid particles settle on surfaces of the earth where it can acidify any moisture it comes into contact with. Surface water flow as a result of rain is responsible for the transport of this deposition to surface water bodies or the groundwater system. Their introduction to rivers and streams contributes to a progressive reduction in fish populations or their total elimination as a result of the change in habitat chemistry (Institution of Electrical Engineers, 2002*)*. There is an overall decline in the diversity of other freshwater organisms. Acid rain also causes substantial damage to plants and animals.

- Global Warming

The Earth's surface receives solar energy from the sun and the stability of the Earth's temperature depends on a proportion of this energy being radiated back into space. Various gases that occur naturally in the atmosphere, viz. water vapour (H_2O), carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), bring about a reduction in the re-radiation of solar energy. The net effect of this process is a rise in the average temperature of the earth and its surrounding atmosphere. This effect is termed "the greenhouse effect" due to its similarity to the trapping of heat in a greenhouse, where the glass has a similar effect. It must however be noted that this is a natural effect that adds about 30^{o}C to the Earth's temperature (Institution of Electrical Engineers, 2002*)*. The absence of this process would make life on earth impossible.

The "greenhouse effect" or global warming, as it is commonly referred to, is an increase in this natural effect as a result of man's activities through the burning of fossil fuels or destruction of the rain forests. Over the last 2 centuries, man has substantially increased the amount of greenhouse gases in the atmosphere through processes such as fossil fuel burning. Fossil fuels are primarily composed of carbon (C) and hydrogen (H), which on combustion are converted to water (H_2O) and CO_2. The combustion of fossil fuels has resulted in more than a 25 percent increase in the amount of carbon dioxide in the atmosphere since the 1880's (US Department of Energy, 2003). Fossil fuels are also implicated in increased levels of atmospheric methane and nitrous oxide, although they are not the major source of these gases.

Climate change is becoming a matter of increased concern and although there are uncertainties regarding the science of the relationship between man and the climate, it is obvious that climate change is linked to the increasing concentrations of greenhouse gases (GHGs) in the atmosphere. Carbon dioxide (CO_2) is the most significant of these GHGs. After the industrial revolution, the quantities of anthropogenic carbon dioxide emitted to the atmosphere increased substantially from the preindustrial levels of 280 parts per million (ppm) to present levels of approximately 365 ppm (US Department of Energy, 2003). The increased use of fossil fuels for power generation suggest a continued increase in carbon emissions and increased concentrations of CO_2 in the atmosphere unless major changes are made in the way in which we produce and consume energy (US Department of Energy, 2003). South Africa has been an active member of the United Nations Framework Convention on Climate Change (UNFCCC) and acceded to the Kyoto Protocol in August 2002. Currently South Africa is under no obligation to mitigate CO_2 emissions. As a coal intensive economy, however, it will be advantageous to remain aware of developments in this area.

Carbon dioxide is one of the most important of the man-made greenhouse gases, because of the sheer volumes emitted. It is potentially the most damaging of the power station emissions because, at present, there is no economical technology capable of removing CO_2 from flue gases (US Department of Energy, 2003). Other gases contributing to global warming include Chloro-Fluoro-Carbons (CFCs), which are also known to damage the ozone layer, and methane (CH_4), which occurs naturally in the decomposition of plant life, in land-fill sites and coal mines and is the main constituent of natural gas. Nitrous Oxide (N_2O) is a greenhouse gas, although a minor one, as is tropospheric ozone (O_3) produced by industrial emissions and exhausts from motor vehicles.

The main thrusts of CO_2 mitigation are carbon sequestration, de-carbonisation of fuels and improved efficiencies. Climate scientists predict that if carbon dioxide levels continue to increase, the planet will become warmer in the next century. Projected temperature increases will most likely result in a variety of impacts. In coastal areas, rising sea levels due to the warming of the oceans and the melting of glaciers may lead to the inundation of wetlands, river deltas, and even populated areas. Altered weather patterns may result in more extreme weather events and inland agricultural zones could suffer an increase in the frequency of droughts (US Department of Energy, 2003).

- Thermal Pollution

During the electricity-generation process, burning fossil fuels produce heat energy, some of which is used to generate electricity. Because the process is inherently inefficient, much of the heat is rejected to the atmosphere. This rejected heat can have impacts on the climate of an area by altering the temperature regime and altering its weather patterns (Union of Concerned Scientists, 2004).

- Trace Elements and Radioactivity

A number of trace elements occur naturally in small quantities in fossil fuels, although the proportions thereof are known to vary widely. Examples of these elements include arsenic, lead and mercury, which are known to be toxic or have other negative environmental effects. Radioactive trace elements including uranium, thorium and radium are also present in fossil fuels. The proportions of trace elements in coal are generally minimal, however, due to the large quantities of coal that are burnt in a power station and the tendency of these elements to become selectively concentrated in the fly ash particles, comparatively high concentrations of these elements result in both the collected and emitted ash. Most of these elements are locked into the ash particles and are not readily soluble and therefore are not biologically active (Institution of Electrical Engineers, 2002*)*.

3.1.2 Emissions to Water

Coal-fired power stations use substantial amounts of water for cooling purposes. In light of the fact that South Africa is a water scarce country, a reliable supply for power generation is ensured by building reservoirs at the power station to ensure a supply for several days of power generation.

Eskom developed a philosophy of zero-liquid effluent discharge (ZLED) at all its newer power stations. This implies that within the water management system, a hierarchy of water uses, based on quality, is established. A system of re-use exists whereby the effluent from one water using system would be utilised by another system, where lower quality water is acceptable, and so consecutively down to final consumption by evaporation or encapsulation in the ashing systems (Gewers, 2004). Water is effectively lost only by evaporation, whilst the accompanying dissolved salts are encapsulated in the coal ash deposits.

Pollutants build up in the water used in the power plant boiler and cooling system. If the water used in the power plant is discharged to a lake or river, the pollutants can harm fish and plants. Further, if rain falls on coal stored in piles outside the power plant, the water runoff can flush heavy metals such as arsenic and lead from the coal into nearby bodies of water or the groundwater. Surface as well as groundwater may be polluted from leachates seeping through coal stockyards, coal discard dumps, ash dams, as well as solid waste sites.

Liquid effluents from a coal-fired plant may include boiler blowdown, cooling process wastes, coal pile run-off, cooling process wastes and boiler cleaning wastes, floor and equipment drains, storm water drains and sewage discharges. Most of these discharges would harbour low levels of residual pollutants, which are normally non-biodegradable in nature. Residual waste compounds may therefore include small amounts of metals and residual chlorine, salts, phosphorous and ammonia from boiler blowdowns (Power Scorecard, 2004a).

A variety of processes associated with fuel handling and ongoing maintenance of large thermal power plants create or concentrate chemical pollutants that are then discharged into nearby water bodies. Even when releases are limited to what is allowed in water use permits, there is still the occasional accidental release.

Although both of these sources of pollution are within legal limits, they can cause significant harm to streams, rivers, lakes, estuaries and the groundwater system. Water quality can degrade to the point where fish and other aquatic populations decline - even when power plant operators abide by water permit restrictions. Often, the water used in the power plant is also being diverted from other "higher" uses such as recreation or tourism, drinking water supplies, and other less intrusive commercial opportunities (Power Scorecard, 2004a).

The biggest potential for environmental impacts is as a result of thermal pollution from the cooling water outfall. Emitting cooling waters with elevated temperatures (thermal emissions) with respect to receiving waterbodies could have the following negative effects:

- Impacts as a result of reduced oxygen supply

An important physical property of water is its ability to dissolve gases that sustain macro and microfauna. The solubility of gases is an inverse function of temperature and time. A sustained increase in water temperature decreases the capability of water to retain dissolved oxygen. Aggravating this condition is the fact that aquatic organisms metabolic rates are increased by the rise of temperature, resulting in an increased demand for oxygen. The overall effect of thermal pollution will therefore be to reduce the overall number of individual organisms as well as the number of species that exist in the area. Alternatively, discharging cooler water should increase the capability of water to retain dissolved oxygen. This may still impact on the type of species that exist in the area and impacts could result from opportunistic species taking advantage of the altered temperature regimes.

- Impacts resulting from direct mortality of macro and micro fauna and decreases in food availability in the outfall plume

Large quantities of water will pass through the system daily. This water will contain a vast number of larvae, spat and planktonic organisms. The entrainment process subjects these organisms to stresses, namely heat, chlorination as well as physical forces. This typically results in high levels of mortality of the affected organisms as well as reducing food availability for other organisms in the plume around the outfall.

- Impacts of chlorine or other biocides

This impact may be significant even when the wastewater is dechlorinated and the concentrations at the outfall are very low. A number of marine species are very sensitive to chlorine in the water column.

3.1.3 Water Requirements

Thermal electricity generating facilities produce electricity through the conversion of water into high-pressure steam that drives a turbine. The water that passes through this cycle is cooled and condensed back into water before it is reheated to drive the turbines again. The condensation process requires a separate cooling water body to absorb the heat of condensation. These condenser systems generally consist of thousands of one-inch diameter tubes, through which cooling water is run, and over which the steam is circulated (Power Scorecard, 2004a).

There are two cooling technologies that are currently used, closed-cycle systems and once through systems. Closed-cycle systems discharge heat through evaporation in cooling towers and recycle water within the power plant. The water required to do this is comparatively small since it is limited to the amount lost through the evaporative process. Once-through systems require the intake of a continual flow of cooling water. The water demand for the once-through system is 30 to 50 times that of a closed cycle system. In light of the expenses associated with closed-cycle cooling, once-through systems are far more common (Power Scorecard, 2004a). The amount of water used for power plant cooling also varies depending on each specific power plant's generating technology and size. According to ESEERCO (1995), PF stations with closed cycle cooling systems utilise approximately 1.06 liters/ kWh of electricity generated.

Large quantities of water are also frequently needed to remove impurities from coal at the mine. In addition, coal-fired power plants use large quantities of water both for producing steam and for cooling. When coal-fired power plants remove water from a lake or river, fish and other aquatic life can be affected, as well as animals and people who depend on these aquatic resources.

3.1.4 Waste Generation

A large coal-fired power station produces approximately 1 million tonnes of ash each year (Michael, 2004), together with small quantities of other waste. Ash is composed primarily of metal oxides and alkali. Much of this waste is deposited in landfills and abandoned mines, although some amounts are now being recycled into useful products, such as cement and building materials. This ash is removed from the power station, and deposited in dumping sites that cover large areas of the surface, rendering these land areas useless for other purposes. Apart from covering land, the ashing sites can also cause dust problems when wind blows the fine ash into the atmosphere. Water leaching through the ash can result in alkaline surface run-off that can pollute streams and groundwater

The other smaller volumes of waste produced at power stations include:

- domestic waste mainly from the offices,
- kitchen wastes mainly from the canteens and
- maintenance waste, that includes garden wastes, building rubble and metals.

Hazardous wastes products at a power station, include asbestos insulation from the older power stations and oil wastes containing polychlorinated biphenyls (PCB), which are still contained in equipment such as transformers, medical wastes from medical centres, fluorescent tubing and batteries used in the power station, oils and greases, and solvents from the chemical laboratories, which may be considered to be of a hazardous nature.

3.1.5 Noise

Most of the activities relating to the construction and operation of power stations are generally noisy. The constant maintenance, transport and waste disposal mechanisms contribute substantially to increased noise levels.

3.1.6 Land and Aesthetics

The construction of a power station uses many hectares of land. However, those portions of land that are not utilised, are leased to farmers who continue farming practices. Soil at coal-fired power plant sites can become contaminated with various pollutants from the coal and take a long time to recover, even after the power plant closes down (Power Scorecard, 2004b).

The general infrastructure, coal stockpiles, ash disposal heaps and gaseous emissions impact on the environmental aesthetics around power stations, where land degradation through erosion, as well as a deterioration in the natural fauna and flora can occur if not properly managed. The power station buildings use relatively small areas of the total land area, however, the sites utilised for ash dams cover large areas, as these are continuously growing features. The coal stockpiles sites are smaller, because the amount of coal kept in these stockpiles are relatively fixed. A conventional PF station utilises approximately 0.299 hectares /MW of capacity for the station (ESEERCO, 1995).

The utilisation of land for power generation has however, over the years proved to have a positive, rather than a negative effect on the environment. The eradication of exotic or invader species of both fauna and flora often improves the veld surrounding the power station (Michael, 2004). Indigenous species are re-introduced, and protected, eroded land is rehabilitated and further erosion prevented, while new habitats are created at the water reservoirs, as well as the dirty and clean water dams of the power station.

3.1.7 Impacts associated with the mining and transportation of coal

The mining and transport of coal has substantial environmental impacts. These impacts have not been discussed as they fall outside the scope of this study.

3.2 GAS-FIRED GENERATION

This section details the impacts associated with the generation of electricity from natural gas and the expected levels of impacts have been sourced from the New York State Environmental Externalities Cost Study (ESEERCO, 1995). The values are based on the average emissions for gas-fired facilities from the US.

3.2.1 Emissions to Air:

- Oxides of Sulphur

The negligible quantity of sulphur present in natural gas means that the concentrations of SO_2 in the flue gas will be minimal. When using distillate fuel oil, the concentration of SO_2 in the flue gas will be limited due to the comparatively low sulphur content of distillate fuel oil (max. 0.3% by weight). A natural gas-fired CCGT emits approximately 1.5g SO_2/MWh of electricity generated (ESEERCO, 1995).

- Oxides of Nitrogen

The production of nitrogen oxides is unavoidable for any power station burning fossil fuels however this can be limited by the Dry Low NO_x (DLN) combustion system suitable for certain gas turbines. This system includes the use of a wet control system when burning distillate fuel oil.

The DLN combustion system is designed to minimise the creation of nitrogen oxides during the combustion process, but it cannot eliminate them completely (Chappel *et al, 1994.* p8). The waste gases are emitted from approximately 40-60m high stacks at sufficient velocity and temperature for a substantial plume rise. This causes dispersion of the NO_x formed during combustion so that the impact on background level concentrations is insignificant. Combustion NO_x emissions as a result of the oxidation of nitrogen compounds in the fuel is not significant due to the low levels of nitrogen compounds in natural gas and distillate fuel oil.

The other source is from the fixation of atmospheric nitrogen in the flame. This is known as thermal NO_x. Dry low NO_x burners are designed to minimise thermal NO_x. The rate of generation of thermal NO_x is generally accepted as being an exponential function of flame temperature and the time that the hot gas mix is at flame temperature (Chappel *et al*, 1990. p 148). Flame temperature is highest when there is just enough fuel to react with all of the available oxygen. This is called the stoichimetric mixture. It follows that adjustment of the fuel/oxygen mix away from the stoichimetric mix will reduce the flame temperature. This adjustment can be achieved by either increasing or decreasing the fuel (fuel rich or fuel lean) for available oxygen. It is better to control the NO_x emissions through the fuel lean method since this means that fuel is not wasted and unburned hydrocarbons are not released into the atmosphere. CCGT plants emit approximately 31g NO_x/MWh of electricity generated (ESEERCO, 1995).

- Oxides of Carbon

Gas contains a much lower proportion of carbon than oil or coal, so the use of gas as a primary fuel causes less CO_2 to be produced per unit of electricity. For a fixed amount of energy generated by either gas or coal, gas-fired generation produces approximately 50% of the CO_2 that would normally be produced by coal-fired generation (Clark *et al, 1991*).

In addition, the efficiency with which energy is converted to electricity in a gas fired combined cycle plant is greater than that of the most efficient PF coal-fired stations, around 55% for gas compared with 38% for coal. This has the effect of reducing the production of CO_2 per unit of electricity generated even further. Approximately 181.1kg of CO_2 is emitted per MWh of electricity generated (ESEERCO, 1995).

Together with the lower carbon content of gas and the greater conversion efficiencies, the Combined Cycle plants result in minimal CO emissions (Chappel *et al*, 1990 p 148). CCGT plants emit approximately 12.4g CO per MWh of electricity generated (ESEERCO, 1995).

- Unburned Hydrocarbons (UHC)

Multi-burner combustion chambers, which characterise most gas turbines, ensure almost complete combustion of all fuels. Approximately 99.99% combustion efficiency results in a minimum of unburnt hydrocarbons (UHC) and negligible CO emissions.

Under mid-merit operating conditions, using natural gas (dry) with a 15% oxygen content, the concentration of UHC in the exhaust gas amounts to only 4ppmv. This corresponds to just 18mg/kWh. Approximately half of this is methane, which is assessed to contribute the equivalent of 21 times more to the greenhouse effect than carbon dioxide. In light of this, the emissions can be considered the same as 740mg CO_2 per kWh (Chappel *et al*, 1990 p148). This is insignificant when compared to the actual amount of CO_2 that is released. Burning distillate oil or other fuels increases the UHC emission but this is dependent on the properties of the fuel utilised.

The non-methane components of the total UHC, also known as Volatile Organic Carbons (VOC's) are particularly important because of their ability to form ozone in the atmosphere in conjunction with NO_x and sunlight. They contribute roughly half of the total UHC. A CCGT plant emits approximately 1.9g CH_4 and 4.7g Volatile Organic Carbons (VOC's) per MWh of electricity generated (ESEERCO, 1995).

- Particulate Matter

The emission of particulate matter from the combustion process will be negligible. This is because there are negligible quantities of solid matter in the fuel and the air drawn into the gas turbine compressors will be cleaned by passing through filters. These filters must be replaced periodically. The frequency of replacement is typically between 6 months and 2 years. When burning distillate fuel oil, a small emission of particulate matter occurs as the oil will contain very small quantities of ash (approx. 0.01% by weight). According to ESEERCO (1995), a CCGT emits 15.5 g PM_{10}/MWh of electricity generated.

- Heat

The majority of the losses resulting from a single gas turbine are from discharge in the form of hot exhaust gas to the atmosphere. This means that some of the useful energy in the fuel supplied to the turbine is rejected directly into the atmosphere. However, converting the single gas turbine to a combined cycle gas turbine to obtain a higher than 55% efficiency, results in the plant generating more power for the same amount of fuel as a PF station, thereby leading to a corresponding reduction in heat rejected to the environment (Chappel *et al*, 1994 p4). CCGT's major heat losses occur as a result of heat rejected indirectly into the atmosphere as a form of low–grade thermal energy from the lower steam turbine condenser to an appropriate heat sink, e.g. a river or the sea.

3.2.2 Emissions to Water

The operation of the gas turbine, where air is passed through a compressor, heated, expanded through a turbine and then exhausted, may result in the deposition of airborne impurities on the compressor blading. These compressors may be cleaned either off-line when cold, or on-line during operation. Periodic off-line cleaning, combined with cyclic on-line cleaning has been identified as the most effective method of achieving consistently high levels of performance over long periods of operation. On-line washing is done with reserve feed water, while for off-line washing, a detergent solution is used.

The gas turbine blading may be cleaned while the plant is on-line or off-line using a hydrocarbon based solvent, which will be mixed with water to form an emulsion. In the course of on-line cleaning, the solvent and any dissolved oils and greases scoured from the blading will be completely burned in the combustion chamber of the gas turbine. The effluent produced by the off-line cleaning will be drained from the compressor housing using a controlled process, passed through an oil separator and pumped to an adequate disposal system. The best anti-fouling agent that can be utilised in the cooling water system is a sodium hypochlorite solution, containing 15% available chlorine (Anon, 1993). The hypochlorite solution is injected directly into the cooling water by a controlled pumping system. The minimum effective injection of hypochlorite necessary is used. The residual oxidant in the purge water is monitored. Below are some guidelines for the handling and disposal of effluents.

- Warm Water Discharges: To maintain cooling water quality, water must be purged from the system continuously after passing through the cooling system. The temperature differential between the discharge water temperature and receiving water body temperature must be of a level that would not have any adverse impact on aquatic fauna and flora in the thermal sink.

- pH limits: All effluent from the demineralisation plant must be neutralised before being discharged to any water system.

- Suspended solids: To maintain the availability of the system, the intake pipework and screens are backwashed in daily rotation to clear any larger solids that have settled out. Downstream of the make up pumps, filters are installed to remove any particles larger than 300 microns. These filters are automatically backwashed according to the rate of accumulation of solids. Under extreme tidal or seasonal conditions, backwashing could effectively be continuous but normally would be on an intermittent basis. The filter backwash would then be returned to the aquatic system with the main cooling water purge.

- Oils: There is a risk of contamination with oil, water spillage or leakage from within the plant buildings and this is drained to the wastewater pump house through an oil separator. The cleaned wastewater is pumped to the river with the cooling water purge effluent. Accidental spillage of oil on site is minimised by good housekeeping practices, secure storage of reserve stocks and local containment of all areas liable to oil contamination by use of sumps or bunds. This containment will allow the discharge of effluent under controlled conditions.

All effluent, which may be contaminated with oil, must be passed through oil separators before being discharged into the local drainage system.

Reduced ground water consumption and the non-existence of coal or ash dumps reduces the risk of ground water contamination significantly.

3.2.3 Water Use

Water requirements for the closed cycle cooling for a CCGT plant compares favourably to that of a coal-fired plant. According to ESEERCO (1995), CCGT stations with closed cycle cooling systems utilise approximately 0.94 liters of water for 1 kWh of electricity generated. Potable water is also required for cleaning, fire fighting and for domestic use.

3.2.4 Waste Generation

Gas-fired electricity generation technologies generates less waste compared to conventional coal fired stations that produce large volumes of ash. The only general solid waste that is produced by a gas-fired power station is the same as produced by a workshop for ± 100 people.

3.2.5 Noise Impacts

A CCGT can generate high noise levels that are associated with air intakes for gas turbines, the combined operation of the gas turbines, generators, transformers, pumps, pneumatic controls, diesel generator sets and generator ventilation systems. The gas turbine air intake facility causes the highest level of residual noise (78 dB at 1m from the gas turbine building) as it is located outside (ABB, 1995). Acoustic enclosures reduce the internal build up of noise and minimise its transmission outside.

The maximum acceptable levels in terms of the World Bank noise guidelines for an industrial or commercial area are an equivalent sound level (Leq) of 70 dB(A) over a one-hour period. This is measured at receptors located outside the property boundary. The maximum allowable increase in the existing ambient noise levels is Leq 3 dB(A) where existing ambient levels exceed Leq 45 dB(A).

3.2.6 Land and Aesthetics

A 2500 MW CCGT can be sited on 12 ha compared with 200 ha for an equivalent coal-fired facility (Chappel *et al*, 1990). Conventional coal-fired power plants are usually characterised by high stacks and large boiler furnaces while CCGT's possess low stack heights (40-60m above ground). This is due to the fact that no particulate emissions are generated and gas fired stations generally have low levels of emissions.

The overall visual impact is positive to a large extent as a clean facility results from the absence of coal dust, ash and fine particulate. The supply of natural gas to the plant can be achieved via underground piping and this has substantially less impact when compared to a coal-fired facility, which would have to obtain its coal supplies by a conveyer, trucks or rail transport. The compact nature of the plant and the reduced need for auxiliary equipment such as precipitators, coal staithes, and ash dumps mean a much-reduced land demand in comparison to conventional coal-fired facilities thereby leaving more land available for other development purposes. The visual impact of the power station structures depends on their relationship to the landscape. A CCGT station utilises approximately 0.045 hectares/MW of capacity (ESEERCO, 1995)

3.2.7 Impacts associated with the extraction and delivery of natural gas

There are substantial environmental impacts associated with the extraction and delivery of offshore and onshore natural gas, however, these impacts are not discussed as they fall outside the scope of this study.

3.3 INTEGRATED GASIFICATION COMBINED CYCLE

This section details the impacts associated with the generation of electricity from IGCC and the expected levels of impacts have been sourced from the New York State Environmental Externalities Cost Study (ESEERCO, 1995). The values are based on the average emissions for IGCC facilities from the US.

3.3.1 Emissions to Air:

- Oxides of Sulphur

Most of the sulphur present in coal is released at high temperatures during the entrained flow gasification process, and converted to H_2S, as well as a small amount of carbonyl sulphide (COS). These products are formed due to the reduced oxygen environment. These H_2S, COS and particulate contaminants are largely removed from the syngas prior to combustion by acid gas removal equipment. Approximately 95-99% of the H_2S and COS are removed from the fuel gas and converted to a saleable sulphur or sulphuric acid (H_2SO_4) by-product (Ratafia-Brown, *et al*, 2002). The minimal amounts of residual sulphur that are still present in the syngas are converted to SO_2 in the combustion turbine and released to the atmosphere in the primary stack gas or in the secondary stack gas from the sulphur recovery equipment. A IGCC emits approximately 61.9g SO_2/MWh (ESEERCO, 1995)

- Oxides of Nitrogen

Majority of the NOx produced during the combustion of syngas is in the form of NO, however it is subsequently oxidized to NO_2 in the atmosphere. Coal, unlike natural gas, contains chemically bound nitrogen that forms a larger percentage of the NOx emissions when combusted in a typical excess-oxygen environment, such as a utility boiler. Over 80% of the total NO_x emissions in a coal-fired combustion unit are due to the NO present in the fuel. It must however be noted that its formation is not dependant on the flame temperature (Ratafia-Brown, *et al*, 2002).

The gasification process differs significantly from PF coal-fired plants with respect to the effect on chemically bound nitrogen in coals. Due to the fact that gasification operates with a deficiency of oxygen, most of the fuel nitrogen is converted into harmless nitrogen gas (N_2) with a small portion converted to ammonia (NH_3), as well as small amounts of hydrogen cyanide (HCN) and thiocyanate. These water-soluble species are removed during fuel gas cooling and cleaning and are usually converted to nitrogen in the sulphur recovery process. The product fuel gas is virtually free of fuel-bound nitrogen and NO_x formation arises primarily as a result of thermal NO produced at the high temperatures in the combustion turbine. NO_x formation can be reduced by maintaining a low fuel-air ratio (lean combustion) and adding a diluent (e.g., nitrogen from the air separation unit or steam), thus lowering the flame temperature (Ratafia-Brown, *et al*, 2002). IGCC plants emit approximately 155g NO_x/MWh (ESEERCO, 1995).

- Oxides of Carbon

The sources of CO emissions in an IGCC system are typically the gas turbine, sulphur recovery unit tail gas incinerator, and the flare system and equipment leaks. The largest contributor to greenhouse gas (GHG) emissions from IGCC power generation is the production of CO_2 from the carbon originally contained in the fuel that is gasified. The production of other GHG emissions, such as N_2O and NH_3, are insignificant compared with CO_2 (Ratafia-Brown, *et al*, 2002). Although CO_2 emissions are higher than natural gas-fired plants, IGCC's improved efficiency reduces CO_2 emissions relative to conventional PF coal fired plants. The high CO_2 concentrations in the syngas and relatively high pressures that IGCC gasifiers typically operate under, make the recovery of the CO_2 from the syngas much easier than capture from flue gas. A recent study of one design concept concluded that 75% of the CO_2 could be captured from an IGCC plant with only a 4 percent loss in efficiency (Ratafia-Brown, *et al*, 2002). Approximately 306.5kg of CO_2 and 3.1g of CO is emitted per MWh by an IGCC system (ESEERCO, 1995).

- Particulate Matter

The control of particulates in a gasification process is highly efficient, due to the fact that gasifiers operate at high pressure and generate a significantly smaller gas volume than coal combustion. The gasification process does not only provide an inherent capability to remove most of the ash as slag or bottom ash, but the fly ash produced is concentrated in a smaller gas volume and this substantially assists in its cost effective collection (Ratafia-Brown, *et al*, 2002). Particulate removal also occurs in the gas cooling operations and in the acid gas removal systems. As a result, very low particulate emission levels can be achieved. According to ESEERCO (1995), an IGCC emits approximately 31g PM_{10}/MWh.

- Heat

IGCC can achieve efficiencies approaching 50% and this results in the plant generating more power for the same amount of fuel as a conventional PF station, thereby, leading to a corresponding reduction in heat rejected to the environment.

The majority of the heat losses associated with an IGCC plant are from heat rejected indirectly into the environment as a form of low–grade thermal energy from the lower steam turbine condenser to an appropriate heat sink.

3.3.2 Emissions to Water

Coal gasification plants have two main water effluents that are similar to those in PF plants. The first is wastewater from the steam cycle, which includes blowdowns from the boiler feedwater, purification system and the cooling tower. Gasification processes generally purify and recycle raw process streams, and net water discharge is normally only a blowdown stream. These effluents contain salts and minerals that result from concentration of the raw feedwater (Ratafia-Brown, *et al*, 2002). The second aqueous effluent is process water blowdown, which is typically high in dissolved solids and gases along with the various ionic species washed from the syngas. This process water blowdown is typically recycled to any one of the coal feed preparation areas, the scrubber after entrained solids have been removed, a zero discharge water system or a wastewater treatment system. Wastewater control technologies vary significantly, however all the necessary control technologies are commercially available and are currently used in various industries, such as chemical, pulp and paper, oil, and steel. Overall, water effluents may create fewer problems for IGCC than for PF power generation, due to the fact that the steam cycle in an IGCC plant produces less than 40% of the power plant's output (Ratafia-Brown, *et al*, 2002). In light of this, effluents from boiler feedwater preparation and cooling-water blowdown are significantly reduced. However, the amount of process water blowdown is about the same for both gasification and PF combustion.

3.3.3 Water Use

An IGCC plant will utilise marginally more water than a CCGT plant. This is primarily due to the fact that the water requirements of the combined cycle component of the IGCC plant will remain the same however additional water will be required by the gasifier. Overall the expected consumption of water will be approximately 50-60% of that used by a reference PF coal-fired unit.

3.3.4 Waste Generation

The largest solid waste stream produced by recent IGCC installations is slag, a black, glassy, sand-like material that is potentially a marketable by-product. Slag production is a function of ash content, so coal produces much more slag than an alternative fuel such as petroleum coke. Regardless of the feed, as long as the operating temperature is above the fusion temperature of the ash, slag will be produced. This gasifier slag is highly non-leachable. The possible use of slag in a variety of applications may negate the need for long-term disposal. The primary technical barrier to using IGCC slag for applications such as cement production is excessive carbon content, but technical solutions have already been developed. The Polk IGCC plant has installed additional slag handling equipment to separate unconverted carbon (Ratafia-Brown, *et al*, 2002). Not only does the slag meet specifications, but also the unconverted carbon can be recycled back to the plant or used elsewhere.

The other large-volume by-product produced by IGCC plants is solid (or liquid) sulphur or sulphuric acid, both of which can be sold to help offset plant-operating costs. In comparison, most coal combustion plants recover sulphur as wet scrubber sludge, dry or semi-dry spent sorbent, or gypsum. These sulphur forms have significantly larger mass and volume than elemental sulphur, are often more difficult to handle and market, and must usually be disposed of in an appropriate landfill or surface impoundment.

3.3.5 Noise Impacts

The noise impacts for an IGCC will be similar to a CCGT with the major source being the air intakes for gas turbines, the combined operation of the gas turbines, generators, transformers, pumps, pneumatic controls, diesel generator sets and generator ventilation systems. The gas turbine air intake facility causes the highest level of residual noise. Acoustic enclosures reduce the internal build up of noise and minimise its transmission outside.

3.3.6 Land and Aesthetics

The area required for siting a CCGT power station is roughly 30% of that required for a reference coal-fired unit. The additional requirements of the coal stock yard and gasifier, as components of an IGCC, would increase this comparative area to approximately 40-50% of a PF station. According to ESEERCO (1995), an IGCC station utilises approximately 0.121 hectares/MW of capacity.

IGCC plants will have similar impacts to a CCGT plant however the presence of coal staithes, storage silos, the coal gasifiers and slag storage facilities will increase these impacts. An IGCC will have a reduced aesthetic impact compared to a reference coal fired unit, however this will be substantially more than a reference gas-fired unit. Emissions will be substantially lower than a PF station but higher than a CCGT. An IGCC will also generate substantial wastes, due to its use of coal as a fuel. These wastes can however be sold as by-products.

3.3.7 Impacts associated with the extraction and delivery of coal

The impacts associated with the delivery of coal are the same as discussed for PF coal-fired plants under section 3.1.7.

CHAPTER 4

4 COMPARATIVE ASSESSMENT OF ENVIRONMENTAL IMPACTS ASSOCIATED WITH THE THREE TECHNOLOGIES.

In this chapter, conventional coal-fired power generation (PF) options, combined cycle gas turbine (CCGT) and integrated gasification combined cycle (IGCC) options are compared against each other in terms of environmental performance.

The environmental performance of the different technologies in terms of stack emissions of criteria pollutants, ionic species and CO_2, water consumption, and solid waste/by-product generation are tabulated in Table 2. The data for these technologies were obtained from the reference data provided by the ESEERCO (1995). The data is an average for power stations monitored by the US Environmental Protection Agency (EPA) and the Electric Power Research Institute (EPRI) across the US. Emissions for a PF plant are based on the incorporation of advanced emission control technologies in the form of wet, limestone flue gas desulfurization (FGD) for SO_2 control, low-NO_x burners and selective catalytic reduction (SCR) for high-efficiency NO_x control, and an electrostatic precipitator (ESP) for particulate control. It is also assumed that CCGT's utilise SCR equipment for NO_x removal.

It can be seen that a CCGT generally emits far lower levels of pollution than any of the other technologies. Combined cycle plants using natural gas as fuel are 'clean' power generation systems. Unlike other fossil fuels, natural gas produces virtually no SO_2 and also relatively little CO_2 when burned. The impact of combined cycle power plants on the environment is therefore considerably reduced. Also combined cycle plants use combustion technology, developed by certain technology suppliers, which reduces other harmful pollutants such as NO_x, CO and UHC (Unburned Hydro Carbons) to just a few ppm, well below the levels prescribed in most countries.

An IGCC yield the lowest SO_2 emissions among the technologies due to its amine-based process for acid gas control that removes up to 99% of the sulphur. The wet FGD process employed by the PF plant is also capable of very efficient SO_x removal levels of up to 95%. The effectiveness of these acid gas control systems and efficient particulate control are highly effective in limiting the emissions of ionic species. Conventional PF systems emit the highest levels of uncontrolled NOx emissions in light of the very high combustion temperatures and the combustion method utilised in this technology. However, SCR technology can be used to reduce these NO_x emissions by up to 90%. In IGCC and CCGT systems, the fuel gas produced is virtually free of fuel-bound nitrogen and NO_x forms primarily as a result of thermal NO formation in the gas turbine combustor. In light of this, CCGT and IGCC equal or exceed the

NO_x emissions performance of the other technologies without the use of additional control equipment. All of the technologies make use of highly efficient particulate control equipment to limit PM_{10} emissions. However, in CCGT and IGCC, particulate emissions are generally influenced by the particulates contained in the input air. In natural gas and IGCC systems, this is minimal due to the acid gas cleanup procedures prior to combustion of the gas in the turbine. The particulate control devices also effectively control non-volatile trace elements by promoting their selective condensation on the fine particles of fly ash that is removed from the flue gas of a plant. These trace organic and inorganic species are disposed of with the wastes at a waste dump. It must, however, be noted that some of the semi-volatile and volatile species, such as mercury, may not be removed in the particulate collection equipment. In general, trace metal emissions are quite low for all technologies, and IGCC or CCGT emissions appear to be comparable to a well-controlled coal-fired power plant.

Carbon dioxide emissions of the respective cycles generally correlate with their thermodynamic efficiencies, compared on an electricity output basis. Therefore, CCGT has the lowest CO_2 emissions with the IGCC plant close behind. In addition to the low levels already achieved, the IGCC's systems also provide optimum conditions for CO_2 removal prior to combustion, if this is required. This capability has the potential to further favour IGCC systems from the other coal-fueled power generation technologies. Depending upon a plant's location, captured CO_2 has the potential to be transported to an appropriate area where it can be utilised for enhanced oil or gas recovery applications or sequestered in an appropriate reservoir.

IGCC's and CCGT's clearly have an advantage with respect to water consumption over PF systems. CCGT and IGCC systems consume approximately 30% to 60% less water thus allowing them greater siting and permitting flexibility. CCGT systems generate minimal wastes while IGCC systems solid waste generation amounts to about 75% less than that produced by a PF plant. All the technologies produce by-products that may have commercial value. Gasification products however include slag, sulphur, ammonia, tars and sludge, toluene, napthalene, anthracene and phenols, and the demand and higher value returns of certain chemicals could possibly offset the higher costs associated with commissioning an IGCC power station.

Table 1: Comparative assessment of a PF coal-fired, CCGT and IGCC power station.

	PF	**CCGT**	**IGCC**
Fuel Supply	Coal Mine Overland Coal Conveyer Strategic Stockpile	Gas Field Offshore Pipeline Landfall Onshore Pipeline	Coal Mine Overland Coal Conveyer Strategic Stockpile
Power Station Facilities	Coal Staithe Boiler FGD DENOX Precipitators Ash Conveyers Ash Dump Gypsum Dump Steam Turbine Cooling System	Gas Storage Tanks Gas Turbines Heat Recovery Steam Generator (HRSG) Steam Turbine Cooling System	Coal Staithe Gasifier Gas Cleanup Plant Gas Turbine HRSG Slag Conveyers Slag Storage Steam Turbine Cooling System
Efficiency*	36-40%	55-60%	44-46%
Water Use*	1.06 m^3/MWh	0.94 m^3/MWh	1.06 m^3/MWh
Emissions*			
CO_2	340 kg/MWh	181.1 kg/MWh	306.52 kg/MWh
PM_{10}	49.5 g/MWh	15.5 g/MWh	31 g/MWh
SO_2	0.604 kg/MWh	1.55 g/MWh	61.9 g/MWh
NOx	0.650 kg/MWh	31 g/MWh	154.8 g/MWh
Wastes Generated*			
Ash	±78.1 kg/MWh	Minimal	±17.8 kg/MWh
Landfill	±2.9 kg/MWh	±0.36 kg/MWh	±2.6 kg/MWh

* - Sources: ESEERCO, 1995.and Wibberley *et al, 1999.*

CHAPTER 5

5. VIABILITY OF IMPLEMENTING THESE TECHNOLOGIES IN SA

An attempt is made in this chapter to identify the viability of implementing the technologies under consideration in South Africa. The main requirement of any electricity generation technology is an adequate supply of fuel, which is economically feasible for the operation of the power station over its design life. The technologies discussed in this study use either coal or natural gas as fuel and the following section attempts to briefly outline the availability of coal and natural gas in South Africa. A limited description of the economics associated with the various technologies is also provided in this chapter, along with the influence of fuel prices and availabilities on the viability of implementing these technologies in the country.

5.1 FUEL AVAILABILITY

The coal resources of Southern Africa, and especially South Africa, are abundant. Recoverable reserves in South Africa are estimated at 54.6 billion short tons (EIA, 2004). This represents 6% of world recoverable coal reserves. In 2001, regional coal production reached nearly 257 million short tons, of which South Africa produced 250.3. Coal in the region is used primarily for electricity generation and there are more than adequate supplies to meet demand well into the 21st century. The high availablity and low costs of coal have made it the preferred fuel for electricty generation in South Africa.

Africa's proven gas reserves have grown significantly over the past 20 years and in 1995 totalled 6.3 trillion cubic metres (tcm) with potential reserves estimated to be 17.65 tcm. Of the gas reserves in Africa, 50% is associated gas. Nigeria has 78% of the proven gas reserves, while the balance is confined to a few other countries which include Algeria, Egypt, Angola, Mozambique, Namibia and Tanzania (Mbendi, 2004). Large-scale utilisation of gas for local consumption in Africa is restricted to four countries, viz. Nigeria, South Africa, Angola and Gabon. Algeria accounts for approximately 66% of natural gas produced on the continent however a large proportion of this is exported to Europe.

The total natural gas reserves in Southern Africa are estimated at 4.765 billion cubic metres (bcm) and present recoverable reserves are estimated at 870 bcm (Mbendi, 2004). The most notable reserves are concentrated in Angola, Mozambique and Namibia. The majority of this gas is flared while approximately 11% are used for field operations. The previous development and utilisation of gas in Africa has been impeded by several factors. These included hydrocarbon laws which tend to ignore gas and uncompetitive taxes and incentive schemes that discourage potential investors (Mbendi, 2004). The domestic demand for gas in most countries of Africa is not substantive enough, by international standards, to encourage development. The creation of regional markets are further complicated by factors including high political risks of countries with exploitable gas reserves, and the political mistrust prevalent between neighbouring states. Additional obstacles include payment risks associated with the weak financial position of gas customers, higher costs that arise primarily as a result of corrupt and inefficient practices and finally an inadequate return on the investment laid out (Mbendi, 2004).

The development of the South African gas industry has been limited by gas resources. This contrasts with the situation in Namibia and Mozambique who possess substantial gas reserves, but are unable to utilise this resource. In order to overcome the problem, agreements have been entered into between the governments of Mozambique and Namibia and the government of South Africa to supply natural gas to South Africa (DME, 2004). The two major sources of supply include the Pande and Temane fields in Mozambique and the Kudu field in Namibia.

In September 2003, the Minister of the Department of Minerals and Energy of South Africa outlined a general timetable for the construction of pipelines in which the state-owned Oil Company PetroSA will participate. The Minister indicated that once the pipeline between Temane in Mozambique and Secunda in South Africa was fully operational, South Africa would build another to supply the Western Cape from either the Kudu fields in Namibia or the Ibhubesi fields in South Africa. A third pipeline would subsequently link the West Coast to Gauteng via Sishen, followed by a fourth that would supply Port Elizabeth (Infochain, 2004b). In addition to the supply of environmentally friendly fuel for electricity generation, the projects are beneficial in employment and empowerment creation in all the countries involved. A brief description of the developments associated with Kudu gas field and the Pande and Temane gas fields are provided below.

5.1.1 The Kudu Gas field

The Kudu gas field is located approximately 170km northwest, offshore of Oranjemund with an estimated proven reserve considered to be 36.8 bcm (Bolin, 2004). Energy Africa currently intend to assume 100% interest and operatorship of the Kudu gas field (Bolin, 2004). The move follows a December 2003 announcement that ChevronTexaco was relinquishing its interest in Kudu, primarily because the Kudu project did not align with the firms' West African strategy. This left the South African based (but Malaysian owned) Energy Africa as the sole permit holder, as operator ChevronTexaco was the major partner in the Kudu field after Shell withdrew from the project in 2002 having concluded that reserves were insufficient for large-scale exports (EIA, 2004).

The Kudu Gas Fields Project or Kudu Power Project (KPP), aimed at making Namibia self sufficient with regards to power in the near future, entails piping natural gas from the Kudu Gas

Fields off the coast of Namibia to initially a gas fired power station at Oranjemund, and subsequently to the Western Cape to be used in another gas-fired power station. Phase 1 involves the provision of facilities to feed Kudu gas into a 800 MW gas-fired power station at Oranjemund with half the power to be exported to the Western Cape. The cost of the first phase of Kudu's development is estimated to be US$ 400 million (EIA, 2004). First gas is expected to be produced in 2008 (Business Day, 2003).

Further development would involve the transmission of gas to Mossel Bay and Coega to support industrial development in these regions (Infochain, 2004b). PetroSA's Mossgas supply from two offshore fields is expected to end in approximately 3-4 years and the supply of gas from Kudu would supplement the facility's feedstock.

5.1.2 The Pande and Temane Gas fields

The Pande and Temane gas fields lie to the north of Maputo, with the estimated reserves of the Pande gas field considered to be in excess of 59.5 bcm and Temane reserves in the order of 28.3 bcm (Mbendi, 2004). Sasol Petroleum International was awarded the rights to exploit the gas in a joint venture partnership with the South African and Mozambican governments in 2002. The first delivery of natural gas from the Temane natural gas fields in Mozambique to Sasol's synfuels plant at Secunda, near Johannesburg occurred in late February 2004. The gas was delivered using the 865km pipeline that runs from the Mozambican fields to Secunda (EIA, 2004).

This pipeline and gas development project arose primarily from a joint venture between Sasol and the governments of Mozambique and South Africa. It includes the development of the Pande and Temane gas fields, a central gas processing facility in Mozambique and the pipeline. The associated costs are approximately US$ 1.2 billion (EIA, 2004). Sasol plans to initially use the gas as supplementary feedstock for its Secunda synfuels plant and to supply industrial demand. In addition, the Sasol Infrachem feedstock in Sasolburg would be converted to natural gas from coal (EIA, 2004). The pipeline will ultimately supply the market in South Africa with about 120 million GJ a year, increasing natural gas's contribution to South Africa's primary energy supply from 1.5 % to above 4 %. If gas-fired power stations are built in South Africa, gas could account for 10 % of all energy used by the end of the decade (Infochain, 2004b).

The longer term objective of the project would be to fuel gas-fired power stations thereby assisting Eskom meet its peaking demands. Cogeneration energy plants, which produce steam and electricity, are being investigated as supply options to industrial clusters. The first potential sites are Sasolburg and the Durban South Basin (Business Day, 2004).

5.2 ECONOMIC IMPLICATIONS

The economics associated with a power station can be divided into capital costs and operating costs. This section provides a brief overview of the two components and how they vary between the technologies. No detailed study is made as this is far beyond the scope of this investigation.

5.2.1 Power station costs

The capital costs include the costs of acquiring the site, major equipment and construction of the plant itself. These costs tend to comprise a higher proportion of the life cycle costs of a plant. Operating costs are those associated in running a power station. They will generally include fuels costs, manpower and maintenance costs.

Capital costs are generally lower for more mature technologies like coal-fired power stations and those stations that use cleaner, easier to handle fuels like gas turbines. Combined cycle gas turbine plants (CCGT) generally have the lowest capital because it is a relatively mature technology and most of the turbine itself is fabricated in a factory rather than on-site. IGCC systems are more expensive than the other systems studied because the technology is still relatively new and there are substantial requirements for fuels handling and processing. IGCC systems comprise equipment normally associated with a CCGT and infrastructural requirements for the transport, processing and storage of coal. Additional requirements are the coal gasification unit and the storage area required for the ash/slag from the gasification process. These additional facilities make an IGCC station substantially larger than any of the other technologies therefore it has higher costs associated with it.

Coal fired power stations are generally expensive in that they require facilities for coal storage, transport and processing, the power plant and its associated equipment and large areas for the disposal of the substantial amount of wastes that are generated. These plants also require pollution control mechanisms such as Flue Gas Desulphurisation (FGD), Selective Catalytic Reduction (SCR), etc. to ensure that their emission levels are within legal limits. All these factors and the large tracts of land that are required contribute to the high costs of coal-fired power stations.

The operating costs comprise mainly the cost of fuel, staff costs and maintenance costs. Highly efficient plants able to burn low priced fuels will generally have low fuel costs. Due to the low cost of coal in South Africa, the operating costs are generally lower than other technologies although the required staff component is larger. Coal-fired power stations also have additional expenses in that the treatment and disposal of the substantial ash generated is costly. They also require large amounts of power and sorbents or catalysts for flue gas clean-up equipment. A CCGT station has high efficiencies and requires fewer staff to operate the station, however, its operational costs are generally higher primarily because the price for natural gas is substantially higher than for coal. A gas turbine plant can reach full power in minutes compared to steam plants, which take hours, thus gas turbines have substantially lower start-up costs than coal fired power stations.

The IEA Clean Coal Centre in the United Kingdom conducted a comparative study of the costs associated with the technologies being studied. International equipment and fuel prices were utilised and the results are an approximate indication of the costs associated with establishing these technologies anywhere in the world. Table 2 is a summary of the outcomes of this study. The fuel costs utilised are projections by IEA for the year 2005 (coal at US$ 1.93/GJ and natural gas at US$ 4.48/GJ). In this example, a discount factor of 10% has been used over a 28-year plant life (IEA Clean Coal Centre, 2004).

Table 2: Costs associated with the various technologies

Technology	Cost US c/kWh			
	Capital	Fuel	Other	Total
Conventional Pulverised Coal with FGD	3.45	1.54	0.67	5.66
IGCC	4.43	1.94	0.87	7.24
CCGT	2.46	3.57	0.53	6.56

(Source: IEA Clean Coal Centre, 2004).

The above table confirms the status of conventional PF stations as the cheapest generating technology while IGCC is the most expensive. The main reason contributing to the low cost associated with PF stations are lower operating costs that are influenced by the low price of coal and the maturity of the technology. This scenario is also applicable to South Africa in that the cost of coal is substantially lower than natural gas and there is vast knowledge with regards to operating a PF station. In addition to the lack of expertise in running a gas-fired power station in South Africa, the uncertainty with regards to natural gas delivery hampers the development of gas-fired power stations in the country. IGCC is the most expensive option. However by-product sales and economic incentives could make this technology economically comparable to a conventional pulverised coal-fired station.

5.2.2 Economic Incentives

The majority of electricity in South Africa is generated by coal-burning power stations, with associated emissions of GHG, acid gases and particulates. Modern gas-fired electricity generation plants are significantly more efficient than coal-fired stations, with concomitant benefits in terms of reduced emissions, including GHG. The potential sources of GHG's from fossil fuel electricity generation include CO_2 and NO_2.

In 1997, the conference of the parties to the United Nations Framework Convention on Climate Change (UNFCCC) adopted the Kyoto Protocol. This provides the means and mechanisms for implementing the UNFCCC, including firm emissions reduction commitments for Annex I countries.

To enter into force, the Kyoto Protocol requires the ratification or accession of at least 55 countries, accounting for a least 55% of the world's total carbon dioxide (CO_2) emissions. Although the first criterion has already been comfortably met, the protocol has not yet entered into force as the countries currently committed to the process can only account for about 44% of total emissions. This is mainly due to withdrawal of the support of the United States who, on its own, accounts for about 36% of global CO_2 emissions. However, even if the United States continues with its current stance, the protocol would still come into with the accession of other countries, notably Russia, who are expected to ratify imminently (Koksharov, 2004). Russia accounts for about 17% of global CO_2 emissions. Developing countries that have not acceded to the Kyoto Protocol run the very real danger of being effectively excluded from its provisions when it enters into force, as there is expected to be fierce competition for the resources on offer.

Among other measures, the Kyoto Protocol provides for the Clean Development Mechanism (CDM). With CDM, an Annex I (donor) country can claim greenhouse gas emission reduction credits by materially assisting the establishment of projects that limit emissions and promote sustainable development in a developing (host) country.

South Africa ratified the UNFCCC, in August 2002, as a non-Annex 1 country. There are thus no current obligations for South Africa to reduce greenhouse gas emissions. Signatories to the UNFCCC are currently in negotiations concerning emission reduction targets for Annex 1 signatories. Annex 1 signatories may, in future, fund emission reductions in non-Annex 1 countries in order to meet their own reduction targets. The costs of emission reductions vary widely, to the extent that even some negative cost (benefits) options are available. The potential benefits that can be derived from the CDM could enhance the viability of a project in terms of potential financial and environmental benefits. Thus by providing such assistance, the donor country transforms a project that would not be financially viable in its own right.

This scenario is beneficial to South Africa in that implementation of current gas-fired generation initiatives in South Africa are hampered by the uncertainty and costs associated with natural gas delivery. Obtaining CDM credits for GHG emissions reduction could enhance the viability of these initiatives.

CHAPTER 6

6. CONCLUSION

The objective of this study was to evaluate the environmental impacts of three fossil fuel electricity generation options for South Africa. These were conventional pulverised fuel (PF) coal fired electricity generation, gas-fired electricity generation and integrated gasification combined cycle (IGCC) electricity generation technologies.

6.1 LIMITATIONS OF THE STUDY

- The study is based on information from international literature studies for fossil fuel electricity generation, and no detailed assessment of specific power stations were available for analysis.
- The impacts of gas-fired and IGCC technologies are difficult to quantify in a South African context, as there are no experimental or operational stations using these technologies in the country.
- IGCC plants around the world are highly variable in terms of the gasification techniques utilised. Determination of techniques appropriate for use in the South African context with local coals are complicated due to the absence of detailed data which can be customised for local conditions.

6.2 FURTHER STUDIES

There are numerous technologies being developed in the world that are reported to be superior to conventional PF generation in reducing environmental impacts associated with fossil fuel electricity generation. Some of these technologies which were excluded from this study include Fluidised Bed Combustion (FBC) (with all its variations) and supercritical plants. These technologies should also be analysed to compare their performance to the technologies evaluated in this report, and the feasibility of implementing them in South Africa determined. Data for plants, utilising fuel qualities similar to that present in the country, must be modified for local conditions and analysed to provide a more comprehensive assessment of the impacts of implementing these technologies in the country. The economic feasibility of utilising various fuels for electricity generation must also be evaluated in detail.

6.3 CONCLUSIONS

Gas-fired electricity generation is extremely successful as electricity generation systems in the world due to inherently low levels of emissions, high efficiencies, fuel flexibility and reduced demand on finite resources. A combined cycle plant requires one third less cooling water than a conventional PF power station of the same capacity. Associated benefits are lower operating costs due to the reduced water consumption, smaller size equipment for cooling the water and a reduction in the wastewater that has to be treated before being returned to the environment. The compact design of combined cycle power plants substantially reduces their space requirement, which also lowers costs. All of this reduces the burden on the environment.

Combined cycle plants using natural gas as fuel are 'clean' power generation systems. Unlike other fossil fuels, natural gas produces virtually no SO_2 and also relatively little CO_2 when burned. The impact of combined cycle power plants on the environment is therefore considerably reduced. Also combined cycle plants use combustion technology, developed by certain technology suppliers, which reduces such harmful pollutants such as NO_x, CO and UHC (Unburned Hydro Carbons) to just a few ppm, well below the levels prescribed in most countries.

Combined cycle power plants are processes that make very good use of fuel energy. Instead of simply being discharged into the atmosphere, the gas turbines' exhaust gas heat is used to produce additional output in combination with a Heat Recovery Steam Generator (HRSG) and a steam turbine. This is the reason for the high efficiency of combined cycle systems, which today is above 55%. As finite resources are becoming increasingly scarce and energy has to be used as wisely as possible, generating electricity economically and in an ecologically sound manner is of the utmost importance. Their clean, reliable operation with significantly reduced noise levels and their compact design, makes their operation feasible in heavily populated areas, where the energy is needed most. At the same time, energy can be consumed in whatever form needed, i.e. as electricity, heat or steam.

The economy of South Africa is dependant on cheap coal and it will remain a vital component of future electricity generation options in the country, however, this dominance of coal-fired generation in the country is responsible for South Africa's title as the largest generator of CO_2 emissions on the continent. The country could possibly be requested to reduce its CO_2 emissions at the next international meeting of signatories to the Kyoto Protocol (Gosling, 2004).

There is also a growing concern with regards to the environmental and health impacts of fossil fuel electricity generation. In light of this, new technologies will have to be identified to generate electricity with reduced environmental impacts whilst remaining economically feasible. These factors would force South Africa to re-look at its electricity generation mix and consider options that are capable of generating lower levels of CO_2. One method of reducing CO_2 emissions can be achieved by utilising gas-fired generation technologies, which has numerous environmental and economic benefits that make it fuel of choice for electricity generation in the world. However the uncertainty and costs associated with natural gas in South Africa hampers the implementation of this technology. There are numerous initiatives currently surrounding the development of natural gas in the country, viz. the Pande and Temane projects in Mozambique and the Kudu project in Namibia, and this is likely to positively influence the choice of fuel utilised for electricity generation in the future. The economic viability of these projects would be further enhanced through the obtaining of CDM credits for GHG emissions reduction.

Alternatively, more efficient methods of generating electricity from coal must be developed and implemented. IGCC is capable of achieving this because of the high efficiencies associated with the combined cycle component of the technology. These higher efficiencies result in reduced emissions to the atmosphere for an equivalent unit of electricity generated from a PF station.

An IGCC system can be successful in South Africa in that it combines the benefits of utilising gas-fired electricity generation systems whilst utilising economically feasible fuel, i.e. coal. IGCC systems can economically meet strict air pollution emission standards, produce water effluent within environmental limits, produce an environmentally benign slag, with good potential as a saleable by-product, and recover a valuable sulphur commodity by-product. Life-cycle analyses performed on IGCC power plants have identified CO_2 release and natural resource depletion as their most significant positive lifecycle impacts, which testifies to the IGCC's low pollutant releases and benign by-products. Recent studies have also shown that these plants can be built to efficiently accommodate future CO_2 capture technology that could further reduce environmental impacts.

The outstanding environmental performance of IGCC makes it an excellent technology for the clean production of electricity. IGCC systems also provide flexibility in the production of a wide range of products including electricity, fuels, chemicals, hydrogen, and steam, while utilizing low-cost, widely available feedstocks. Coal-based gasification systems provide an energy production alternative that is more efficient and environmentally friendly than competing coal fuelled technologies. The obstacle to the large-scale implementation of this technology in the country is the high costs associated with the technology. CDM credits and by-products sales could possible enhance the viability of implementing these technologies in South Africa.

6.4 RECOMMENDATIONS

Recommendations based on this study are:

- Gas-Fired Generation should form the basis of future generation options as this technology offers superior environmental performance and exhibits the lowest capital cost of the technologies studied. The issue of readily available fuel and its cost are however issues that will need to be addressed. Gas-Fired Generation does offer opportunities for fuel diversification in line with Eskom's vision.

- The development of natural gas in South Africa must be monitored, as this will influence the feasibility of commissioning a gas-fired power station in South Africa.
- The addition of gas-fired generation will result in a skills transfer of a new technology to South Africa.
- IGCC should be considered as a future option for electricity generation in South Africa due to the fact that it has all the advantages of gas-fired electricity generation whilst being able to utilise coal as a fuel.

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