Strategies for reduced pollution caused gaseous emission from coal fired power stations in Australia

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Strategies for Reduced Pollution Caused by Gaseous Emission from Coal Fired Power Stations in Australia

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This is to certify that this work has not been submitted for a degree to any other university or institution

Liu De-Ying,
Dedicated to my wife, Zhu Gang, and my daughter, Liu Yi,
for their love, support and patience
Acknowledgements

For their guidance and suggestions, I would like to thank Dr. A. G. Mclean, Senior Lecturer, the Department of Mechanical Engineering and Professor T. G. Rozgonyi, Dean, the Faculty of Engineering. A special thanks to Dr. Mclean for giving his often precious time and for his encouragement throughout the year.
Acronyms and abbreviations

ACIRL  Australian Coal Industry Research Laboratories
AED  Advanced Energy Dynamics
adb  air dried basis
AED  Advanced Energy Dynamics Inc
AFBC  atmospheric fluidised bed combustion
BGL  British Gas/Lurgi
CCC  chemical coal cleaning
CFB  circulating fluidised bed
CGC  cold gas cleanup
CGFC  coal gasification fuel cell
CGMFCFC  coal gasification molten carbonate fuel cells
CGPAFC  coal gasification phosphoric acid fuel cells
CGSOFAC  coal gasification solid oxide fuel cells
COE  cost of electricity
CO₂  carbon dioxide
CSIRO  Commonwealth Scientific and Industrial Research Organisation
CWM  coal water mixtures
DM  dense medium
ECNSW  Electricity Commission of New South Wales
EER  Engineering and Economic Research
EPRI  Electric Power Research Institute
ERDC  Energy Research and Development Corporation
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<tr>
<th>Acronym</th>
<th>Full Form</th>
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<tbody>
<tr>
<td>ESAA</td>
<td>Electricity Supply Association of Australia</td>
</tr>
<tr>
<td>FBC</td>
<td>fluidised bed combustion</td>
</tr>
<tr>
<td>FC</td>
<td>fine coal</td>
</tr>
<tr>
<td>FGD</td>
<td>flue gas desulphurisation</td>
</tr>
<tr>
<td>FSI</td>
<td>furnace sorbent injection</td>
</tr>
<tr>
<td>GSP</td>
<td>Gaskombinat Schwarze Pumpe</td>
</tr>
<tr>
<td>HGC</td>
<td>hot gas cleanup</td>
</tr>
<tr>
<td>HHV</td>
<td>higher heating value</td>
</tr>
<tr>
<td>H₂S</td>
<td>hydrogen sulphide</td>
</tr>
<tr>
<td>HTW</td>
<td>High Temperature Winkler</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>IGCC</td>
<td>integrated gasification combined cycle</td>
</tr>
<tr>
<td>KRW</td>
<td>Kellogg Rust Westinghouse</td>
</tr>
<tr>
<td>LHV</td>
<td>lower heating value</td>
</tr>
<tr>
<td>LNB</td>
<td>low NOₓ burner</td>
</tr>
<tr>
<td>MCFC</td>
<td>molten carbonate fuel cells</td>
</tr>
<tr>
<td>Mtce</td>
<td>million tonnes coal equivalent</td>
</tr>
<tr>
<td>NOₓ</td>
<td>nitrogen oxides</td>
</tr>
<tr>
<td>NSPS</td>
<td>New Source Performance Standards</td>
</tr>
<tr>
<td>NSW</td>
<td>New South Wales</td>
</tr>
<tr>
<td>NT</td>
<td>Northern Territory</td>
</tr>
<tr>
<td>OECD</td>
<td>Organisation for Economic Cooperation and Development</td>
</tr>
<tr>
<td>OEE</td>
<td>overall energy efficiency</td>
</tr>
<tr>
<td>OFA</td>
<td>overfire air</td>
</tr>
<tr>
<td>PAFC</td>
<td>phosphoric acid fuel cells</td>
</tr>
<tr>
<td>PC</td>
<td>pulverised coal</td>
</tr>
<tr>
<td>PCC</td>
<td>physical coal cleaning</td>
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</table>
PCF  pulverised coal firing  
PF   pulverised firing  
PFBC pressured fluidised bed combustion  
PG&E Pacific Gas and Electric  
ppm parts per million  
ppb parts per billion  
PRENFLO Pressurised Entrained Flow  
QLD Queensland  
ROM run of mine  
SA South Australia  
SCR selective catalytic reduction  
SECV State Electricity Commission of Victoria  
SNCR selective noncatalytic reduction  
SOFC solid oxide fuel cells  
SO2 sulphur dioxide  
TAS Tasmania  
UAG Utility Advisory Group  
UFC ultra fine coal  
UCC ultra clean coal  
VIC Victoria  
WA Western Australia (WA)
Summary

For the improvement of Australian and world environment the Australian Government has already set a target to reduce emissions of greenhouse gases, not controlled by the Montreal Protocol on ozone depleting substances, to 1988 levels by the year 2000 and to further reduce those emissions by 20% by the year 2005.

The need to control the emission of pollution gases is an issue of major economic, social and political consequence. In particular the use of coal in power generation contributes greatly to pollution gases, mainly carbon dioxide, in addition to nitric oxide and nitrogen dioxide and sulphur dioxide, which influence our environment and health. The need to reduce these emissions is therefore very strong; hence the strategy by which these reductions can be effected should be carefully assessed in order to avoid severe impact on our environment and economy.

The objective of this study is to attempt to put forward short term strategies relating to current power plants, which will help restrain pollution gaseous emissions. With respect to this aspect, four subprograms are discussed. These are coal cleaning technology with emphasis to coal combustion; improvement of combustion with emphasis to reduce SO₂ and NOₓ emissions and treatment of flue gas. In addition the study will also examine long term strategies relating to new power generation design. Obviously the latter must provide higher overall cycle efficiency and generate lower emissions. Here the characteristics of advanced coal-fired power generation technologies such as fluidised bed combustion
technology, integrated gasification combined cycle technology and coal gasification fuel
cell technology will be examined.


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Chapter 1

Introduction
1.1 Background

Australia is one of the most liberal coal resourced countries in the world. This is confirmed by data provided by the International Energy Agency Coal Research (IEA, 1987) which suggests that Australia accounts for 7.1% of the world’s recoverable coal reserves. Hence it is very important for Australia to produce and export its coal. As a result Australia produces around 140 million tonnes coal equivalent (Mtce) in 1987-1988. The highly significant aspect of Australia's coal industry is that over two-thirds of the output is exported. Australia is the world's largest exporter of coal, with a dominant 32% of world coal markets, earning 5.5 billion Australian dollars during 1986-1987. Of the coal component (48 Mtce) of net domestic energy supply 80% was used for electricity generation. Coal is projected to continue as the principal indigenously produced Australian primary energy source. Australian coal production is estimated to increase to 190 Mtce in the year 2000 of which 64% is projected for export (E D Jamieson, 1990).

A recent internal survey from the Department of Primary Industries and Energy(1991) reveals that Australia is likely to continue to rely heavily on coal for electricity generation. In 1990, Australian electricity generation from primary energy sources involved 80% of coal, 11% of hydro, 8% of natural gas and 1% for oil. The State electricity authorities of New South Wales (NSW), Victoria (VIC), Queensland (QLD), Western Australia (WA) and South Australia (SA) have substantial coal-firing capacity. In comparison the Tasmania (TAS) and Northern Territory (NT) electricity systems have no coal-fired generating capacity. Hence electricity in mainland Australia is predominantly produced by coal fired power stations with a total installed capacity of some 34.92 GW.

Table 1.1 gives details of Australian electricity generation and coal fired capacity by State.
### Table 1.1 Australian Electricity Industry By State (ERDC/EASS, 1991)

<table>
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<tr>
<th>State</th>
<th>Generating Capacity (MW)</th>
<th>Coal Fired Capacity (%)</th>
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<tr>
<td>NSW</td>
<td>14500</td>
<td>80</td>
</tr>
<tr>
<td>VIC</td>
<td>7700</td>
<td>68</td>
</tr>
<tr>
<td>QLD</td>
<td>5200</td>
<td>93</td>
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<tr>
<td>WA</td>
<td>2600</td>
<td>70</td>
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<tr>
<td>SA</td>
<td>2300</td>
<td>40</td>
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<tr>
<td>TAS</td>
<td>2300</td>
<td></td>
</tr>
<tr>
<td>NT</td>
<td>320</td>
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In regard to the future of Australian energy production and consumption and the expected absence of nuclear power generation, the energy situation summarised in Table 1.1 will remain unchanged for considerable time in the future.

Primary energy demand is forecast to increase by 33% between 1987 and 2000 (A Mannini, 1990). Over this same period coal requirements for electricity generation are forecast to increase by 43-65%, depending on the State. Hence total coal fuel will be over 90 Mt in the mid 1990s, and 108 Mt in 2000. A recent forecast (M Daniel, 1991) shows that in the year 2000 electricity production and input by fuel will reach 242.3 TWh. This production will comprise 68.8% coal, 19.2% hydro, 2% oil and 10% natural gas power generation. It is expected that coal will maintain this dominant role in the electricity industry after the turn of the Century.
1.2 Pollutants Generated By Coal Fired Power Plants

Almost all people wish to maintain and where possible improve their standards of living. Meeting this objective requires extensive use of fossil fuel energy. However there has been increasing awareness that this can have adverse effects on our environment. This environmental pressure has been mounting particularly over recent years.

Coal fired electricity generation by conventional means is now recognised as a major contributor to greenhouse gases and acid rain. A number of gaseous products of combustion are formed namely: carbon dioxide (CO₂), water vapour, sulphur dioxide (SO₂), nitrogen oxides (NOₓ) and small quantities of hydrogen chloride and hydrogen fluoride. The focus of this investigation is on atmospheric emissions, as this is the sector which has seen the greatest recent changes in pollution control requirements. Coal fired power generation inevitably generates greenhouse effects, mainly from the emission of CO₂, and secondary emissions such as SO₂ and NOₓ.

An estimate, according to I. M. Smith (1989), suggested that the total emissions from all coal use worldwide are responsible for about 17%, of which it is estimated that coal fired power generation accounts for approximately 8% of the enhanced greenhouse effect. Power stations were also recognised as a major source of NOₓ emission. Notably power stations are responsible for 25% of man made NOₓ emissions. Of equal importance is the predominance of SO₂ emissions. In some countries, up to 70% of man made emissions of SO₂ come from power stations. A report from the Electricity Commission of New South Wales (1991) indicates that each year consumption of fossil fuels worldwide releases an estimated 80 million tonnes of NOₓ and 140 million tonnes of SO₂.
The worldwide emission of carbon dioxide amounted to approximately 22Gt in the year 1988 as a result of the consumption of commercial primary energy; world electricity generation contributed about 28% of this. With respect to the Australian situation, from the total of 282 million tonnes produced during 1989-1990, 132 million tonnes was contributed by power generation. This is approximately 47% of the CO₂ emission caused by the consumption of fossil fuels (I Walker, 1992). Hence it should be noted, as previously stated, that already about 80% of the generated electricity in Australia is based on coal-fired power generation.

Presently Australia contributes less than 2% to the world's emissions of greenhouse gases of which the CO₂ contribution accounts for 44%. However, in per capita terms Australia is a major contributor to the greenhouse effect, with the fifth highest emission of CO₂ (4 tonnes per person per annum) in the world.

1.3 Objectives

For the improvement of Australian and world environment, the Australian Government has already set a target to reduce emissions of greenhouse gases, not controlled by the Montreal Protocol on ozone depleting substances, to 1988 levels by the year 2000 and to further reduce those emissions by 20% by the year 2005.

The need to control the emission of pollution gases is an issue of major economic, social and political consequence. As stated previously the use of coal in power generation contributes greatly to pollution gases, mainly carbon dioxide, in addition to nitric oxide and nitrogen dioxide and sulphur dioxide, which influence our environment and health. The need to reduce these emissions is therefore very strong; hence the strategy by which
these reductions can be effected should be carefully assessed in order to avoid severe impact on our environment and economy.

With the increased demand for world electricity generation, there is great potential to increase our overseas coal sales. However our coal sales are strongly threatened by competition from other coal exporters, by the need for much better environmental control (especially as noted in regard to CO₂, NOₓ and SO₂ emissions), and by the rapid development of advanced power generation technologies. The latter two challenges also present significant opportunities. Hence we have to determine our strategies for future power generation in Australia.

The objective of this study is to attempt to put forward short term strategies relating to current power plants, which will help restrain pollution gaseous emissions. With respect to this aspect, four subprograms are discussed. These are coal cleaning technology with emphasis to coal combustion; improvement of combustion with emphasis to reduce SO₂ and NOₓ emissions and treatment of flue gas. In addition the study will also examine long term strategies relating to new power generation design. Obviously the latter must provide higher overall cycle efficiency and generate lower emissions. Here the characteristics of advanced coal-fired power generation technologies such as fluidised bed combustion technology, pressurised fluidised bed combustion technology, integrated gasification combined cycle technology and coal gasification fuel cell technology will be examined.
Chapter 2

Brief Review of Environmental Impacts and Control Technologies Associated with Power Generation Emissions
2.1 History and General Environment Impact

There were few references to environmental considerations in the early years of the Australian industrial development. Notably 'Environmentalism' had not been invented and the generation of electricity added insignificantly to what was already a far from clean industrial environment, dominated in towns and cities by smoke from the domestic use of coal and to a lesser extent by the generation of coal gas.

In fact for a considerable period, there were far fewer environmental problems in Australia relative to many other western countries. The major reason for this is that Australia has considerable land area and low population density. In addition Australia is extremely fortunate in having a large supply of excellent quality coal with low sulphur content. The majority of this coal, with a sulphur content ranging from 0.2% to 0.6%, is used for coal-fired power generation.

With the concern for environmental damage and possible increasingly stringent requirement for future environment controls, any expansion in electricity generation, especially coal-fired power generation will experience greater attention to environmental concerns. Hence Australia now recognises the importance for reducing the emission of pollutants such as NO\textsubscript{x}, SO\textsubscript{2} and CO\textsubscript{2}.

This action is also consistent with the need for environmental impact assessments and environmental impact studies associated with major projects. Notably Commonwealth legislation (Environmental Protection Act 1974) and state legislation provide for environmental impact assessments in the context of energy project evaluations. The guidelines were recently revised by the Australian Environment Council in 1986. Existing
plant must satisfy national emission standards for industrial and new steam boilers set by the National Health and Medical Research Council. In addition to this, States such as Victoria, Queensland and New South Wales have their own emission standards.

2.2 Environmental Impact of Coal Fired Power Generation

2.2.1 General

Coal fired power generation is considered as one of the main sources of greenhouse gases and acid rain. It is clear from discussions that the main pollutant emissions from the exhaust gases of power plants are carbon dioxide, sulphur dioxide and nitrogen oxides. These pollutant gases have become the main problems in the world because of the serious environmental impact so generated.

2.2.2 Effect of CO₂ on the Environment

With the growth in fossil fuel use since the industrial development, it is not surprising that atmospheric concentration of CO₂ indicates an increase. This trend is clearly evident by the data collected by Torrens (1989). This data suggests that the carbon dioxide concentration has increased from about 285 ppm in 1860 to about 350 ppm in 1990. Based on this finding the concentration should reach 380 ppm in 2000, and 410 ppm in 2020.

The reason for concern about the increasing atmospheric CO₂ concentration is because of the so called greenhouse effect of the gas which, assuming, all other factors being constant, would lead to an increase in the earth's surface temperature.
Although there are considerable uncertainties in the predictions, best estimates of the combined effect for a global warming is about 3°C. The predicted 3°C warming of the earth's surface will cause a rise in sea level of the order of one metre (Roberts, 1990). Many other meteorological, hydrological, and oceanographic parameters are also affected; some have been referred to already.

2.2.3 Effect of SO\textsubscript{x} and NO\textsubscript{x} on the Environment

Sulphur is an impurity found in most forms of coal. During the combustion process, sulphur reacts with oxygen to form, primarily, sulphur dioxide, and small quantity of sulphur trioxide. These oxides of sulphur emitted from the combustor and will be eventually released to the atmosphere. It has been estimated that about 75-85% of man-made sulphur emissions is emitted directly by fossil fuelled electricity generation stations.

In industrialised regions or urbanised regions there is an ample evidence to indicate that the acidity of rain is significantly increased as a result of the combustion of coal fuels (Roberts et al., 1990). The resulting environmental consequences for this acid rain pollutant include the effects on natural reservoirs such as soils, rivers and lakes, crops and forests. The other impact of acid rain is the long term durability of man made buildings. These effects as outlined by Roberts (1990) are now discussed.

In regard to the natural environment various components are affected by increased rain acidity to different extents. Some of these effects are now briefly discussed. Firstly soil fertility is affected. Obviously the pH of the soil will tend to decrease, and this will disadvantage some plant species. The release of soluble forms of aluminium and trace metals may also prove toxic to some crops. Secondly the pH level of rivers and lakes will
increase. This increase will provide the clearest impact of acidified rain on the environment due to the resultant decreasing population of extremely sensitive plant and marine life. The acidification of water sources such as lakes and rivers in some areas of the world during the past two decades has been linked to acid from precipitation. In turn, this increased acidity has resulted in the decline of various species of fish. Thirdly ground water run off will exhibit decreased pH. However, in regions with well developed soils, which can neutralise acidity, the impact of acid rain is likely to be small. Another possible impact of acidified rain is on crops and plants. Here laboratory experiments with crops exposed to elevated SO₂ levels do indeed show that damage can occur at concentrations significantly higher than ambient. This finding supports the much heard of 'forest dieback' problem. Notably trees show signs of damage and death in large numbers. Unfortunately sulphur dioxide absorbed by plant life can cause acute injury associated with high concentrations over short intervals, resulting in drying of injured tissues to a dark brown colour. Chronic injury leads to chlorosis, in which the chlorophyll-making mechanism is impeded and leads to a gradual yellowing of the plants.

The acidic products of coal fuel combustion can also have detrimental effects on building stone. This leads to the black, grimy appearance of many buildings in industrial cities due to soot and sulphur dioxide from previous fuel consumption. It is also expected that acidified rain will lead to enhanced corrosion of building materials particularly masonry.

It is well established that burning coal can have deleterious impacts on human health. The more obvious short-term effects are on the respiratory system as produced by smoke and in particular, sulphur dioxide and sulphuric acid derived from its oxidation. The best known example occurred during December 1952, in London when during one week four thousand deaths occurred over the expected number. This increased death rate was due to
respiratory failure produced by high levels of smoke and SO₂. Another potential health hazard of power generation is the general concern induced by pollutant emissions. For example Fremlin (1987) estimated that for each power generation station one death per year per 1000 MW of coal fired power plant capacity is typical for plant burning high sulphur coal especially within the European context.

According to Sloss’s review (1991), NO₂ is responsible for about 6% of the enhanced greenhouse effect in the 1980s. This contribution of NO₂ may increase to 10% by year 2000 and could continue to increase.

Nitrogen oxide emissions initiate atmospheric reactions which lead to the production of photochemical smog. Photochemical oxidants can affect plants in a number way, eg, necrosis, bronzing, silvering, etc. of leaves, and in reducing yield and output. Other effects of photochemical smog products include damage to fabrics, cracking of rubber, eye irritation, loss of atmospheric visibility (Chiger, 1981 and El-Hinnawi, 1981).

In a similar manner to SOₓ NOₓ can also produce acidic deposition which damage to soils and plants. Acidic deposition is causing major damage to stonework in many cities. NOₓ may also form acid gases which damage metals, stone, ceramics and glass.

NOₓ is recognised as a direct effects on human health. Sloss (1991) reported that short-term exposure to 50 ppb can result in breathing difficulties in sensitive individuals and long-term exposures can cause pulmonary damage. Exposure to NO₂, even in low-level dosage, can also induce alterations in the function of the kidneys, liver, spleen, red blood cells and cells of the immune system.
2.3 Brief Review of Emission Control Technologies

Technologies for the control of emission from coal-fired power station have developed over the last decade with improvements in coal cleaning processes, the fuel combustion process and post-combustion cleaning of flue gas.

2.3.1 Coal Cleaning Technology in Pre-Combustion Process

Coal cleaning as a pre-combustion control technology results in the reduction of sulphur variability in the feed coal to conventional boilers. Coal cleaning effectively reduces the variability of coal sulphur as well as the mean sulphur content itself. Variations in SO\textsubscript{2} emissions from conventional boilers are thus reduced when using cleaned coal as opposed to raw coal. Coal cleaning technologies can generally be grouped into two categories: Physical Coal Cleaning (PCC) and Chemical Coal Cleaning (CCC). PCC can reduce pyritic sulphur in the range of 30% to 60%. In comparison CCC can remove over 90% of the pyritic sulphur and remove up to 40% of the organic sulphur as well. However it is expected that CCC will be applied in combination with PCC for economic reasons.

2.3.2 Removal of SO\textsubscript{2} and NO\textsubscript{x} During Combustion

The majority of currently applied technologies for sulphur capture rely on the use of an alkaline sorbent, such as limestone, lime, etc., injected into the combustion zone of boilers. The sulphur is retained as calcium sulphate (or gypsum). This approach can be applied to conventional combustion plants, and it is possible to retrofit controls to existing units as well as including them in the design of new plants.
Technologies for the reduction of NO\textsubscript{x} emissions from stationary sources include combustion measures. Combustion measures have been developed continually since they were first employed in the 1970s. Several types of combustion measures exist and the result of a given technology depends on, amongst other things, combustion conditions. In general combustion measures, such as low excess air, over fire air, low NO\textsubscript{x} burners and reburning can be expected to give a reduction in NO\textsubscript{x} emissions of between 30\% and 50\%. These techniques are summarised in Table 2.3.2.

Table 2.3.2 NO\textsubscript{x} Control by Combustion Modification

<table>
<thead>
<tr>
<th>Item</th>
<th>Flame Combustion</th>
<th>Brief Description</th>
<th>Typical NO\textsubscript{x} Reduction (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Low Excess Air</td>
<td>Simply reduces and controls the total air level for minimum NO\textsubscript{x} emissions and satisfactory combustion efficiency.</td>
<td>10-30</td>
</tr>
<tr>
<td>2</td>
<td>Overfire Air (OFA)</td>
<td>Substantial reduction in air to the main burners with excess air being directed to ports above the burners.</td>
<td>20-50</td>
</tr>
<tr>
<td>3</td>
<td>Low NO\textsubscript{x} Burner (LNB)</td>
<td>Air is diverted away from the inner main combustion zone and is used to burn volatiles in an outer secondary flame.</td>
<td>30-50</td>
</tr>
<tr>
<td>4</td>
<td>Reburning (Fuel Staging)</td>
<td>A fraction of the fuel is injected downstream of the main flame zone followed by OFA for final combustion.</td>
<td>40-50 (With LNB)</td>
</tr>
</tbody>
</table>
2.3.3 Flue Gas Treatment

2.3.3.1 Sulphur Dioxide Removal

Flue gas desulphurisation (FGD) technology is the most widespread method of post-combustion SO$_2$ emission control. This is consistent with the fact that FGD is one of the most effective means of meeting SO$_2$ reduction targets. In view of this proven ability if local medium sulphur coals are utilised and/or Australia elects to have strict sulphur emission standards in the future effective sulphur control, as set by ground level concentrations, could be effected by installing FGD equipment.

There are well over 100 FGD processes available at various stages of development in the world. Generally, 90% SO$_2$ efficiencies are achieved with most FGD processes. They fall into two generic types, namely non-regenerable and regenerable systems.

2.3.3.2 NO$_x$ Control

Where the limits on NO$_x$ emissions cannot be met by combustion control, NO$_x$ has to be removed from the flue gases through installation of flue gas treatment equipment. The processes in use at present for reduction of NO$_x$ in flue gases are mainly selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR).

Up to now, SCR has been the dominant method of flue gas NO$_x$ treatment. In this method ammonia is injected into the flue gas in the presence of a catalyst, commonly titanium oxide based, to reduce NO and NO$_x$ to nitrogen and water. Most denitrification plants are designed for a 70-80% NO$_x$ reduction to meet emission levels of 200 mg NO$_2$/m$^3$, at 6%
However, a few plants are designed for reduction of emissions by over 90% where the NO\textsubscript{x} concentration after the boiler are particularly high.

SNCR is an attractive method from the point of view that no costly catalyst is required. Nitrogen oxide can be controlled through thermal reactions, using appropriate reducing chemicals. This method is expected to reduce NO\textsubscript{x} typically down to 30-50% or up to 70-80% under favourable conditions. However, SNCR is only just beginning to gain commercial acceptance.

2.4 Introduction to Advanced Combustion Technologies

There are various advanced power generation technologies which offer both energy and environmental advantages. On the energy side the technologies provide more efficient use of energy through high combustion efficiency as well as the possibility to use low-quality fuels, or mixture of fuels. On the environmental side, emission per unit of energy generated, particularly SO\textsubscript{2} and NO\textsubscript{x}, are reduced by a significant amount through the generation process itself. Strict emission standards may therefore be met without costly measures such as post-combustion flue gas treatment.

Most advanced among those new coal fired technologies are fluidised bed combustion (FBC) steam plants, pressurised fluidised bed combustion (PFBC) systems, integrated gasification combined cycle (IGCC) generation systems and coal gasification fuel cell (CGFC) energy systems.

The above technologies offer a number of advantages over conventional ones including: lower emission of SO\textsubscript{2} and NO\textsubscript{x}, high thermal efficiencies and considerable fuel
flexibility. These technologies will continue to promote the role of coal for electricity generation. Programs to develop and commercialise these technologies are under way in Australia. However, there is a particular emphasis on these advanced coal-fired technologies as a major strategy for longer term emission control for Australia.

2.5 Summary of Emission Control Technologies

Table 2.5 summarises the control technologies for SO₂ and NOₓ presented in the chapter, including their commercial status and SO₂ or NOₓ reduction effectiveness.

Table 2.5 Power Plant Control Technology for Sulphur and Nitrogen Oxides (OECD, 1988)

<table>
<thead>
<tr>
<th>Technology</th>
<th>Commercial Status</th>
<th>Application Waste</th>
<th>SO₂ and NOₓ Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-Combustion</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PCC</td>
<td>Commercial</td>
<td></td>
<td>10-30% SO₂</td>
</tr>
<tr>
<td>Advanced PCC</td>
<td>R&amp;D</td>
<td></td>
<td>80% SO₂</td>
</tr>
<tr>
<td>CCC</td>
<td>R&amp;D</td>
<td></td>
<td>90% Pyritic SO₂; 40% organic SO₂</td>
</tr>
<tr>
<td>Combustion Control</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Combustion Modification/Low-NOₓ Burners</td>
<td>Commercial as well as R&amp;D</td>
<td>Retrofit and New</td>
<td>30-50% NOₓ</td>
</tr>
<tr>
<td>Technology</td>
<td>Status</td>
<td>Application</td>
<td>NOx Reduction</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>-----------------</td>
<td>----------------------------------</td>
<td>---------------</td>
</tr>
<tr>
<td>Advanced Low-NO(_x) Burners</td>
<td>R&amp;D</td>
<td></td>
<td>Up to 70%</td>
</tr>
<tr>
<td>Off-Stoichiometric Control</td>
<td>Commercial</td>
<td>New</td>
<td>30% NO(_x)</td>
</tr>
<tr>
<td>Catalytic Combustion</td>
<td>Initial Testing</td>
<td>Retrofit</td>
<td>80% NO(_x)</td>
</tr>
<tr>
<td>Furnace Sorbent Injection</td>
<td>Demonstrated</td>
<td>Retrofit; Waste may be Hazardous</td>
<td>60-75% SO(_2)</td>
</tr>
</tbody>
</table>

### Post-Combustion

<table>
<thead>
<tr>
<th>Technology</th>
<th>Status</th>
<th>Application</th>
<th>NOx Reduction</th>
<th>SO2 Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>FGD-Wet Lime and Limestone</td>
<td>Commercial</td>
<td>New and retrofit; gypsum or wet by-product</td>
<td>&gt;90% SO(_2)</td>
<td></td>
</tr>
<tr>
<td>Spray-Dry FGD Lime</td>
<td>Commercial</td>
<td>New and retrofit; dry by-product</td>
<td>70-80% SO(_2)</td>
<td></td>
</tr>
<tr>
<td>Regenerable FGD</td>
<td>Commercial</td>
<td>New; limited quantities of waste</td>
<td>90% SO(_2)</td>
<td></td>
</tr>
<tr>
<td>SCR</td>
<td>Commercial</td>
<td>Industrial and Utility; New and retrofit</td>
<td>80-90% NO(_x)</td>
<td></td>
</tr>
<tr>
<td>SNCR</td>
<td>Commercial</td>
<td>Compact and easy to install; waste may be considered hazardous</td>
<td>30-50% NO(_x)</td>
<td></td>
</tr>
<tr>
<td>Dry Injection of Sorbents</td>
<td>R&amp;D and Demonstrated</td>
<td>New and retrofit (suitable for low sulphur coal)</td>
<td>up to 50% SO(_2)</td>
<td></td>
</tr>
</tbody>
</table>
Chapter 3

Coal Cleaning Technologies
3.1 **Introduction**

Pre-combustion control methods generally refer to physical coal cleaning (PCC) or beneficiation technologies, and chemical coal cleaning (CCC) methods. There are two major types of sulphur in coal: pyritic and organic sulphur. Pyritic sulphur is found in coal as small particles of iron pyrite. Because it is heavier than coal, pyritic sulphur can be removed, provided the pyritic components are suitably liberated, from coal particles through a flotation or other hydro-based process, generally known as physical coal cleaning (PCC). The second type of sulphur in coal is organic sulphur, this forms one of the many different chemical compounds which make up coal. It appears that this type of sulphur can be removed through chemical or biological cleaning processes, however the effectiveness of organic sulphur removal by these processes are still under research.

3.2 **Physical Coal Cleaning Technology**

3.2.1 **General**

PCC processes are those that remove ash forming minerals and pyritic sulphur from coal without chemical modification or destruction of the coal or other minerals. Commercially available PCC processes have been used world wide for many years to upgrade coal quality. In the past, its principal purpose was to reduce the amount of ash-forming impurities. However, today cleaning is of significant value in reducing the sulphur content of certain coals. Relatively simple systems were used to remove ash-forming constituents from coals supplied for boiler fuels. More elaborate systems are used to remove pyritic sulphur when there is greater attention to cleaning coal.
3.2.2 Physical Coal Cleaning Practices

PCC processes used and the degree of cleaning employed are very dependent on the type of coal and product coal specification desired. In general, PCC rely on the use of gravitational and/or centrifugal forces to effect the separation of the clean coal from the accompanying impurities. In a modern coal cleaning plant, the coal is typically subjected to following unit operations:

(1) Coal pretreatment, mainly in size reduction and screening,

(2) Coal cleaning with gravity separation of coal from its impurities,

(3) Product conditioning such as dewatering and drying.

Coal cleaning units are the heart of all physical coal cleaning plants. They involve mainly the separation of the physically attached sulphur and/or mineral impurities of higher specific gravities from the coal of lower specific gravity. This step is often accomplished by using jigs, cyclones, and concentration tables, which utilise a combination of frictional and/or gravity or centrifugal forces to effect an apparent density differential between the coal and its sulphur and mineral impurities. Another, commonly used, cleaning method is heavy-medium separation which employs fine heavy minerals, such as magnetite or sand, of an intermediate specific gravity dispersed in water to effect the desired separation. In general, heavy medium separation results in a relatively high recovery of clean coal, although the latter fraction has to be separated from the heavy medium before it can be either used or processed further. Finally, froth flotation processes are generally used to beneficiate the very fine size fraction (ie that less than 500μm). In froth flotation, the coal
is beneficiated in a liquid medium by air bubbles that levitate the very fine clean coal particles to the liquid surface where the coal particles are mechanically skimmed. A surfactant is generally added to the coal bath to render the coal more hydrophobic and thereby facilitate the flotation of the coal particles. In this process the hydrophilic mineral matter accumulates at the bottom of the vessel from where it is removed for eventual disposal.

In general, coal beneficiation plants use various combinations of all or some of the above unit operations to beneficiate different size fractions of the raw coal, depending upon the level of beneficiation desired. In regard the US situation there are three levels of cleaning coal generally used in the preparation of steaming coal.

Level 1. This design uses rotary breakers, crushers and screens for top size control and for the removal of coarse refuse. This system is most effective for processing high quality coal with low sulphur content or when market specifications and raw coal characteristics are similar.

Level 2. Coal is crushed and sized, followed by dry screening at typically 9.5 mm and wet beneficiation of the oversize material is then effected with a jig or dense medium (DM) vessel. The undersize material is then mixed with the coarse product without washing. This system provides removal of only coarse pyritic sulphur and is therefore recommended for a moderate pyritic sulphur content coal.

Level 3. Coal is crushed and separated into three size fractions by wet screening. The plus 9.5 mm material is beneficiated in a coarse coal circuit. The 9.5 mm by 28 mesh (0.54 mm) material is beneficiated by hydro cyclones, concentrating tables or dense
medium cyclones, and the 28 mesh (0.54 mm) by 0 material is dewatered and shipped with the clean coal or discarded as refuse. As such a Level 3 system is basically an extension of level 2 system. The sulphur removal of this system is suitable for use on low and medium sulphur content coals which are relatively easy to wash. This process provides rejection of free pyritic and ash, as well as enhancement of energy content.

3.2.3 Cleaning Performance of Physical Coal Cleaning Processes

To highlight the effectiveness of sulphur removal by PCC process, the three PCC processes, which are widely used commercially in the U.S.A, are as follows (Khoury, 1981):

PCC I Process. Raw coal is crushed to three size fractions, each of which is processed separately. A DM vessel is used for the coarse coal, a DM cyclone for the intermediate size coal, and froth flotation for the fine coal.

PCC II Process. After crushing, the coarse fraction is processed in DM cyclones operated at low specific gravity to produce a small overflow of relatively clean coal. The underflow from the low gravity cyclones are pumped to high gravity cyclones to produce medium quality coal and refuse. The fine coal is recovered by froth flotation.

PCC III Process. In this process, about two thirds of the crushed coal feed is a coarse fraction treated in DM cyclones. A fine coal fraction, amounting to about one third of the coal feed, is cleaned on concentrating tables. The remaining very fine coal fractions, thickened and filtered without cleaning, is added to the clean coal product.
The estimated performances of the above three PCC processes are listed in Table 3.2.3 for a typical 5% sulphur coal (Khoury, 1981). The base case condition for coal cleaning evaluations assumes the coal supply is to a new 2000 MW power plant with a design heat rate of 10070 kJ/kWh and operating on a schedule equivalent to full capacity for 5500 hours per year. The power plant life is assumed to be 30 years.

Table 3.2.3 Cleaning Performance of PCC Processes (Khoury, 1981)

<table>
<thead>
<tr>
<th>Item</th>
<th>Raw Coal</th>
<th>PCC I</th>
<th>PCC II</th>
<th>PCC III</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total S, %</td>
<td>5</td>
<td>3.67</td>
<td>3.51</td>
<td>3.78</td>
</tr>
<tr>
<td>Pyritic S, %</td>
<td>3.35</td>
<td>2.02</td>
<td>1.86</td>
<td>2.13</td>
</tr>
<tr>
<td>Organic S, %</td>
<td>1.59</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sulphate S, %</td>
<td>0.06</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>S Removal, %</td>
<td></td>
<td>26.6</td>
<td>29.8</td>
<td>24.4</td>
</tr>
<tr>
<td>Ash, %</td>
<td>16.7</td>
<td>10.1</td>
<td>9.3</td>
<td>10.6</td>
</tr>
<tr>
<td>Investment, US$/kW</td>
<td></td>
<td>34</td>
<td>40</td>
<td>39</td>
</tr>
</tbody>
</table>

3.3 Advanced Physical Coal Cleaning

3.3.1 Process Description of Advanced PCC processes

More effective advanced physical coal cleaning methods have been developed in the USA with emphasis on both removal of sulphur and minerals. These advanced physical coal cleaning processes are described as follows:
Heavy Medium Cyclone/Flotation (Case 1): The coal cleaning circuitry tested processed the 28-mesh by 150-mesh material in a heavy medium cyclone and routed the minus 150-mesh coal to a rougher-cleaner flotation circuit.

Advanced Flotation (Case 2): The rougher-cleaner advanced multistage flotation process was evaluated on 100 mesh by 0 coal feed. The first stage rougher cells were operated to separate as refuse the least floatable and high-ash materials. The froth product from this stage was then reprocessed in a second bank of cells in which a pyrite depressant and a coal collector was added. The froth product was taken as final product while the rejects were combined with the rougher stage refuse for discard.

Dow True-Heavy Liquid Separation (Case 3): The Dow process uses two beneficiation steps to clean coal and a proprietary solvent recovery technology to remove solvent from water circulating through the system. The two beneficiation steps involve liquid-liquid partitioning to treat the minus 100-mesh coal particles and cyclone separation for all coal particle sizes.

Advanced Energy Dynamics (AED) Electrostatic Separation: AED has engineered two electrostatic processes, The fine coal (FC) (Case 4) and ultra-fine-coal (UFC) (Case 5). The processes can be used alone or in combination to produce a clean coal product.

The FC process uses an electrostatic drum-separator technology. The pulverised coal is fed onto the surface of a rotating drum and then subjected to electrostatic charging. The charge remains on the non-conductive coal particles, attracting them to the drum. The charge on the conductive sulphur and ash-bearing materials drains off to the drum, releasing these materials. Centrifugal and gravitational forces separate the impurities from
the coal. The coal adhering to the drum is then scraped off using a scraper blade. The FC process operates most efficiently on particles larger than 37 microns (400-mesh).

The lack of FC cleaning effectiveness on coal particle sizes below 400-mesh prompted the development of the UFC process. The UFC process is based upon the phenomenon that the fresh surfaces created when any solid material is broken emit electric charges. When a mixture of two types of particles is introduced into a system in which at least some of the particles are broken, a differential charge is created. One type of particle is charged positively and the other negatively.

Oil Agglomeration (Case 6): Oil agglomeration is a process which separates coal particles from mineral matter particles through differences in their surface properties. Coal particles are hydrophobic, whereas the refuse and pyrite particles are hydrophobic. When a small amount of liquid is added to a strongly agitated coal-water mixture, the carbonaceous components of the coal become wetted with this liquid and collect as a cluster. The agglomerated coal can be easily separated from the water and unagglomerated pyrite and refuse particles.

3.3.2 Cleaning Performance of Advanced PCC Processes

Boron et al (1986) provided the estimated process results and process economics of the above advanced PCC processes. These performances are listed in Table 3.3.2 for a typical 2.5% sulphur coal (Upper Freeport Coal, USA). The base case condition for coal cleaning evaluations assumes the coal supply is to a 500 MW power plant with a design heat rate of 9975 kJ/kWh and operating at 65% load for 3500 hours per year.
Table 3.3.2 Cleaning Performance of Advanced PCC Processes (Boron et al., 1986)

<table>
<thead>
<tr>
<th>Item</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
<th>Case 4</th>
<th>Case 5</th>
<th>Case 6</th>
</tr>
</thead>
<tbody>
<tr>
<td>S, feed, %</td>
<td>2.5</td>
<td>2.5</td>
<td>2.5</td>
<td>2.5</td>
<td>2.5</td>
<td>2.5</td>
</tr>
<tr>
<td>S, product, %</td>
<td>1.3</td>
<td>1.5</td>
<td>1.1</td>
<td>1.5</td>
<td>0.9</td>
<td>1.5</td>
</tr>
<tr>
<td>S removal, %</td>
<td>62.6</td>
<td>55.0</td>
<td>66.4</td>
<td>51.6</td>
<td>74.4</td>
<td>52.0</td>
</tr>
<tr>
<td>Ash, feed, %</td>
<td>29.8</td>
<td>29.8</td>
<td>29.8</td>
<td>29.8</td>
<td>29.8</td>
<td>29.8</td>
</tr>
<tr>
<td>Ash, product, %</td>
<td>8.9</td>
<td>10.5</td>
<td>9.5</td>
<td>14.9</td>
<td>3.0</td>
<td>11.3</td>
</tr>
<tr>
<td>Capital cost, $/kW</td>
<td>97.6</td>
<td>110.2</td>
<td>91</td>
<td>13.26*</td>
<td>41*</td>
<td>85.2</td>
</tr>
<tr>
<td>Operating cost, $/kW</td>
<td>15.73</td>
<td>19.82</td>
<td>14.76</td>
<td>2.73*</td>
<td>6.694*</td>
<td>19.82</td>
</tr>
<tr>
<td>Unit cost, Mils/kWh</td>
<td>7.56</td>
<td>9.50</td>
<td>7.09</td>
<td>6.19</td>
<td>7.64</td>
<td>11.20</td>
</tr>
<tr>
<td>Unit cost, $/t clean coal</td>
<td>20.60</td>
<td>25.40</td>
<td>19.40</td>
<td>12.64</td>
<td>21.35</td>
<td>23.20</td>
</tr>
</tbody>
</table>

* Estimated by AED, exclusive of material handling system. Process is located at power plant.

Cost is based on US dollars.
3.4 Chemical Coal Cleaning

3.4.1 Chemical Coal Cleaning Processes

Chemical coal cleaning (CCC) methods presently being developed beneficiate the coal under much more severe operating conditions relative to that for physical coal cleaning methods. The majority of the CCC processes can effect a significant reduction (up to 90-95%) in the pyritic sulphur and also remove varying amounts of the organic sulphur present in the coal.

A whole range of chemical processes have been looked at and tested at laboratory, and sometimes pre-pilot stage. Most of the work to date has been at laboratory or bench scale (Couch, 1991). These processes tend to use high-cost chemicals and /or involve the use of high temperatures and pressure and long residence time.

The description of the main chemical cleaning processes developed in the USA is outlined in Table 3.4.1 (Khoury, 1981 and Couch, 1991). However, the major research and development effects are currently being focused on two chemical cleaning processes: TRW and Microwave (EER et al., 1986).
### Table 3.4.1 Major Chemical Coal Cleaning Processes

<table>
<thead>
<tr>
<th>Process</th>
<th>Sulphur removal method</th>
<th>Extent of sulphur removed</th>
</tr>
</thead>
<tbody>
<tr>
<td>TRW</td>
<td>Gravity separation of feed at a specific gravity of 1.3; the sink is treated with Fe$_2$(SO$_4$)$_3$</td>
<td>Over 90% pyritic</td>
</tr>
<tr>
<td>Microwave</td>
<td>Microwave irradiation and NaOH treatment</td>
<td>70%-90% of total sulphur</td>
</tr>
</tbody>
</table>
| Kennecott | 1) Oxidative leaching using O$_2$ in an acidic solution at 130°C and 1-2 MPa  
2) Oxidative leaching using O$_2$ in an ammonia solution at 130°C and 1-2 MPa | 1) 90%-95% pyritic  
2) Over 90% pyritic and up to 40% organic |
| KVB     | Sulphur is oxidised in NO$_2$ containing atmosphere. Sulphates are washed out | 60% to 95% pyritic and 30% to 50% organic |

### 3.4.2 Cleaning Performance of CCC Processes

For a comparison with PCC processes, two CCC methods will be examined. These CCC techniques are the Microwave process and the TRW process.
Boron and Kollrack (1986) presented some indicative results of the microwave process which are given in Table 3.4.2a. The reported removal of both sulphur and ash was substantial.

**Table 3.4.2a  Cleaning Performance of the Microwave Process**

<table>
<thead>
<tr>
<th>Coal</th>
<th>Pittsburgh, Ohio</th>
<th>Western Kentucky No 11</th>
<th>Illinois No 6</th>
<th>Upper Freeport</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feed, S, %</td>
<td>3.7</td>
<td>4.6</td>
<td>5.0</td>
<td>2.4</td>
</tr>
<tr>
<td>Feed, Ash, %</td>
<td>30.2</td>
<td>29.0</td>
<td>24.2</td>
<td>35.4</td>
</tr>
<tr>
<td>Feed, MJ/kg</td>
<td>18.9</td>
<td>21.1</td>
<td>19.2</td>
<td>19.7</td>
</tr>
<tr>
<td>Product, S, %</td>
<td>0.4</td>
<td>0.7</td>
<td>0.5</td>
<td>0.2</td>
</tr>
<tr>
<td>Product, Ash, %</td>
<td>2.4</td>
<td>4.1</td>
<td>1.1</td>
<td>1.9</td>
</tr>
<tr>
<td>Product, MJ/kg</td>
<td>31.1</td>
<td>29.9</td>
<td>31.0</td>
<td>31.1</td>
</tr>
<tr>
<td>S reduction, %</td>
<td>89</td>
<td>85</td>
<td>90</td>
<td>92</td>
</tr>
<tr>
<td>Ash reduction, %</td>
<td>92</td>
<td>86</td>
<td>95</td>
<td>95</td>
</tr>
</tbody>
</table>
The estimated performances of the TRW process is presented in Table 3.4.2b (Meyers et al., 1986). The average of the process results obtained on all three coals tested show that TRW process sulphur removals are 87%-92% and ash reductions are over 98%.

Table 3.4.2b  Cleaning Performance of the TRW Process

<table>
<thead>
<tr>
<th>Coal</th>
<th>Pittsburgh No. 8</th>
<th>Kentucky No. 11</th>
<th>Middle Kittanning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feed, S, %</td>
<td>4.22</td>
<td>3.34</td>
<td>2.08</td>
</tr>
<tr>
<td>Feed, Ash, %</td>
<td>10.34</td>
<td>10.74</td>
<td>10.97</td>
</tr>
<tr>
<td>Feed, MJ/kg</td>
<td>30.68</td>
<td>30</td>
<td>29.16</td>
</tr>
<tr>
<td>Product*, S, %</td>
<td>0.33</td>
<td>0.33</td>
<td>0.27</td>
</tr>
<tr>
<td>Product*, Ash, %</td>
<td>0.18</td>
<td>0.22</td>
<td>0.18</td>
</tr>
<tr>
<td>Product*, MJ/kg</td>
<td>30.12</td>
<td>29.83</td>
<td>30.23</td>
</tr>
<tr>
<td>S reduction, %</td>
<td>92.13</td>
<td>90.07</td>
<td>86.97</td>
</tr>
<tr>
<td>Ash reduction, %</td>
<td>98.26</td>
<td>97.95</td>
<td>98.36</td>
</tr>
</tbody>
</table>

* Temperature, 400°C

There is a scarcity of reliable cost projections for chemical coal cleaning technologies as a result of limited research results available. A series of conceptual designs and cost estimates for 10,000 tons per day TRW Gravimelt process commercial plants have been prepared with variations in reactor type, ratio of caustic to coal, washing system and regeneration options (Meyers et al., 1985). Total installed capital cost varies from US$250M to US$350M, for the 10,000 ton/day plant, which is sufficient to feed a 1000 MW utility operating at 100% load factor. Operating costs, including annualisation of the total capital cost, vary from US$35 to US$50 per ton of coal processed. Couch (1991)
reported that the cleaning costs of coal cleaned by the TRW Gravimelt process is about US$75/ton. By comparison with the cost of the physical coal cleaning process chemical coal cleaning process is likely to remain a high-cost route.

3.5 Other Economic Benefits and Penalties of Using Cleaned Coal

In evaluating the capital investment and annual revenue requirements associated with coal cleaning, it is useful to also assess the other economic benefits and penalties that result from use of cleaned coal. In addition to the primary benefits that the cleaned coal is lower in sulphur, it is generally also lower in ash and higher in heating value/unit mass. Unfortunately cleaned coal is often higher in surface moisture content. Combustion of coal with these characteristics has numerous benefits as well as certain disadvantages to the user. The net effect is a credit which may be of sufficient magnitude to offset some of the increased cost of cleaned coal. These advantages and disadvantages are now briefly discussed.

Transportation Costs: Coal beneficiation at the mine decreases the cost of coal transportation by increasing the heating value of the coal, consequently reducing the quantity of coal necessary to supply a given heat requirement.

Pulverisation Costs: PCC, by reducing mineral matter, decreases coal hardness and enhances crushing. The increased heating value of cleaned coal also reduces the quantity of coal to be crushed. The size of the cleaned coal product is also considerably smaller than that of raw coal so that significant pulverisation costs, which are already covered in the coal cleaning costs, are saved. Unfortunately the additional surface moisture of cleaned coal may partially offset these advantages. This is consistent with the fact that mill
operators also experience reduced mill wear when grinding PCC. This reduced wear is associated with lower operating costs and increased plant availability.

Boiler Capacity: The higher heating value of cleaned coal decreases the possibility that the utility boiler capacity will be derated because of deteriorating coal quality.

Boiler Performance: Cleaned coal can improve boiler performance by reducing slagging, fouling, and corrosion problems. This can significantly reduce the cost of boiler operation and maintenance and increase the availability of the generating facility.

Ash Handling: Ash handling and disposal costs are decreased since coal cleaning generally reduces the total amount of ash handled. Furthermore less sensible heat is lost in the bottom ash because of the lower ash levels.

3.6 Coal Cleaning Technologies in Australia

3.6.1 General

Australia has made great effort to develop advanced physical cleaning and advanced chemical cleaning processes. The objectives of Australian coal preparation research and development is to support established markets for coking and thermal coals. With access to generally low sulphur coal the Australian coal cleaning processes mainly concentrates on demineralisation rather than sulphur removal. In Australia there is emerging technology to produce superclean coal (ash contents of 1-6%) and ultraclean coal (ash contents of less than 1%). Superclean coal can usually be obtained by using physical coal cleaning
processes, while ultraclean coal generally involves further treatment by chemical techniques (Lockhart, 1992 and Couch, 1991).

3.6.2 Physical Coal Cleaning Practices

As stated previously physical coal cleaning in Australia has been developed with emphasis on coal déminéralisation for both the local and overseas markets. In particular flotation columns have recently gained attention for fines cleaning, and have been used on a commercial scale in conventional cleaning plants, such as that at the Riverside coal preparation and cleaning plant in Queensland, Australia. There has been extensive pilot-plant and laboratory-scale work as well (Couch, 1991).

The plant experience with flotation columns at Riverside is discussed by Bensley and others (1988). The Riverside plant produces some 5.5Mt/y of coal and it is estimated that the cyclone overflow contains-75μm material which represents about 8% of the raw coal feed. It has been estimated that the installation of columns to treat all the currently discarded desliming cyclone overflow would recover over 0.2Mt/y of clean coal with a potential value approaching A$8 million. The performance characteristics of this plant is presented in Table 3.6.2.

The Jameson Cell, one of recent major research developments, was firstly developed by Professor Jameson in 1986. A demonstration unit has been successfully operated at Newlands colliery in Australia (Kennedy, 1990). A comparative trial on a pilot-scale Jameson Cell was also conducted at the BHP Blackwater, Queensland mine (Cheng and Clarkson, 1992). The performance characteristics of the Jameson Cell unit are also summarised in Table 3.6.2.
Table 3.6.2 Cleaning Results of Some PCC Units on Typical Australian Bituminous Coals

<table>
<thead>
<tr>
<th>Item</th>
<th>Feed ash, (%)</th>
<th>Product ash, (%)</th>
<th>Combustible recovery, (%)</th>
<th>Mine</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flotation Column</td>
<td>40-50</td>
<td>8-10</td>
<td>70-80</td>
<td>Newlands</td>
</tr>
<tr>
<td>Jameson Cell</td>
<td>15-40</td>
<td>5-8</td>
<td>90-95</td>
<td>Blackwater</td>
</tr>
</tbody>
</table>

3.6.3 Chemical Coal Cleaning Practices

A ultra clean coal process (UCC) for the chemical cleaning of coal, pioneered by the CSIRO, is currently under development in Australia (refer to Figure 3.6.3). The chemical cleaning process, which is currently under development involves a number of distinct processing stages. Generally these stages can be described as: caustic digestion of the mineral matter, followed by acid neutralisation and finally water washing. The reagents which are used throughout the process can be regenerated for re-use in the process. Whilst being environmentally sound and avoiding problems with waste disposal of chemicals this also reduces the cost of the overall process and hence the finished product.
It is expected that this process will reduce the ash in coal to less than 0.5% at competitive cost and hence broaden the technologies for which coal would be a substitute fuel.

A continuous pilot-scale plant co-funded by the Electricity Commission of NSW (ECNSW), was constructed for production of tonnage quantities of UCC and to investigate the effects of process conditions on different coals. Some of the coals were tested as coal-water mixtures (CWM) (Couch, 1991 and ECNSW, 1991). The operation also provided design data for scale-up. Some of the results obtained are given in Table 3.6.3.
Table 3.6.3 Typical Results for CSIRO Demineralisation Trials (Bowling, 1990)

<table>
<thead>
<tr>
<th>Item</th>
<th>Ulan underground</th>
<th>Ulan underground</th>
<th>Ulan open cut</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feed coal ash, %</td>
<td>11</td>
<td>6.6*</td>
<td>12*</td>
</tr>
<tr>
<td>Operation</td>
<td>continuous</td>
<td>batch</td>
<td>batch</td>
</tr>
<tr>
<td>Residence time, Min</td>
<td>10</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Alkaline leaching</td>
<td>210</td>
<td>210</td>
<td>210</td>
</tr>
<tr>
<td>temperature, °C</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Product coal ash, %</td>
<td>5.0</td>
<td>1.0</td>
<td>0.6</td>
</tr>
</tbody>
</table>

* coals were precleaned using a dense-medium cyclone

The production of the CWM facilitated comparative research at ACIRL on the NO$_x$ emission which was made between the CWM and its parent coal under the same furnace loading show that the CWM has a lower NO$_x$ emission than the pulverised counter part due to the lower flame temperature (Chan, 1992). In addition, to the suggested process for producing UCC some other very distinct benefits arise particularly in the area of electricity generation. Some of these benefits include:

- a reduced dependence on gas and petroleum products in electricity generation as more and more processes can be adapted to use UCC;

- increased export earnings through shipping a more versatile fuel to other countries;

- reduced transport and shipping costs for a fuel which can be up to 30% lighter than raw coal from the mine;
• the ability to transport UCC through pipelines in preference to coal movement by rail or road transport;

• the development of high quality carbon anodes for use in the production of aluminium.

3.7 Conclusions

During the last ten years, much of the effect in developing methods for cleaning coal has been carried out in countries such as USA and Australia. In the USA there is a parallel interest in the possibilities of sulphur removal before combustion and of ash removal to improve the economics of utility boiler operation. The Australian processes with its somewhat less intense requirements, concentrates on déminéralisation due to the reduced need for sulphur removal. For instance the ultraclean coal process, developed by the CSIRO in Australia, can achieve ash contents below 0.5%. However, for application to US coals sulphur removal is essential. In view of this need 50%-75% sulphur removal has been achieved using advanced physical cleaning methods. Furthermore, sulphur concentrations can be reduced to 10% of their original value using chemical cleaning treatment.

Irrespective of any short term strategy applied to the coal cleaning technology, Australia should continually use low sulphur coal which is the simplest SO\textsubscript{2} control approach. If increasing strict regulations apply and the availability of inherently low sulphur coals are not sufficient to meet regulatory requirements Australia should set its long term strategy toward to coal cleaning technology. The second focus for Australian coal cleaning research and development should be to reduce sulphur content well below expected
legistrated SO$_2$ emission levels. Hence coal cleaning technology in Australia will require considerations that are related to the future environmental standards, coal properties and of course economic merit. It is recommended that research and development of coal cleaning units to treat medium sulphur coal in the range of 1-3% should occur. This is relevant since increasing supplies of medium sulphur coals will become available in the future. fortunately coals with higher sulphur content (ie 3-5% sulphur) is not typical of Australian thermal coals.
Chapter 4

Combustion Control Technologies
4.1 Sulphur Dioxide Control

Emissions of SO₂ are directly related to the sulphur content of coal, with only a small proportion of coal sulphur being retained in the ash after combustion in most cases. The general world SO₂ emissions standards currently applied to coal fired power plants range from 400 to 2400 mg/m³, equivalent to coal sulphur levels of around 0.25% to 1.25%.

Limits on SO₂ emissions in Australia have so far been set in the Northern Territory only. For Australian coals which have overall low sulphur content this in itself is considered adequate measures for SO₂ emissions controls. However, should Australia need more stringent controls on SO₂ emissions in the future, advanced SO₂ control technologies will be necessary for Australian power stations in the long term. Over this period utilisation of low sulphur coal may not be sufficient to meet such environmental standards. Fortunately for coals containing relatively low sulphur contents there is a range of technologies which use alkaline sorbents to absorb the SO₂ generated. Generally the sorbents used are calcium based, mainly lime (CaO), hydrated lime (Ca(OH)₂), or limestone (CaCO₃).

4.1.1 Sorbent Addition and Injection Processes

SO₂ reduction through control is a relatively simply concept. This simplicity is apparent in Figure 4.1.1 which indicates the configuration of the various sorbent processes. As indicated a range of technologies have been developed, using different sorbents added with the fuel, injected into the boilers, the economiser or duct work. Such processes have developed rapidly over recent years, particular in response to the need of those coal fired power generation plants desiring moderate efficiency, low cost SO₂ control methods.
Although the various sorbent addition and injection processes differ in many ways, the effectiveness of these techniques depends on a number of common factors, including choice of sorbent, firing technique and operation conditions.

Sorbent addition, that is adding sorbent with the fuel, is the simplest dry sorbent approach. In principle, in-combustion control systems rely on modification of the combustion process to reduce the formation of SO$_2$ pollutant during combustion. In conventional pulverised coal boilers it has limited efficiency. This work is at an early stage and has achieved modest SO$_2$ control. Generally the efficiency of sulphur capture using this approach is limited to 30-40% (J L Vernon, 1990).

Where coal fired boilers use fluidised bed combustion (FBC) the conditions for addition of a dry sorbent are particularly suited to this form of SO$_2$ control. Most new FBC boiler units are designed with in-bed limestone for sulphur removal. The temperature in FBC
boilers is within the optimum range for sulphur capture by limestone (800-900°C) and removal efficiency of around 90% can be achieved in both deep bubbling bed and circulating bed systems (Vernon, 1990 and Cooke and Pragnell, 1990). Further discussion of the FBC systems will be given in the Section 6.2.

Most dry SO2 control processes on conventional boilers require sorbent injection into either the boiler or the downstream duct-work of the coal fired power plant. This technology is generally used by utilities as minimal additional equipment is needed. Namely only facilities for storing and handling the sorbent plus injection equipment is required. Further discussion of downstream injection will be delayed until Chapter 5.

Furnace sorbent injection (FSI) is producing promising results for SO2 control. This dry control method injects a sorbent (usually lime or hydrated lime) into the furnace where the sorbent reacts with sulphur-forming solid particles. The solid particles can then be collected by convectional particulate control devices. Use of FSI often requires upgrading of the particulate control devices particularly electrostatic precipitator devices to maintain operation within particulate emission standard. In demonstration units (Cooke and Pragnell, 1990), furnace sorbent injection has proven SO2 emission reduction of 50-60%, which still lies below the reduction required by most regulations for SO2 control in new plants. FSI system is gaining in popularity due to their relative simplicity and lower capital costs. Based on US experience (Katzberger and Sloat, 1988) the costs per kW capacity for the retrofit of FSI technology are A$110-185/kW by comparison with spray dry FGD process and wet limestone FGD technology yielding from A$180-370/kW, A$220-440/kW respectively. Current costs are possibly lower than this due to the increasing market and refinement of these technologies (refer to Table 5.1.3).
For in-duct injection, the equipment requirements are also minimal. Removal efficiencies as high as 60-80% have been reported using calcium based sorbents (J L Vernon, 1990) especially when humidification is used as an enhancement measure. One important feature of these systems is its applicability to the retrofit of existing installations, in both small industrial and large utility sectors.

In technologies using dry sorbent addition or injection for sulphur control, a mixed dry residue of fly ash, desulphurisation product, unused sorbent and any unburnt carbon is produced. Where large volumes of sorbent are used, the total volume of solid residue can make disposal or utilisation difficult. Some problems have been experienced with fouling and deposition in the boiler and duct work following furnace injection. With calcium to sulphur (Ca:S) molar ratios of 2 to 3, a significant additional burden is placed on particulate collection and handling equipment (Vernon, 1990 and Wismann, 1988).

Table 4.1 summarises the benefits and disadvantages of the various approaches to reduce SO2 emission available for coal fired boilers during combustion. From an examination of Table 4.1 it is apparent that for Australian conditions the above technologies should be employed, mainly for existing coal-fired power plants, as a favoured strategy to limit SO2 emission subject to moderate requirements.
### Key Benefits and Disadvantages of the Main SO₂ Control Technologies for Coal Fired Boilers

<table>
<thead>
<tr>
<th>Process</th>
<th>Benefits</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>sorbent addition</td>
<td></td>
<td></td>
</tr>
<tr>
<td>conventional plants</td>
<td>• simple process</td>
<td>• efficiency (30-40%)</td>
</tr>
<tr>
<td></td>
<td>• minimal investment required</td>
<td>• potential for fouling of boiler</td>
</tr>
<tr>
<td></td>
<td>• can be implemented rapidly</td>
<td>• limited practical experience</td>
</tr>
<tr>
<td></td>
<td>• can be implemented rapidly</td>
<td>• potential difficulties with residue handling and disposal</td>
</tr>
<tr>
<td>FBC boilers</td>
<td>• high removal efficiency</td>
<td>• potential difficulties in residue handling and disposal</td>
</tr>
<tr>
<td></td>
<td>• new FBC designs</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• retrofit to older designs</td>
<td></td>
</tr>
<tr>
<td>sorbent injection</td>
<td></td>
<td></td>
</tr>
<tr>
<td>in furnace</td>
<td>• simple process</td>
<td>• efficiency (&lt; 60%)</td>
</tr>
<tr>
<td></td>
<td>• limited investment required</td>
<td>• potential for fouling of boiler</td>
</tr>
<tr>
<td></td>
<td>• can be implemented rapidly</td>
<td>• potential difficulties with residue handling and disposal</td>
</tr>
<tr>
<td>in duct</td>
<td>• limited investment required</td>
<td>• practical experience very limited</td>
</tr>
<tr>
<td></td>
<td>• up to 70% removal</td>
<td>• potential difficulties with residue handling</td>
</tr>
<tr>
<td></td>
<td>• reduced potential for fouling</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• readily combined with humidification</td>
<td></td>
</tr>
</tbody>
</table>
4.2 NO\textsubscript{x} Control Technologies

The most notable developments in coal fired power plants have been in NO\textsubscript{x} control, where combustion modification now represents the standard new boiler design and emission control approach. There are different types of combustion modifications, which reduce the formation of NO\textsubscript{x} during the combustion process.

Before discussing the technique to reduce NO\textsubscript{x} emission it is first appropriate to examine the processes responsible for its formation. NO\textsubscript{x} emissions are produced by two primary mechanisms during combustion. The first mechanism is responsible for what is termed thermal NO\textsubscript{x} whereas the second associated with the initial coal nitrogen content, is termed fuel NO\textsubscript{x}.

Thermal NO\textsubscript{x} is the chemical formation of NO from N\textsubscript{2} and O\textsubscript{2} which occurs at temperatures exceeding 1400°C. The nitrogen source for thermal NO\textsubscript{x} is the combustion air. Up to 40\% of the NO\textsubscript{x} from the combustion of pulverised coal is derived from thermal NO\textsubscript{x}.

Three reactions comprise the thermal NO mechanism,

\[
\begin{align*}
O + N_2 & \rightarrow NO + O \\
N + O_2 & \rightarrow NO + O \\
N + OH & \rightarrow NO + H
\end{align*}
\]

In comparison fuel NO\textsubscript{x} is related to the nitrogen content of the fuel and combustion conditions. Obviously fuel NO\textsubscript{x} levels depend on the nitrogen content of the fuel as well.
as other fuel properties. Organic nitrogen bound chemically in the fuel is the principal source of NO\textsubscript{x} emission during the combustion of coal accounting for up to 60% of the NO\textsubscript{x} emissions. The extent of conversion of this organic nitrogen to NO is strongly dependent on the fuel-air ratio and on the combustion temperature, and only slightly dependent on the identity of the parent nitrogen compound.

There are a number of options for combustion modification measures, such as reduction of the combustion temperature, reduction of the residence time in the high temperature zones and reduction of excess air. The following different approaches can be used to reduce the NO\textsubscript{x} emissions from the boiler.

4.2.1 Operational Modifications

The simplest approach involves reduction in the amount of primary air used to reduce the oxygen available to oxidise the fuel nitrogen within the flame and hence reduce NO\textsubscript{x} formation. Excess air should be reduced as much as possible without causing problems such as unstable combustion, corrosion and increased unburnt carbon in the fly ash. When reducing excess air NO\textsubscript{x} formation will decrease. The excess air level at this point varies for different fuels, boiler designs and operation.

It is also important to control air and fuel distribution to each burner in pulverised coal firing especially in low excess air operation. Notably an uneven distribution can easily create areas where the excess air is to low, leading to a reduced combustion efficiency and increased content of unburnt carbon.
Usually, operational modifications can reduce NOx emissions from furnaces by around 20%.

4.2.2 Design Modifications

Unfortunately relatively simple design modifications involve significant alterations to the boiler. In air staging low excess air levels are created in the initial combustion zone, with more complete burnout taking place higher up the furnace. This can be achieved by installing Over Fire Air (OFA) ports.

Installation of OFA allows the fuel rich region formed in the burner region to be extended, and control NOx to low levels. Staging the addition of combustion air in this way can reduce NOx emissions by up to 30%. This approach can be applied to FBC systems as well as conventional boilers. Problem with air staging include the creation of under-stoichiometric zones where accelerated corrosion may occur, an increase in unburnt carbon in fly ash, higher carbon monoxide (CO) emissions, and potential slagging on the heating surface.

Another way to achieve air staggering is by using Low NOx Burners. Conventional boilers using pulverised coal combustion can be fitted with a range of commercially available low NOx burners, which are becoming widely used in power plants. In these burners, the fuel and combustion air are separated to reduce the oxygen concentration in both the area of ignition and main combustion zones. Figure 4.2.2 presents a schematic of a typical low NOx burner.
The hydrocarbon radicals necessary for the NO\textsubscript{x} reduction are produced in the hydrocarbon radical generation zone from the main fuel. The radicals react with nitric oxide in the NO\textsubscript{x} reduction zone and complete burnout occurs in the oxidising zone through staged air in the burner.

This approach can reduce NO\textsubscript{x} emissions by 30-50\% (Cooke and Pragnell, 1987 and OECD, 1988). Low NO\textsubscript{x} burners are relatively low cost (Juniper and Pohl, 1991) and are readily available for retrofit as well as new plant use.

The use of low NO\textsubscript{x} burners to achieve the required mixing and distribution often results in an increased pressure drop. Low NO\textsubscript{x} burners are more complex than conventional burners, and require more operator attention. This may result in increased maintenance costs.
4.2.3 Fuel Staging (Reburning)

The aim of this technique is to reduce the NO\textsubscript{x} already formed back to nitrogen during combustion. The technique involves injecting fuel into a second substoichiometric combustion zone in order to let hydrocarbon radicals from the secondary fuel reduce the NO\textsubscript{x} produced in the primary zone.

Here, as suggested in Figure 4.2.3, the combustion is divided into three zones. In the primary zone the main fuel, in this case coal, is burned in an oxidising or slightly reducing atmosphere. In the next combustion zone secondary fuel is injected in a reducing atmosphere producing hydrocarbon radicals. These radicals react with nitric oxide produced in the first combustion zone, mainly to form nitrogen although unwanted volatile nitrogen compounds such as ammonia may also be formed. This second zone is often called the 'reburning zone' and the secondary fuel is called the 'reburning fuel'. Combustion is then completed through the addition of final air in the burnout zone (Hjalmarsson, 1990 and Allen, 1990).
The amount of reduction that can be achieved by reburning is often stated as being around 50% (Juniper and Pohl, 1991). Due to the necessity of additional furnace ports and fuel pipework the cost of this technology is higher than that associated with the use of low NO\textsubscript{x} burners.

**4.2.4 Flue Gas Recirculation**

The purpose of flue gas recirculation aimed at reducing NO\textsubscript{x} production, is to decrease the level of available air through dilution and to decrease the flame temperature. Flue gas recirculation can also be used to improve mixing. Figure 4.2.4 indicates a principle of internal flue gas recirculation.
Alternatively in an external system recirculation of a certain proportion (usually around 25%) of the flue gas flow is separated from the main down flow stream of the air preheater, commonly after the initial particulate control device. The recirculated flue gas can be mixed with combustion air in the burner, with primary air or other staging air, or in the furnace. It can also be injected and subsequently mixed through separate ports in the furnace as an alternative to or in combination with combustion air. Vernon (1990) reported that flue gas recirculation can reduce NO\textsubscript{x} emissions by around 20%.

Flue gas recirculation requires more modification to the boiler than the other NO\textsubscript{x} control measures and thus has a higher investment cost. The use of flue gas recirculation leads to a shorter residence time in the furnace due to the large flow through the boiler and also to higher gas flow pumping power consumption.
4.2.5 Costs of Main NO\textsubscript{x} Control Technologies

The costs of the main NO\textsubscript{x} control technologies can be difficult to predict since they depend on many factors such as the level of NO\textsubscript{x} reduction required, combustion technology, fuel properties, plant size and especially whether new or retrofit plant. Depending on Hjialmarsson's review (1991) and other related publications the relative costs of removing nitrogen oxide by different technologies are generally summarised in Figure 4.2.5.

**Figure 4.2.5 Relative Costs of Reducing NO\textsubscript{x} Emissions**
As indicated in Figure 4.2.5 low excess air is expected to cost up to US$10/kW to achieve up to 20% reduction of NO\textsubscript{x} emissions. In a cost estimate for low NO\textsubscript{x} burners, with 30-50% NO\textsubscript{x} reduction the required investment is in the range of US$10-15/kW. OFA is expected to cost US$12-18/kW with NO\textsubscript{x} reduced by 18-30%, whereas OFA incorporated with low NO\textsubscript{x} burners, yielding a 50% reduction on average, is expected to cost US$20-30/kW. Reburning is estimated to cost US$30-70/kW to install depending on boiler size with a typical 35-50% NO\textsubscript{x} reduction.

### 4.2.6 Summary of the Main Combustion NO\textsubscript{x} Control Technologies

The key benefits and disadvantages of the main combustion NO\textsubscript{x} control technologies are summarised in Table 4.2. An examination of this Table suggests that local operations should adopt low excess air conditions for furnaces both existing and future. Furthermore all existing furnaces should be upgraded to low NO\textsubscript{x} burners during planned shut down periods. In comparison new furnaces should be designed for low NO\textsubscript{x} burners or over fire air systems. In the long term local operations should examine the reburning and flue gas circulation operations.

#### Table 4.2 Key Benefits and Disadvantages of the Main Combustion NO\textsubscript{x} Control Technologies

<table>
<thead>
<tr>
<th>Process</th>
<th>Benefits</th>
<th>Disadvantages</th>
</tr>
</thead>
</table>
| Operational measure:  
  low excess air  | • cost minimal  
  • up to 20% NO\textsubscript{x} removal | • requires careful control of airflow  
  • can have negative impact on combustion efficiency |
| Design measure: | • cost low  
• up to 30% NO\textsubscript{x} removal  
• applicable to all types of boilers | • potential for corrosion and slagging  
• unburnt carbon in fly ash may increase  
• potential negative impact on combustion efficiency |
| --- | --- | --- |
| low NO\textsubscript{x} burners | • readily available for new plants or retrofit  
• cost relatively low  
• growing experience in use  
• up to 50% NO\textsubscript{x} removal | • more complex, with potential increased maintenance  
• applicable only to pulverised coal |
| Reburning | • can reduce NO\textsubscript{x} already formed  
• up to 50% NO\textsubscript{x} removal  
• intermediate cost | • requires addition of secondary fuel feed  
• requires careful control of operational conditions |
| Flue gas recirculation | • allows oxygen reduction without affecting gas mass flow  
• can overcome temperature problems (low excess air)  
• up to 20% NO\textsubscript{x} removal | • greater modification to boiler required  
• potentially higher cost  
• efficiency penalty due to recirculation fan power demand  
• may need significant maintenance |
4.3 Conclusions

International allowable emission levels for both $\text{SO}_2$ and $\text{NO}_x$ will become lower in the future. Control of the emissions from coal fired power plants in Australia will require many considerations that are related to the individual governing or enforceable standards, fuel properties, boiler design, and money available to achieve the required emissions.

In the short term utilisation of low sulphur coals in Australia should be still sufficient to meet current $\text{SO}_2$ emissions regulations without introducing specific technologies to control these emissions. In regard $\text{NO}_x$ control technologies existing PF boiler operators should retrofit and introduce staged combustion or low $\text{NO}_x$ burners during planned plant shutdowns. In comparison new PF plants operational measures including low $\text{NO}_x$ burners and over fired air techniques should be incorporated. In the long term local furnace operations should also examine reburning and flue gas circulation operations. These technologies should prove the most efficient and cost effective NO$_x$ controls for Australian application.
Chapter 5

Treatment of Flue Gas
5.1 Fuel Gas Desulphurisation

On the international scene Fuel Gas Desulphurisation (FGD) is the most widespread method in use for control of SO2 emissions. The generic term, FGD refers to sulphur control devices that are fitted to the back-end of the combustion process at the point of flue gas emission. In general, FGD systems use a sorbent to react with and scrub sulphur directly from flue gas, which in turn produces a by-product. The family of FGD technologies is large, and choice of a system depends on a variety of factors including capital and running cost, operating characteristics, ability to handle different qualities of coal, performance, and waste by-products.

FGD systems can be grouped into two broad categories, namely regenerable and nonregenerable systems, based on the way the sorbent is treated after it has taken up SO2. In nongenerable systems, the SO2 is permanently bound in a chemical compound which must be disposed of as waste or sold as a by-product. In regenerable systems, the SO2 is subsequently removed from the sorbent and the regenerable sorbent is returned to absorb more SO2. Recovered SO2 may be further processed and/or sold as a by-product.

5.1.1 Regenerative Processes (ERDC/EASS, 1991)

There are two types of regenerable FGD systems which are discussed. They are the Wellman Lord process and the Magnesium Oxide process.

The most common regenerable FGD system is the Wellman Lord process (refer to Figure 5.1.1), which is a wet system using sodium sulphite as a sorbent. In the absorber, which operates counter current to the flue gas stream, the following reaction takes place:
The absorption liquor leaves the bottom of the column rich in SO₂ and is transferred to the regeneration section via an intermediate storage tank. Regeneration is accomplished by heating the liquor in a forced circulation evaporator and the regenerated liquor is returned to the absorber circuit. Water vapour is driven off along with the SO₂ and is condensed from the gas stream in a series of heat exchangers. Typically the gas at the outlet of the final heat exchanger contains over 90% of SO₂ the balance being water vapour.

**Figure 5.1.1 Schematic Diagram of the Wellman Lord Process (ERDC/EASS, 1991)**

The other commercially operated regenerable system is MgO slurry scrubbing which is used in a spray tower to remove SO₂ and form magnesium sulphite via the reaction:

\[
\text{MgO} + \text{SO}_2 \rightarrow \text{MgSO}_3 \text{ (absorption)}
\]
The solids are dewatered and the resulting magnesium sulphite is calcined to release \( \text{SO}_2 \) and regenerate \( \text{MgO} \) in accord with the following reaction.

\[
\text{MgSO}_3 \rightarrow \text{MgO} + \text{SO}_2 \text{ (calcination)}
\]

Over 90% removal of the \( \text{SO}_2 \) in flue gases has been reported using this process.

### 5.1.2 Non-Regenerative Processes (ERDC/EASS, 1991)

In these processes, an alkaline absorbent liquor is recirculated in a closed loop. The sulphated reaction products are separated and fresh absorbent is added. The sulphated products may be disposed of as waste or solid as by-products.

#### 5.1.2.1 Limestone Gypsum

The limestone gypsum process (refer to Figure 5.1.2.1) consists essentially of an absorber section, usually a spray tower, in which a limestone slurry is contacted counter current to the flue gas stream. The absorption liquor is recirculated downwards through the tower and the scrubbed gas exits the tower through demisters. The absorption reaction can be represented as follows:

\[
\text{CaCO}_3 + \text{SO}_2 + \frac{1}{2}\text{H}_2\text{O} \rightarrow \text{CaSO}_3\cdot\frac{1}{2}\text{H}_2\text{O} + \text{CO}_2
\]

Depending on the system manufacturer, the calcium sulphite is either oxidised to gypsum in the base of the absorber or by an air blast in a separate tower. The gypsum slurry is
then thickened and dewatered in a filter press or centrifuge. Thickener overflow and filter press liquors can be returned to the absorber circuit.

The main gypsum product should be physically-chemically stable and may have an end use in plasterboard manufacture. In any case gypsum should be a suitable material for landfill disposal but may contain impurities that might cause secondary pollution problems. These problems include trace element and heavy metal contamination.

**Figure 5.1.2.1 Schematic Diagram of the Limestone Gypsum Process**
(ERDC/EASS, 1991)

5.1.2.2 Spray Dry Process

The spray dry absorber system (refer to Figure 5.1.2.2) consists essentially of contacting the flue gas with a finely atomised spray of slaked lime in a tower absorber. The tower is normally located upstream of the dust collection system and the lime spray will wash out
particles from the flue gas in addition to absorbing SO$_2$. Normally, the tower does not contain any packing and the lime droplets descend concurrently with the gas flow, absorbing SO$_2$ and trapping particles whilst the water is simultaneously evaporated. The absorption reaction is:

\[
\text{Ca(OH)}_2 + \text{SO}_2 \rightarrow \text{CaSO}_3 + \text{H}_2\text{O}
\]

By the time the droplets have reached the bottom of the tower, all the surface moisture has evaporated and a nominal dry powder containing the captured SO$_2$ is obtained. Some of the solids will deposit in the tower bottom and be recycled, but the bulk of the solids will be carried forward to the electrostatic precipitator, or fabric filter, where they are removed from the gas stream.

**Figure 5.1.2.2 Schematic Diagram of the Spray Dry Process** (ERDC/EASS, 1991)
5.1.2.3 Dual Alkali Process

Initial problems with scaling in the absorbers of the systems using lime or limestone led to the introduction of the Dual Alkali system in which scrubbing is carried out using a sodium salt, and the calcium sulphite/sulphate product is then precipitated in a separate reactor by the use of lime or limestone.

Here SO₂ is absorbed by contacting flue gas with a sodium sulphite/bisulphite solution. The sulphite reacts with the SO₂ producing additional bisulphite according to the following overall reactions:

\[
Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3
\]

Several companies have developed Dual Alkali processes. The US processes are of the waste-producing type, producing a calcium sludge consisting primarily of CaSO₃•H₂O. In comparison the processes installed in Japan generally result in the production of high quality gypsum. These latter improved processes incorporate an additional oxidation stage converting calcium sulphite to calcium sulphate.

Dual Alkali processes have achieved SO₂ removal efficiencies in excess of 90%.

5.1.2.4 Seawater Scrubbing

Seawater scrubbing of flue gases is little applied at present but appears attractive for future application at certain coastal sites. In this process SO₂ is removed from the flue gases by
passing the gas through seawater to which lime or limestone may be added to increase its alkalinity. The SO$_2$ reacts with the water in two stages;

$$\text{SO}_2 + \text{H}_2\text{O} \rightarrow 2\text{H}^+ + \text{SO}_3^-$$

and

$$\text{SO}_3^- + \text{H}_2\text{O} \rightarrow 2\text{H}^+ + \text{SO}_4^-$$

to form sulphate, sulphite and hydrogen ions. The resulting acidity is neutralised by the natural alkalinity of the seawater before discharge. Oxidation of sulphite to sulphate is carried out by aeration. The discharged seawater has a pH of about 7.0 and contains additional sulphate ions. In locations where a discharge of heavy metals could lead to a problem, a pre-scrubber, which is small in volume, and utilises conventional precipitation techniques is used to remove the heavy metals. The treated pre-scrubber effluent is mixed with the main absorber tower effluent prior to discharge.

5.1.3 Capital Costs and SO$_2$ Removal Efficiency of FGD

Although reported costs of FGD vary widely between systems and countries, in general they lie within the range 15-20% of total new power plant capital costs, and contribute an additional 5-10% to the costs of electricity generation from a power plant depending on load, fuel characteristics etc (Vernon, 1990).

Cost and SO$_2$ removal efficiency estimates for the installation of the various FGD technologies are given in Table 5.1.3. This cost includes the annual capital charge plus the costs for operation, chemicals and maintenance of the FGD plant (from the ERDC/ESAA referred to Australian cost factors by Ewbank Preece Sinclair Knight, 1991).
Table 5.1.3 Typical Costs and Efficiency For FGD Plant

<table>
<thead>
<tr>
<th>Process</th>
<th>Capital cost (A$/kW)</th>
<th>Operating cost (A¢/kW)</th>
<th>Efficiency (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regenerable</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wellman Lord</td>
<td>170 - 290</td>
<td>0.75 - 1.30</td>
<td>&gt;90</td>
</tr>
<tr>
<td>MagOx</td>
<td>180 - 270</td>
<td>0.82 - 1.17</td>
<td>90 - 95</td>
</tr>
<tr>
<td>Non Regenerable</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dual Alkali</td>
<td>160 - 260</td>
<td>0.71 - 1.12</td>
<td>&gt;90</td>
</tr>
<tr>
<td>Limestone/Gypsum</td>
<td>140 - 240</td>
<td>0.63 - 0.95</td>
<td>90 - 95</td>
</tr>
<tr>
<td>Spray Dry (Lime)</td>
<td>100 - 180</td>
<td>0.55 - 1.28</td>
<td>70 - 90</td>
</tr>
<tr>
<td>Seawater Scrubbing</td>
<td>120 - 130</td>
<td>0.52 - 0.59</td>
<td>80 - 90</td>
</tr>
</tbody>
</table>

5.2 Post Combustion Methods for NO\textsubscript{x} Reduction

Where the limits on NO\textsubscript{x} emissions cannot be met by combustion control, NO\textsubscript{x} has to be removed from the flue gases through installation of flue gas treatment equipment. The processes in use at present for reduction of NO\textsubscript{x} in flue gases are mainly selective catalytic reduction in which the NO\textsubscript{x} concentration is reduced by over 70-90% and selective noncatalytic reduction which have NO\textsubscript{x} reduction efficiencies between 30-60%.

5.2.1 Selective Catalytic Reduction

Up to now, selective catalytic reduction (SCR) has been the dominant method for flue gas NO\textsubscript{x} treatment. In this method ammonia is injected into the flue gas in the presence of a
catalyst, commonly titanium oxide based, to reduce NO and NO₂ to nitrogen and water.

The most common reactions are:

\[
4\text{NO} + 4\text{NH}_3 + \text{O}_2 \rightarrow 4\text{N}_2 + 6\text{H}_2\text{O} \quad (1)
\]

\[
\text{NO} + \text{NO}_2 + 2\text{NH}_3 \rightarrow 2\text{N}_2 + 3\text{H}_2\text{O} \quad (2)
\]

\[
2\text{NO}_2 + 4\text{NH}_3 + \text{O}_2 \rightarrow 3\text{N}_2 + 6\text{H}_2\text{O} \quad (3)
\]

\[
6\text{NO}_2 + 8\text{NH}_3 \rightarrow 7\text{N}_2 + 12\text{H}_2\text{O} \quad (4)
\]

The catalyst can be situated at different positions in the flue gas flow, the important factor is that conditions, such as the flue gas temperature, are optimum for the type of catalyst used. The optimum temperature is usually between 300 °C and 400°C. The positions that are used for the catalyst are high dust, where the catalyst is placed between the economiser and the air preheater, low dust, with the catalyst situated after a hot gas precipitator and before the air preheater, and tail end, with the catalyst situated after the desulphurisation plant. The most widely used position worldwide is the high dust position, in which untreated flue gas containing SO₂ and particulates passes through the catalyst.

The technology was developed in Japan, where the first plant on a coal fired unit started to operate at the end of 1980. The first system in Europe began operating in the West Germany at the end of 1985. The next country to implement this technology was Austria. At the demonstration plant scale systems have been operating in the Netherlands since 1987, and pilot plants have been operating in Denmark and Sweden. Tests at pilot scale are planned in the USA. By the end of 1990 there was a total installed capacity of 41 GWe
equipped with selective catalytic reduction in 184 coal-fired power plants, with the majority located in West Germany (129 plants, 28.15 GWe). The efficiency of NO\textsubscript{x} reduction for SCR technology is dependent upon several factors such as NO\textsubscript{x} concentration at the inlet and outlet of the catalyst, flue gas temperature, the ratio of ammonia injection, oxygen concentration, and catalyst properties such as space velocity, and active area. Most plants are designed for a 70-80\% NO\textsubscript{x} reduction efficiency to meet emission levels of 200 mg NO\textsubscript{2}/m\textsuperscript{3}, at 6\% O\textsubscript{2}. A few plants in West Germany are designed for reduction of emissions by over 90\% where the NO\textsubscript{x} concentration after the boiler has been particularly high.

Obviously the cost for SCR plants depend on design criteria and operating conditions. Estimated costs for SCR on future coal-fired boilers, reducing the NO\textsubscript{x} level by 70-90\% for black coal and 70\% for brown coal, vary over the range US$40-120/kWe; the upper level is for retrofit installations and high NO\textsubscript{x} reduction. It is estimated that retrofit installations can cost up to 50\% more than for new installations (Hjialmarsson, 1990).

5.2.2 Selective Non-catalytic Reduction

Selective non-catalytic reduction (SNCR) is an attractive method from the point of view that no costly catalyst is required. Nitrogen oxide can be controlled through thermal reactions, using appropriate reducing chemicals.

The reaction usually occurs at temperatures of 900-1100°C. Ammonia and urea are generally used as the reducing chemicals. The process, using urea together with enhancers (additives), is called NO\textsubscript{x}OUT. The process, using ammonia as the reducing chemical, is patented in several countries as the Exxon process. The purpose of the additive in
NO$_x$OUT process is to enable the reactions to occur at lower temperatures. Tests have also been conducted using urea with or without additives, using different chemicals as additives, and using ammonia in solution.

The SNCR method results in less NO$_x$ reduction than SCR, the common view is that SNCR processes are in general capable of 30-60% reduction as an average covering different operational conditions, although a higher consumption of chemicals is required.

Two commercial plants started to operate in 1986, one in Austria and one in West Germany. In 1988-1989, another four were installed in West Germany and two in Austria. The first circulating fluidised bed boiler to be equipped with selective non-catalytic reduction began operating in the USA in 1988. This has been followed by other similar installations in the USA. Selective non-catalytic reduction is expected to cost US$16-25/kWe to reduce NO$_x$ by 30-50%. Higher reduction, up to 70-80%, is considered achievable under favourable conditions (Hjialmarsson, 1990).

For the SCR and SNCR technologies cost and NO$_x$ removal efficiency estimates from the ERDC/ESAA report, referred to Australian cost factors, are presented in Table 5.2.3.

<p>| Table 5.2.3 Costs and Efficiency of NO$_x$ Removal Technologies in Flue Gases |</p>
<table>
<thead>
<tr>
<th>Technology</th>
<th>Capital cost (A$/kW)</th>
<th>Operating cost (A$/kWh)</th>
<th>Efficiency ( % )</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR</td>
<td>100-150</td>
<td>0.18-0.36</td>
<td>80</td>
</tr>
<tr>
<td>SNCR</td>
<td>5-13</td>
<td>0.05-0.10</td>
<td>40-50</td>
</tr>
</tbody>
</table>
5.3 Conclusion

To date the low levels of sulphur content in coals used in Australian power stations have fortunately allowed Australian plants to operate without any need to control or remove oxides of sulphur from flue gases. In the future it would be possible that stricter requirements in relation to power plant SO₂ emissions, may apply. The stringer limits may follow that for SO₂ emissions from power station operation in European countries which are currently down from 2000 to 400mg/m³ for large scale power plants. If such strict requirements become applicable Australia would require FGD devices to be fitted even despite the use of good quality coals with sulphur contents in the 0.5% to 1.0% range.

There are numerous factors such as coal properties, site specific factors, and capital and operating costs which affect selection of FGD technologies for Australia. It is recommended that spray dry FGD system should be selected for convenient and effective use in Australia. The main advantages of this FGD system include lower energy losses, ease of handling the by-product, and lower capital and operating costs. In commercial applications using low sulphur coal, the simple lime injection addition technique will typically achieve SO₂ reduction in the range of 70-80%.

As a result of high cost and limited experience it is hard to consider that either SCR or SNCR techniques will ever be applied in Australia. The potential application of these technologies will depend on the NOₓ emission standards to be applied, the fuel to be used, the boiler designs, and the capital funds available to achieve the required reduction.
Chapter 6

Advanced Coal Combustion Technologies
6.1 Conventional Power Generation and Efficiency Improvements

6.1.1 Thermodynamic Power Plant Cycle

The Rankine cycle in thermodynamics has been used almost exclusively in conventional steam power plant. As with all ideal processes, the processes in the Rankine cycle are reversible. Figure 6.1.1 depicts the ideal Rankine cycle on a temperature-entropy (T-s) diagram.

Figure 6.1.1 T-s Diagram of the Ideal Rankine Cycle

The thermal efficiency is defined as:

\[
\eta_t = \frac{W_{\text{net}}}{Q_s} = \frac{W_t - W_p}{Q_s}
\]  

(1)

where \( W_{\text{net}} \) is the net work output, \( W_t \) is the turbine work, \( W_p \) is the pump work and \( Q_s \) is the heat supplied.
In general the pump work is very small compared to the turbine work. For a basic raw evaluation equation (1) reduces to:

\[ \eta_t = \frac{W_t}{Q_s} = \frac{h_2 - h_3}{h_2 - h_4} \]  

(2)

where \( h_2, h_3 \) and \( h_4 \) are the enthalpies of the steam at the boiler outlet, the turbine outlet and the condenser outlet, respectively.

The overall efficiency of the entire power plant, including the cyclic power plant and the heating device is given by Horlock (1987) as follow:

\[ \eta_o = \eta_t \eta_b \]  

(3)

where \( \eta_b \) is the boiler efficiency.

### 6.1.2 Comparison between Supercritical and Subcritical Power Plant

The improved efficiency of supercritical cycles relative to that for subcritical operation is highlighted by determining the ideal thermodynamic efficiency of the simple Rankine cycle, as illustrated by Figure 6.1.1, for the following four cases of operating parameters.

Case 1: Subcritical power plant (15MPa/510°C/7kPa)
Case 2: Subcritical power plant (15MPa/510°C/5kPa)
Case 3: Supercritical power plant (25MPa/560°C/2kPa)
Case 4: Supercritical power plant (30MPa/600°C/2kPa)
For the above four cases the values in the brackets define the steam pressure, steam temperature and condenser pressure, respectively.

The thermal efficiency, overall plant efficiency for the above cited cases are indicated in Table 6.1.2. The boiler efficiency is assumed to be 90% for calculation of the overall plant efficiency. About 5% for other losses, including piping and transformer et al., is assumed in this calculation.

Table 6.1.2 Comparison of subcritical and supercritical power plant cycles

<table>
<thead>
<tr>
<th>Item</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
<th>Case 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>$h_2$ (kJ/kg)</td>
<td>3336</td>
<td>3336</td>
<td>3367</td>
<td>3443.9</td>
</tr>
<tr>
<td>$h_3$ (kJ/kg)</td>
<td>1985</td>
<td>1945.7</td>
<td>1795.5</td>
<td>1810</td>
</tr>
<tr>
<td>$h_4$ (kJ/kg)</td>
<td>168.78</td>
<td>137.8</td>
<td>73.48</td>
<td>73.48</td>
</tr>
<tr>
<td>$\eta_t$ (%)</td>
<td>42.6</td>
<td>43.5</td>
<td>47.7</td>
<td>48.5</td>
</tr>
<tr>
<td>$\eta_o$ (%)</td>
<td>38.3</td>
<td>39.2</td>
<td>42.93</td>
<td>43.7</td>
</tr>
<tr>
<td>Condenser heat loss (%)</td>
<td>46.7</td>
<td>45.8</td>
<td>42.07</td>
<td>41.3</td>
</tr>
</tbody>
</table>

From the above evaluation it is apparent that the net plant efficiency of supercritical cycles are about 4% to 6% higher than that for subcritical cycles. This improved cycle efficiency will yield a 15% to 20% reduction of CO$_2$ emissions.
6.1.3 Cogeneration

Coal fired power generation systems discussed up to this point can not improve their efficiency further as a result of the considerable waste heat losses from the steam Rankine cycle. This heat loss results essentially by the inability of the Rankine cycle to utilise the latent energy of vaporisation of steam. As indicated in Table 6.1.2, for a supercritical steam cycle a condenser heat loss of 42% of the fuel input occurs (case 3). This percentage loss increases to approximately 47% for subcritical steam plant (case 1). Obviously the overall system efficiency can be improved if the waste heat can be gainfully utilised. One such technique to utilise this waste heat is cogeneration.

Cogeneration is the combined production of useable heat and electrical power. Cogeneration enables significant increases in the overall energy efficiency by making use of the available waste heat which can be charged for as industrial process heat or as an energy supply to users.

For an open circuit cogeneration plant an overall energy efficiency (OEE) is defined as

\[ OEE = \frac{W + Q_u}{F} \]  

(4)

where \( W \) is the fractional generation of electricity work, \( Q_u \) is the fractional supply of useful heat and \( F \) is the energy input factor.

When \( F \) is unity (\( F=1.0 \)) equation (4) simplifies to

\[ OEE = W + Q_u \]  

(5)
Timmerman (1978) provides typical values for the overall energy efficiency (OEE) for four cogeneration examples which are indicated in Table 6.3.

Table 6.1.3 Cogeneration Efficiency for Coal Fired Systems

<table>
<thead>
<tr>
<th>Item</th>
<th>F</th>
<th>W</th>
<th>Qd</th>
<th>OEE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Extraction condensing power plant</td>
<td>1.0</td>
<td>0.38</td>
<td>0.10</td>
<td>0.48</td>
</tr>
<tr>
<td>Black-pressure steam power plant</td>
<td>1.0</td>
<td>0.25</td>
<td>0.60</td>
<td>0.85</td>
</tr>
<tr>
<td>Gas turbine with waste heat recuperator</td>
<td>1.0</td>
<td>0.30</td>
<td>0.55</td>
<td>0.85</td>
</tr>
<tr>
<td>Gas turbine/back pressure steam turbine</td>
<td>1.0</td>
<td>0.40</td>
<td>0.42</td>
<td>0.82</td>
</tr>
</tbody>
</table>

From the above discussion of power generation efficiency, relative to the reference PF power generation systems it is apparent that the thermodynamic advantages of cogeneration associate with substantial improvements in net plant efficiency, for ideal conditions, to the 80-90% range. This significant increase in cycle efficiency will yield potential reductions in CO₂ emissions in the range of 50-75%. Significant reductions in CO₂ emissions also apply to practical cogeneration systems exhibiting typical OEE of 60-65%.

In view of this vast important in OEE there is considerable activity in the view of cogeneration application in Australia, particularly in Victoria where the political climate has resulted in financial incentives which favour cogeneration. However, currently primary
fuel and electricity costs are relatively low, which does not provide an attractive environment for cogeneration schemes.

Since a cogeneration scheme significantly reduce carbon dioxide emissions, compared with separate central power stations and boiler heating plants, it should be a favoured strategy to reduce greenhouse effects in Australia.

6.2 Fluidised Bed Combustion Technology

6.2.1 General

The use of fluidised bed combustion (FBC) for power generation has increased rapidly in recent years. As a result of this increased application this technology is considered fully commercial. It is claimed that the main advantages for fluidised bed combustion over pulverised fuel firing are reduced acid gas emission and improved fuel flexibility. There are literally thousands and thousands of FBC units employed in the world, including some 250 large scale units in operation or under construction (R J Dry, 1991).

The first fluidised bed combustion concept to receive substantial attention was the atmospheric bubbling fluidised bed. This technology was investigated intensively in the 1960's and 1970's, particularly in Britain and the United States. The bubbling fluidised bed combustors are now well established in the industrial boiler sector of the market. Several fairly large utility units are in operation in the USA, notably, the largest of which has a generating steam capacity of 499 t/h.
Circulating fluidised bed (CFB) boiler units first appeared in 1979 and have since then enjoyed remarkable growth and user acceptance. The CFB generally offers two main advantages over the bubbling fluidised bed these being: high carbon combustion efficiency and better sulphur capture performance. For these reasons large numbers of CFB boiler have been employed from 1982 to present. The largest generating steam capacity for a CFB unit is 465t/h (Hunwick, 1991).

Pressurised fluidised bed combustion (PFBC), as a concept has been considered seriously for some time, in the form of CFB. However, engineering problems relating to tube material wastage, solids handling and hot gas cleaning have slowed development. The system itself offers advantages in term of cycle efficiency, with some 4 percentage points in overall thermal efficiency to be gained in relation to the atmospheric alternatives.

6.2.2 Atmospheric Bubbling Fluidised Bed Boiler

A typical atmospheric bubbling fluidised bed unit is illustrated in Figure 6.2.2 (R J Dry, 1991). In this system a pre-heated air fluidises a shallow bed via a multi-orifice distributor.
In comparison coal is fed directly into the bed through a number of feed ports, either from above (top size typically 25 mm) or by pneumatic under-bed feed (top size typically 12 mm). The bed material itself is usually around 500 to 1000 microns (average) in size and the system operates at a superficial velocity of around 1-3 m/s. Heat is extracted by steam generation in tubes immersed in the bed. High heat transfer coefficients are observed (by PF standards) as a result of the solids movement around the heat transfer surfaces. Gas and entrained fine solids are carried out of the furnace and are subjected to heat extraction in a conventional backpass arrangement.

Boilers of this type tend to have relatively large plan areas (relative to CFB and PFBC units), with heat release rates of around 1-1.5 MW per square metre of bed. Excess air levels are usually maintained at around 10-20 percent, corresponding to 2-5% oxygen in the flue gas.
One of the main advantages of the fluidised bed boiler over PF systems is the fact that the temperature variation in the furnace is small due to solids mobility in the fluidised state. This feature is commonly exploited for sulphur capture using limestone, viz.

\[ \text{CaCO}_3 \rightarrow \text{CaO} + \text{CO}_2 \]  

followed by

\[ 2\text{CaO} + 2\text{SO}_2 + \text{O}_2 \rightarrow 2\text{CaSO}_4 \]

The thermodynamic stability of the sulphur capture product declines sharply as temperature is increased above 900°C and, for this reason, bed temperatures are maintained between 800 and 900°C. Ca/S molar feed ratios of around 2-2.5 are typically used and sulphur capture efficiency for this type of system is usually in the range 70-90 percent, depending on limestone reactivity. Soft, dolomitic limestones are claimed to be the most effective sorbent for sulphur removal (Dry, 1991).

Direct addition of limestone to the bed is a highly effective means of controlling sulphur dioxide emissions. Disposal of sulphated limestone is usually not a problem: it reports to the ash discharge and is considered a component of the ash itself.

Thermal nitrogen oxide formation is not significant under bubbling bed combustion conditions (due to low combustion temperature) and emissions tend to originate mainly from fuel-bound nitrogen compounds. This emission level can be further reduced by employing staged combustion. Here the bed itself is operated in a reducing environment, and "over-fire" air is added above the bed surface. As a result, initial volatile combustion takes place in an oxygen-lean environment within the bed and this tends to inhibit nitrogen oxide formation. Nitrogen compounds which do not volatilise in the early stages of
combustion are not as effectively dealt with by this means; since the overall strategy aims at staging oxygen potential in the gas (upflow) phase rather than in the solids (mix flow). As a result, staged combustion is more effective for a coal with a high volatile content (Dry, 1991).

It has recently been discovered (Dry, 1991) that nitrous oxide (N₂O) is present in FBC system flue gas at levels similar to that of (NO + NO₂). It would appear that organic nitrogen in the fuel is the precursor of N₂O, with partial oxidation passing through a cyanide intermediate stage:

organic N → HCN → NCO → N₂O (3)

Interestingly enough, N₂O levels respond in an inverse manner to NOₓ minimisation strategies (low temperature, staged combustion) and it appears that the total (NO + NO₂ + N₂O) emission may be more difficult to control than previously thought.

Furthermore sulphur capture and nitrogen oxide minimisation interact with one another in a negative sense. In particular staged combustion controls, to reduce oxygen potential in the bed, inhibits sulphur capture in accordance with equation (2) above. In addition, over-fire air often results in a significant temperature increase in the above-bed region, and this can have a deleterious effect on sulphur capture by locally exceeding the upper temperature limit of calcined sulphur stability. In fact there is strong evidence to suggest that calcined limestone is a catalyst for nitrogen oxide formation; here too a balance is needed between the two acid gas minimisation approaches (Dry, 1991).
In an overall sense, FBC acid gas emissions are dramatically lower than those from an equivalent PF plant (without external flue gas treatment). Emission limits of typically 200-300 ppm for $SO_x$ and 100-150 ppm for $NO_x$ can usually be met without resorting to post-treatment of flue gas.

6.2.3 Atmospheric Circulating Fluidised Bed Boiler

A typical circulating fluidised bed boiler is illustrated in Figure 6.2.3 (R J Dry, 1991). The furnace itself is significantly different to that of a bubbling bed boiler, but the rest of the plant including the convection heat transfer arrangement is fairly standard.

Figure 6.2.3 Schematic of a Circulating Fluidised Bed Boiler (Dry, 1991)

The principal difference between bubbling and circulating bed systems is the gas velocity at which the unit is operated. Bubbling bed boilers run at 1-3 m/s as stated earlier, while CFB units run at velocities of 6-10 m/s. This has a number of important implications:
turbulence levels are higher and as a result lateral mixing is more intense. Heat release rates per unit (plan) area are higher at 5-6 MW per square metre and units tend to be tall and narrow relative to bubbling bed boilers. Axial density profiles generally do not show a dense-lean bed interface but rather a gradual reduction in density from the bottom to the top of the riser.

Gross entrainment of solids by the upflowing gas stream is an essential feature of the system, as is solids re-injection at the bottom of the riser- without re-injection the vessel would empty itself in a short time. As described earlier, a large hot cyclone is used to separate gas and solids as they leave the top of the riser. These solids fall from the base of the cyclone into a small-diameter dense bubbling fluidised bed and are transferred downward from a region of low pressure to a region of higher static gas pressure. From here they are re-injection into the riser via a loopseal or similar device. The dense bed in the cyclone dipleg is a critical component of the system: it operates as a pressure recovery system, using a gravity head of fluidised solids to "pump" particulate material from a low pressure to a higher gas pressure and thus provide a driving force for circulation around the CFB loop. The greater the inventory of solids in the return leg, the stronger the gravity head and the higher circulation around the loop.

The solids in a CFB system are finer than those in a bubbling bed, typically 200 to 300 microns average in size, and the coal feed top size is limited to about 12 mm or so.

It is reported that many of the CFB's advantages over the bubbling bed are related to the fact that fines retention is greater— this is reflected in the efficiency of limestone use for sulphur capture. A finer limestone feed can be used and less un-reacted material is
discarded in the centre of the sulphated particles. For CFB systems Ca/S molar ratios of 1.2-2.0 are sufficient to achieve the commonly required 70-90 percent sulphur removal.

Nitrogen oxide minimisation strategies are similar between bubbling and circulating bed systems, with secondary air addition on CFB units often referred to as "overfire air" despite the fact that there is no distinct bed-freeboard interface in the system. The fact that bulk gas flow involves less backmixing (a direct consequence of operating at a higher gas velocity) implies that staged combustion is more efficient for suppressing nitrogen oxide formation from nitrogen-bearing volatiles.

In Australia the CSIRO has conducted technical-scale fluidised bed combustion trials which would be applied to both BFBC and CFBC plant. This work as reported (Peeler et al., 1991) indicated that for low sulphur content high rank Australian coals only minimal limestone addition will be needed to meet emissions limits. In addition these studies indicated the average NO$_x$ emission for Australian coals varied from 55ppm to 165ppm.

6.2.4 Pressurised Fluidised Bed Combustion

Pressurised fluidised bed combustion (PFBC) aims at using flue gas expansion through a gas turbine to enhance overall thermal efficiency. PFBC systems operating at pressures of between 1 and 3 MPa, at temperature of ranging from 800 to 900 °C are currently being tested in demonstration facilities of a commercial scale. A typical combined cycle configuration of the type envisaged is illustrated in Figure 6.2.4 (R J Dry, 1991).
With conventional power generation facilities now reaching a plateau in terms of efficiency improvement, combined gas/steam cycles offer the potential to once again significantly increase power generation efficiencies. The pressure energy of the fluidised bed exhaust gases is recovered (after being cleaned of entrained ash particles), in a gas turbine before heat recovery and exhaust to the atmosphere. It is important to ensure the gas is sufficiently clean so as not to damage the gas turbine blades through erosion. The gas turbine compressor, indicated in Figure 6.2.4, supplies compressed air for combustion in the pressurised fluidised bed. The generation of electricity is therefore possible from both the gas turbine generator and a conventional steam turbine and generator. Approximately 20% of the electricity generated is provided by the gas turbine whilst the remaining 80% is generated by the steam cycle. This combination provides a significantly higher efficiency typically between 40-45% (HHV). Such high efficiencies are due to the combined use of gas turbine technology and heat recovery systems.
The pressurised combustion environment leads to a significant improvement in acid gas emission behaviour. In particular, high sulphur dioxide and oxygen partial pressures lead to more rapid and complete sulphation of calcined limestone. The fact that limestone is present in its sulphated form rather than in its simple calcined form implies that fewer catalytically active sites are available for formation of nitrogen oxides — the observed result is lower emissions of both nitrogen and sulphur oxides, along with limestone requirements and utilisation in line with that of atmospheric CFB technology. In particular it was quoted Hippinen's research (1992) that PFBC systems have efficiencies of sulphur removal over 90%. At his facility the emission levels of NO\textsubscript{x}, typically ranged between 82-410 mg/m\textsuperscript{3}, with different kinds of coal including peat, brown and bituminous coal.

6.2.5 Comparison of Gaseous Emission and Plant Efficiency between FBC and PF Systems

The overall plant efficiency for conventional PF power plants is usually in the range of 33% to 35%. A modern large scale power plant would contribute around 900kg/MWh of CO\textsubscript{2} emission (Duffy and Dave, 1992). The average NO\textsubscript{x} emission level of these coal fired power generation systems is typically 850mg/m\textsuperscript{3} (Vernon, 1990).

As stated previously atmospheric bubbling and circulating fluidised bed combustors are also used for power generation. The major benefits of this method of coal combustion are the in ‘bed’ removal of sulphur oxides and the low emission of nitrogen oxides arising from the lower fuel combustion temperatures (<900°C). Despite the low SO\textsubscript{2} and NO\textsubscript{x} emission levels, net efficiencies are roughly as same as the pulverised coal fired plants. However, there is a slightly higher emission of CO\textsubscript{2} from the use of sorbents for desulphurisation and this fugitive emission is estimated to be 990kg/MWh.
Pressurised fluidised bed combustors which operate at temperatures of 850-950°C and pressures of up to 1.2 MPa may be either used for coal combustion and to power a gas/steam turbine combined cycle. In regard the latter net power station efficiencies of 40% to 42% have been proposed for PFBC systems. The PFBC system have efficiencies of sulphur removal in the range of 90-98%. The emission levels of NO\textsubscript{x} and CO\textsubscript{2} are respectively 350mg/m\textsuperscript{3} and 940kg/MWh (Smith and Thambimuthu, 1991). Table 6.2.5 presents a summarised comparison of FBC and PF systems gaseous emission characteristics.

Table 6.2.5  Comparison of FBC and PF Systems

<table>
<thead>
<tr>
<th>Item</th>
<th>Net efficiency (%)</th>
<th>Sulphur removal (%)</th>
<th>NO\textsubscript{x} emission (mg/m\textsuperscript{3})</th>
<th>CO\textsubscript{2} emission (kg/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PF</td>
<td>33-35</td>
<td>0</td>
<td>850</td>
<td>900</td>
</tr>
<tr>
<td>PF + FGD</td>
<td>33-35</td>
<td>90</td>
<td>850</td>
<td>900</td>
</tr>
<tr>
<td>BFBC</td>
<td>33-35</td>
<td>70-90</td>
<td>125-600</td>
<td>990</td>
</tr>
<tr>
<td>CFBC</td>
<td>33-35</td>
<td>70-90</td>
<td>100-420</td>
<td>990</td>
</tr>
<tr>
<td>PFBC</td>
<td>40-42</td>
<td>90-98</td>
<td>350</td>
<td>940</td>
</tr>
</tbody>
</table>

Over the last 20 years or so Australia has made attempts to develop and apply FBC technology, especially in regard burning coal wastes. In particular from 1977 to 1985, the CSIRO Division of Fossil Fuels and the Joint Coal Board operated a 4.5 MW (thermal) pilot plant at the Clutha Development Ltd., Glenlee coal preparation plant, New South Wales (Duffy and Kable, 1985). The operating experience suggested that no technical difficulties arise meeting environmental emission requirements.
In addition two other small-scale commercial applications of FBC technology exist locally. Both plants burn high ash coals. The first, is the Blue Circle Southern Cement Ltd, Berrima, New South Wales. This plant fires a coal containing 28-36% of ash in a Dorr-Oliver BFBC to dry clinker feed in a wet milling process. The second unit, supplied by Babcock Australia Ltd, is also a bubbling fluidised bed unit. This unit has been operating for eight years supplying steam to the Petersville food processing plant at Scottsdale, Tasmania, burning a high ash, bituminous coal from the Fingal Valley. In addition, several large circulating fluidised beds are in operation in Australia’s big alumina refineries (Hunwick, 1991).

6.3 Integrated Gasification Combined Cycle Technology

6.3.1 General

A promising technology for power generation which is expected to contribute a considerable share of electricity supply by the year 2000 and beyond is the integrated gasification combined cycle (IGCC) system. As a result IGCC systems firing coal, will become a key option for coal fired power plants in the future because of their high efficiency and minimal environmental impact.

A simple schematic of a coal based IGCC power generation system is shown in Figure 6.3.1. High temperature fuel gas is generated in the gasifier and purified and removed of particulates in the gas cleanup system. Clean gas is sent to the gas turbine where it is burnt with compressed air to provide a stream of hot, high pressure gas which drives a gas turbine to generate electricity. The exhaust gases from the turbine pass to a waste heat boiler where steam at high pressure and high temperature is raised by heat exchange with
the boiler feed water. This steam then passes to the steam turbine which generates additional electricity.

**Figure 6.3.1 Simple System Diagram for IGCC Generation**

At this stage there are two types gasification processes. They are the slagging gasification process and the non-slagging gasification process.

In slagging gasifiers the mineral matter in the coal is melted and extracted as molten slag, usually at temperatures above 1350°C. The slag is then solidified and collected. Slagging gasifier systems which are at or near commercial scale operation include the British Gas/Lurgi (BGL), Dow, Gaskombinat Schwarze Pumpe (GSP), Krupp Koppers Pressurised Entrained Flow (PRENFLO), Shell, and Texaco Process units.
One general class of non-slagging gasifiers is fluidised bed units. These gasifiers must operate at temperatures which do not cause ash fusion, and therefore operate at lower temperatures than slagging gasifiers. The gasifier residues from these lower temperature processes are either ash or partially bound agglomerated ash. Fluidised bed processes which could potentially be scaled up to commercial IGCC operation include the High Temperature Winkler (HTW), Kellogg Rust Westinghouse (KRW), and Utility Gas (U-Gas) processes. Table 6.3.2 presents a summary of typical gasification operating conditions and performance of selected major gasifiers (Clark, 1991).

### Table 6.3.2 Gasification Processes and Typical Operating Conditions

<table>
<thead>
<tr>
<th>Gasifier</th>
<th>Bed type</th>
<th>Ash type</th>
<th>Feed</th>
<th>Fuel*</th>
<th>Pressure MPa</th>
<th>Reaction T, °C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slagging:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BGL</td>
<td>moving</td>
<td>slag</td>
<td>dry</td>
<td>b/sb</td>
<td>2.5</td>
<td>2000+</td>
</tr>
<tr>
<td>Dow</td>
<td>entrained</td>
<td>slag</td>
<td>slurry</td>
<td>sb/l</td>
<td>2.2</td>
<td>1320-1430</td>
</tr>
<tr>
<td>GSP</td>
<td>entrained</td>
<td>slag</td>
<td>dry</td>
<td>b/sb</td>
<td>3.0</td>
<td>1800-2200</td>
</tr>
<tr>
<td>PRENFLO</td>
<td>entrained</td>
<td>slag</td>
<td>dry</td>
<td>b/sb</td>
<td>3.0</td>
<td>1500-2000</td>
</tr>
<tr>
<td>Shell</td>
<td>entrained</td>
<td>slag</td>
<td>dry</td>
<td>b/sb/l</td>
<td>3.0</td>
<td>1350-1700</td>
</tr>
<tr>
<td>Texaco</td>
<td>entrained</td>
<td>slag</td>
<td>slurry</td>
<td>b</td>
<td>4.1</td>
<td>1260-1540</td>
</tr>
<tr>
<td>non-slagging:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HTW</td>
<td>fluidised</td>
<td>dry</td>
<td>dry</td>
<td>l/p</td>
<td>1.0</td>
<td>800-1000</td>
</tr>
<tr>
<td>KRW</td>
<td>fluidised</td>
<td>agglomerate</td>
<td>dry</td>
<td>b/sb</td>
<td>2.1</td>
<td>870-1040</td>
</tr>
<tr>
<td>U-Gas</td>
<td>fluidised</td>
<td>agglomerate</td>
<td>dry</td>
<td>b/sb</td>
<td>0.4-3.2</td>
<td>950-1090</td>
</tr>
</tbody>
</table>

* fuel types: b-bituminous; sb-subbituminous; l-lignite; p-peat
6.3.3 Gaseous Emissions from IGCC

One of the principal advantages of IGCC power generation is the ability to reduce atmospheric emissions. Most of the IGCC systems use processes in which the coal is completely gasified and impurities in the coal gas are removed in the gas cleaning phase. Details of which will be discussed shortly. The required reduction in emissions is thus achieved without post flue gas treatment systems.

A wide range of gas treatment processes are available from other applications, many of which are capable of delivering fuel gas with extremely low levels of undesirable constituents such as sulphur compounds. At present, the majority of proven gas purification processes employ either aqueous solutions or low boiling organic reagents for gas scrubbing, which can only accept gas for processing at relatively low temperature. Consequently, until high temperature, dry, alternative gas processing techniques can be introduced commercially, there are penalties in terms of plant complexity and overall thermal efficiency arising from the necessity for gas cooling and unavoidable heat losses from the system.

Under the reducing conditions found in any gasifier, the sulphur in the coal is mostly converted into hydrogen sulphide (H₂S) rather than sulphur dioxide (SO₂). It is claimed that many sulphur cleaning systems have been employed in coal gasification systems. However, most operate at low temperatures and involve the use of organic or aqueous based liquids. At these low temperatures H₂S in the raw gas can easily be removed to extremely low levels, over 99% sulphur recovery, by wet scrubbers.
Fluidised bed gasifiers may be operated with in bed sulphur removal using calcium based sorbents, such as limestone and dolomite, as sulphur-capturing agents. Limestone is added with the coal and reacts with sulphur compounds produced by the gasification process to form calcium sulphide. The calcium sulphide is converted into more stable calcium sulphate either by oxidation after discharge from the gasifier or in an external sulphurator.

Hot gas sulphur removal processes are currently under development and evaluation in many countries. Gas cleaning systems using various sorbents have been tested. At present those using zinc ferrite or certain other metal oxides in external fixed, moving or fluidised bed desulphurisation vessels are the most promising sulphur removal methods for future gasifier processes (Takematsu and Maude, 1991). The metal oxides used in external desulphurisation are regenerable, but the method of regeneration is critical and affects both the economic viability of the system and the performance.

A further advantage is that nitrogen oxide are not formed during the gasification part of the IGCC process due to the reducing conditions in the gasifier. Most of the nitrogen present in the feed coal is converted to $N_2$ in the gasifier. A small fraction is hydrogenated and forms ammonia under the reducing conditions. The amount of NH$_3$ formed depends mainly on the gasification temperature, and also on the gasifier design. Notably higher temperatures usually result in lower NH$_3$ yields with the actual conversion rate of fuel bound nitrogen to NH$_3$ varying widely, from about 10% to 60%.

Since ammonia is soluble in water, it can be easily removed from the fuel gas using low temperature cleaning systems based on wet scrubbers. The NH$_3$ is usually removed prior to H$_2$S removal in the desulphurisation processes. Any HCN present in the gas is
typically converted to water soluble, bio-degradable cyanide derivatives. After scrubbing, the NH$_3$ content of the fuel gas is negligible.

The most important source of NO$_x$ in IGCC systems is from the combustion chamber of the gas turbine. Part of the nitrogen in the combustion air is converted to thermal NO$_x$ when the fuel gas is burnt. Inert fluids, such as steam, or nitrogen can be injected into the gas turbine and used as diluents to suppress NO$_x$ formation by reducing the adiabatic flame temperature. Using established and commercially available techniques a reduction of approximately 80% in the NO$_x$ emissions can be achieved. If additional NO$_x$ abatement is required by future legislation, it may be achieved by catalytic reduction, which has been successfully used in installation on coal combustion systems (Hjialmarsson, 1990). Further advances in gas turbine technology and operation may provide further NO$_x$ reductions.

Since the majority of both the sulphur and nitrogen found in the raw coal is removed in the gas cleaning stage, prior to combustion, in the gas turbine undesirable gaseous emissions from the power generation stage of the plant, in particular that in the final flue gas, can be quite low.

Carbon dioxide emission are closely linked with the fuel (coal) and the efficiency of a particular plant. In particular as the high-temperature gas turbine technologies continue to evolve and improve, the combined cycle production of electricity is of superior efficiency compared with conventional steam cycle systems. As a result proposed IGCC plants would produce between 10-20% less CO$_2$ compared with equivalent conventional pulverised coal firing (PCF) + FGD plant. Emissions of CO$_2$ per kilowatt hour could be reduced by as much as 25% compared with PCF + FGD plants, if the full potential of gas
turbine technology were realised (Clarke, 1991). R. Kane (1989) provides an approximate estimate that for each 5% efficiency improvement, CO₂ emissions are reduced by approximately 15%. This argument suggests that IGCC systems would have a CO₂ emission some 20% to 30% less than existing conventional power generation stations.

An evaluation of the IGCC technology from the CSIRO Division of Coal and Energy Technology (Duffy and Dave, 1992) indicated that IGCC offers the possibility of achieving overall plant efficiencies ranging from 40%-42.5% in black coal fired plant, compared to 35% to 37% for existing coal fired power plant. In regard CO₂ emission levels the same study suggested that IGCC should yield CO₂ emissions below 750 tonnes/GWh, compared to about 900 tonnes CO₂/GWh typical of present NSW power stations. In addition the technology offers further environmental benefits in terms of lower NOₓ and SO₂ emissions.

6.3.4 IGCC System Performance, Cost and Emissions

An assessment of various IGCC technologies, conducted by British Coal (S. G. Dawes et al., 1990), is summarised in Table 6.3.4a. In this assessment it was assumed that the coal was a typical UK coal with 17% ash, 11% moisture and 2% sulphur. The steam conditions were assumed to be 12.5 MPa pressure, 538°C superheat and 538°C reheat. The turbine entry temperature for the IGCC plant was assumed to be 1260°C. This study also included capital costs data evaluated in term of A$ per kW.
Table 6.3.4a  Predicted Performance of IGCC Systems (Dawes et al., 1990)

<table>
<thead>
<tr>
<th>Item</th>
<th>Shell</th>
<th>Texaco</th>
<th>BGL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal size (MW)</td>
<td>270</td>
<td>290</td>
<td>230</td>
</tr>
<tr>
<td>Efficiency (%)</td>
<td>39.8</td>
<td>38.5</td>
<td>38.5</td>
</tr>
<tr>
<td>CO₂ (kg/kWh)</td>
<td>0.81</td>
<td>0.84</td>
<td>0.84</td>
</tr>
<tr>
<td>SO₂ removal (%)</td>
<td>99</td>
<td>99</td>
<td>99</td>
</tr>
<tr>
<td>NOₓ (mg/Nm³)</td>
<td>115-280</td>
<td>115-280</td>
<td>115-280</td>
</tr>
<tr>
<td>Capital cost (A$/kW)</td>
<td>2387</td>
<td>2242</td>
<td>2251</td>
</tr>
</tbody>
</table>

Recently, a preliminary design and evaluation of IGCC technologies has been conducted by ERDC/ESAA (Ewbank Preece Sinclair Knight, 1992). This study based in Australian context examined the application of IGCC to both black coal (Edinglassie, refer to Appendix 3) and brown coal (Loy Yang, refer to Appendix 4). The design basis was selected to consider Shell-IGCC systems as follows: Shell-IGCC plant operating at baseload, firing Edinglassie coal at Liddell power station, NSW, Australia. The performance of the Shell-IGCC plant was assumed to be that appropriate to a ambient temperature of 15°C. The performance predicted of the Shell-IGCC system, under these conditions, is summarised in Table 6.3.4b.
Table 6.3.4b  The Performance of Shell-IGCC System under Australian Conditions (ERDC/EASS, 1992)

<table>
<thead>
<tr>
<th>Item</th>
<th>Shell, with gas clean-up</th>
<th>Shell, no gas clean-up</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity (MW)</td>
<td>1666</td>
<td>1684</td>
</tr>
<tr>
<td>Efficiency (% HHV)</td>
<td>40</td>
<td>43.3</td>
</tr>
<tr>
<td>CO₂ emission (kg/MWh)</td>
<td>830</td>
<td>770</td>
</tr>
<tr>
<td>SO₂ emission (mg/Nm³)</td>
<td>6.8</td>
<td>780</td>
</tr>
<tr>
<td>NOₓ emission (mg/Nm³)</td>
<td>70</td>
<td>70</td>
</tr>
<tr>
<td>Capital cost (A$/kW)</td>
<td>1704</td>
<td>1624</td>
</tr>
</tbody>
</table>

In regard to brown coal operation the design basis was selected to consider a HTW-IGCC systems as follows: HTW-IGCC plant operating at baseload, firing Loy Yang coal at Loy Yang A power station, Victoria, Australia. The performance of the HTW-IGCC plant was evaluated assuming an ambient temperature of 15°C. The performance predicted of HTW-IGCC systems are summarised in Table 6.3.4c.
Table 6.3.4c The Performance of HTW-IGCC System under Australian Conditions (ERDC/EASS, 1992)

<table>
<thead>
<tr>
<th>Item</th>
<th>HTW (air, no gas clean-up)</th>
<th>HTW (air, gas clean-up)</th>
<th>HTW (oxygen, no gas clean-up)</th>
<th>HTW (oxygen, gas clean-up)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity (MW)</td>
<td>1574</td>
<td>1490</td>
<td>1475</td>
<td>1423</td>
</tr>
<tr>
<td>Efficiency (%) HHV</td>
<td>41.5</td>
<td>36.3</td>
<td>37.1</td>
<td>33.4</td>
</tr>
<tr>
<td>CO₂ emission (kg/MWh)</td>
<td>820</td>
<td>940</td>
<td>920</td>
<td>1000</td>
</tr>
<tr>
<td>SO₂ emission (mg/Nm³)</td>
<td>450</td>
<td>14</td>
<td>410</td>
<td>9</td>
</tr>
<tr>
<td>NOₓ emission (mg/Nm³)</td>
<td>70</td>
<td>70</td>
<td>70</td>
<td>70</td>
</tr>
<tr>
<td>Capital cost (A$/kW)</td>
<td>1640</td>
<td>1797</td>
<td>1876</td>
<td>2015</td>
</tr>
</tbody>
</table>

The performance of IGCC systems which is presented here varies greatly dependent on plant size, fuel properties, coal gasification and gas clean-up techniques. In regard to Australian conditions, especially noting the availability of low sulphur coals in the near and medium term, cost effective IGCC systems such as Shell-IGCC without gas clean-up for black coal and HTW-IGCC, air feed, without gas clean-up or HTW-IGCC, oxygen feed, without gas clean-up will become key options enhanced by both financial investment and environmental considerations.
6.4 Coal Gasification in Fuel Cell Energy Systems

6.4.1 Introduction

Coal gasification fuel cell power plants (CGFC) are a possible basic integrated energy conversion technology suitable in the longer term. This suitability result from the higher system efficiencies and lower environmental emissions exhibited by these systems. These CGFC systems operate at an energy conversion efficiency advantage of better than 7-15% and generate very low air and water pollutants relative to other coal-fired power generation technologies. In addition, many other benefits such as quiet operation, high part-load efficiency, better power quality, and modularity make CGFC systems very attractive power generation options for the future.

6.4.2 Fuel Cells

6.4.2.1 General

A fuel cell is an electrochemical energy conversion device which can convert the chemical energy of a hydrocarbon fuel and oxidant directly into electricity and thermal energy. Unlike a battery, the fuel cell does not run down or require recharging; it will operate as long as both fuel and oxidant are supplied to the electrodes. The electrodes act as catalytic reaction sites where the electrochemical transformation of fuel and oxidant occurs producing DC electricity. Because the fuel cell is able to achieve a direct conversion of the fuel's chemical energy into electrical energy the Carnot cycle efficiency limitation, based on the difference of temperatures, does not apply. The fuel cell can therefore yield a higher
fuel to electrical energy conversion efficiency relative to conventional energy conversion
devices operating at comparable temperatures.

Most utility fuel cell systems will have four major subsystems: a fuel processing
subsystem to convert feed stock such as natural gas, distillates or even coal to hydrogen-
rich fuels which the fuel cells will ultimately utilise to produce electricity; a cell stack
subsystem wherein hydrogen fuel and air are reacted electrochemically to produce
electricity, a power conditioning system which converts the direct current (DC) power
produced by the fuel cell to a utility grade alternate current (AC) power and a balance-of-
plant subsystems which can include heat recovery and thermal management, electronic
controls and water management subsystems.

6.4.2.2 Fuel Cell Types and Characteristics

The basic fuel cell consists of a positive and negative electrode separated by an electrolyte
which transmits ions but not electrons. Fuel cells are generally named according to their
electrolyte composition and operating temperature as summarised in Table 6.4.2.2.
### Table 6.4.2.2 Fuel Cell Types and Characteristics

<table>
<thead>
<tr>
<th>Characteristics</th>
<th>First Generation</th>
<th>Second Generation</th>
<th>Third Generation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrolyte</td>
<td>Phosphoric Acid H$_3$PO$_4$</td>
<td>Molten Carbonate LiKCO$_3$</td>
<td>Solid Oxide Y$_2$O$_3$ and ZrO$_2$</td>
</tr>
<tr>
<td>Operating Temperature, °C</td>
<td>200</td>
<td>650</td>
<td>1000</td>
</tr>
<tr>
<td>Operating Pressure, Bar</td>
<td>1-10</td>
<td>1-10</td>
<td>1-NA</td>
</tr>
<tr>
<td>Module Size, Current</td>
<td>200 kW</td>
<td>2-10 MW</td>
<td>5-100 kW</td>
</tr>
<tr>
<td>Advanced</td>
<td>25-50 MW</td>
<td>100-500 MW</td>
<td>25-50 MW</td>
</tr>
<tr>
<td>Materials of Construction</td>
<td>Carbon Based Materials</td>
<td>Nickel and Stainless Steel</td>
<td>Ceramics</td>
</tr>
<tr>
<td>System Efficiency</td>
<td>%, HHV</td>
<td>40-47</td>
<td>50-57</td>
</tr>
<tr>
<td></td>
<td>kJ/kWh</td>
<td>8715-7350</td>
<td>7140-6300</td>
</tr>
</tbody>
</table>

#### 6.4.3 Coal Gasification Fuel Cell Power Plants

Coal gasification fuel cell power plants refer to the application of integrated coal gasification, fuel cell systems and steam turbine power plant for electric utility central station application.
There are several conceptual system configurations for CGFC power plants. A general system is presented in Figure 6.4.3. Usually each CGFC power plant system consists of three basic subsystems: the gasification subsystem, the gas cleanup subsystem, and the electricity generation subsystem which includes the fuel cell system and other power producing units.

From theoretical considerations, it is possible to integrate phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC) and solid oxide fuel cells (SOFC) technologies with coal gasifiers and steam bottoming cycles for central power station application. However, application of PAFC technology is limited due to the relatively low operating temperature. In particular under the low operating temperature conditions, there is insufficient net enthalpy for a steam bottoming cycle because of the low quality heat available. In addition, coal gasification phosphoric acid fuel cells (CGPAFC) systems face very strong competition from other advanced energy conversion technologies such as IGCC systems and PFBC combined cycle power plants. In comparison high temperature, MCFC and SOFC, make available high quality heat. Hence coal gasification molten carbonate fuel cells (CGMCFC) systems and coal gasification solid oxide fuel cells (CGSOFC) systems have high potential for achieving high overall cycle efficiency.
6.4.3.1 Coal Gasification Molten Carbonate Fuel Cell Power Plant System

6.4.3.1.1 General

As described above, molten carbonate fuel cells are employed in CGMCFC power plant systems. A typical system diagram for CGMCFC power plant system is shown in Figure 6.4.3.1.1. Basically CGMCFC system is IGCC technology integrated with MCFC technology.
6.4.3.1.2 Gasifiers

In general fluidised bed gasifiers, which produce a fuel gas in the 650 to 1000°C range, and entrained bed gasifiers, which produce even higher temperature fuel gas (beyond 1000°C) could ultimately be incorporated into CGMCFC power plant systems. This application is due to their excellent temperature and pressure match, and also, these gasifiers have been developed to the full scale and are commercial.

6.4.3.1.3 The Cleanup Subsystem

The use of coal as a fuel involves the generation of coal-derived contaminants which must be addressed in CGMCFC system design.
Each CGMCFC power plant system developer has met this challenge by selecting some of the hot or cold gas cleanup subsystems for incorporation into one or other of their systems. These systems are necessary to protect both the MCFC and the environment from coal-derived contaminants and are essential to the development of integrated coal fuelled system.

In the CGMCFC design, the cleanup systems include gas cleanup options consisting of cyclones and candle filters for particulate control; gasifier dolomite injection, zinc ferrite, and zinc oxide guard bed for sulphur control; catalytic decomposition of ammonia or staged catalytic combustion for NO\textsubscript{x} control and a sodium carbonate guard bed for chloride control.

6.4.3.1.4 Performance

The performance and economics of two kinds of CGMCFC power plant systems are presented in Table 6.4.3.1.4. Case 1 is based on a Texaco entrained bed gasifier utilising cryogenic oxygen for oxidant and cold gas cleanup. In comparison Case 2 utilises a KRW fluidised bed gasifier, cryogenic oxygen for oxidant and hot gas cleanup type.
Table 6.4.3.1.4 Basic Characteristics of CGMCFC and CGSOFC Systems

<table>
<thead>
<tr>
<th>Characteristics</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Cell Modules</td>
<td>MCFC</td>
<td>MCFC</td>
<td>SOFC</td>
</tr>
<tr>
<td>Efficiency, %</td>
<td>45.1</td>
<td>47.1</td>
<td>45</td>
</tr>
<tr>
<td>Capital Cost</td>
<td>$1000/kW</td>
<td>$930/kW</td>
<td>$1000-1500/kW</td>
</tr>
<tr>
<td>Cost of Electricity</td>
<td>1.00 Mills/kWh</td>
<td>1.07 Mills/kWh</td>
<td></td>
</tr>
<tr>
<td>$\text{SO}_2$</td>
<td>0.014 kg/MWh</td>
<td>0.0014 kg/MWh</td>
<td>0.05 kg/MWh</td>
</tr>
<tr>
<td>$\text{NO}_x$</td>
<td>Trace</td>
<td>0.045 kg/MWh</td>
<td>0.11 kg/MWh</td>
</tr>
<tr>
<td>$\text{CO}_2$</td>
<td>717 kg/MWh</td>
<td>726 kg/MWh</td>
<td>680 kg/MWh</td>
</tr>
</tbody>
</table>

6.4.3.2 Coal Gasification Solid Oxide Fuel Cell Power Plant

CGSOFC power plants have similar system flow processes to CGMCFC power plant systems. Here obviously in reference to the simple functional flow diagram represented in Figure 6.3.3, SOFC play the role of the fuel cell subsystems. It is estimated that CGSOFC power plant will have the major characteristics listed as Case 3 in Table 6.4.3.1.4. Furthermore Figure 6.4.3.2 represents a 250 MW CGSOFC power plant pictorial view (W L Lundberg, 1990). Details of the plant performance summary is given in Appendix 1.
Figure 6.4.3.2  250 MW CGSOFC Power Plant Pictorial View.
6.5 Conclusion

Advanced coal fired power generation technologies with substantial efficiency improvements such as supercritical parameter power plant, cogeneration technology or with significant reduction of gaseous pollution emissions including AFBC and PFBC systems will become near term options to meet Australian needs of greenhouse effect reduction.

Other advanced coal fired power plant technology such as IGCC and CGFC systems, with a combination of efficiency improvement and greenhouse gas emission reduction, will become the key options for future power generation in Australia.

A detailed system comparison for the various coal fired power plant technologies will be presented in the next Chapter.
Chapter 7

System Comparison for Power Generation Technologies
7.1 Main Coal Fired Power Plant Technology Comparisons

7.1.1 General

A comparison of the four major contender power plant technologies is now presented. They are pulverised coal (PC), atmospheric fluidised bed (AFBC), advanced integrated gasification combined cycle (IGCC) and coal gasification molten carbonate fuel cell (CGMFC). Here the competing power plant systems are analysed to the same level of detail as the baseline for CGFC systems. Relative design and economic basis for the above four main power generation technologies come from a US based Utility Advisory Group (UAG) which consists of the Electric Power Research Institute (EPRI), Pacific Gas and Electric (PG&E), and Virginia Electric Power Company all in U.S.A. The power plant design details are summarised as follows. Plant capacity 200 MW at Chicago, USA. This plant is planned to operate at baseload, firing Illinois No.6 bituminous coal (composition based on EPRI Technical Assessment Guide Manual (EPRI, 1986) or Appendix 2) and must meet stringent environmental standards.

7.1.2 Design Basis for the Four Power Plant Systems

The design basis of the four power plant systems are identified below (Farooque et al., 1990):

1. Pulverised Coal (PC)
   a. PC with Flue Gas Desulphurisation (FGD), design basis: EPRI CS-5296.
   b. PC with Coal Cleanup, FGD and Catalytic DeNOx, Fluor Daniel Design.

2. Atmospheric Fluidised Bed Combustion (AFBC)
a. AFBC with In-Bed Sulphur Capture, Fluor Daniel Design.
b. AFBC with Coal Cleanup plus In-Bed Sulphur Capture, Fluor Daniel Design.

3. Advanced IGCC

KRW/O2 blown Gasifier with In Bed Sulphur Capture;
Zinc Ferrite Hot Gas Cleanup (HGC);
General Electric’s MS7001F Gas Turbine, 538°C inlet gas temperature and 1260°C expander inlet temperature;
Reheat Steam Cycle, 538°C and 10.1 MPa steam. Fluor Daniel Design.

4. CGMCFC

a. TEXACO Gasifier with Cryogenic Oxygen and Cold Gas Cleanup (CGC), MCFC plus steam turbine cycle. Fluor Daniel Design.
b. KRW Gasifier with Cryogenic Oxygen and Hot Gas Cleanup, MCFC plus steam turbine cycle. Fluor Daniel Design.

7.1.3 Discussion

The baseline PC with wet flue gas desulphurisation and AFBC with in bed sulphur capture, respectively, permitted 90% sulphur recovery, not meeting the stringent new source performance standard (USA) of 95%. Therefore an alternate design incorporating coal cleanup was considered, and a sulphur removal of 96% and 98% for PC and AFBC was achieved, respectively. A catalytic DeNOx unit was added to the PC system to conform to the New Source Performance Standards (NSPS) requirement for NOx emissions of 300 to 850 mg/m³ (at 6% O2) (Farooque, 1990).
In regard to this specific USA investigation, especially in the gaseous emissions such as 
SO\textsubscript{2}, NO\textsubscript{x} and CO\textsubscript{2}, the present day power generation technologies, such as PC and 
AFBC (these options do not reduce in the emissions of CO\textsubscript{2}), are difficult to compete with advanced IGCC system and CGMCFC system in relation to futuristic options. The results 
also highlight that coal cleaning, which improved the sulphur emission characteristics of 
PC and AFBC, increases capital cost.

The efficiency, capital cost and cost of electricity (COE) for the PC, AFBC, IGCC and 
CGMCFC power plants are indicated in Figure 7.1.3 whereas environmental emissions 
are compared in Table 7.1.3. By almost each basis of merit, the CGMCFC power plant 
systems are obviously superior to both PC and AFBC systems. This superiority is evident 
from the fact that even the modified PC and AFBC systems, with additional cleanup 
equipment would result in orders of magnitude greater SO\textsubscript{x} and NO\textsubscript{x} emissions relative to 
the futuristic CGMCFC plant.

The toughest competition to CGMCFC is expected to come from advanced IGCC 
systems. Again, in term of efficiency and environmental emissions, the CGMCFC system 
offers superior characteristics. Even the CO\textsubscript{2} release and makeup water requirements are 
15\% and 40\%, respectively, lower for the CGMCFC system. The CGMCFC system 
capital is slightly higher, however, the COE is slightly lower because of efficiency and 
availability advantages. In addition, CGMCFC systems have excellent part load and load-
following capability. For instance at 50\% of design load, for the CGMCFC systems the 
heat rate increase is only 6\%, by comparison with a 25 \% increase in heat rate for an 
IGCC system.
Figure 7.1.3  Major Coal Fired Power Plant Comparison

(based on 1988 US dollars)
(based on 1988 US dollars)
<table>
<thead>
<tr>
<th>Power Plant Technologies</th>
<th>SO₂</th>
<th>NOₓ</th>
<th>CO₂</th>
<th>Make-up Water</th>
<th>Solid Waste</th>
</tr>
</thead>
<tbody>
<tr>
<td>CGMFC</td>
<td>0.014</td>
<td>Trace</td>
<td>717</td>
<td>1361</td>
<td>41</td>
</tr>
<tr>
<td>TEXACO/O₂/CGC</td>
<td>0.0014</td>
<td>0.045</td>
<td>726</td>
<td>1678</td>
<td>127</td>
</tr>
<tr>
<td>KRW/O₂/HGC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PC Wet FGD</td>
<td>1.77</td>
<td>2.77</td>
<td>983</td>
<td>2631</td>
<td>200</td>
</tr>
<tr>
<td>Coal Cleanup,</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DeNOₓ and Wet FGD</td>
<td>0.36</td>
<td>0.48</td>
<td>939</td>
<td>2722</td>
<td></td>
</tr>
<tr>
<td>AFBC In-Bed</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Desulphurisation</td>
<td>1.81</td>
<td>0.36</td>
<td>956</td>
<td>2268</td>
<td>159</td>
</tr>
<tr>
<td>Coal Cleanup, In-Bed</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Desulphurisation</td>
<td>0.73</td>
<td>0.40</td>
<td>956</td>
<td>2268</td>
<td></td>
</tr>
<tr>
<td>Advanced IGCC</td>
<td>0.036</td>
<td>0.46</td>
<td>844</td>
<td>2177</td>
<td>145</td>
</tr>
</tbody>
</table>
7.2 Coal Fired Power Plant Technology Comparisons for Australia

7.2.1 General

A recent comparison of available advanced generation technologies has been effected for the ERDC/ESAA study by Ewbank Preece Sinclair Knight (1992) with emphasis on the basis of their impacts on greenhouse emissions. This technology comparison, based in an Australian context, examines the utilisation of both black coal (Edinglassie, refer to Appendix 3) and brown coal (Loy Yang, refer to Appendix 4). In all cases the proposed conceptual power plants would meet current and future environmental standards in Australia.

7.2.2 Black Coal Fired Power Generation

Edinglassie Black Coal was examined in this study. The fuel has a following characteristics (ERDC/EASS, 1992).

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>HHV:</td>
<td>23.975 MJ/kg as received</td>
</tr>
<tr>
<td>LHV:</td>
<td>22.811 MJ/kg as received</td>
</tr>
<tr>
<td>Moisture:</td>
<td>8% as received</td>
</tr>
<tr>
<td>Carbon:</td>
<td>63.4% (adb, ultimate, 3.3% H2O)</td>
</tr>
<tr>
<td>CO2 released:</td>
<td>92.7 kg/GJ (HHV)</td>
</tr>
<tr>
<td>Sulphur:</td>
<td>0.6% (adb, ultimate, 3.3% H2O)</td>
</tr>
</tbody>
</table>

The design basis of the six black coal power plant systems case studies are identified below.
Case A: PC with current technology, no FGD or catalytic NO$_x$ reduction
Case B: PC with advanced technology plus FGD, 90% sulphur removal
Case C: ACFB, 90% sulphur removal by limestone addition
Case D: PFBC, 90% sulphur removal by limestone addition
Case E: IGCC with entrained flow, no gas clean up
Case F: IGCC with entrained flow, gas clean up

The capacity, efficiency and cost of the various black coal power plant systems are indicated in Table 7.2.2a. Equally important are the atmospheric emissions from the black coal power plant systems as detailed in Table 7.2.2b.

Table 7.2.2a  Capacity, Efficiency and Cost for Black Coal Technologies
(1991 Australian dollars)

<table>
<thead>
<tr>
<th>Technology (Case)</th>
<th>Capacity (MW)</th>
<th>Efficiency (%, HHV)</th>
<th>Capital Cost ($/kW)</th>
<th>Total Cost ($/kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>1320</td>
<td>35.9</td>
<td>1160</td>
<td>1400</td>
</tr>
<tr>
<td>B</td>
<td>200</td>
<td>35.5</td>
<td>1900</td>
<td>2300</td>
</tr>
<tr>
<td>C</td>
<td>150</td>
<td>33.8</td>
<td>1640</td>
<td>1890</td>
</tr>
<tr>
<td>D</td>
<td>150</td>
<td>35.5</td>
<td>1740</td>
<td>2000</td>
</tr>
<tr>
<td>E</td>
<td>1684</td>
<td>43.3</td>
<td>1620</td>
<td>1960</td>
</tr>
<tr>
<td>F</td>
<td>1666</td>
<td>40.0</td>
<td>1700</td>
<td>2030</td>
</tr>
</tbody>
</table>
### Table 7.2.2b Atmospheric Emission for Black Coal Technologies

<table>
<thead>
<tr>
<th>Technology (Case)</th>
<th>CO$_2$ (kg/MWh)</th>
<th>SO$_2$ (kg/MWh)</th>
<th>NO$_x$ (kg/MWh)</th>
<th>Particulates (kg/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>930</td>
<td>4.6</td>
<td>&lt; 2.7</td>
<td>0.3</td>
</tr>
<tr>
<td>B</td>
<td>940</td>
<td>0.5</td>
<td>&lt; 2.7</td>
<td>0.3</td>
</tr>
<tr>
<td>C</td>
<td>990</td>
<td>0.5</td>
<td>&lt; 2.3</td>
<td>0.3</td>
</tr>
<tr>
<td>D</td>
<td>940</td>
<td>0.5</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>E</td>
<td>770</td>
<td>3.8</td>
<td>0.3</td>
<td>-</td>
</tr>
<tr>
<td>F</td>
<td>830</td>
<td>0.04</td>
<td>0.4</td>
<td>-</td>
</tr>
</tbody>
</table>

### 7.2.3 Brown Coal Fired Power Generation

Loy Yang Brown Coal was examined in this same study. The low calorific value fuel has the following characteristics (ERDC/EASS, 1992).

- **HHV:** 9.95 MJ/kg as received
- **LHV:** 8.03 MJ/kg as received
- **Moisture:** 62.3% as received
- **Carbon:** 25.6% (ultimate, as received)
- **CO$_2$ released:** 94.3 kg/GJ (HHV)
- **Sulphur:** 0.14% (ultimate, as received)

The design basis of the four brown coal power plant systems case studies are identified below.
Case G: PC with current technology, no FGD or catalytic NO\textsubscript{x} reduction
Case H: PC with advanced technology plus FGD, 90% sulphur removal
Case I: IGCC with fluidised bed (HTW), air blown, no gas clean up
Case J: IGCC with fluidised bed (HTW), air blown, plus gas clean up

The capacity, efficiency and cost of the various brown coal power plant systems are indicated in Table 7.2.3a. The atmospheric emissions for the brown coal power plant systems are given in Table 7.2.3b.

Table 7.2.3a  Capacity, Efficiency and Cost for Brown Coal Technologies
(1991 Australian dollars)

<table>
<thead>
<tr>
<th>Technology (Case)</th>
<th>Capacity (MW)</th>
<th>Efficiency (% , HHV)</th>
<th>Capital Cost ($/kW)</th>
<th>Total Cost ($/kW)</th>
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</thead>
<tbody>
<tr>
<td>G</td>
<td>1320</td>
<td>27.7</td>
<td>1500</td>
<td>1810</td>
</tr>
<tr>
<td>H</td>
<td>200</td>
<td>28.2</td>
<td>2300</td>
<td>2730</td>
</tr>
<tr>
<td>I</td>
<td>1574</td>
<td>41.5</td>
<td>1640</td>
<td>2000</td>
</tr>
<tr>
<td>J</td>
<td>1490</td>
<td>36.3</td>
<td>1800</td>
<td>2230</td>
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</table>
Table 7.2.3b  Atmospheric Emission for Brown Coal Technologies

<table>
<thead>
<tr>
<th>Technology (Case)</th>
<th>CO₂ (kg/MWh)</th>
<th>SO₂ (kg/MWh)</th>
<th>NOₓ (kg/MWh)</th>
<th>Particulates (kg/MWh)</th>
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</thead>
<tbody>
<tr>
<td>G</td>
<td>1200</td>
<td>3.7</td>
<td>&lt;4.2</td>
<td>0.4</td>
</tr>
<tr>
<td>H</td>
<td>1200</td>
<td>0.4</td>
<td>&lt;4.2</td>
<td>0.4</td>
</tr>
<tr>
<td>I</td>
<td>820</td>
<td>2.7</td>
<td>0.4</td>
<td>-</td>
</tr>
<tr>
<td>J</td>
<td>1000</td>
<td>0.06</td>
<td>0.5</td>
<td>-</td>
</tr>
</tbody>
</table>

7.2.4 Discussion

As indicated in Tables 7.2.2a and 7.2.3a the efficiency of IGCC plant burning black coal would be up to 43.3%. This improvement in efficiency is around 8% higher than conventional PF systems. Furthermore, the efficiency of IGCC plant burning brown coal would increase up to 14% by comparison with existing brown coal fired technology. These efficiency improvements would make IGCC technologies become more competitive in future coal utilisation technologies. In comparison AFBC technology do not associate with such efficiency improvements and so compare with PF plant.

As a result of the increased efficiency, the emission levels of CO₂ from IGCC processes should be up to 17.2% lower than PF technology in the case of black coal technology and 31.7% lower than that in the case of brown coal technology. This reduction of greenhouse gas emissions would make IGCC technologies the favoured option to meet the "Toronto Target" for Australia.
For the AFBC and PFBC systems more CO₂ emission are produced from the SO₂ removal reaction. Fortunately, with the Australian coals, with their low sulphur content, this additional emission of CO₂ is not significant.

A 90% efficiency of sulphur removal would be easily achieved using FGD, AFBC and PFBC technologies. In addition the sulphur removal of IGCC with gas cleaning would be up to 99%. However, with the low sulphur Australian coals, to meet anticipated levels of SO₂ emissions, minimum attention to the sulphur content in the firing rate need to be made, especially in the short term.

In regard NOₓ emissions the lower bed temperatures in AFBC and PFBC systems is favourable. Notably for these systems the actual combustion temperature in the bed is only 850 to 900°C. This, in association with the ability to closely control the air/fuel ratio, results in reduced formation of NOₓ compared with conventional firing. In the CFB system, combustion is staged to reduce the formation of NOₓ.

With IGCC plants the formation of NOₓ is mainly associated with the combustion process in the gas turbines. With conventional gas turbines the syngas has to be saturated before entry into the combustor as a means of keeping NOₓ emissions below the required limit. As a result, as mentioned in the case study, NOₓ emissions expected from the IGCC systems are dramatically lower than conventional PF system.

Conventional PF fired steam boiler and turbine technology is fully mature and well-understood, and provides a cost-effective method of electricity generation using various coal sources. As a result of the low sulphur coal available in Australia it would appear that expensive, in both capital and operating cost, FGD technology is not relevant for
application under the present circumstances. This irrelevance is made even more apparent in view of the case of installation, operation and cost effectiveness of SO₂ reduction during combustion, using dry sorbent addition technology or furnace sorbent injection technology applied immediately upstream of the particulate collection device or into the boiler.

Fortunately the relative high capital cost of PFBC and IGCC technologies and limited operation experience at the commercial scale plant compared to existing large scale PF system is compensated by the expected high efficiency and low pollution characteristics.

Such advantages suggest that these advanced power generation technologies including AFBC, PFBC and IGCC systems should be applied in the medium term. In the long term it is expected that fuel cells, as a result of their expected high efficiency and low pollutant emissions, when integrated with coal gasification would compete with IGCC technology. However, it seems unlikely that CGFC power plant technology will enter service in Australia before the year 2015.
Chapter 8

Conclusion
Over 80% of current electricity generation in Australia is from coal using pulverised fuel technology. The environmental effects of coal fired electricity generation will have to be considered as an important part of the strategy associated with energy use in Australia.

8.1 Coal Cleaning Technology

Coal cleaning technology is likely to play an increasingly significant role in partially meeting the environmental requirement especially in regard sulphur oxide emissions. Australia is extremely fortunate in having a large supply of excellent quality coal with low sulphur content ranging from 0.2% to 0.6% for coal fired power generation. However, particular Australian coals have a higher sulphur content in some areas. For example, black coals at Greta and Tomago in NSW have sulphur content of 1.5% and 1.4%, respectively and also black coal at Wintinna in South Australia has a sulphur content of some 1.95%. In addition black coals at Hill River and Eneabba in Western Australia have sulphur contents of 2% and 2.8%, respectively. On the other hand, brown coals at Lochiel, Bowmans and Sedan in South Australia have sulphur contents of 3.5%, 5.8% and 6.7%, respectively.

Conventional coal cleaning is a physical cleaning process which removes pyritic sulphur and ash. It can reduce SO$_2$ emissions by 10-30% but has no effect on NO$_x$ emissions. Particulate emissions is also reduced due to the lower ash content of the coal. Because cleaning does not remove organic sulphur it has limited environmental benefit. This limitation implies that if high sulphur coal use and strict air emission regulations are imposed then alternative environmental control technology may still be required. In Australia coal washing is being applied usually at or near the mine. It is used for high ash coal because the costs of the cleaning can be offset by lower transportation costs, higher
combustion efficiency, and lower mill, boiler and particulate control device maintenance costs.

Here it should be noted that the intended PCC essentially involves the use of large capacity jigs to remove high ash particles from the coarse consist. In comparison the fine fraction sieved from the ROM product, is not subject to any beneficiation process. This direct use of the fine fraction avoids the high cost of fine coal unit processes and dewatering. In addition the severe capacity limitation of these unit processes is avoided. Obviously this PCC operation is particularly relevant for high ash local coals.

Advanced coal cleaning relies on the use of chemical cleaning processes to remove both pyritic and organic sulphur, and ash from coal. While not yet commercial, the process appears to have the potential of up to 40% organic sulphur removal and a 90% reduction in total sulphur content. However, it is expected these processes will not become common place in Australia as a result of the availability of low sulphur coal. A further reason for the expected limited application is that the processing costs are substantially higher than physical coal cleaning but these costs may be offset slightly by lower maintenance costs and a lower overall cost of emission control. However, it is expected that CCC would be preceded by PCC for economic reasons.

**8.2 SO₂ and NOₓ Reduction in Combustion Processes**

Combustion techniques for emission control are well developed, with effective methods reducing SO₂ by up to 70% and NOₓ emission by 50%. 
In regard to SO₂ reduction technology during combustion, there are two main methods, sorbent addition and injection process. Sorbent addition can reduce SO₂ emissions by 10-30%, while sorbent injection techniques under development may be able to achieve 70% reduction. These control technologies are currently available at the demonstration scale but are very limited at the commercial scale.

NOₓ control via combustion modification has involved several approaches with the NOₓ reduction ranging from 20-50%.

Low excess air is the simplest approach which can reduce NOₓ by 20% with minimal cost. Here it may be noted that operation at low excess air is now possible with modern instrumentation for flue gas oxygen and carbon monoxide content and combustion losses.

Another relatively simple technique to employ is over fired air reduction. Over fired air can be used on all types of boilers. This method has a 20% NOₓ removal efficiency and a low cost.

One of the most common techniques for NOₓ control is low NOₓ burners which regulate the combustion process to reduce NOₓ emission by up to 50%. Its cost is relatively low and the technology is readily available for new coal fired power plants.

Flue gas recirculation can reduce NOₓ emission by around 20%. Flue gas recirculation requires more modification to boilers relative to other NOₓ control measures and thus has a higher investment cost. In addition, fuel staging (reburning) has also been used as a NOₓ reduction measure on some boilers. This technique simply reduces or dilutes the NOₓ already formed during the combustion process.
Combustion modification for NO\textsubscript{x} removal are expected to cost up to US$40/kWe to achieve up to 50% reduction; whereas 25-40% reduction on average is expected to cost between US$10-30/kWe.

8.3 Post Combustion Desulphurisation and Denitrification

FGD is the most widespread method of SO\textsubscript{2} emission control. Within FGD systems, wet lime/limestone scrubber systems dominate. Wet scrubber FGD commonly achieves SO\textsubscript{2} reductions of 90% or more which can meet stringent standards of SO\textsubscript{2} removal. In general costs of FGD are quite high and typically represent between 15-20% of total new power plant capital cost, and contribute an additional 5-10% to the costs of electricity generation from such power plant.

Selective catalytic reduction has been the dominant method of flue gas NO\textsubscript{x} treatment. Typically SCR can achieve NO\textsubscript{x} reductions in the range of 80-90%. However SCR has a very high investment cost which vary between over US$40-120/kWe. In comparison the alternate methods using, SNCR, are expected to cost between US$16-25/kWe and reduce NO\textsubscript{x} by 30-50%.

8.4 Advanced Combustion Technology

Advanced generation technologies, such as AFBC, PFBC, IGCC and CGFC, offer a number of advantages over conventional technologies including: low emissions of SO\textsubscript{2}, NO\textsubscript{x} and CO\textsubscript{2}, high thermal efficiencies and fuel flexibility. These technologies should continue to promote the role of coal for electricity generation.
AFBC circulating bed design can reduce SO\textsubscript{2} emissions by 90-95\% and limit NO\textsubscript{x} emissions to 100-300mg/Nm\textsuperscript{3}, a performance which would meet strict emission standards. PFBC is similar to AFBC, but achieves a higher combustion efficiency, and the high pressure combustion system makes it well suited for use in cogeneration and combined heat and power systems. The environmental performance of PFBC is comparable to that of AFBC. Unfortunately development of PFBC is mainly in the research and demonstration phase, hence commercial scale application of PFBC is still limited.

Atmospheric Circulating Fluidised Bed (ACFB) technology is fast maturing as a low cost method of using coals with high sulphur content and could be employed in Australia. It, however, has much the same rate of carbon dioxide emission as pulverised fuel firing. In view of this similarity it is doubtful this technology will be applied locally for large-scale application.

IGCC is a highly efficient and environmental clean generation process which uses coal. The synthesis gas which is derived from coal can be treated before combustion by removing up to 99\% of the sulphur and reducing NO\textsubscript{x} emissions by about 40\%. The IGCC process either produces saleable by-products or non-toxic dry waste. IGCC is also suitable for cogeneration applications.

Special forms of IGCC, with simplified gas clean up or without gas clean up, but which would meet present and likely future SO\textsubscript{x} and NO\textsubscript{x} emission standards in Australia, could be more competitive. Calculations in this and other published studies show that CO\textsubscript{2} emissions would be some 17\% lower and electricity cost increases of only 1c/kWh or 2-3\%, compared with conventional technology.
Once fully developed to commercial scale CGFC power plant technologies will have certain significant advantages. In particular the predicted high overall efficiency (> 45%) of CGFC power plants will contribute to reduced fuel consumption. This technology will also meet increasingly strict environmental objectives such as minimising CO₂ production, SO₂ and NOₓ exhaust concentrations. In addition, quiet performance and vibration-free operation will contribute to maximum siting flexibility.

Since CGFC power plant technologies do not have additional environmental equipment requirements, the cost of producing electricity by CGFC power plants can increase at least by the cost of reducing emissions from other coal-fired power plant technologies such as PC and AFBC technologies.

Although CSIRO, Monash University and SECV together with some private companies, are planning to develop fuel cell technology, CGFC power plant technology in Australia is still under developed by comparison with that in U.S.A, Japan and West Europe. Hence Australia should take CGFC technologies as a key part of the future energy and environment strategy in the 21st century.

More investigations into the application of high efficiency PFBC, IGCC and CGFC technologies, tailored to Australian black coals and Australian environmental conditions is paramount.

Australian government should also fund some research organisations and experts to study PFBC, IGCC and CGFC power plant technologies for Australia to play the role of "clever country" in these emerging key technologies.
Chapter 9

Strategies and Recommendations
9.1 General

The Government's recent announcement that greenhouse gas emissions, excluding ozone depleting gases, were to be reduced 20% from 1988 levels by the year 2005, means that Australia has twelve years to achieve the target. Such an achievement is made more difficult by the fact that energy demand over the period will increase. The achievement of targets will require strategies in both the short term and long term to decrease demand levels of gaseous emissions.

9.2 Short Term Strategies

9.2.1 Efficiency Improvement and CO$_2$ Reduction

The densities of both population and of power station locations in Australia are not high relative to other industrialised nations. Fortunately most Australian coal fired power plants have access to substantial reserves of coal with relatively low sulphur contents. The conventional power generation technology would provide mature experience in the operation and low cost electricity (provided capital interest rates can be curbed). Hence in the short term modification of existing power plants is probably the most expedite and cheapest way to make an impact on CO$_2$ emissions. These improvements are possible noting existing power plants generally operate with efficiencies of typically about 35% when burning black coal and typically 29% when burning brown coal.

One such improvement is to adopt supercritical steam at 25MPa and 560°C or 30MPa and 600°C with a condenser pressure at 7kPa. On application of this technology this study suggests the net plant efficiencies of 42.9% and 43.7%, respectively, for the forestated steam conditions. In comparison existing subcritical steam cycle plants (with
15MPa/510°C/7kPa steam conditions) has a maximum efficiency of 38.3%. As a result of this efficiency improvement CO₂ emissions would be reduced by some 15% to 20% compared with existing subcritical steam cycle plant. However, under such supercritical conditions power plant life is limited. This limitation results from the severe operating conditions, which necessitates the use of high alloys, especially when firing typical coals. Alternatively standard steel can be used if less aggressive combustion conditions can be effected. Such favourable combustion conditions would result when burning highly beneficiated coal, eg. the CSIRO-developed ultra clean coal process.

The second option recommended for the short term is active encouragement of cogeneration. There is potential for substantially increased cogeneration in Australia even in the classic cogeneration industries of paper, chemicals, oil refining and sugar. These plants can produce electricity either for their own needs, or generate surplus power for sale to the grid while utilising all waste heat produced in the plant. The thermodynamic advantages of cogeneration bring with them substantial improvement of net plant efficiency in the 80-90% range, and hence potential reduction in CO₂ emissions in the range of 50-75%. Such advantages confirm that cogeneration could be a cost effective means of adding financial benefits to carbon dioxide emission controls.

9.2.2 SO₂ Reduction

Australia has abundant supply of low sulphur coal reserves utilisation of which is the simplest SO₂ control approach available to its power generation plant. Presently there is no argument for the introduction of strict sulphur emission regulations that would necessitate introduction of sulphur control technologies. Hence it recommended to
continue to utilise low sulphur coal as the major SO$_2$ control strategy for Australian power generation in the short and medium term.

9.2.3 NO$_x$ Reduction

It is recommended that existing PF boilers be retrofitted with cost effective and reliable NO$_x$ reduction technology including low excess air firing, over fire air and low NO$_x$ burners. Among these options, low NO$_x$ burners promise the greatest potential for significant (50%) NO$_x$ reductions and are thus receiving substantial development attention. In the design of new conventional coal fired power plant, low NO$_x$ burners and combustion control techniques should be also adopted. The specific control techniques include low excess air firing and/or over fire air in combination with low NO$_x$ burners. These technologies have the potential to reduce NO$_x$ emissions by up to 20% to 50% at a relatively low capital cost of between 13A$/kW-38A$/kW. Details of NO$_x$ reduction techniques and cost factors for specific installation in Australia will highly depend on individual specifications, coal properties, boiler design, and capital available to achieve the required emissions.

9.3 Long Term Strategies

9.3.1 Efficiency Improvement and CO$_2$ Reduction

It is highly recommended to develop IGCC systems which are particularly suitable for the Australian situation with specific regard to fuel properties and cost effectiveness. IGCC with high plant efficiency and low gaseous emissions will become a very competitive technology in the medium-long term. The efficiency of IGCC plant with black coal
technology would be up to 43.3%. This efficiency improvement will associated with a CO₂ reduction of about 17.2% in comparison with conventional black coal power plant. The efficiency of IGCC plant burning brown coal would be 14% higher than conventional brown coal power plant and the emission of CO₂ would reduce by up to 31.7%. For both black and brown coal successful application of IGCC demands development of effective, relatively low cost, high temperature particulate removal technology and equipment.

In the longer term, a number of potential technologies may become available. In particular CGFC technology with further efficiency improvement and lower pollutant emissions may compete with IGCC technology. However, it is doubtful that such technology, on the large scale, will enter service in Australia before year 2015.

9.3.2 SO₂ Reduction

If increasingly stringent specifications are set and the low sulphur coals are not sufficient to meet such stringent environmental standards Australia should be encouraged to utilise different kinds of sulphur removal technologies.

In the event of more stringent specifications for sulphur emissions sulphur removal will become a major focus in Australian coal cleaning operations using both PCC and CCC technologies. Noting this it is recommended that research and development of the cost-effective coal cleaning processes, to treat low and medium sulphur coals in the range of 0.5% to 3%, be instigated and maintained.

For high sulphur coals FGD is an effective option to reduce sulphur emissions from power generation plant. However, FGD equipment is expensive in both capital and operating
costs, and troublesome to design, install, operate and maintain. If Australia has to apply FGD equipment, it would be best to select spray dry FGD processes. Such processes associate with lower energy losses and attract relatively low cost. For low sulphur coals, the lime spray dry technique typically associate with SO₂ reductions in the range of 70 to 80%.

With only minimum additional cost, in both installation and running, advanced coal fired technologies such as AFBC, PFBC and IGCC in the medium term and CGFC in the long term are better options to control sulphur emissions from power stations.

9.3.3 NOₓ Reduction

It is recommended that the combined technologies of combustion modification and low NOₓ burners or reburning technology be introduced at future power plant to meet stricter environmental requirements.

Alternatively, it is highly recommended that advanced coal fired technology such as AFBC, PFBC and IGCC in the medium term and CGFC in the long term be used as the key options to control NOₓ emissions from power stations. These technologies have a NOₓ reduction efficiency up to 90% , without incurring significant additional capital and running cost.

In view of the suggested relatively lower cost of SNCR systems this technology could be selected as an alternative method to control NOₓ. However, commercial scale application needs more development and evaluation time.
Despite the higher efficiency of SCR for NO\textsubscript{x} reduction, ie up to 95%, the high costs both capital and operating, reduce the use of this technology relative to other technologies.
References


35. Hjalmarsson A. K., (1990), "NOx Control Technologies for Coal Combustion", IEA Coal Research, London (June 1991)


Appendices
### Appendix 1

**Indicative Analyses of Illinois No.6 Coal**

<table>
<thead>
<tr>
<th>Coal seam</th>
<th>Illinois No.6 coal</th>
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<tr>
<td>Volatile matter ( % )</td>
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<tr>
<td>Fixed carbon ( % )</td>
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<tr>
<td>Ash ( % )</td>
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</tr>
<tr>
<td>Sulphur ( % )</td>
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<tr>
<td>Specific energy ( MJ/kg )</td>
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</table>

(As received basis)
Appendix 2

250 MW CGSOFC Power Plant Performance Summary

Coal Flow Rate, tons/day 2300.0

Plant Power Output, MW

Fuel Gas Expander 41.0
SOFC Generator 117.0
Steam Turbine 104.0

Plant Gross AC Power, MW 262.0
Plant Net AC Power, MW 250.0

Net Plant Heat Rate (HHV), kJ/kWh 8098.0

Bottoming Cycle Steam Conditions

Pressure, MPa 9.8
Superheat Temperature, °C 538.0
Reheat Temperature, °C 538.0
Final SOFC Exhaust Temperature, °C 144.0
**Appendix 3**

**Specification for Edinglassie Coal**

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<td>LHV, MJ/kg (as received)</td>
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Appendix 4

Specification for Loy Yang Coal

Proximate Analysis, % (air dried)

- Moisture: 62.3
- Ash: 0.6
- Fixed Carbon: 17.6
- Volatile matter: 19.5

(wet basis 1% to 99%)

Ultimate analysis, %

- Carbon: 25.61
- Hydrogen: 1.81
- Oxygen (by difference): 9.4
- Nitrogen: 0.19
- Total Sulphur (organic): 0.14
- Minerals and Inorganics: 0.55

HHV, MJ/kg: 9.95
LHV, MJ/kg (Wet): 8.03