Retrofitting lignite plants to improve efficiency and performance

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Preface

This report has been produced by IEA Clean Coal Centre and is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member countries.

IEA Clean Coal Centre is an organisation set up under the auspices of the International Energy Agency (IEA) which was itself founded in 1974 by member countries of the Organisation for Economic Co-operation and Development (OECD). The purpose of the IEA is to explore means by which countries interested in minimising their dependence on imported oil can co-operate. In the field of Research, Development and Demonstration over fifty individual projects have been established in partnership between member countries of the IEA.

IEA Clean Coal Centre began in 1975 and has contracting parties and sponsors from: Australia, Austria, China, the European Commission, Germany, India, Italy, Japan, Poland, Russia, South Africa, Thailand, the UK and the USA. The Service provides information and assessments on all aspects of coal from supply and transport, through markets and end-use technologies, to environmental issues and waste utilisation.

Abstract

The lignite power industry produces low cost electricity but the associated pollutant emissions are higher than from other fossil fuels. Tighter environmental legislation requires older facilities to either upgrade or face closure. The rising contribution of renewable energy sources obliges plants to operate more flexibly, responding to variable demands.

This report provides a comprehensive review of suitable technologies for the retrofitting of lignite pulverised coal power plants to lower emissions while raising plant performance. Adaptations based upon the existing plant technology include: combustor modification, advanced instruments and controls, anti-fouling systems and steam turbine upgrades. Alternatives to mainstream effluent treatments are discussed, including hybrid and multi-component technologies to lower emission of NOx, SOx, particulates and mercury. Unique to lignite, the drying and pre-treatment of the fuel is explored as one route to improved heat rate. Flexible plant options reviewed include energy storage, indirect firing and natural gas integrated co-generation. Latest developments on the introduction of CCUS techniques applied to lignite plants are discussed together with other means to lower plant carbon footprint.

Acronyms and abbreviations

ACI	activated carbon injection
AQCS	air quality control system
BAT	best available technology
BPAC	brominated pulverised activated carbon
Btu	British thermal unit
CAES	compressed air energy storage
CapEx	capital costs
CCS	carbon capture and storage
CCS(g)	clean combustion system (gasifier)
CCUS	carbon capture use and storage
CFB	circulating fluidised bed
CFBC	circulating fluidised bed combustion
CFBS	circulating fluidised bed scrubber
CFD	computational fluid dynamics
DCS	digital control system
DSI	direct sorbent injection
EPA	Environmental Protection Agency (USA)
ESP	electrostatic precipitator, h denotes hot, c cold, LLT lower temperature
FBC	fluidised bed combustion
FEGT	furnace exit gas temperature
FF	fabric filter
FGD	flue gas desulphurisation, w denotes wet, also dry and semi dry versions
FGR	flue gas recirculation
GRE	Great River Energy
HELE	high efficiency/low emission
HEX	heat exchanger
HHV	higher heating value
HP	high pressure
HR	heat rate
HWES	hot water energy storage
IEA	International Energy Agency
IED	Industrial Emissions Directive (EU)
IGCC	integrated gasification combined cycle
IP	intermediate pressure
kWh	kilowatts per hour
LAES	liquefied air energy storage
LHV	lower heating value
LNB	low NOx burner(s)
LP	low pressure
LSFO	limestone forced oxidation
MATS	Mercury and Air Toxics Standards
m^2	square metres
m^3/d	cubic metres per day
mg/Nm^3	micrograms per cubic metre
million Btu	million British thermal units
MJ	mega joule
MJ/s	mega joules per second

MWe	**megawatts electric**
MWh	**megawatts hour**
NOx	**nitrogen oxides NO and NO_2**
NSR	**normalised stoichiometric ratio**
O&M	**operating and maintenance**
OFA	**overfire air**
OPAH	**oxygenated poly-aromatic hydrocarbons**
OpEx	**operating costs**
PAC	**powdered activated carbon**
PAH	**poly-aromatic hydrocarbons**
PC	**pulverised coal**
PCC	**pulverised coal combustion**
PM	**particulate matter**
ppm	**parts per million**
ppmv	**parts per million by volume**
RES	**renewable energy sources**
t/h	**tonnes per hour**
SBC	**sodium bicarbonate**
SC	**supercritical**
SCR	**selective catalytic reduction**
SDA	**spray dryer absorber**
SNCR	**selective non-catalytic reduction**
SOx	**SO_2 and SO_3**
TRIG	**Transport Integrated Gasification**
USC	**ultra-supercrcritical**
wFGD	**wet FGD**
WTA	**fluidised bed drying with internal waste heat utilisation**

Conversions applied

lb/million Btu to ppmv NOx (as NO_2, 6% O_2) multiply by 598

lb/million Btu to ppmv SO_2 (at 6% O_2) multiply by 430

1% efficiency corresponds to approximately 300 Btu/kWh Heat Rate

(Note that these conversion factors are approximate and subject to lignite fuel quality)

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1 Introduction

The worldwide lignite power industry faces an unprecedented challenge to generate electricity more efficiently and cleanly against a background of tightening emissions legislation. The industry currently exhibits two distinct trends: constructing new stations in developing countries where there is strong growth in generating capacity, while in mature economies lignite power competes against renewable energy resources resulting in the scheduled closure of some stations. New lignite power plant construction and upgrading is concentrated in Asia and Eastern Europe while Germany, possessing the largest lignite power capacity in 2014, is set to substantially reduce lignite power generation. In all cases, international commitments to lower greenhouse gas emissions, rising carbon taxes and more restrictive environmental legislation on other pollutants is driving a transformation to cleaner and more efficient technologies for lignite combustion. In considering modifications to existing lignite plants it is the need to meet tighter emissions legislation that is the primary consideration followed closely by plant efficiency improvement.

The commercial availability of high efficiency/low emission (HELE) technologies means that it is now possible to both reduce emissions and substantially raise the efficiency of lignite power plants. New ultra-supercritical (USC) installations, utilising HELE technology, can potentially generate power with ~25% lower CO_2 emission per MWh when compared to the typical subcritical steam technology that is the industry standard. There is further potential for efficiency gain in the coal industry by the utilisation of new technologies that include: double reheat USC steam systems; lignite gasification to form syngas in IGCC plant as an alternative to pulverised fuel combustors (EPRI, 2015); while supercritical carbon dioxide driven turbines, replacing steam systems, may achieve 50% plant efficiency with commensurate reductions in all emissions (Jung, 2015).

While the performance of new lignite power plants, employing the latest techniques, have the potential to approach the efficiency of advanced hard coal stations, the majority of the global lignite power industry operates using less advanced technologies. Boiler design is generally based upon less efficient subcritical steam conditions. In addition, the accompanying emission treatment designed for limits set at the time of construction is now outdated. The effect of wear and tear on key station equipment, such as the combustor, heat exchangers and steam turbines, is to produce a gradual decline in performance over time. The average efficiency for lignite power stations is assessed as ~28% to 29%, with many performing below that level. This is in contrast to a 'best in class' subcritical lignite plant operating at up to 36% efficiency, indicating the benefit to be gained by technology improvement without changing the basic boiler design (McCulloch, 2007; Mitsubishi Hitachi power Systems, 2014a).

Typically a station is designed to operate for 25 to 40 years with the expectation that eventually older plants will be phased out; much of the current lignite power industry falls into this age bracket or exceeds it (*see* Figure 1). However, due to an acute shortage of electricity generation capacity in many countries, and resistance to the construction of new coal stations in mature economies, older lignite stations will have to continue operating. These plants now need to introduce upgrading technology to meet legislation on emissions, and in some cases meet specific Heat Rate targets, based upon their existing subcritical steam conditions. Although older plants need to comply with less stringent emission controls than new facilities, these limits are continually falling in successive periods. A plant adding treatment units which only meet current emission limits may find this is not the most economical long-term response, with the predicted life of the station an important factor in these decisions.

The smaller proportion of modern stations utilising super or ultra-supercritical steam systems, already achieve higher efficiency and consequently lower pollutant emissions. However, the challenge in the future for these plants, as indeed for the whole industry, will be to possess sufficient flexibility to respond to rapidly changing electricity demand responding to the impact of variable renewable power.

This report evaluates potential retrofit options to existing lignite power plants; examines various potential upgrade technologies for subcritical stations and also considers techniques to address flexibility issues. The study draws from recent research and industrial publications as well as incorporating IEA CCC studies on aspects of lignite power technology, including: combustion technology (Zhu, 2012), lignite fuel drying techniques (Dong, 2014), effluent treatment (Carpenter, 2013) and advanced sensors and controls (Lockwood, 2015).

The most promising retrofit technologies for older subcritical stations may be classed as ‘add-on’ technologies that offer low capital cost solutions which avoid substantial plant downtime for installation compared with technologies preferred for new stations. These add-on options include: lignite pre-drying and segregation; boiler combustion modification; hybrid reactor technology; steam turbine upgrades; and cost effective alternatives to current accepted Best Available Technologies (BAT) for controlling emissions of NOx, SOx, particulates and mercury (Hg). To achieve emissions targets, smaller power stations may be restricted to retrofit technologies where there are reduced effects of scale and where the installation costs are lower, even if that results in higher operating charges.

To improve plant flexibility there are a number of technology options including boiler and turbine optimisation, co-feed options, thermal storage, and the use of dry lignite in low level firing. The report also briefly reviews recent developments in carbon capture and storage applied to existing lignite plants which are making significant progress towards commercial lignite power with carbon capture utilisation and storage (CCUS).

The report describes commercial technologies which are currently implemented in lignite plant retrofits, and also established, but recently implemented, technologies that have been demonstrated on hard coal plants and offer new options for lignite plant upgrades.

2 Lignite power station fleet, fuel quality, technology and legislation

2.1 Lignite power stations 1950–2015

The number and scale of lignite power plants is increasing, with maximum capacity rising from typically 200 MWh in the 1960s to over 1000 MWh for latest designs, with the largest stations achieving the greatest construction cost benefit due to plant scale. However, smaller plants continue to be installed most likely due to limited local power demand, or for specific applications in industrial generation. Figure 1 shows the variation of plant capacity over the period 1950 to 2015. Early plants constructed around the 1950s have proved robust and still operate using traditional technology. In countries with a growing contribution from renewable energy there is now a view that, despite the higher relative cost, smaller generation units may make more sense as they can respond better to intermittent operation (Then, 2015).

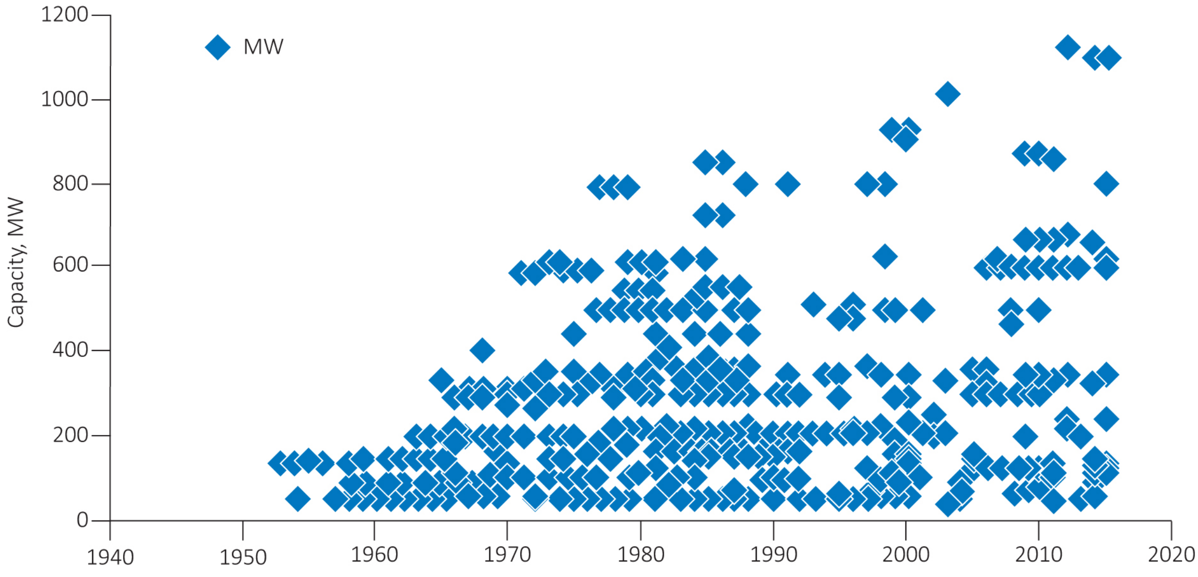

Figure 1 Generating capacity MWh of the worldwide lignite power 1950 to 2015 (Platts, 2015)

In all there are over 1000 plants in the global lignite electric power fleet, and of these there are currently over 700 lignite power stations that exceed 100 MWh, with the majority at 150 to 350 MW capacity. The remaining ~300 smaller facilities are mostly dedicated to providing power directly for manufacturing industry (Platts, 2015). Historically, the first plants to use a particular lignite supply would be relatively small, with subsequent plants gradually increasing in capacity as boiler issues are resolved. While the majority of plants (>60%) exceed a typical design life of 25 years, almost 10% of power stations (95) have come on stream within the last five years, confirming the continuing importance of lignite fuel to electricity generation.

Geographical trends in the development of lignite power are affected by a number of factors including: the relative cost of electricity generation from lignite fuel; the impact of economic growth on electricity demand; tightening emissions legislation; and competition from renewable energy and cheap natural gas.

Worldwide, China has seen the most growth in new lignite power development, forming a significant part of a steep increase in overall coal generation capability; with China's new coal capacity totalling up to 49 GW per year, the trend mirrors the surge in economic growth. The movement to renew Chinese stations accelerated recently with a programme to reduce air pollution in urban areas which has led to closure of smaller stations that cannot meet new emission standards. The intention of the Chinese Government is to phase out stations which do not possess clean coal technology by 2020 (Reuters, 2015). This has led to increased interest in retrofit 'add-on' technologies capable of delivering enhanced emission reduction.

Germany, traditionally the largest user of lignite power, and possessing some of the most efficient large-scale stations, is now unlikely to install new lignite capacity, but will require existing stations to operate more flexibly. The lignite power sector is contracting, and less efficient stations are to be reassigned as reserve capacity and eventually will be retired to meet stringent greenhouse gas targets by 2017.

Internationally, the governments of Asia and Eastern Europe have highlighted the importance of lignite power, sanctioning new build and refit projects, due to attractive economics compared to other energy sources. Within the EU region there is an extensive plant upgrade programme in progress to meet new emissions legislation.

For Russia, there is an ageing fleet of lignite stations as more than 80% of lignite power plants exceed 25 years of age. The use of older technologies, ageing boiler and turbine designs inevitably impact upon efficiency. These plants also possess limited emissions control (Platts, 2015).

New US regulations for electricity generating units are set to come into force (EPA, 2014), with state wide average carbon dioxide limits to be established which are to be linked to an improvement in the performance of fossil fuelled plants. The expected level of reduction in Heat Rate required will lie within the range of 4 - 6% based upon an analysis of the US coal fleet. To achieve such an improvement the plants will need to select cost effective retrofit measures to extend the life of the plant for perhaps an additional 10-years' service, bearing in mind that new effluent treatment measures that are also required will act to increase Heat Rate.

2.2 Lignite fuel resources and consumption

Lignite is an important strategic fuel resource forming 30% of the world's recoverable coal reserves and is of particular importance to those countries with an expanding power need and seeking a secure resource. Table 1 shows a recent assessment of lignite reserves by country and the associated production rates. The top two lignite power producers are shown to be China and Germany, combusting approximately 150 and 180 million tonnes (Mt) of lignite respectively each year. Recent changes in the German electricity market indicate that Germany's lignite production may have peaked from a maximum production of 185 Mt/y. The other significant countries generating electricity from lignite include: Australia; Czech Republic, Greece; India; Poland; Russia; Turkey; and the USA.

Table 1 **Lignite proven reserves, million tonnes** (>100)/Annual Production Data (2011 data: World Energy Council, 2013 and for EU 27 in 2012: Ernst & Young, 2014, Michel, 2015a)

Albania	794	Australia	37200/66
Austria	333	Belarus	100
Bosnia Herzegovina	2369/11	Bulgaria	2174/31
Canada	2236/10	China	18600/147
Czech Republic	871/44	Germany	40500/178 (2014)
Greece	3020/63	Hungary	1208/9
India	4500/32	Kazakhstan	12100/8
Kyrgyzstan	812	Laos	499
Macedonia Rep.	332/7	Mongolia	1350/10
New Zealand	333	Pakistan	1904/1
Philippines	105/4	Poland	1287/64
Romania	280/30	Russian Federation	10450/81
Serbia	13400/40	Slovak Republic	280/2
Slovenia	140/4	Thailand	1239/18
Turkey	8380/74	Ukraine	1945
USA	30176/81	Uzbekistan	1853/3

While lignite power generation is under pressure in mature economies from gas and renewable power, new lignite power plants are under construction in Asia and Eastern Europe including stations in Thailand, Laos and Poland. The Polish Turów 500 MW MHPSE plant for example (Mitsubishi Hitachi Power Systems, 2014b), forms part of a significant programme in Eastern Europe of lignite plant upgrading and retrofitting to increase generation capacity and comply with EU emissions legislation. Adopting lignite based power generation is often against a background of limited alternatives where hard coal and gas fuelled plant are uncompetitive (Baruya, 2015), renewable energy still requires considerable government support and additional nuclear power production currently appears unlikely.

Lignite power stations normally act as base load providers, due to the relatively low cost of lignite compared to other fuels. For example, lignite production costs range from 5 to 21 €/t in the EU-27 depending on the seam thickness, overburden depth and lignite quality (Ernst & Young, 2014). Although there is a growing European market in the rail transport of dry pulverised lignite to smaller power plants (Michel, 2015a), there are limited alternative uses for the fuel and when this is combined with cost of transporting a low quality, volatile wet fuel, lignite remains most suitable for local power generation.

For Germany the reduction in lignite power generation is led by greenhouse gas emissions legislation, and the impact of renewable energy resources. Tighter legislation is also an important factor affecting lignite power in North America: abundant, low cost gas supplies from shale fracking has made gas based power uniquely competitive with hard coal generation leading to the scheduled closure of a number of American coal stations. The lower lignite feed cost has meant that lignite fuelled stations have not yet been affected but will now have to compete against gas power and the larger capacity, more efficient coal stations that remain.

2.3 Lignite fuel quality: energy content, water and ash

In contrast to hard coals, lignite fuels contain substantial levels of water and minerals which have a significant impact on the selection of lignite plant technology and ultimate plant efficiency. Due to the volatility of lignite any individual plant is usually restricted to a local lignite supply. The chief technological concern for the application of modern high severity steam systems has been the quantity and composition of the ash derived from lignite; this has hampered the widespread implementation of SC and USC systems due to concerns over fouling and slagging. Where the ash affects the operation of the boiler, the moisture content of lignite reduces the energy content of the fuel; high water levels lower thermal efficiency as the water contained within the fuel must be evaporated requiring additional fuel use to compensate for the added energy burden.

The quality of lignite fuel in the most significant countries is shown in Figure 2. The fuel is classified by its moisture and total ash composition and the diagonal contours indicate the energy content. As the ash or moisture levels increase then the ‘mine to power’ efficiency of the station reduces due to three factors: the greater quantity of material processed to generate power; increased heat capacity of the feed; and energy consumed to evaporate water. The energy content of the fuel is highest for low water, low ash lignite such as Indonesian Lignite, while Czech lignite is shown to be one of the most challenging fuels with both high ash and water content. More detailed information on lignite resources by country and composition is available in earlier IEA CCC reports (Burnard, 2011, Couch, 1988).

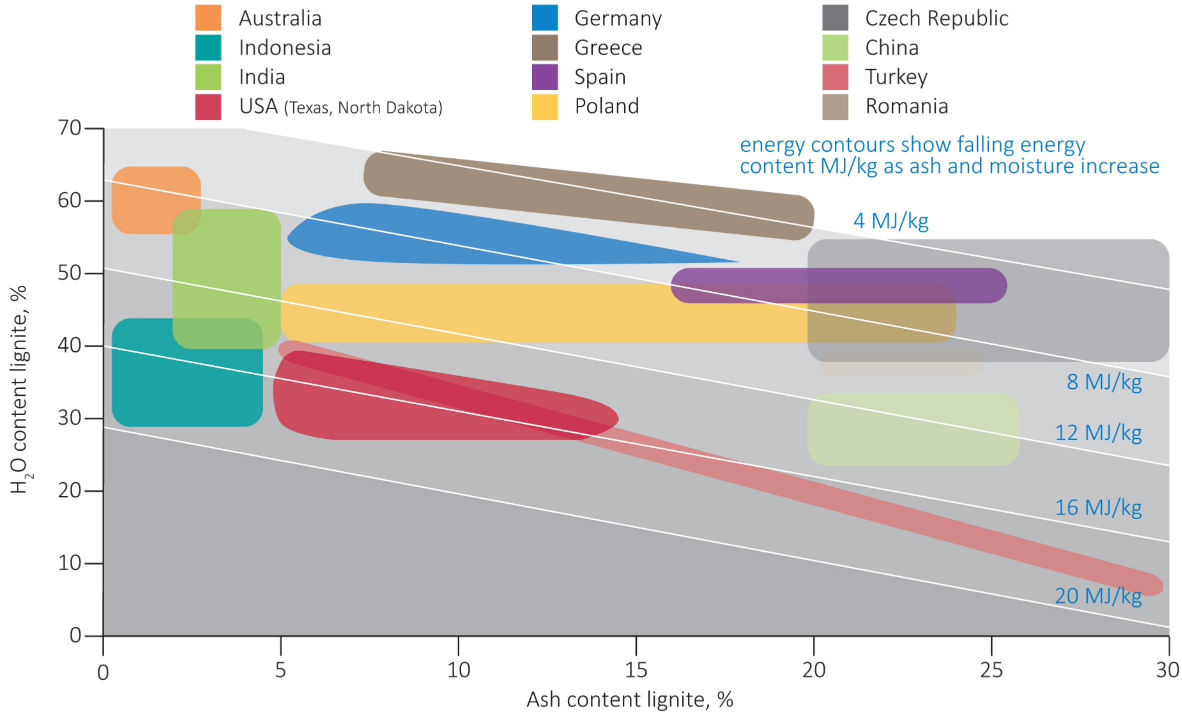

Figure 2 Lignite fuel qualities in terms of moisture and ash, shown by country (Burnard, 2011)

High mineral content does add to the heat capacity load on the plant but, of more concern is that it contains the main source of sulphur and heavy metals which have to be removed from the stack gas. High ash production can lead to combustion difficulties in the boiler exacerbated by higher steam temperature design. Of the main users of lignite power, the German lignite tends to be of low ash content but possess high moisture levels of ~60% while the Chinese lignite is typically of high ash content and lower moisture levels of about 30%. Given that Germany and China are the leading producers of lignite based power, the technology to process lignite has been focused on these countries and the most advanced steam technology has been introduced for both cases.

The high temperature behaviour of ash is determined by testing of ash samples, where ash pyramids heated until they show signs of deformation, or begin to fuse, indicate temperature limits for slagging in a boiler. Of particular concern for burner retrofits introducing low NOx devices is that the tendency for ash particles to fuse together is found to be at lower temperature under fuel rich conditions rather than in an oxidising atmosphere that is prevalent in older designs (Couch, 1989).

In the past, reliability of lignite plants has been reduced where the fuel contains high levels of minerals, particularly in the presence of alkali salts. However, greater control over the combustion process (moderating peak temperatures), some limited modification of the lignite feed composition (combining varying lignite sources to reduce slagging), and more advanced sootblowing techniques have combined to mitigate the impact of the mineral content. Higher ash containing lignite may now be processed at supercritical conditions raising the potential station efficiency for these more challenging fuels (Burnard, 2011). The most recent Thai lignite plant at Mae Moh will apply USC technology to high ash lignite continually monitoring the acid-base composition of the fuel, with high alumina feed content preferred to limit slagging.

2.4 Lignite power plant boiler technology

Emissions legislation has a more powerful influence on the design of modern coal-fired stations than ever before, favouring the installation of ultra-supercritical (USC) boilers. The ultimate efficiency and associated emissions of a station are dependent on the steam conditions selected at the design stage. However, the vast majority of the lignite power fleet operates on traditional boilers based upon subcritical steam conditions, albeit at lower efficiency.

While a growing proportion of the newest lignite stations plants adopted super or ultra-supercritical technology, ⅔ still chose subcritical technology to benefit from lower installation costs and to reduce project risk associated with high ash levels. The Hongsa plant (1878 MW) in Laos, expected to commence operation in 2015, is an example of a new station adopting subcritical technology to process high ash lignite (25 wt%); the total project cost including the new mine has been quoted as $3.7 billion (Banpu, 2014).

Relative to a subcritical station, the capital cost of a plant based on supercritical (SC) steam conditions is 5% more expensive, and for ultra-supercritical (USC) designs the cost rises by 12%; this is due to higher temperature operation of the boiler and turbine requiring more specialised metal alloys in construction (Beér, 2007*)*. The higher capital cost of the boiler and turbine is partly offset by the reduced quantity of feed to be processed in SC and USC plant. This leads to a substantial reduction in the size of downstream process equipment handling reduced stack volumes.

Turning to the benefit of plant efficiency, a station using supercritical steam conditions would be approximately 4% more efficient than a new subcritical plant. The plant efficiency impacts strongly upon all emissions: comparing a supercritical lignite PC plant at say 37% efficiency to a subcritical station operating at 33% efficiency means that all plant emissions would be ~12% lower. This represents a significant improvement in both Heat Rate and carbon dioxide release.

As the industry has moved toward ultra-supercritical technology for low ash fuels (with the plant at Mae Moh actually feeding high ash lignite to a USC boiler) then supercritical technology has become more viable for higher ash containing lignite. A number of supercritical plants in China have achieved several years' operating experience processing high ash lignite, but with the ash composition beneficially high in alumina content, for example, Huaneng Jiutai 1; Huaneng Yimin; and Baicheng CP1 (Platts, 2015).

There are no recent examples of stations upgrading from subcritical to supercritical boiler design due to the cost and downtime associated with a complete plant refurbishment. An upgrade to SC or USC boilers would likely require special conditions driven by legislation and planning restrictions over the construction of a new facility. Where an upgrade from subcritical conditions is considered then it may be more logical that a subcritical station would be entirely replaced with a higher capacity clean technology SC or USC lignite plant.

2.5 International commitments to lower greenhouse gas emissions

The United States, Europe and China have all recently agreed further reduction targets for carbon dioxide emissions. The USA and Europe are currently on course to achieve targets originally set for 2020, by raising plant efficiencies, switching from coal power to gas or by the introduction of renewable energy. Due to its low combustible content, three times the tonnage of lignite is needed compared to equivalent black coal fuel per megawatt. Lignite power currently possesses the lowest average efficiency of fossil fuelled stations and thus the highest carbon dioxide emissions at ~984 kg (2170 lbs) per MWh making these stations most affected by greenhouse gas emission legislation. Conversely, given the gap between the actual and potential efficiency of many lignite stations compared to best in class subcritical plant, there is the potential to make a substantial contribution towards lowering emissions through modernisation while retaining the base boiler technology. An average lignite power plant operating at 28% efficiency will release 1.23 tCO_2/MWh (McCulloch, 2007). This compares to the best in class subcritical station which has a lower output of ~1 tonne CO_2/MWh, with SC and USC plants at lower rates.

Table 2 Carbon Dioxide Emission Reduction Targets (Fransen, 2014 and Climate Action, 2014)

Date	EU (ref 1990)	North America Ref 1990	China	India
Current Share of global CO_2 emission 2014	10%	USA 14%	28%	7%
2020	20% (Germany 40%)	USA 17%	Carbon trading scheme from 2017	
2025		USA 26–28%		
2030	40%	Canada 30% USA 32%	Emission peak	

The data in Table 2 show that the EU is seeking a reduction in emission rates of 40% by 2030 compared to 1990 reference levels, having already achieved intermediate targets. China aims to show that CO_2 emissions will have peaked by 2030, and intends to achieve that target much sooner with an intensive modernisation and construction programme underway (Gielen, 2014). India is yet to set CO_2 targets but has set emissions targets for other pollutants for the first time.

Legislation changes to take place under the USA Clean Power Plan (EPA, 2015a) mean that averaged USA state power emissions are set to be less than 592 kg (1305 lbs) CO_2/MWh compared to 984 kg (2170 lbs)/MWh for an average lignite plant. It is proposed that this target be achieved by a series of steps over an 8 year period (2022-30) and will partly be met by improvement to lignite plant efficiency. It will also require a reduction in coal/lignite power production in favour of natural gas (532 kg (1175 lbs) CO_2/MWh) and renewable energy (Institute for Energy Research,2015). Individual states or integrated regions are to manage their own averaged power supply structure to meet these targets.

3 Overview of retrofit opportunities for the lignite power fleet

Retrofit technology is defined as 'improved' technology rather than 'like-for-like' replacement which would serve to restore performance in the plant to the original design. Thus retrofit implies that the existing equipment is modified or a new unit is added to the plant to improve performance and efficiency or reduce emissions.

Table 3 provides a listing of potential technology upgrade options in the following categories: flexibility, efficiency and emissions control. Although the study considers commercially available technology, some adaptations may be novel applications to the lignite power industry. The optimum retrofit options will be determined by the current status of a plant, the predicted lifespan, and the legislative framework driving plant modernisation.

Table 3 Summary of lignite thermal plant retrofit options

Flexibility – Load sharing	Efficiency – performance	Emissions treatment – CO_2,NOx, SOx, Hg, particulates
Repowering using natural gas (gas turbine)	Increased steam temperatures and pressures	Low NOx burners
Automated plant control systems	Lignite pre-drying: eg Dryfining™, WTA	NOx emission reduction SCR/SNCR/Ultra/LoTOx™
Low load operation mitigation	LP long blade and 3D turbine technology	SOx: Wet FGD/semi dry FGD/lignite pre-treatment/ multicomponent
Energy storage options including hot water	Reduced parasitic load of auxiliary systems	Particulate control, ESP, fabric filtration
Dry lignite & plasma ignition to replace oil	Intelligent soot management	Mercury capture: activated carbon, oxidation, mineral segregation
		CCUS (EOR), CCS
		Reduced CO_2 emission using co-feed: natural gas, bio-waste

The listing in Table 3 summarises the topics covered by this report which are currently the most suitable for economic retrofits to existing plants. However, there are additional technologies which may be relevant for specific advantageous circumstances that include: fluidised bed technology preferred for processing bio-feedstock; oxy-combustion for improved carbon capture efficiency; gasification to facilitate pre-combustion capture; and the addition of solar energy technology operating in tandem with traditional plants.

3.1 Efficiency and performance improvement

Power stations that need to improve efficiency are likely to select replacement upgrades or new 'add on' technologies that can be fitted during plant outages, avoiding high capital investment and prolonged plant shut-down.

In terms of boiler technology, manufacturers offer upgrades that include the introduction of revised low NOx burner (LNB) designs delivering uniform temperature profiles within the boiler and the application of advanced control systems combined with enhanced reaction monitoring to optimise boiler operation. The effect of these modifications is to allow a closer approach to optimum fuel-air ratios by eliminating hot spots, avoiding an increase in slagging within the boiler. In the current climate, the upgrading of boilers for higher temperature and pressure stream conditions is unlikely to be adopted due to the financial constraints and loss of generation during what would necessarily be an extensive modification.

Eastern European power companies have instigated a programme replacing aged steam turbine installations with more advanced 3D turbine designs to restore lost performance and in most cases realise a modest increase in generating capacity. Clearly the more inefficient the steam turbine currently in place then the greater the benefit of a retrofit to lower plant Heat Rate (HR); in some cases the improvement can be by as much as 14% (Electric Light and Power, 2015).

Auxiliary systems within the plant that include milling, heat exchangers, fans, pumps, compressors, and control systems all offer opportunities for modernised replacement technology where performance has deteriorated and parasitic load upon the plant has risen with time.

Uniquely among the fossil fuels the variability in composition of lignite, in respect of ash and moisture content, can have a significant impact on the long-term performance of lignite boilers and upon the overall efficiency of the station. The presence of water in the fuel combined with traditional boiler designs that utilise full reaction heat to evaporate that moisture leads to lower plant efficiency. Compared to the equivalent subbituminous coal fuelled plant, lignite thermal efficiencies are generally lower by up to 9% , corresponding to ~60% water content (Dong, 2014).

Although not yet widely adopted there are a number of technologies under development to dry fuel using low grade heat sources external to the boiler (*see* Table A1 on page 96). Of the available pre-drying techniques, two fluidised bed drying technologies have recently been demonstrated at full commercial scale as retrofits to existing plants in Germany (RWE) and in the USA (GRE). Both utilise waste heat streams to dry lignite, and the GRE technology possesses the additional benefit of mineral segregation by gravitational separation, potentially alleviating ash issues within the boiler.

3.2 Emissions reduction

There are a range of measures that may be adopted to help meet new legislation on pollutant emissions: lignite pre-drying, acid gas removal, mercury oxidation and fly ash collection.

Waste energy from the plant is used to pre-dry lignite, lowering pollutant emission by reducing the overall quantity of fuel needed.

One of the pre-drying systems, Dryfining™, uses gravitational segregation to partly remove sulphur and mercury from the feed upstream of the boiler, reducing the concentration of pollutants in raw stack gas emissions.

The latest low NOx lignite burner designs are tangentially fired providing more uniform combustion conditions with enhanced NOx reduction that minimises the use of chemicals (ammonia/urea) in downstream processes.

Figure 3 shows the relative cost of a range of treatment units relative to a SOx scrubbing plant (wet FGD (wFGD)); showing that the 'best available technologies' fitted to a new plant are also the most expensive units. In a review of the continued operation of combustion plants under the IED (Loyd, 2011) there was an expectation that plants expecting to operate for a further 25 years would already have installed SCR/ESP/wFGD technology, or their equivalent.

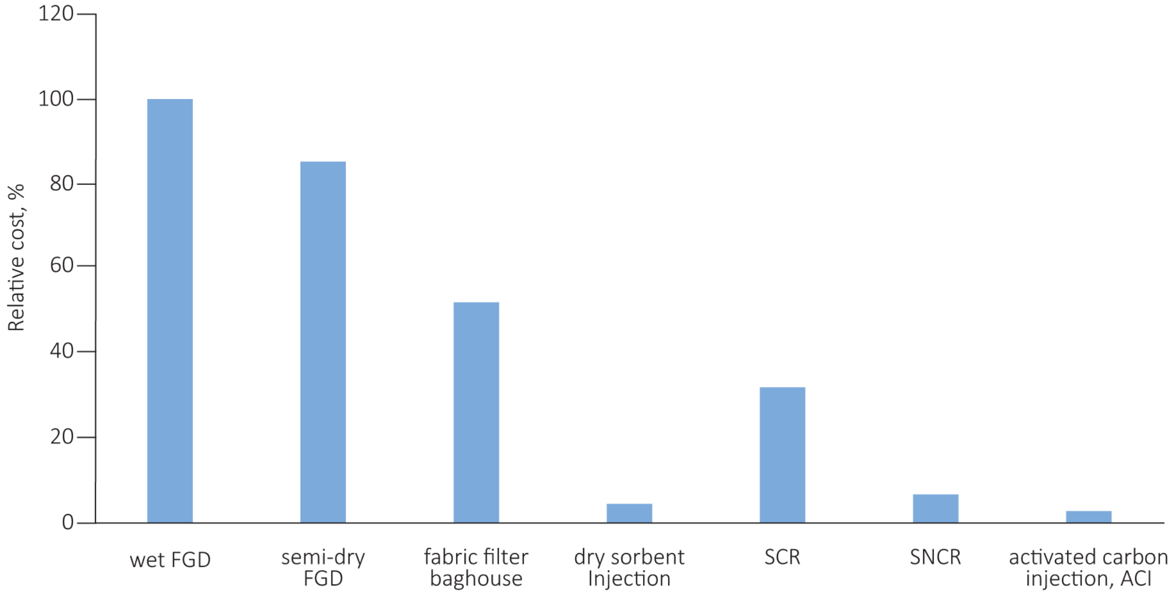

Figure 3 SOx, NOx, Hg removal treatment costs relative to a wet FGD plant (Sjostrom, 2012)

The preferred system for NOx removal in a new plant is selective catalytic reduction (SCR). However SCR is a relatively high capital investment option that may be too expensive to install as a retrofit. In seeking a low cost alternative to SCR, a number of new methods are beginning to be deployed in hard coal stations. The most promising of these processes include: hybrid technologies that utilise non-catalytic selective reduction (SNCR); oxidative removal based upon Ozonolysis; and multi-component technologies that efficiently remove more than one pollutant using a single reagent (*see* Table 20 on page 68-69).

Sulphur dioxide treatment is dominated by wFGD or semi-dry FGD, with the latter costed at approximately ~85% of the wFGD (Figure 3). Direct Sorbent Injection (DSI) is an alternative chemical process option which is less effective as it only removes between 50 - 80% of SOx. However, there are new applications that can achieve high pollutant recoveries with capital costs that are competitive with wFGD, for example multi-component methods based upon sodium bicarbonate.

Activated carbon injection (ACI) for mercury control is relatively low cost if injected into the final stage of an existing electrostatic precipitator (ESP), but now tends to be installed with a fabric filter (FF) baghouse assembly that can also address new lower limits for particulates. New to the industry is the direct oxidation of mercury that allows its removal in a scrubber system.

There is immense interest in the potential of carbon capture (CCS, CCUS) to moderate carbon dioxide emission from fossil fuelled power plants. CCS places considerable energy demand on a power plant of the order of 20% of total capacity and so previously only highly efficient stations would consider applying the technology. However, the lower cost of lignite-based power has led to significant developments in lignite/CCS plants. At Boundary Dam in Canada, SaskPower has retrofitted CCS to a 110 MW subcritical lignite plant which commenced operation at the end of 2014.

In the USA, a new 600 MW lignite gasification/CCS plant is under construction at Kemper County developing the technology Transport Integrated Gasification (TRIG). From the perspective of retrofitting plants, CCUS technology is currently at the commercial proving stage, aiming to substantially reduce costs in order to implement the technology internationally.

3.3 Flexibility

The emergence of a growing renewables sector means that in the future lignite stations will need to respond to rapidly changing market conditions. Figure 4 shows power generation in Germany during the month of November 2014, exhibiting the contribution of coal and lignite.

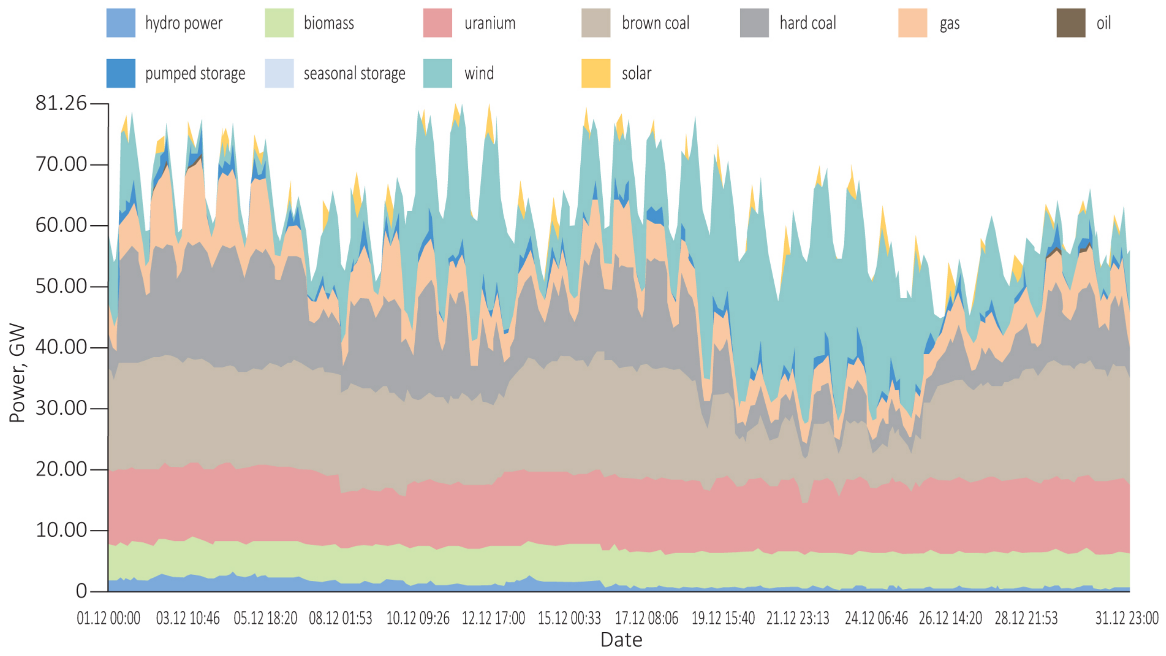

Figure 4 Germany, December 2014: contribution of brown coal power generation (Fraunhofer ISE, 2014)

During mid-December there is a a period of considerable variability in fossil fuel generation, which significantly affected the lignite supply for the first time (Schiffe, 2015). During periods where wind and solar are both delivering maximum output, then the day-ahead pricing falls below the cost of generation for lignite power (Michel, 2015b). As the contribution from renewable energy increases, with prices guaranteed until 2030 under the EEF feed-in-law, this will result in further reductions in fossil power generation in Germany, and a number of lignite power plants are due to be reassigned as reserve stations from 2016.

In reacting to such a variable power market, there are a number of technology options to enhance load flexibility including: boiler modifications to improve response to changing temperatures and conditions, cofuel firing using gas or bio-waste feed, the use of dry lignite support combustion, and energy storage systems.

4 Lignite power plant efficiency improvements

A typical lignite PC plant is shown schematically in Figure 5. In this example the plant is fitted with selective catalytic reduction (SCR), electrostatic precipitation (ESP) and flue gas desulphurisation (FGD). Lignite is milled and heated by hot air, or flue gas, that dries the lignite to a residual moisture content of around 20% before transport to the burners using the primary air flow. Low NOx burners form a fuel rich combustion zone in the near burner region to reduce NOx. Additional ‘overfire air’ (OFA) is added to control the final stoichiometry of the effluent to complete fuel burn out. There is an optimum overall fuel/air ratio for high efficiency operation but higher air/fuel ratios reduce risk of slagging and fouling.

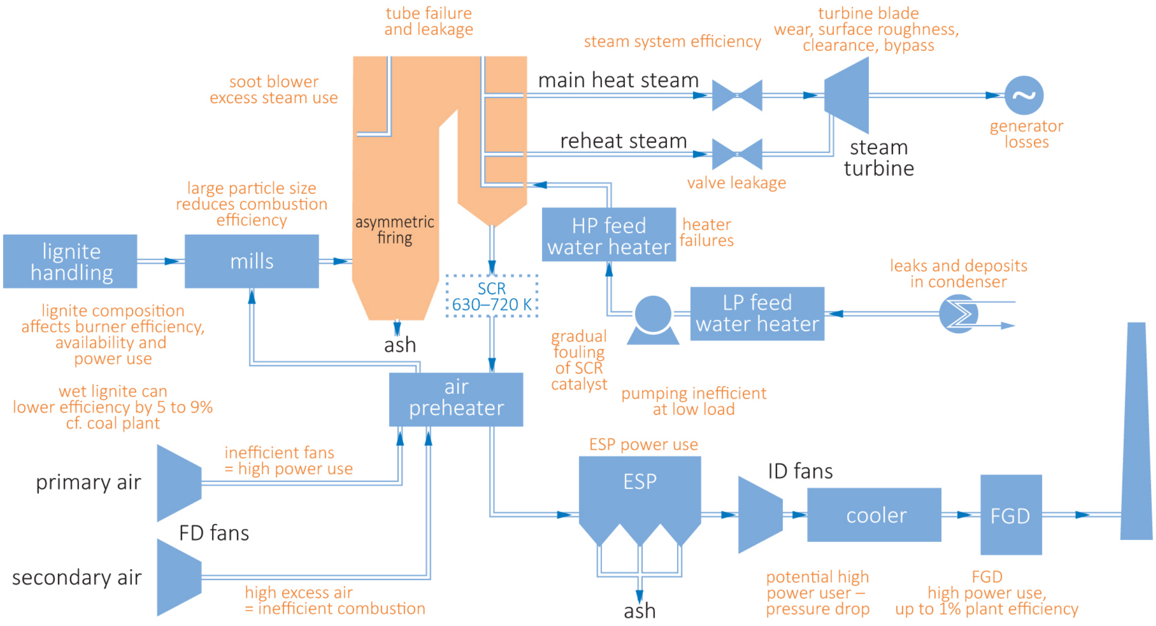

Figure 5 Lignite plant efficiency issues (adapted from Burnard, 2011)

Above the combustion zone, steam is raised in the convection bank. The temperature and pressure of the steam depend upon whether the plant operates sub, super or ultra-supercritical conditions. Subcritical systems require a steam drum to separate steam and liquid. The generated steam is expanded through a series of turbines, returned to the combustor for reheat and then re-expansion. Sootblowers, if required, are activated to blow deposits from heat exchange surfaces at established intervals. Finally the resultant steam/water droplet mix is condensed and returned as a liquid stream.

As the cooled stack gas progresses to the SCR catalyst unit, ammonia is injected to reduce the NOx. The SCR has tight operating limits of 680 +/- 50°C and so is normally located before a fly-ash ESP. Flue gas is then passed into a wFGD unit, sprayed with lime to remove SOx and the cleaned stack gas released to atmosphere.

A schematic plant is used to illustrate various sources of efficiency loss found throughout the design; areas of concern are depicted in orange text (Figure 5). Initially, at the feed section the use of low quality feed containing high ash and moisture content places a thermal load upon the combustion process.

Additionally the use of raw lignite also raises overall gas flows resulting in higher parasitic loads from fans, compressors and pumps; and the size of all equipment must therefore be larger. Corrosion and thermal stress will lead to thermal energy losses through water, steam and air leakage within and around the boiler and air preheater; deterioration of the heat exchangers within the boiler together with bypass at the steam turbine are also areas of significant energy loss.

The plant control system for an older boiler design is likely to be basic, restricting the periods of operation under optimum conditions. Within the boiler the limited number of reaction sensors for temperature, CO and O_2 provide partial data on conditions in the fire box, and may not detect asymmetric combustion conditions. The formation of localised high temperature zones exacerbates slagging and produces more NOx, forcing the plant to operate under more conservative high air ratios.

The presence of earlier types of low NOx burners and ancillary systems, which use a high proportion of primary air (high air to carbon ratios) leads to greater chemical demand for NOx treatment units. Finally the control of deposits on heat exchange surfaces is an important aspect of lignite combustor management that begin with basic empirical methods for the management of sootblowers.

The deterioration of auxiliary equipment on the plant, such as fans, pumps and compressors, can all contribute to a rise in energy losses over time.

A measure of the overall energy losses on the plant may be expressed as the Heat Rate according to:

Heat Rate, HR (Btu/kWh) = F (heat energy input, Btu)/ E (energy output, kWh)

The Heat Rate increases with the mass of fuel (chemical energy) admitted to the combustor to achieve the design power output of the plant. For illustration, a subcritical lignite plant will possess a Heat Rate value ranging from 10,000 for a high efficiency boiler, rising to 13,000 Btu/kWh for low efficiency plant (EIA, 2013).

4.1 Reported efficiency improvements

Table 4 summarises actual costs and benefits obtained from plant modification and upgrades as reported by operators located in the USA. The table covers a wide range of the technologies of interest including: lignite pre-drying, prevention of leakage at preheaters/boiler and steam systems, the introduction of advanced combustion and plant control, turbine replacement, improved heat recovery and anti-fouling methods.

Table 4 Potential plant modification leading to efficiency gains (Campbell 2013; Dong, 2014; Cichanowicz 2014)

Plant section	Process	Issue	Technology options	Reported efficiency improvement CapEx/OpEx
Feed	Lignite drying	Lignite typically contains 30–70% water	Use of waste heat to dry feed prior to admittance to the boiler	To 1.7% Depends on % moisture removal and boiler technology CapEx ~ $50 million (RWE/GRE data)
Air heater	Leakage control	Air bypass	Some plants change heater every 5 years	0–0.13% CapEx $0.7 million OpEx $75,000 (US)*
Combustion	Advanced control system	Uneven combustion can lead to high local temperatures resulting in slagging or damage and high NOx chemical use	Neural network with measurement of air-lignite flow rate to each burner in addition to sensors for carbon in ash, CO, O_2	0.15–0.84% CapEx $0.75 million/ OpEx $50,000 (US)*
Combustor sootblower optimisation	Soot control in the boiler	Ash accumulation on heat transfer surfaces must be controlled	Optimisation of intermittent sootblowing: intelligent sootblowing in response to plant conditions	0.1 to 0.65% (low to high ash feed) CapEx $0.5 million OpEx $50,000 (US)*
Cooling system	Stream condenser	Heat losses due to high temperature of cooling water to cooling tower	Tuning cooling tower and condenser, replacing cooling tower heat transfer surfaces	0.2–1%
Steam system	Supercritical to replace subcritical	Boiler replacement needed	Tower boiler technology, major plant refurbishment	Up to 4%
Steam turbine	HP, MP and LP turbine upgrades	Aged turbines allow more steam bypass	New technology such as dense pack replacement turbine leads to higher output and efficiency	0.8 to 2.6% Dependent on age and condition of existing unit CapEx site dependent
Flue gas	Heat recovery	Heat loss from hot streams held high to avoid acid dew point	Condensing heat exchanger installation to use heat for boiler feedwater	0.3–1.5%

Each of the process modifications resulted in an improved performance and output, with even small efficiency improvements likely to have a substantial impact on plant emissions that could be critical for plants operating close to legislative limits. However, the magnitude is highly variable, covering an efficiency range of 0.1 to 4% points, and is dependent on the individual operating conditions.

In the case of lignite drying, a technique that is unique to lignite among fossil fuels, the level of moisture reduction will limit the potential benefit which is shown as ranging from 0.1 to 1.7%.

For ash management, sootblowing is clearly more important for those fuels that possess high ash content, with efficiency benefits of up to 0.65%.

The modernisation of steam turbines is a potentially significant improvement to the plant with efficiency improvements of up to 2.6% reported for the best case.

Careful management of conditions associated with flue gas exit temperatures and steam condenser conditions and avoidance of leakage at the air preheater, could cumulatively have a significant impact on plant efficiency of up to 2.5%.

The largest benefit shown in Table 4 is obtained by modification of the boiler from subcritical to supercritical steam conditions, which has the potential to raise efficiency by 4%. However, although SC or USC steam conditions are ideal for a new plant, there have been no recent examples of this technology option being applied as a retrofit to existing facilities.

The following sections examine advanced control and ash management, turbine replacement and lignite pre-drying technologies in more detail.

4.2 Advanced boiler control and optimisation systems

Advanced plant control can offer improved efficiency via computer controlled optimisation of the whole facility, including full integration of the boiler and steam turbine operation. New control systems utilise an array of instruments to measure flow rates, temperatures and other key boiler indicators, and include constant monitoring of turbine status to then optimise the process (Lockwood, 2015). For example, sensors forming the turbine protection system monitor the condition of the turbine on-line using up to 32 instrument channels. Such comprehensive monitoring encompasses measurement of pressure ratios, differential pressures and flows, steam conditions, enthalpy drop, path leakage rates, and vibration monitoring by displacement probes and accelerometers (Beebe, 1998; Berge, 2015).

An important recent development is the introduction of wireless instrumentation which can substantially reduce the cost and time needed for the installation of new sensors. The relative ease of adding new measuring devices forms part of a significant trend for upgrade projects termed the ‘pervasive sensing infrastructure’. Constant online monitoring can replace labour intensive manual checks, where measurements are taken at extended intervals raising plant vulnerability. Such extensive monitoring can avoid potentially costly preventative maintenance and downtime, adopting scheduled maintenance strategies.

For instance the enhanced measurement of fuel flow rate at each burner, replacing measurement for a combined group of burners, can ensure a more even distribution of fuel to the boiler. The more uniform the combustion, with each burner set at the correct ratio, then the closer the boiler can operate to optimum parameters with minimised emission. Although, generally one group of burners is fed by one mill, measurement at each burner will ensure that equal fuel and air flows are supplied, and may be of particular importance under flexible load operations at lower flow rates.

The Polish Belchatów lignite power facility undertook a major retrofit programme in 2012, when Units 5 and 6 (370 MW capacity) were each refitted with 55 Rosemount wireless temperature transmitters (Power Technology, 2012) to provide a detailed temperature distribution within the boiler. This information is valuable in assessing general boiler performance, but can also be relevant to the installation of an SNCR NOx abatement retrofit system to adjust nozzle positions and ammonia injection rates.

The capital cost to upgrade a digital control system (DCS) to an advanced system is reported as ~$0.75 million (Table 4). For plants without a DCS system, the full control package would increase to circa $3-4 million, on a USA cost basis (Cichanowicz, 2014). This can be compared to the installation of a new control system and sensor upgrade project undertaken at Unit 2, Belchatów (370 MW) quoted at a cost of $21 million (EBR, 2013). The project included an Emerson Ovation process optimisation control system together with re-instrumentation of the plant.

4.3 Anti-slagging and fouling measures

High ash containing lignite presents particular difficulties with slagging and fouling which can have a significant impact on the overall boiler performance and reliability. Slagging causes impaired heat transfer due to deposits and corrosion that lead to increased maintenance downtime (Barnes 2010; Hare, 2010). Slagging occurs where ash deposits fuse on surfaces exposed to the radiant heat of the lignite flames, with molten ash then coating boiler surfaces. The factors which contribute to slagging are principally the boiler operating conditions and the thermal chemistry of the ash, but generally slagging is promoted by high local temperatures.

Where slagging is controlled then higher levels of fine ash progress through the boiler to downstream areas. Fouling is then caused by such fly ash depositing on the convective passes within the boiler, again inhibiting heat transfer.

The normal response to slagging problems is to adjust combustion conditions to operate at lower temperature by raising overall air/fuel ratios or by reducing firing rates. The use of staged combustion burners can mitigate slagging as they serve to lower NOx emissions by forming lower temperature/fuel rich flames accompanied by graduated heat release. This lowers temperatures by allowing partial heat transfer to the walls prior to complete oxidation in the overfire air zone. Slagging is more of a problem if operating at higher severity conditions such as those found in plants designed for SC and USC steam duty, making it essential that the boiler combustion conditions are carefully controlled and monitored. Concerns over slagging can deter operators from selecting more efficient SC or USC technology.

To mitigate an existing slagging or fouling issue there are a number of antifouling technologies available for use as a retrofit and the most favoured of these include:

- The installation of internal cameras to monitor problematic areas within the boiler - a relatively low cost measure to assist in optimising sootblowing strategies.
- Installation of strain gauges to monitor the extent of deposition (as the heat exchangers become heavier)
- Intelligent sootblowing using extensive boiler monitoring to forecast ash deposition and then use the data to modify cleaning strategies. There are three different approaches adopted:
  1. Direct systems that use data from fouling measurements to direct sootblowing, including cameras and strain gauges;
  2. Expert systems that adopt a particular strategy dependent upon the specific condition currently in the boiler;
  3. Neural Network systems that adjust conditions in the boiler to direct air and hydro jets to minimise fouling, and then learning from the resultant data to adapt and optimise the cleaning strategy.

A typical intelligent sootblowing installation illustrating locations for sootblowing devices and sensors is shown in Figure 6. Manoeuvrable and programmable lances and cannons replace arrays of individual wall and retractable sootblowers that required hundreds of inlet points which were a feature in earlier designs (Couch, 1989).

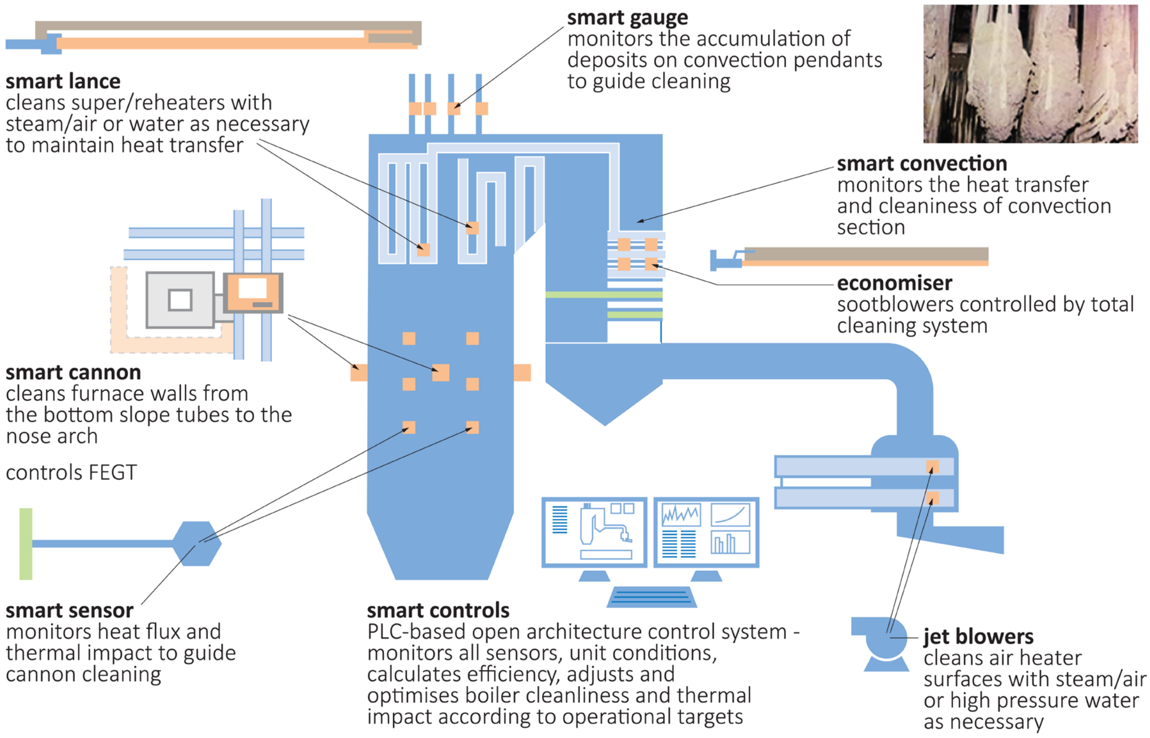

Figure 6 Intelligent sootblowing control strategies and the location of blowers and sensors around the boiler; Photo insert: slag on platen super-heater tubes (Barnes, 2009; Clark 2005; Wicker, 2005).

A water jet cannon has a range of up to 30 m and can be directed in the x and y plane with the range controlled by altering water pressure and adjusting nozzle diameter. The cleaning pattern and timing can be controlled reproducibly so that a programmed regime can be established. Smart lances can traverse across the boiler, varying the degree of cleaning depending upon the severity of deposition. The preferred fluids for sootblowing are compressed air, water, and saturated steam, while superheated steam can also be used but at the expense of plant efficiency.

In some cases pulse detonation wave equipment has been applied to remove heavy deposits. This approach utilises a supersonic combustion (detonation) wave formed in a tube which is directed at the slag location. A fuel-oxygen mixture is ignited in the tube and the ~Mach 3 explosion front forms a pressure pulse introducing shear forces and thermal stresses to target slag deposits which are then dislodged (Hare, 2010).

The capital cost of a sootblowing optimiser is estimated at $0.5 million using existing sootblower equipment (*see* Table 4 above). The installation has the potential to make a significant improvement in the efficient operation of the plant with reported efficiency gains of up to 0.65% depending upon the severity of the problem.

4.4 Steam turbine retrofit

Replacing an aged steam turbine is the most common measure taken to substantially improve the performance of an existing plant. Original turbines dating from the 1970-1990s have been retained in the majority of older subcritical lignite plants; these turbines have proved robust over many years, albeit with a gradual fall in performance.

The following diagram, Figure 7, shows the typical rise in Heat Rate over a 30 year period, that reflects how the plant loses energy due to the deterioration of the multistage turbines. The graph shows an initial rapid rise in heat rate followed by a fall, where performance is partially recovered as a result of cleaning and maintenance. This pattern is repeated at five yearly intervals, giving a saw tooth appearance to the plot. These energy losses are characteristic of those found in older lignite plants dating from the 1980-1990s, with performance impaired by approximately 3% to 4% compared to new units.

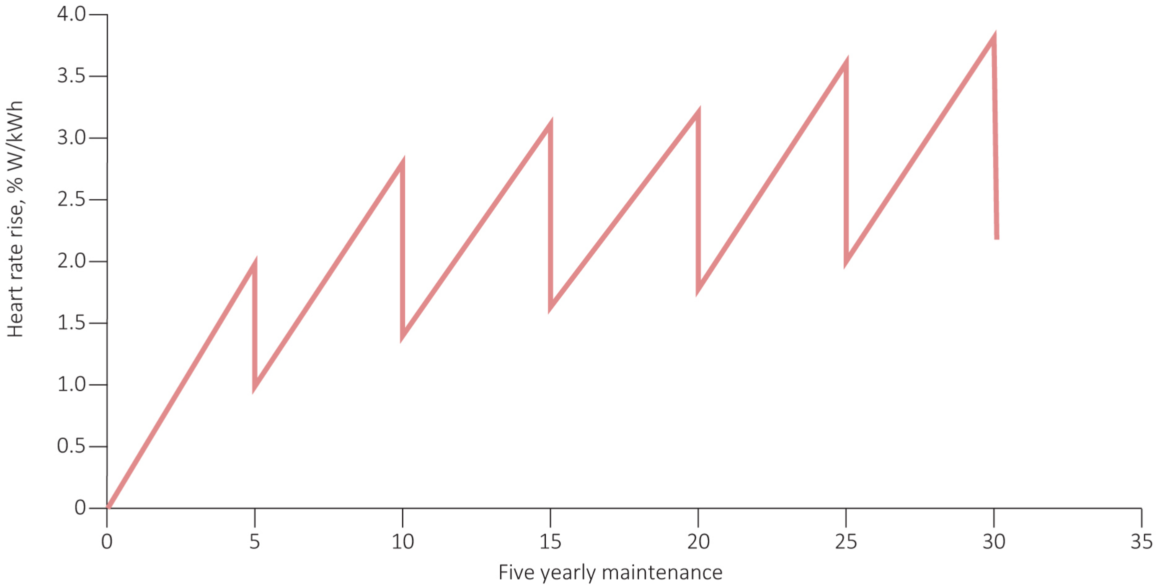

Figure 7 The effect of steam turbine ageing on older turbine designs (early 1990s) alleviated by a regular 5-year maintenance schedule (Schofield, 1996)

The rise in heat rate is most pronounced over the first 10 years at 3%, with a more moderate rate of increase in subsequent years (Schofield, 1996). Reported data on the US Coal fleet, confirms that HP turbine performance declined on average by ~3% (91/93 to 88/91% efficiency, equivalent to 24 W/kWh (80 Btu/kWh) during the first 10-year period of operation (Cichanowicz, 2014).

The change in turbine condition over time depends upon a complex combination of factors that include:

- steam conditions (sub-C/SC/USC) that promote blade creep;
- resilience to the corrosive steam environment;
- thermal stress caused by rotor deflection or bowing in transient operation;
- presence of foreign bodies in the steam flow causing damage;
- tip damage leading to steam bypass;
- blade roughness and deposits increasing flow turbulence;
- packing leakage;
- steam nozzle erosion and roughness;
- unbalanced forces from steam nozzle arrangement (partial 360° inlet nozzle arrangement).

Computational flow analysis methods (CFD) have now led to substantial design improvements focused on turbine seals, diaphragms, and avoidance of turbulent flow, while the construction materials have also significantly evolved (Hansen, 2007).

Perhaps one of the most significant changes has been in low pressure turbines, with the adoption of a longer blade length approaching 1.2 m that can extract more energy from the steam.

Earlier designs of parallel airfoil blades have been replaced by new 3D blade designs optimised by CFD flow analysis. A typical Siemens parallel airfoil design is shown left in Figure 8; this is the prevailing turbine design present in plants exceeding 25-years of age (Smiarowski, 2005). The CFD designed Siemens 3DS blades shown right, produce a 2% efficiency improvement over the previous T4 blade. Turbine retrofits introducing improved steam flow designs would be expected to provide a modest rise in power output above the original nameplate capacity.

Figure 8 Siemens T4 parallel airfoil blade design of the 1990s compared to the 3D Siemens airfoil design

As well as aerodynamic developments, the composition of blades has been modified to improve durability, reducing the effects of creep, corrosion and thermal distortion in order to minimise gradual deterioration in performance. Although primarily developed for higher severity steam conditions, such as USC applications, improved blade stability is beneficial for all cases. Creep (or cold flow) becomes more significant for higher temperature duty and is addressed by the use of thermal ceramic coatings. For example, zirconia oxide is coated onto blades formed from nickel based alloys that include aluminium and titanium.

A turbine retrofit project may feature a completely revised multi-stage turbine or a partial refit of HP, IP or LP turbines to address particular issues at a site. The following Table 5 indicates the potential improvement in efficiency by implementing a range of measures that include replaced seals, new balanced control valves and modified steam paths (Cichanowicz, 2014). The capital cost for upgrading turbine components is estimated at $1 million to introduce new turbine seals, upgraded steam paths at $5–6 million and rotor replacement at $5–8 million (500 MW plant, US 2014 basis). The range of Heat Rate benefits to a given plant depend on the current state of the equipment with more degraded units showing the largest improvement, while costs are affected by plant age and scale.

Table 5 Steam turbine improvement options: capital cost (US$), heat rate and efficiency benefit (Cichanowicz, 2014)

Parameter	Capital cost $ million	Heat rate Improvement HR Btu/kWh	Generating efficiency improvement
Partial arc admission steam control valves (balanced)	1	50	0.17
HP steam seal upgrade	1	50	0.17
HP steam path upgrade	6	95-135	0.3-0.45
IP steam seal upgrade	1	20	0.1
IP steam path upgrade	5	50-100	0.17-0.33
LP steam seal upgrade	0.75	120	0.4
LP steam path upgrade	5	65-225	0.22-0.75
Upgrade cooling tower (packed)	3	0.7	0.25

Steam turbine suppliers (such as Alstom and MHPS) are now prepared to install new turbines into existing casings from other manufacturers, and the turbines can be prepared up to 2 years ahead of a planned shutdown to minimise installation time. Alstom is undertaking a partial turbine retrofit project at the Polish Electrownia lignite plant at Belchatów I, renewing the HP and IP turbines, renovating auxiliary systems and modernising the generator. The retrofit is expected to increase the plant output from 360 to 380 MW (+6%), at a total project cost of $36 million (Alstom, 2013a).

Another Alstom retrofit project, for hard coal rather than lignite, is the implementation of a full shaft-line refit of two 200 MW LMZ steam turbines for BHEL plants located at Ukai and Wanakbori in Gujarat, India. The upgraded turbines are anticipated to raise efficiency by 14 per cent over the existing plant, with an estimated cost quoted at $29 million (Electric Light and Power, 2015).

The growing number of projects reported by Eastern European stations confirms turbine retrofits to be a favoured means to recover lost performance while minimising plant downtime. New designs offer improved durability to thermal stresses, leading to reduced loss of performance over time and enhanced robustness for quicker stop/start cycles; an important factor as operators adapt to the rising competition from renewable energy.

4.5 Lignite drying and demineralisation

The implementation of pre-drying technology has been limited to date, due to the additional cost of dryers, and the ensuing need to adjust boiler operation. However, the legislative environment with new HR targets and higher carbon taxation, mean that the benefits of this 'add-on' technology may need to be re-evaluated. Water evaporation from lignite fuel places a significant thermal load on lignite power plants and drying the fuel prior to use is a potential route to lower plant Heat Rate. The heat source utilised for drying is critical, as only low grade or waste heat streams will provide an efficiency benefit.

Although commercial installations are limited, a substantial research effort on lignite drying has led to the development of many pilot and demonstration projects that have been reviewed in recent IEA CCC reports (Zhu, 2013; Dong, 2014). Table A1, Appendix 1, lists the majority of available lignite drying processes that cover rotary, mechanical, microwave, high velocity air, hydrothermal and fluidised bed dryers.

The more ash and water that is present in the fuel, the larger the quantity of raw lignite that is required to achieve any given power target. Switching to pre-dried feed reduces the total quantity of raw lignite mined and transported which is beneficial on a 'mine to stack' analysis of carbon emission. The dried fuel is friable and easily milled, potentially lowering energy use, cost and maintenance. When dried feedstock is used the total gas flow through the boiler is less than that from using raw lignite fuel, leading to smaller capacity downstream equipment, important when considering the retrofit of new stack gas treatments.

Commercial fluidised bed pre-drying technologies can continuously process run-of-mine lignite utilising low grade heat streams. Established plants in Germany (RWE) and the USA (GRE) have successfully operated drying systems for over five years, with individual commercial dryers sized at 115–200 t/h. These two plants operate differing drying methods. Selection of the most suitable dryer is dependent on the moisture/ash composition of the lignite feed.

The RWE dryer (WTA), originally designed for German lignite containing 60% water, can reduce the moisture content to 12%. The capital cost of the RWE (200 t/h) pre-drying plant is likely to be of the order of $50 million (Dong, 2014). The GRE dryer (Dryfining™) designed for USA lignite containing 30% water, removes less moisture but additionally separates a proportion of dense mineral matter, potentially alleviating effluent treatment to remove SOx and mercury. The base equipment cost of a GRE (115 t/h) dryer is of the order of US$10 million, $33 million plus installation cost to process 460 tons of lignite per hour (Bullinger, 2016).

The technical and operational details of these two drying technologies are discussed in the following sections; with key features summarised in Table 6.

Table 6 Key features of WTA and DryFining™ lignite dryers

	WTA	DryFining™
Raw lignite size mm	1	6
Drying medium	Steam at 13.7 bar, fluidised bed at 6 bar	Air and released water vapour
Moisture reduction	60% to 12% water content	Dried from 39% to 29% moisture content. Partially removed iron pyrite and Hg by gravity segregation
Process unit scale	One dryer processes 200 t/h raw lignite extracting 100 t/h water	A single unit processes 125 t/h, using 6 for 900 t/h (1100 MW)

The WTA dryer utilises fine milled raw feedstock heated by pressurised, superheated steam to remove 80% of water from raw lignite. Operating under milder conditions, with coarser feedstock, DryFining™ uses air with hot water heating to remove ~25% of water while dense mineral matter is also extracted.

Modern pre-drying processes are expected to raise efficiency by up to 1.7% points when retrofitted to a typical lignite-fired power plant (Cichanowicz, 2014). Following an extensive plant modernisation programme to optimise the processing of dried feedstock, GRE report a 3.4% efficiency improvement at the subcritical Coal Creek Station (Bullinger, 2014). The main operational concern is the reduction in mass flow rate through the boiler when water is extracted from the fuel, as this can lead to reduced heat transfer in the convection bank. To compensate for reduced flows and increased reaction temperatures, operators can recirculate part of the flue gas flow back to the burner level. In the absence of any modification to the boiler, the overall gas flow rate is lower and sets a limit on the practical extent of moisture reduction. Technologists have developed systems to establish optimum moisture removal levels for an individual boiler retrofit (Bullinger, 2015b).

4.5.1 WTA lignite dryer (RWE) – fluidised bed drying with internal waste heat utilisation

RWE of Germany developed a superheated steam/fluidised bed dryer (WTA), where the lignite is subjected to high temperature and pressure steam conditions. This method utilises finely milled raw lignite (containing 60% water) to maximise water extraction, retaining only the tightly bound water held within the interior of the lignite particles.

There are two process concepts based on the source of the superheated steam:

- ‘open’ cycle – steam is drawn from an external source;
- ‘closed’ cycle – steam is generated from the lignite.

The ‘open’ design draws the heating steam from an external source, such as a low pressure steam turbine and this simpler version is shown in Figure 9. Drying heat is provided by a heat exchanger immersed in the fluid bed, and to a lesser extent by the fluidising steam and coal vapour.

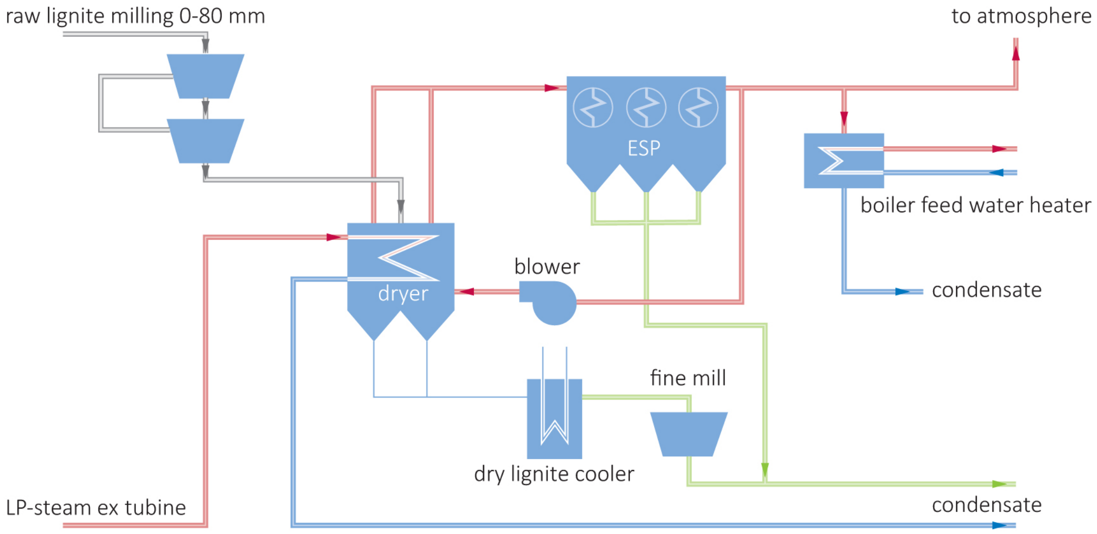

Figure 9 WTA Dryer: Open Cycle using steam from an LP turbine

The lignite is first milled to provide a small particle size of 1 mm found in trials to be beneficial for fluidisation and dehydration, and has resulted in a reduction in dryer size. A more typical grain size of 6 mm had previously been used.

The optimum running conditions at the plant utilised a temperature difference of 30°C between the heat exchanger and fluidising medium, with the fluid bed pressure at about 6 bar and the heat exchanger at 13.7 bar (Klutz 2010). Formerly such plants operated at 1.1 bar/110°C, however, higher steam conditions improve heat transfer leading to a more compact/lower cost design, resulting in a modest penalty on the overall efficiency gain.

In applying WTA technology, changing the steam conditions in the dryer allows a degree of control over the degree of moisture reduction, and this flexibility is an important consideration in applying a dryer in a retrofit situation where limited modification of the boiler will be desired.

The Niederaussem single dryer unit has now operated for over five years drying 200 t/h of raw lignite and evaporating 100 t/h of water, providing 30% of the feed to the plant (RWE Niederaussem Coal Innovation Centre, 2015). RWE reports that full integration of the WTA dryer applied to high moisture lignite on a USC plant has the potential for up to 10% overall efficiency improvement by reducing the scale of the downstream plant, lowering auxiliary power requirements and potentially reducing the scale of the boiler and emissions treatment to effectively process half the mass of lignite feed.

4.5.2 DryFining™ technology: dewatering and mineral segregation

DryFining™ technology, developed by Great River Energy (GRE) at their Coal Creek station, may be classed as a 'fuel improving' technology since in addition to reducing the water content in lignite, a proportion of dense mineral matter is also removed. The dryer was originally conceived as a means of improving the heating value of lignite feed which was of lower quality than the plant was designed to accept (for example 15.8 MJ/kg design compared to 14.4 MJ/kg delivered). The lower feed quality impaired the efficiency at each stage of the plant. The coal flow rate increase of 10% required a rise in primary air flow to deliver the fuel. The resulting higher stack gas flow through the plant exceeded the FGD tower design limits. Following drying of the lignite, the flows through the plant approached the optimum design case.

The typical water content of lignite in the US is ~30–40%, and the dryer has been configured to remove water that is loosely bound to the lignite particles. The current plant achieves drying from 38% to 29% moisture content. The eight DryFining™ lignite dryers installed at GRE's Coal Creek plant (4 per boiler) can process ~ 900 tons per hour, with each commercial-scale dryer capable of processing 115t/h raw lignite feed. Each complete system costing ~ $10 million includes the dryer, heat exchangers, fans, baghouse and instrumentation (Bullinger, 2016). Commissioned in 2009, GRE has operated the dryers in continuous mode for over five years, processing 40 Mt of raw lignite providing the supply for the 2 x 546 MW boilers.

The DryFining™ dryer uses a combination of low grade steam, essentially a waste stream, obtained from a combination of flue gas coolers located downstream of the air preheater and hot water feed to the cooling tower. The steam is supplied to a heat exchanger located in the fluidised bed, and air is fed as the fluidising gas (Figure 10). The use of air as the fluidising medium does raise the risk of oxidation in the dryer, but the atmosphere in the dryer is heavily diluted by steam extracted from the lignite that also acts to control temperature and mitigate this risk. The post crusher particle size of lignite fed to the dryer is typically ~6 mm, sufficient for fluidisation at modest velocity.

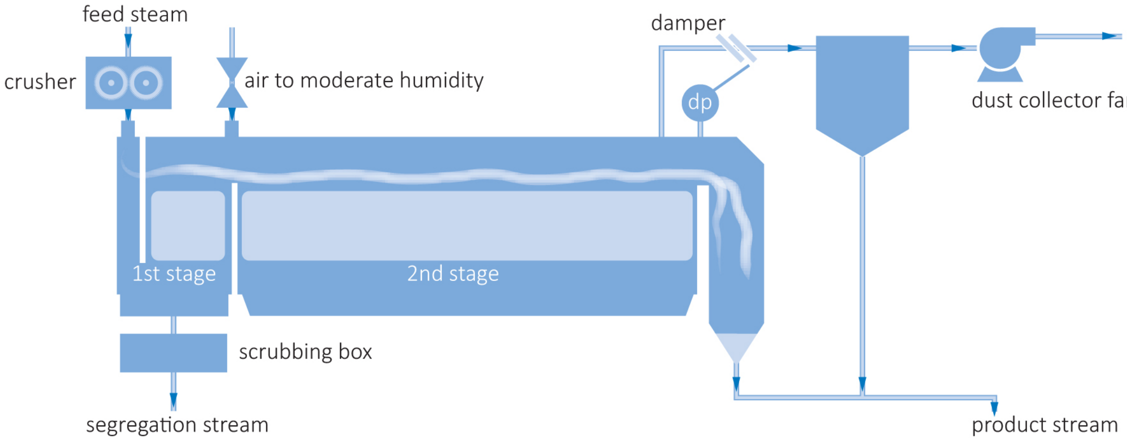

Figure 10 DryFining™ processor showing a preliminary gravity segregation stage followed by the main drying heat exchanger

In the dryer, heated air fluidises the crushed lignite and transports away evaporated moisture. The partially dried lignite (for example the Coal Creek station moisture reduction is 24%) is fed to a bunker and then milled prior to admission to the boiler. The dry matter proves to be more friable and easily milled than raw feed that lowers the energy needed for lignite milling.

Figure 11 shows the mineral densities of common components found in lignite. The denser matter present in the fuel is predominantly mercury and iron sulphide (pyrites), and it is these components which are partially removed by gravitational segregation in the first section of the dryer. However, while removing sulphur containing minerals and mercury is the most important benefit of segregation, other dense mineral matter will also be removed, contributing to a reduction in ash formation within the boiler.

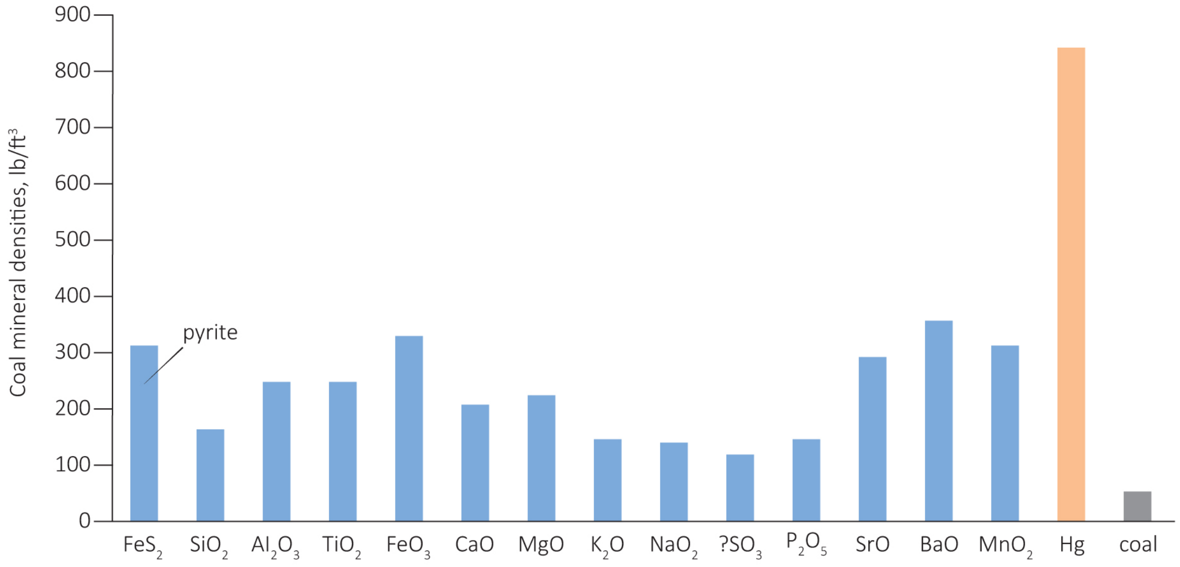

Figure 11 Density data of minerals found in lignite, note iron pyrites (WorleyParsons, 2013).

WorleyParsons carried out a case study of the DryFining™ dryer applied as a retrofit to the Loy Yang A subcritical station processing 2500 t/h raw lignite, as part of a study on incorporating a 5000 t/d carbon capture plant (WorleyParsons, 2013). The thermodynamic analysis showed that adding DryFining™ would have raised the plant efficiency by 1.3%, but this benefit was not fully realised because the lower air/fuel throughput somewhat unbalanced the steam system and led to a reduction in the flow of steam to the superheaters and reheaters while water flow through the boiler membrane wall increased. The study emphasises the need to ensure that the boiler can be optimised for the revised dry feed supply, and that installation of drying technology may mean that the boiler will require modification.

Operation of the DryFining™ dryer at Coal Creek station realised an overall efficiency improvement of 3.4%, and the dryer modified the feed to that expected at design (Bullinger, 2015b). Recently released data from the five year commercial demonstration of DryFining™, Table 7, show the improvement to plant performance and stack gas emissions. Prior to drying, the flue gas desulphurisation (FGD) unit was undersized and could only scrub 75% of the stack gas flow. The combination of reduced coal flow and mineral segregation resulted in the plant running with lower scrubber bypass (25% bypass reduced to <15%) in addition to a substantial reduction in plant SOx concentration.

Table 7 shows the benefits of lignite drying to the Coal Creek station examining: feed drying and segregation, boiler and process, and reduction in stack gas emission of acid gases and mercury.

Table 7 Impact of DryFining™ on plant operations and emissions (Bullinger, 2015a)

Feed drying and segregation	Boiler and process	Stack emissions reduction compared to raw lignite feed
11% reduction in moisture: 39% to 28%	Lower exit temperature –20°C	>20% reduction in NOx – due to improved combustion control and lower fuel mass
6 lignite mills needed instead of 8 and lower power due to lignite friability (1 MW saved)	5.8% reduction in exit gas flow rate	40% reduction in SOx – lower fuel rate, and pyrite segregation
9.5% less mass of fuel fed to boiler	Reduction in ID fan power: 2 x 2 MW saved (c.f. 1100 MW plant)	Up to 40% Hg reduction due to Hg segregation and increased Hg oxidation

Dried lignite feed lowered the overall mass flow through the plant improving a number of issues encountered in controlling the boiler and treating the effluent. The table shows that a 9.5% reduction in lignite mass flow reduced the parasitic power load of the mills on the plant, as only 6 of 8 were now needed (500 HP each), and mills used 8% less power as the dry lignite is more friable than the raw feed, leading to a saving of 1 MW overall.

The lower feed rate allowed diversion of part of the primary air flow giving more control over the combustion zone and contributing to a >20% lower NOx emission. This reduction meant that the planned installation of a catalytic unit to meet 2010-15 limits was not required, as the revised operation of the boiler combustion zone sufficiently lowered emissions. Reduced effluent gas rates lowered power demand for ID fans providing a further 4 MW saving. The mineral segregation and improved performance of the FGD unit contributed to a reduction of 40% in sulphur dioxide emission. GRE had costed extensive modifications to lower NOx and SOx at $366 million, now avoided by installing the dryer equipment (eight dryers at $66 million plus installation cost).

The particular benefit of DryFining™ is the substantial removal of SOx and mercury at the pre-treatment stage. Analysis of the segregated stream showed that typically 20–40% of the sulphur and 30–50% of the mercury were removed by the first stage of the dryer. In addition oxygen partial pressure in the boiler is higher for the dried fuel, which leads to enhanced oxidation of the remaining mercury that can then be removed by the scrubber.

In looking beyond the US for applications, a number of coals from Eastern Europe and Australia have been assessed for the suitability of DryFining™. While the DryFining™ unit is currently designed to remove less water than the WTA dryer, it has the benefit of reducing emissions by mineral segregation and may be more suitable for lignite fuels possessing a high level of dense matter (FeS and Hg).

5 Nitrogen oxide abatement

The most advanced stations generally install selective catalytic reduction (SCR) reactors to limit NOx emissions; however the majority of plants rely solely on low NOx burners (LNB) to reduce NOx (Platt's, 2015).

The established technology for NOx abatement required to comply with the latest standards is to combine low NOx burners with a high dust SCR unit. However, for a retrofit scenario, installation of an SCR is awkward due to the limited available space between the boiler and air preheater. Furthermore a retrofit SCR installation is expensive and likely to require a prolonged outage, possibly exceeding a year.

There are alternative techniques which can compete with the installation of an SCR unit on cost, time and emission removal effectiveness. Such technologies may be attractive where the plant life is shorter and unlikely to recover the full investment of an SCR unit.

The latest NOx emission limits set in China, the USA and Europe are shown in Table 8. There are significant emission reduction targets for both new and existing plants.

Table 8 NOx emission standards for China, European Union and the USA (World Resources Institute, 2012)

		China	European Union*	USA†
NOx, mg/m^3	New plants	100	500 until 31 December 2015, then 200	117
	Existing plants	100 (built 2004-11) 200 (built before 2004)	500 until 31 December 2015, then 200	117 (built after 2005) 160 (built 1997-2005) 640 (built 1978-1996)

* for power plants >500 MW in size, † units in the standards have been converted to concentrations

China has imposed the strictest limits, requiring that NOx emissions from some recently constructed plants meet a new standard of less than 100 mg/m^3, the EU has set a limit of 200 mg/m^3 and the USA a figure of 160 mg/m^3 for plants commissioned from 1996. To operate at less than 200 mg/m^3 NOx, represents a substantial reduction to the previous European standard of 500 mg/m^3.

In countries facing a shortage of electricity generating capacity there has been limited legislation on emissions, but that is changing due to growing environmental pressure to address pollution. For example, in India new draft legislation seeks a reduction of up to 70% NOx emission compared to current best in class plants, but less stringent emission limits have been proposed for older facilities (DNA, 2015).

Given the implementation of tighter international NOx limits, in the context of other high profile reports such as the failure of diesel engines to meet NOx emissions standards, it could be beneficial to consider retrofit technologies that may be adapted to achieve the stricter limits of <100 mg/m^3 on existing plants.

Table 9 lists technology combinations which should be capable of meeting current and future NOx limits of <100 mg/m^3. The issue facing existing plants currently relying upon low NOx burners alone is that NOx emissions are typically 350 mg/m^3, well in excess of the new standards.

Table 9 NOx abatement technology retrofit options capable of achieving NOx emissions comparable to an SCR unit of <100 mg/m^3

Reference technology			
LNB – low NOx burners with overfire air (OFA)		SCR – selective catalytic reduction (high dust)	95% NOx removal benchmark
Dry lignite/improved efficiency option			
Dry lignite fluidised bed dryers such as WTA or DryFining™	LNB	SNCR – selective catalytic reduction or SCR	Lignite drying *see* Section 4.5
Hybrid and multicomponent solutions			
LNB		SNCR	Compact high dust SCR (iNOX™)
LNB		SNCR	NOx Oxidation (Ozone LOTOX™)
LNB		Multi-component effluent treatment (including Airborne™, clean combustion system) *see* Chapter 9	

The main alternate technology to selective catalytic reduction (SCR) is selective non-catalytic reduction (SNCR) which has been shown to reduce the NOx concentration in the stack gas to ~150–200 mg/m^3, on the margins of the new limits set in the USA and EU (Schuttenhelm, 2014). The SNCR technology can deliver a typical NOx reduction of up to 50%; in comparison with an SCR where up to 95% NOx removal is achieved. Although SNCR can allow a plant to meet pre-2015 limits, this technology is unlikely to be sufficient in the longer term. SNCR may need to combine with another 'add–on' abatement technology to reach the 100 mg/m^3 target.

Promising commercial technologies and technology combinations (Table 9) offering an alternative to the installation of an SCR unit may include the following:

- Addition of lignite dryer to improve control over the reaction, allowing a reduction in primary air to convey reduced amounts of dry lignite, hence promoting air deficient combustion that enhances conversion of fuel nitrogen to N_2. Reduced fuel consumption also leads to NOx emission reduction.
- The combination of SNCR with an ozoniser to oxidise remaining NO to NO_2 forming soluble N_2O_5 that can be washed out. An ozoniser installation may be a relatively low capital cost option but possesses high operating charges.
- A combination of SNCR and a compact SCR. A compact SCR is intended to treat a reduced proportion of NOx that survives the SNCR stage. A compact SCR is a smaller version of a typical SCR installation, approximately one quarter of the size, and can be more easily introduced as a retrofit.
- Multicomponent emission treatment units that use one reagent and reactor to remove several components.

The following sections will briefly review low NOx burners, SCR and SNCR systems before examining hybrid technology combinations based upon SNCR with Ozonolysis and compact SCR. Multicomponent solutions that can lower NOx, SOx and mercury are discussed in Chapter 9. Drying and pre-treatment of lignite (Section 4.5) can be used in conjunction with all of the above techniques to lower NOx emission by improving efficiency and adjusting combustion conditions.

5.1 Low NOx burners

The first stage of a NOx reduction strategy is to ensure that the combustion process is optimised for both efficiency and raw NOx emission, minimising the quantity of chemicals needed downstream. The majority of lignite plants already possess low NOx burners (LNB) but designs have advanced significantly over the last two decades to produce 40% lower NOx in comparison with earlier circular burners (Ochi, 2009). In original jet burner designs the lignite would be delivered to the boiler with approximately 15% of the air as carrier and the remainder of the air delivered through an annulus around the fuel jet. This simple device leads to largely air rich combustion along the fuel-air boundary and promotes the formation of NOx leading to concentrations of up to 1300 mg/Nm^3. The higher the burner NOx output then the more chemicals would be needed to achieve strict NOx targets.

The LNB method organises combustion in stages, delaying full oxidation of lignite, creating a cooler, fuel rich flame that promotes reduction of fuel nitrogen and avoids thermal NOx formation.

For plants relying solely upon controlling combustion to limit NOx emission, RWE showed that on tangentially fired boilers NOx concentration can be substantially reduced by moderation of combustion intensity (Couch, 1989). Although boiler efficiency may be impaired, the operation of LNBs can be optimised to lower NOx by the following measures (Couch, 1989; Grauss, 2006):

- reduction of excess air;
- addition of overfire air through retrofit ports;
- flue gas recirculation (up to 30%) to primary air intake (partially replacing preheated air);
- reduction in the extent of the combustion zone by closing upper burner sets;
- increased use of dry lignite; and
- flue gas recirculation into the reduction zone to lower combustion temperature.

For a modern LNB approximately three quarters of the air is supplied to the main combustion zone with intense mixing close to the burner exit creating a fuel–rich flame zone where NOx formed from the fuel can be reduced by hydrocarbon radical species (HC·) in the flame. An example of a staged air design suitable for coal burning and fitted with an oil start-up feed that exhibits swirling of the primary air/coal mixture is illustrated in Figure 12.

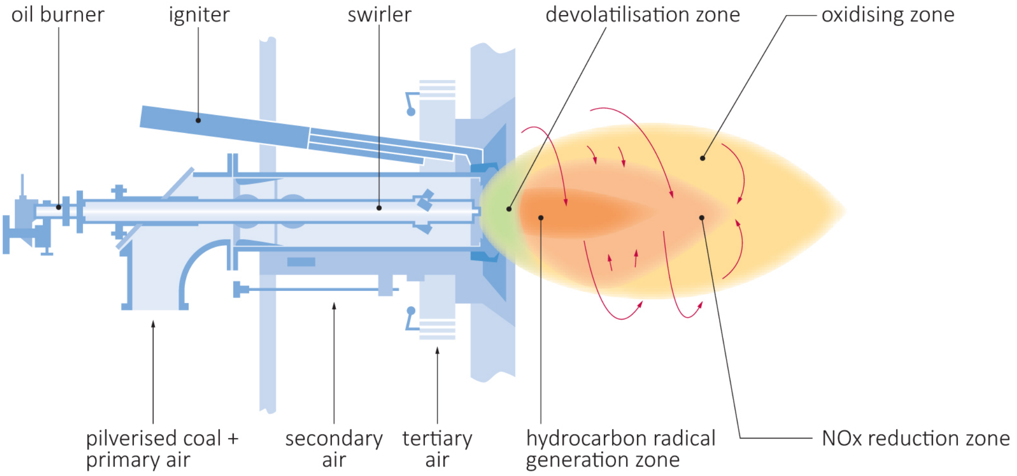

Figure 12 Schematic of a multi-stage low NOx burner design showing different reaction zones at the burner nozzle (Nalbandian, 2009)

The air can be supplied in three stages to allow combustion optimisation by adjusting the primary/secondary/tertiary air flow ratios. A fuel rich NOx reduction zone is formed close to the burner outlet, with additional air then entrained to complete oxidation.

The simplified mechanism for nitric oxide (NO) formation from fuel bound nitrogen and subsequent reduction in the fuel rich zone of the LNB may be described as follows (Ochi, 2009):

Nitrogen present in lignite volatiles is vaporised and then oxidised to form nitric oxide in the gas phase:

$$\text{N (volatile)} + \tfrac{1}{2}\text{O}_2 \rightarrow \text{NO} + \text{O}\cdot$$

NO is formed in the initial reaction zone at the burner mouth (ignition zone). NOx reduction can take place in the subsequent fuel rich, reducing flame according to:

$$\text{NO} + \text{HC} \rightarrow \text{NH} + \text{CO}$$, where HC represents a hydrocarbon radical

$$\text{NH} + \text{NO} \rightarrow \text{N}_2 + \text{OH}$$, with OH reacting to form water

The reaction conditions to limit nitric oxide formation are to lower flame temperature and oxygen partial pressure.

Once the nitrogen reduction reactions are complete, the remaining air is then drawn into the now partly combusted mixture, to complete the burn out of any particles, lower carbon content in fly ash, and also moderate carbon monoxide levels. The carbon content of ash tends to be slightly higher for LNBs than for circular burners due to the initial fuel rich combustion zone. Using LNBs the typical NOx levels from the combustion zone are reported to be 300–400 mg/Nm^3, although lower levels have been reported for subcritical plant (Bullinger and Kennedy, 2010).

When NOx targets fell from 650 mg/m^3 to an intermediate level of 500 mg/Nm^3 in 2008, then the solution generally adopted was to boost overfire air (OFA), lowering the air supply to the burner. However, this did produce difficulties as early LNBs are designed to operate at higher air rates in the absence of OFA. Reducing air to the burners could potentially distort the flame in the furnace due to an imbalance of flows to the device. An additional complicating factor found in older burners is air leakage or 'in-leakage' leading to unintended stoichiometries at the burner and destabilisation of the combustion zone perhaps leading to unstable firing with flames impinging directly onto furnace walls. (Goldring, 2012)

An example of a modern two stage LNB is shown in Figure 13. The Mitsubishi Hitachi Power Systems (Europe) RS burner is designed to introduce high gas swirl into primary air/lignite and secondary air streams that enhance control over fuel air mixing and promote ignition close to the burner face. The burner features a radiation protection tube located close to the burner exit that also serves to concentrate the particle flow. These burners are arranged in an 'all wall' arrangement and do not adopt a tangential firing mode as in earlier designs (Bergins, 2014). The RS burner can lower the NOx production level by up to 60% for conditions present in USC boilers compared to jet burners.

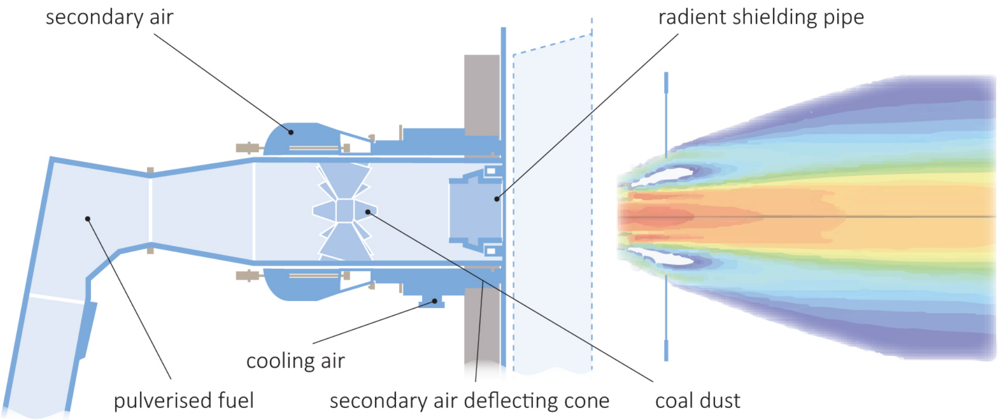

Figure 13 Air cooled RS lignite burner – air cooled, 2 stages with fuel swirl vanes (Mitsubishi Hitachi Power Systems Europe (2014a)

All boiler manufacturers possess variants of LNBs, with a common theme of using high gas swirl to control the air deficient reduction zone. Current examples are listed below:

- Foster Wheeler Split Flame Vortex VS burner design that aims to minimise maintenance with few moving parts (Nalbandian, 2009).
- Alstom Concentric Firing system LNCFS™ which diverts a portion of the secondary air toward the furnace waterwall tubes that delays entrainment of air during the initial combustion phase and increases oxygen levels at the wall to reduce corrosion (Alstom, 2014).
- Siemens Opti-Flow LNB that has a segmented nozzle with external vane swirl stabilizers (Siemens, 2012).
- Veritask PPX-300 ultra-low NOx burner that possesses variable secondary air swirl control to allow burner fine tuning to minimise emission (Veritask, 2015).

To comply with the latest emission targets (100 mg/m³ – China, 160 mg/m³ – US, 200 mg/m³ – EU) solely through combustion moderation would entail sacrificing the plant performance, and an additional treatment plant will need to be installed.

5.2 Selective catalytic NOx reduction, SCR

The selective catalytic reduction unit (SCR) is the technology of choice for pulverised fuel plants and would normally be included, or space allocated for this large reactor, in the design of new lignite coal plants (European Commission, 2010).

The SCR is preferably located in position immediately following the economiser section of the boiler and prior to the air feed preheater, as this is the optimum temperature zone for catalytic NOx reduction reactions. The effluent stream may first pass over flow straightening vanes to create a uniform flow regime, for an injection grid to feed ammonia into the flue gas stream that then passes over a sequence of catalytic beds. The combined ammonia/flue gas mixture reacts heterogeneously with a promoted vanadium/titanium catalyst, which for the high ash case of lignite fuels would normally be of a 'plate' configuration to minimise the risk of blockage, as shown in Figure 14.

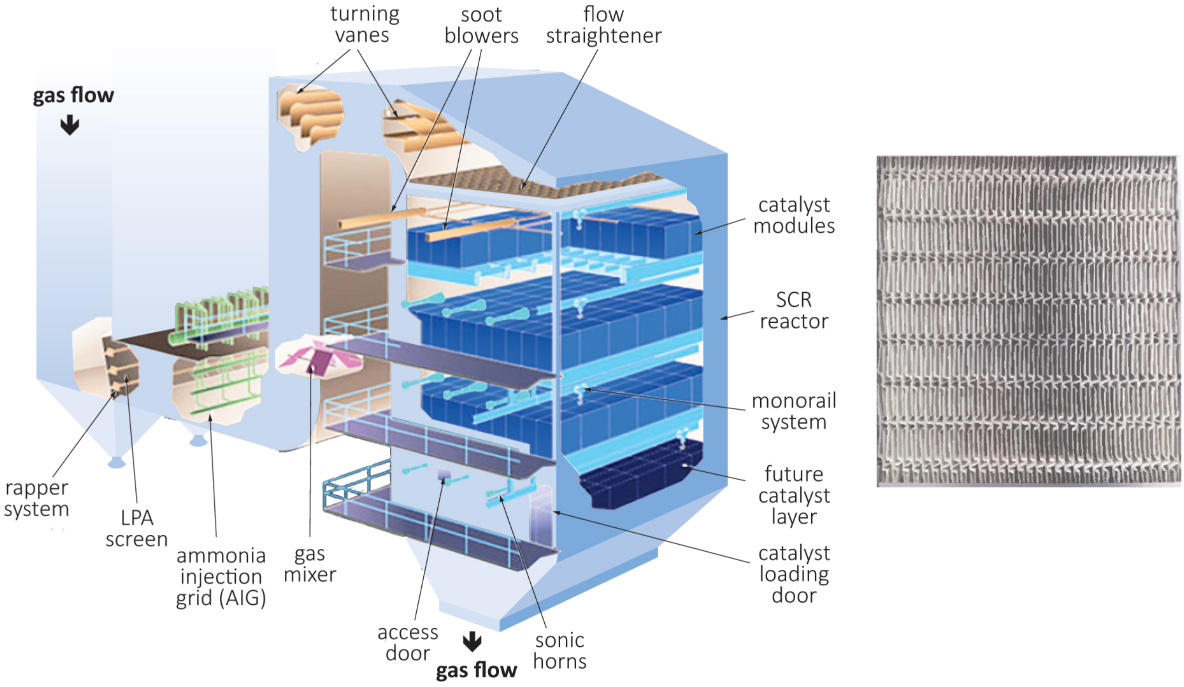

Figure 14 An SCR reactor (Babcock, 2012) **and a plate catalyst support designed to minimise the risk of blockage in high dust environments** (Tuna, 2014)

The Babcock SCR reactor shown in Figure 14 shows a set of three or four catalyst layers located after tuning vanes and a flow straightening grid with ammonia injection upstream followed by a gas mixer. An SCR installation would consist of the following elements: ammonia handling and storage; ammonia vaporisation; an array of injectors; catalyst trays; blowers to disrupt soot, and control instrumentation with DCS supervision. The catalyst must be designed for high ash fuel and the preferred configuration of a plate catalyst that resists deposits is shown on the right. The lifetime of the catalyst will depend on the degree of catalyst poisoning, but several years is typical. Then the catalyst blocks may be removed and regenerated for reinstallation.

Handling ammonia introduces additional hazards, and urea can be used as an alternative and hydrolysed to ammonia immediately prior to injection. An example of this type of system is U2A converting a urea solution to ammonia (Hamon Research-Cottrell, 2015a,b) or SafeDeNOx® (Chemithon, 2015) where urea is melted rather than dissolved before reaction with steam over a catalyst to generate ammonia, CO_2 and water. The SafeDeNOx® Urea to ammonia process claims to have a greater degree of control over the ammonia concentration, responding more rapidly to changing reactor conditions (variable NOx), as well as possessing a smaller footprint, attributes that could be advantageous to a retrofit case.

The catalytic chemistry of the reaction of ammonia with NO in an SCR unit takes place under restrictive reaction conditions in the temperature range 250 - 400°C typical of the region between the economiser and the air preheater. The simplified heterogeneous chemistry of the reduction process with ammonia may be summarised as follows:

$$2NO + 2NH_3 + 0.5O_2 \rightarrow 2N_2 + 3H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

Given that the NOx is dominated by nitric oxide (NO) rather than NO_2,the addition of ammonia must be close to stoichiometric compared to the total ($NO + NO_2$) flow rate, limited by the need to avoid ammonia slip (new systems are guaranteed to <2ppm, <5ppm maximum), that leads to the formation of ammonium bisulphate, a source of downstream fouling.

A new SCR installation would be expected to remove at least 90% of the NOx; as the catalyst gradually deteriorates, poisoned by metals and fouled by fly ash, the level of unreacted ammonia in the effluent will rise and can be monitored to assess catalyst condition. The dosage of ammonia may need to increase to maintain performance, which also indicates catalyst efficiency. Any fouling of the catalyst bed will produce a rise in differential pressure providing further evidence that the SCR will require maintenance, with de-fouling performed using sootblowers or sonic horns. Although the new SCR is efficient at reducing NOx , the unit requires continuous monitoring and maintenance, as well as tight operating conditions.

The following Figure 15 shows a set of alternate SCR configurations to cope with contamination and dust levels that may be present in the effluent.

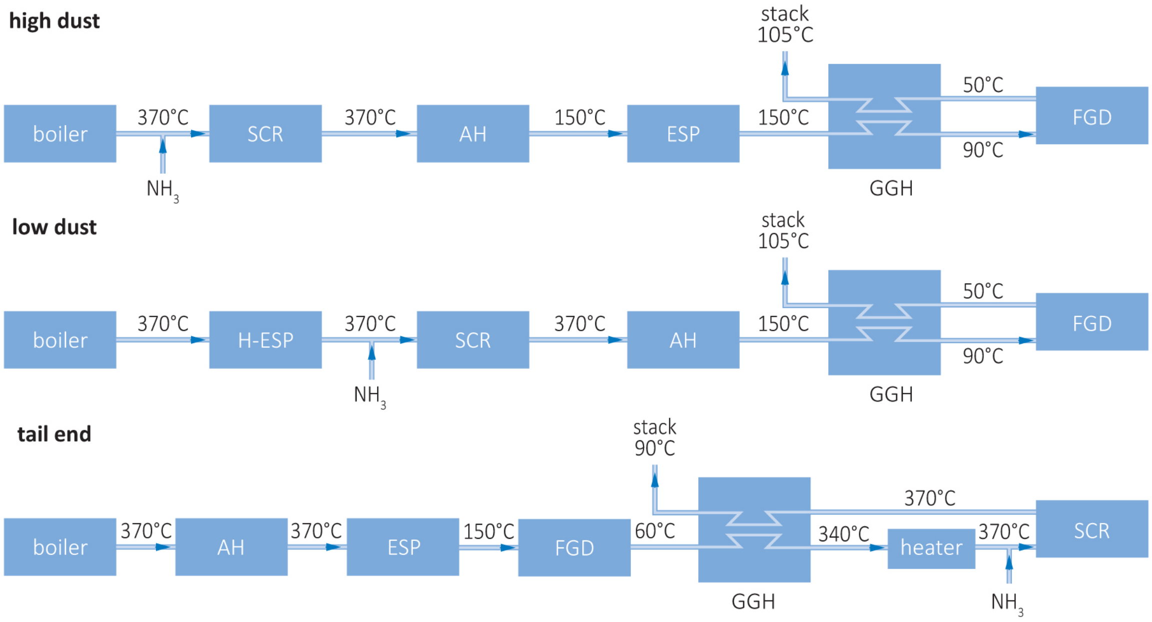

Figure 15 SCR configurations for a range of dust levels in the effluent stream (Wu, 2002)

Figure 15 first shows the normal, high ash, configuration with the SCR located immediately after the economiser at the boiler. Where the ash levels are excessive then a hot ESP dust removal stage can be located upstream of the SCR reactor, shown as the low dust case. For streams containing catalyst poisons then it is possible to locate the SCR after the flue gas scrubber, termed 'tail end' that requires a heat exchanger to control the temperature at optimal reaction conditions. These alternate configurations may also be relevant to potential hybrid systems that are discussed below. Installation in the tail-end configuration may be a means to install an SCR onto an existing plant where there is no space close to the boiler.

SCR technology for NOx reduction in existing lignite plants poses some difficulties for a retrofit project:

- High costs associated with installing a sizeable reactor into the process where space is constricted: CapEx estimates are ~$300/kW, for example $120 million for a 400 MW scale plant (Bible, 2015).
- Installation time of approximately one year to fit a full-scale SCR block in the plant.
- Practical issues arising from high ash content and possibly high alkali earth metal concentration in the lignite; leading to more rapid degradation in performance, either requiring high maintenance or removal of fly ash prior to the unit (low dust or tail end configuration)

5.3 Selective non-catalytic NOx reduction (SNCR)

Selective non-catalytic reduction (SNCR) has been used as an alternative to SCR for smaller-scale plants, and involves the direct injection of ammonia or urea into the hot upper region of a boiler. SNCR is a relatively low cost, straightforward system to add to an existing plant. An SNCR would be expected to remove about half of the NOx produced from the combustion zone.

A schematic of an SNCR installation is shown in Figure 16. Typically ammonia solution is injected into the boiler above the combustion zone, through a network of nozzles in the upper section of the furnace.

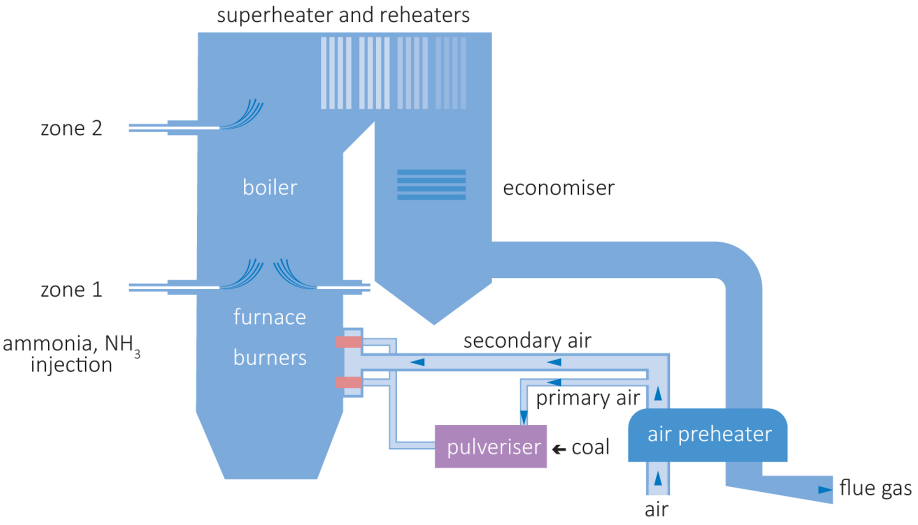

Figure 16 NOx control by SNCR ammonia injection into upper section of the boiler at two or three levels, aiming to reduce NOx boiler emissions by ~50% (Hamon Research-Conttrell, 2015a,b)

For the SNCR system, the atomising fluid is water which boils rapidly to assist the distribution of the reagent to cover the boiler cross section. A nozzle can be adjusted in situ optimising droplet size and velocity to match the variable conditions of the furnace. A range of SNCR injectors are used: mechanical atomisers, multiple nozzles on cooled, retractable lances, dual fluid injectors, and air aspirated nozzles. A limitation of this technology has been to successfully supply reagent to the centre of larger capacity boilers.

Prior to an SNCR installation a full CFD model of the boiler would be prepared; utilising a detailed temperature profile of the upper section to establish flow rates and nozzle designs to optimise the injection of reagent. Higher temperature zones will possess high NOx concentration and the system can be tailored to target those regions.

This SNCR method has been less applicable at larger scale due to difficulties in covering the full cross section of the boiler, and constraints associated with ammonia slip. To implement the technology on larger-scale boilers, direct injection of urea that evaporates at a lower rate, has been developed as a replacement for ammonia (Schuttenhelm, 2014).

The simplified NO reduction mechanism with urea as reagent is as follows:

$$2NO + NH_2CONH_2 + 0.5O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

$$2NO + 2NH_3 + 0.5O_2 \rightarrow 2N_2 + 3H_2O$$

The reduction of nitric oxide to nitrogen is accompanied by the exothermic oxidation of urea to form water and CO_2. Urea decomposition then forms ammonia which reacts with NO in the second stage. The reduction reactions are favoured by high temperatures of ~800°C to 1300°C. As the flue gas cools through the boiler super heaters, the rate of reaction declines leading to the potential escape of reagent downstream of the boiler (ammonia slip).

This SNCR (Urea) technology has been trialled on a bituminous coal feed and retrofitted to a 225 MW boiler at the Polish EDF Electrownia Rybnik SA (ERSA) plant, commissioned in 1974 (ECR: Schuttenhelm, 2014). The project aim was to demonstrate that a NOx emission limit of 200 mg/Nm^3 could be achieved on an existing plant using a urea reagent. The injection of urea overcame the issues associated with ammonia solution; where early evaporation can leave a shortage of reduction agent in the core of the boiler, and unreacted excess ammonia in the outer annulus. Urea solution has been used as a feedstock for SNCR in the past, but was first converted to ammonia prior to injection to avoid ammonia handling safety issues. The direct use of urea achieved NOx reduction to 180 mg/Nm^3 and offers some savings in installation and operating cost compared to an ammonia version.

A typical SNCR urea DeNOx plant would comprise the following:

- Urea storage, metering and mixing plant for the NOx reduction agent – carbamin 5722 (40% solution of Urea in water + additives).
- Nozzle injection system forming a range of droplet sizes to penetrate the boiler cross section upstream of the steam superheaters. Up to three levels of nozzles may be installed.
- Online temperature monitoring for the SNCR control unit to optimise metering/mixing and injection, ensuring that urea dosage is in the correct temperature regime 850–1100°C.

The cost of handling and storage of urea are similar for both SCR (Urea) and SNCR (Urea), but the direct injection of urea in the SNCR system avoids the need to convert urea to ammonia before use. Both technologies require an injection system with the SNCR nozzles and lances exposed to high temperatures in the boiler. However, in comparison to an SCR reactor, the majority of the SNCR installation can be undertaken offline with the additional monitoring equipment and injection system inserted during a normal outage.

There are reports of SNCR installation into large-scale boilers that include a retrofit to six boilers at Melnik lignite power plant (Czech Republic) announced in 2013 and due to be operational in 2015. The Melnik project involved adaption of the combustion system as well as the SNCR installation at a total project cost of 30 million euros to cover six boilers, ranging from 100 to 500 MW capacity, overcoming previous limitations on boiler size.

The SNCR system is much cheaper than SCR, but can only remove ~50% of the NOx emission and may not meet the 200 mg/Nm^3 limit or the more stringent NOx standards that are now required in China. However, SNCR could form part of a progressive DeNOx strategy in combination with other emerging techniques, and in that way provide a lower cost option to SCR to achieve NOx emission targets of less than 100 mg/Nm^3.

5.4 Low temperature oxidative removal of NOx by Ozonolysis

The recently discussed NOx removal technologies are based on NO reduction reaction whereas an alternative method is to oxidise nitric oxide by Ozonolysis. Several technology vendors offer Ozonolysis reactors including EPS, Lextrans and LoTOx™ and this report will focus on LoTOx™ (LoTOx™, 2015). The LoTOx™ technique has drawn interest in a number of industrial applications as a means to meet strict new limits. Initial commercial interest in Ozonolysis was limited as the acceptable NOx emission limits were so much higher at about 500 mg/m^3. Although a low cost installation, the high operating cost means that Ozonolysis would be most useful in removing the last aliquot of NOx from the effluent stream. When combined with other lower cost techniques, Ozonolysis offers an alternative to SCR, and is thus potentially well suited for a retrofit application due to the relatively low investment and small footprint of the technology.

There are a growing number (>30) of LoTOx™ industrial applications cleaning exhaust streams from a range of combustion plant including fluidised catalytic cracking (FCC) regenerators, petroleum coke boilers and, more recently, gas and coal-fired boilers. The technology has been demonstrated on streams containing typically 100–600 mg/Nm^3, lowering the NOx level to 20–90 mg/Nm^3. There is yet to be a lignite PF plant commercial application although successful proving trials were carried out in 2010 at the GRE lignite power plant at Coal Creek, which has already been mentioned as part of the discussion on dry lignite technology. Although technically successful the LoTOx™ technology was not commercially implemented as the higher NOx limit permitted at that time could be achieved primarily by application of the dryer reducing overall emissions, coupled with optimisation of the LNBs. Although consideration of LoTOx™ for lignite plant applications is relatively new this is a proven technology with a steadily expanding applications base.

With few exceptions the removal of NOx from effluent streams is by the chemical reduction of NOx to nitrogen. In Ozonolysis the nitric oxide is first oxidised to NO_2 which further reacts to form N_2O_5, a soluble product that can be scrubbed from the stack gas. The chemistry taking place in Ozonolysis may be summarised according to a sequence of reactions set out in Table 10. The initial stage is the formation of ozone in a coronal discharge through a pure oxygen supply. Ozone then oxidises NO to NO_2 and part of the NO_2 intermediate to NO_3. The reaction stoichiometry is in practice ~1.5 as nitric oxide (NO) initially forms around 90% of the NOx and half of the NO_2 must also be oxidised to NO_3. The O_3/NOx ratio can be optimised by modifying the power supply to the ozoniser adjusting the generation of ozone.

Table 10 Reaction sequence for Ozonolysis of NOx (LoTOx™)

Generation of ozone from oxygen in plasma injector	$O_2 + e \rightarrow 2O$ $O + O_2 + M \rightarrow O_3 + M$
Initial oxidation of NO:	$NO + O_3 \rightarrow NO_2 + O_2$
Oxidation of NO_2 (rate controlling)	$NO_2 + O_3 \rightarrow NO_3 + O_2$
Formation of soluble N_2O_5:	$NO_2 + NO_3 \rightarrow N_2O_5$
Washing to remove as dilute nitric acid:	$N_2O_5 (g) + H_2O \rightarrow 2HNO_3 (aq)$

Figure 17 shows the reaction sequence (NO to N_2O_5) taking place in the reactor duct following removal of dust from the stack gas. Nitric oxide (NO) is first reacted to NO_2, followed by the reaction of NO_2 with NO_3 it forms dinitrogen pentoxide N_2O_5 which can be washed out in a wet flue gas scrubber, located immediately after the ozone reactor. Although the reduction of NOx from 200 to 100 mg/m^3 is indicated here, that is a practical target to meet latest emission standards with modest power use, and in fact the system can reduce NOx to much lower levels of ~20 mg/m^3 if required, and with higher energy input.

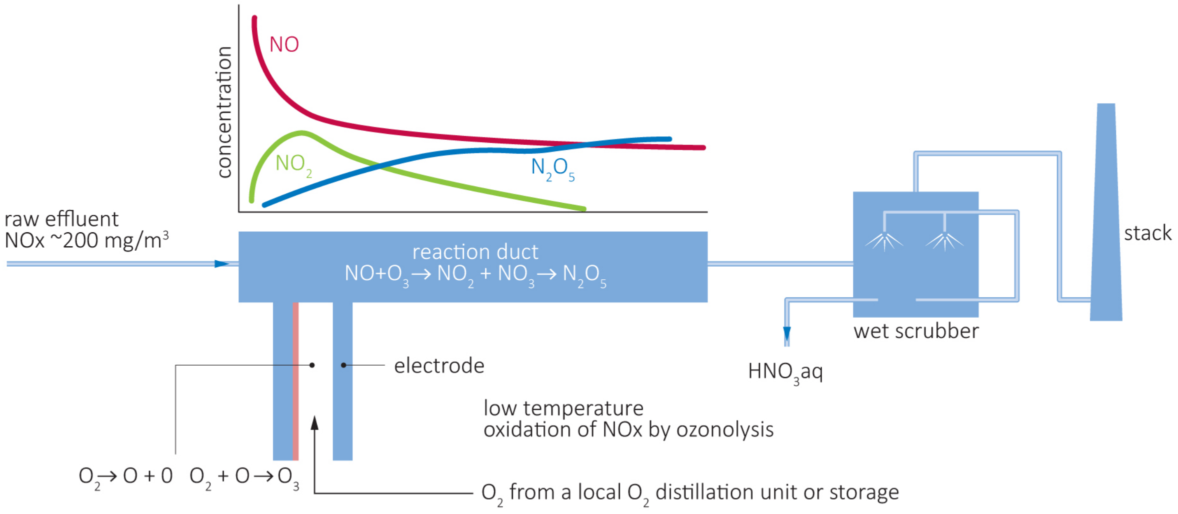

Figure 17 **Schematic of low temperature oxidation of NOx by Ozonolysis, showing raw effluent treated in piping located upstream of a wet flue gas scrubber**

A LoTOx™ installation would consist of an ozone coronal discharge generator analysers controls and an on-site oxygen supply, which could be refillable tanks or a compact oxygen distillation unit dependent upon the scale of NOx removal required.

A 2004 LoTOx™ pilot trial is reported at GRE's Coal Creek lignite PF plant treating a slipstream from the boiler (EPRI, 2004). LoTOx™ simultaneously oxidised NOx and mercury and then captured both products N_2O_5 and mercury oxide (HgO) in a wFGD scrubber. The following Table 11 summarises the results of the Coal Creek LoTOx™ trial where test conditions were as follows: effluent temperature 116–160°C, residence time of 1.5 s and a range of O_3/NOx ratios of 1.5–2.5. By adjusting the O_3/NOx ratio, the NOx concentration could be lowered from an initial 120 ppm by between 50 and 90%, that is to just over 10 ppm. The preferred conditions in this trial were determined to be an O_3/NOx ratio of 1.61 at an effluent temperature of 150°C.

Table 11 Early LoTOx™ trial data for NOx removal from lignite boiler effluent using a slipstream containing 120 ppm NOx (EPRI, 2004)

Residence time 1.5 s*	**%NOx removal**		
Temperature, °F/°C	Low power, (O_3/NOx ~1.6)	Medium power (O_3/NOx ~ 2.0)	High power (O_3/NOx ~2.5)
240/116	54.7	63.1	88.7
275/135	59.4	82.8	90.8
300/149	43.7	69.4	90
320/160	43.2	60.5	86.1

* Data from 0.5 s residence time are similar.

A significant finding is that although ozone can also react with SO_2 to form SO_3 this competing reaction is fortunately relatively slow and does not interfere. If it did much more ozone would have been needed to oxidise NOx, substantially raising energy demand of the ozoniser. High temperatures are undesirable due to the effect on ozone breakdown, but the technology has been demonstrated at <160˚C.

In the case of lignite plants LoTOx™ would be located after the ESP or FF unit to avoid any potential interference from ash and to access a cooler stream,. As the N_2O_5 must be dissolved for removal as dilute nitric acid, this means the plant must possess a wet FGD unit. In fact the LoTOx™ equipment would be fitted into the pipework just upstream of the FGD, and can also be supplied as a package with a new FGD unit, which may be of interest to those plants that must update both NOx and SOx effluent treatment.

The generation of ozone requires significant energy input and the removal of 100 mg/Nm^3 NOx would correspond to just over 1% of plant output: that is 2–3 MW for a 200 MW plant (Hibbett, 2015).

The majority of the installation for LoTOx™ can be done while the plant is in operation with the final connection into the feed line to the FGD unit occurring during an outage. This is in contrast to introducing an SCR that might take up to a year to install, making the plant unproductive during that period. Characterised as a low CapEx/high OpEx alternative to SCR, the LoTOx™ technology is restricted to a NOx 'polishing' role due to the high power demand. The process requires modest low temperature reaction conditions and can match, or exceed, the removal effectiveness of an SCR, and avoids issues associated with operating a catalyst unit in a dusty atmosphere. In addition, LoTOx™ is also effective at oxidising mercury which can be removed at the same time, and so has a multi component removal capability.

The LoTOx™ technology allows the plant operator to achieve any required NOx emission limit simply by adjusting the extent of reaction, balancing the power requirements for the low temperature oxidation against the NOx target. If used as the only NOx treatment then the power requirements may be excessive, and an alternative is to consider deploying LoTOx™ in conjunction with an SNCR system to partially lower the concentration of NOx, with the ozone oxidiser used to complete the NOx removal to the required standard.

5.5 Developments in SNCR/SCR hybrid systems (iNOx™)

Three technologies can be combined to produce the iNOx™ method (Fuel Tech Inc); this technique utilises optimal low NOx burners and SNCR within the boiler, followed by a compact one-layer SCR catalyst. This hybrid approach is intended to avoid much of the high capital cost items and installation downtime of a conventional SCR solution. Originally conceived as a catalytic ammonia slip trap for an SNCR unit, the combined system is now intended to compete with a full SCR reactor. A compact SCR can be considered as the majority of the NOx is removed by the LNB/SNCR stage; and may be installed with minimal modification to the exit pipework of the boiler.

The iNOx™ system is specifically designed for retrofit applications to avoid the need to clear a space for a full-sized SCR reactor within the plant; hence negating the need for preparation of foundations and construction of a structure to house SCR. The NOx removal rate of ~85% approaches that of the full SCR and the combined cost of installation and operation of iNOx™ is estimated at approximately half that of the equivalent SCR unit (Bible, 2015).

The iNOx™ system is a development of NOxOUT® Cascade which required a larger, deeper SCR catalyst due to non-uniform flow across the catalyst bed. The new flow straightening grid, shown in Figure 18, combined with flow tuning vanes produces an even gas velocity ahead of the catalyst bed, allowing a reduction in the size of the compact SCR.

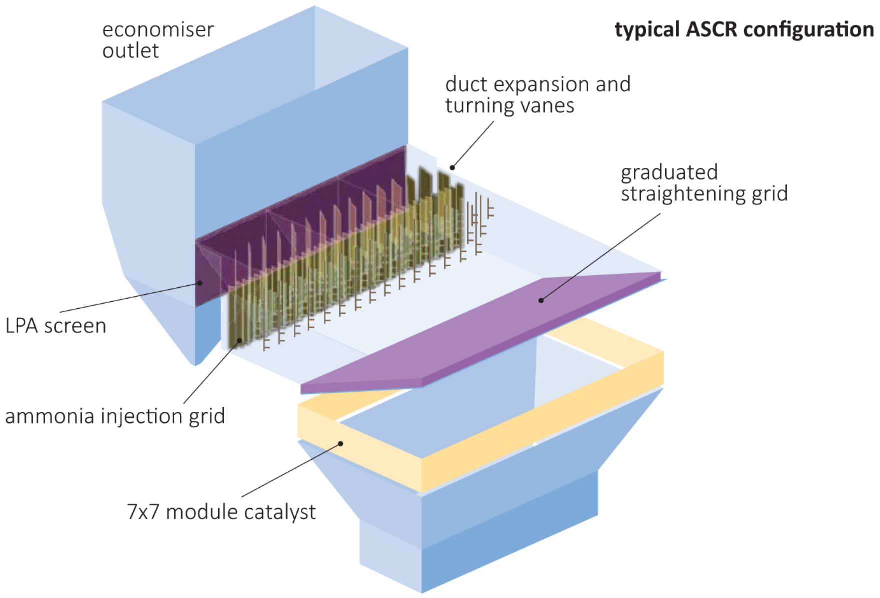

Figure 18 The SCR section of iNOx designed to minimise modification of the existing piping showing a single catalyst layer (Boyle, 2010)

The compact SCR installed in an expanded section of the boiler exit ductwork, Figure 18, consists of the following main features:

- duct expansion and tuning vanes to create a uniform gas flow where the ducting is expanded to adjust gas velocity;
- a network of ammonia injection nozzles across the duct cross-section;
- a graduated straightening grid to direct the effluent at uniform velocity across the entrance to the catalyst section (Fuel Tech Inc, patent pending);
- 7 x 7 catalyst modules, one quarter of a typical SCR catalyst stack.

Optimum combustion conditions must first be established by modifying low NOx burners to minimise raw NOx emission. The second part of the process (SNCR) is the injection of urea above the combustion zone. Higher urea injection rates are possible for the iNOX-SNCR than for a typical SNCR, as the compact SCR reactor essentially acts as a guard bed for ammonia slip. High excess ammonia simply forms part of the reagent for the compact SCR catalytic reduction step.

The single SCR catalyst layer (iNOx™) is more vulnerable to deterioration over time and the module may require more frequent replacement than for a standard SCR. The catalyst would be expected to have a typical lifetime of 8000 hours operation in a coal application with the performance initially permitting 40% removal of the post SNCR NOx (Bible, 2015).

This relatively new technology has been implemented at Castle Peak B, the largest PF coal plant in Hong Kong, China (six 685 MW units) with successful operation since 2014.

The iNOx™ technology has not been applied to lignite plants as yet; for lignite a concern would be the durability of the single SCR catalyst layer in the presence of higher levels of fly ash. In standard SCR technology fly ash is typically managed by the use of sootblowers or sonic horns. For more severe fly ash conditions an alternative SCR arrangement is to locate the reactor downstream of a hot ESP unit; the stack gas is reheated to achieve the required catalytic reaction temperature of 250–400°C. Such an arrangement may also be a possible solution for iNOx™.

Fuel Tech Inc report that the retrofit cost for iNOx™ may range from 35–75 $/kW compared to a full size SCR at ~300 $/kW. The results show that the lower cost iNOx technology has the potential to compete with the performance of a full size SCR.

6 Sulphur dioxide removal in a plant retrofit

Sulphur dioxide treatment is particularly significant for lignite processing plants which generally produce higher SOx emissions than other fossil fuels, due to the low fuel quality. The majority of lignite plants possess sulphur removal technology, but such treatment systems may no longer be sufficient to meet the latest emissions standards. Table 12 shows the current sulphur dioxide limits for power plants in the USA, China and Europe, a significant reduction on previous standards.

Table 12 Emission standards for China, European Union and the USA (World Resources Institute, 2012)

		China	European Union*	USA†
SO^2, mg/m^3	New plants	100	200	160 (built after 2005)
	Existing plants	200 (28 provinces) 400 (4 provinces with high S coals)	400	160 (built 1997-2005) 640 (built 1978-96)

* for power plants >500 MW in size

† units in the standards have been converted to concentrations

Authorities in China have imposed a new standard in most provinces of 200 mg/m^3 in response to worsening air quality in urban areas. As part of the Clean Power Plan the USA has set a lower limit of 160 mg/m^3 for plants commissioned from 1997. Current European Union standard is 400 mg/m^3 for current facilities but the standard is under review and likely to be reduced to 150 mg/m^3 in 2016.

Standards for India are currently under review and it is proposed that new plants will need to reduce emissions by 90%, with earlier plants meeting a typical norm for the industry. This is the beginning of a regulatory framework for India that makes it essential for all new plants to meet stricter emission controls.

The majority of plants (85%) adopt wFGD with the remainder predominantly selecting semi-dry FGD. These two methods, together with a range of alternate technologies, are summarised in Table 13. Detailed descriptions of wFGD and semi-dry FGD (such as Alstom's NID™) technologies are available in IEA reports (*see* Carpenter, 2013).

Table 13 SOx removal technologies

Technology	Description	Removal efficiency %	Indicative capital cost, scale/$/kw
Wet FGD scrubber limestone/gypsum BAT reference technology	Limestone slurry sprayed into the flue gas to react with SO_2 to form calcium sulphate	Up to 99%	MW/$kW 300/404 to 600/284 to 900/290 (Carpenter, 2013, 2008 data)
Semi-dry FGD such as Turbosorp, Alstom's NID	Adsorbent injected into a reactor bed of Ca salts, products and ash Water added separately to the effluent upstream	85–93%	MW/$/kW 500/297 IEA CCC 227 (Carpenter, 2013, 2009 data)
Spray dryer absorber SDA or scrubbers SDS Such as CFB, CDS, GSA, GRAF, RAP	Atomisation of a lime or sodium liquor into hot flue gas, collecting product in the ESP or preferably FF system	70–95% (for lignite <2% S) 95% for twin nozzle designs. Mercury also removed at up to 95%	165–50 $/kW for a 300 MW plant Lower CapEx than wFGD but higher OpEx as uses lime 1 million cfm limit
Circulating fluidised bed scrubber (CFBS)	Circulates ash and lime between scrubber and fabric filter.	95–98% Suitable for feed at up to 3.5% S	Comparable cost to SDA +FF, higher CapEx but lower power and chemical use (Fischer, 2015) 1.8 million cfm limit
Dry sorbent injection Avoids a specific vessel for SOx removal. Includes: HALT, Coolside, Advacate, Hypas	Sorbent Injection into the furnace, economiser, or ducting, or a combination (Hybrid)	40–80% Previously intended for 50% removal	30–130 $/kW for a 500 MW plant
Multicomponent treatment such as Airborne™	Dry sodium bicarbonate addition	Efficient removal of NOx, SOx, PM and Hg	*See* Chapter 9 for details
DryFining™ mineral segregation	Gravimetric partial separation of dense mineral matter including pyrite and mercury	Removal of up to 40% of the sulphur present in dense minerals such as iron pyrite	Details in Chapter 4, current units order of cost at ~$30 million per dryer drying 125 t/h
Addition of limestone to raw lignite	Pulverised limestone added to lignite prior to combustion	Suitable for fluidised bed combustors	Version of DSI *See* Castle-Light add-on hybrid reactor Chapter 9

Both wFGD and semi-dry FGD have proved to be reliable and effective for SOx removal; wFGD shows the most efficient SOx removal but also consumes the most water.

This study focuses on alternative technologies to wet FGD or semi-dry FGD that may compete on cost for a retrofit case, and also treat other components such as SO_3, Hg.

Of particular relevance to plants possessing limited emissions treatment, multicomponent technologies (such as Airborne™ and Castle-Light's clean combustion system) that remove sulphur together with NOx in a single reactor are discussed in Chapter 9. Utilising a sodium bicarbonate reagent which reacts with NO and SO_2, Airborne™ technology has the potential to replace both catalytic reduction of NO (SCR) and a wet SO_X scrubber (wFGD) with a single reactor. The specific feature of Airborne™ is the ability to recycle sodium bicarbonate, an expensive reagent.

The cheapest to install, but also the least efficient, is dry sorbent injection (DSI). DSI is a technology that mechanically fits well with activated carbon addition to control mercury emission as that can take place at the same location (Fischer, 2012). Spray dry scrubbers (SDA) or circulating FB scrubbers (CFBS) offer similar removal efficiency to wFGD at potentially lower cost provided the scale is suitable for a single scrubber.

The lignite drying technology DryFining™ partially removes sulphur in a feed pre-treatment step by gravity segregation (Chapter 4). Extracting minerals from the fuel alleviates the quantity of chemicals required to remove SOx and the technology would be compatible with all the SOx removal treatments listed in Table 13.

6.1 Dry sorbent Injection, DSI

One economic advantage of dry sorbent injection (DSI) is the relatively low cost of equipment and installation that is <20% of wFGD (Feve, 2013). The drawback of DSI is the use of more reagents, up to three times the quantity will be needed for DSI, and the sulphur recovery is less efficient than that for wFGD at typically 50–80% (IEA Clean Coal Centre, 2015a).

DSI avoids the use of a scrubber tower by adding a powdered sorbent directly into the stack gas ducting upstream of a particle control unit. Suitable absorbents include: hydrated lime, trona (sodium carbonate-bicarbonate mineral), or sodium bicarbonate. The pollutant absorbed onto the reagent particles is recovered by an ESP or FF unit. The DSI system is effective at absorbing SO_3 and SO_2 although hydrated lime is less effective than trona. In some instances an existing wFGD plant can be augmented by an additional DSI system added upstream in order to lower sulphur trioxide (SO_3) emission, an example of ‘stacked technologies’ processes.

The DSI system comprises:

- storage and metering of the reagent;
- mills to reduce trona to <15 microns if used;
- control system within the DCS;
- mechanical or pneumatic blowers using cooled and dehumidified air to convey the sorbent (avoiding sorbent calcination);
- injection system.

A typical DSI installation would involve sorbent injection into the flue gas duct either immediately upstream or downstream of the air preheater; an injection point between an ESP and fabric filter would be ideal. Fabric filter installation is preferred so that the ESP is not overwhelmed by the additional sorbent matter which may be a significant factor for high ash lignite fuels. The fabric filter is also more efficient at capturing SOx and Hg, raising the potential removal efficiency above 50%. Installing FF with DSI is a better technical solution but significantly increases the cost.

For DSI duct injection the normalised stoichiometric ratio (NSR) for sorbents compared to SO_2 in the flue gas can vary from optimal 1:1 up to high ratios approaching 4:1. It is difficult to obtain a supplier's performance guarantee with DSI technology due to the wide variation in NSR that may apply in practice. There is a risk of excessive reagent costs with this technology.

Unless new FF are required, then the installation of a DSI system can be much more rapid than for a wFGD. The cost is relatively modest at ~40 $/kW based on installation of three silos with injection upstream of an existing fabric filter unit (Staudt, 2011). NAES Corporation (USA) quoted $17 million for a DSI system fitted to a 400 MW plant; excluding the cost of the pulsed FF system (Broglio, 2014). A typical annual operating cost is quoted as $12 million, using the sorbent SBC and an NSR of 0.8 that proved sufficient to recover 89% of the sulphur emission (coal containing 0.5 lbs S per million Btu).

A reagent recycling scheme may be of particular interest for a retrofit application of DSI to high sulphur containing lignite fuels. Technologies such as NeuStream® can recover and regenerate the sorbent by treating the DSI used solids (fly-ash, sodium carbonate and sodium sulphate) with salt/lime solution to make sodium bicarbonate. The process allows more reagents to be deployed (higher NSR) recovering a greater proportion of sulphur that could potentially rise towards 90% recovery (Feve, 2013).

6.2 Spray dryer absorber and circulating fluidised bed scrubber technology

Spray dryer absorber (SDA) and the circulating fluidised bed scrubber (CFBS) are related SO_2 scrubbing technologies. SDA is a once through design, while the CFBS features solids recycling to potentially recover more sulphur. Capital costs of the two methods are similar, with the SDA somewhat lower but possessing higher running costs due to a higher NSR and the need for compressed air aspiration.

Both technologies are available at lower cost than wFGD provided that the scale is such that a single absorber unit is required (Carpenter, 2013). Previously these technologies were limited to smaller-scale units with low sulphur feedstocks, but the design is suitable for 2.5% sulphur feedstock for SDA and 3.5% for CFBS; and the plant scale has now risen to a maximum of 600 MW.

Figure 19 shows the latest designs from Foster Wheeler for SDA and CFBS units, featuring twin compressed air aspirated nozzles for calcium hydroxide in SDA, and the recirculation of lime in a CFBS unit coupled to a fabric filter.

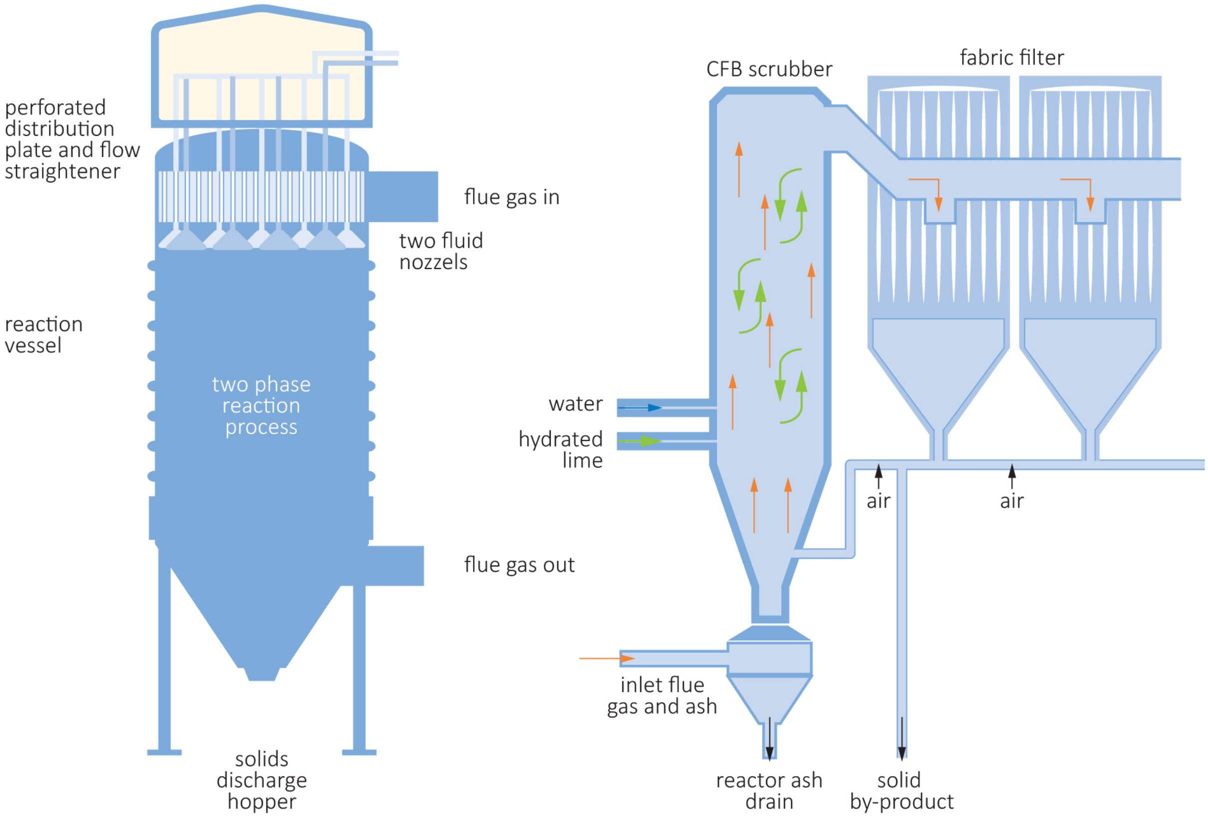

Figure 19 Examples of SDA utilising tungsten carbide coated twin fluid nozzles and a CFBS with integral fabric filter (Foster Wheeler/Fischer, 2015)

SDA involves spraying atomised lime droplets into the flue gas stream with sulphur recovery favoured by the formation of small droplets and even dispersion of reagent across the vessel. There are a number of variants for reagent atomisation including the Foster Wheeler design shown above using air aspirated twin fluid nozzles while other designs include Babcock's rotary high velocity atomiser. The acid gases are absorbed into the atomised slurry droplet to form calcium sulphate which leaves a solid particle following evaporation that can then be collected by an ESP or FF unit.

The CFBS plant can handle higher flue gas volumes than SDA and also higher sulphur content in the flue gas. The technology differs from SDA in that the flue gas is accelerated into a vessel to encourage turbulent mixing between gas and dry solids, consisting of ash and lime, and injected water. Sulphur dioxide reacts with the lime, which is in excess, and then a mixture of reacted and unreacted solids is captured by the fabric filter. Solids are partly returned to the fluidised bed to either improve the recovery efficiency or sent for disposal. Due to very high solid to gas ratios in the fluidised bed and a long contact time approaching 5 s in the 20 m tall vessel, CFBS technology shows a high sulphur recovery of 95%. The CFBS is a more costly unit than SDA but operates more efficiently in terms of energy and uses 10% less reagent with Ca/S ratios of 1.3–1.4.

For the future, an important aspect of these technologies is the potential to inject activated carbon in both systems for the removal of mercury at efficiencies of >95% (Carpenter, 2013). The main factors in selecting between SDA and CFBS would be sulphur content, plant scale and sulphur capture efficiency.

6.3 DryFining™ – lignite pre-treatment for sulphur reduction

DryFining™ is a lignite pre-drying technology that removes sulphur from the feed by separating dense mineral matter; gravity segregation in the first compartment of a fluidised bed dryer removes sulphides derived from iron pyrites (FeS_2) and mercury (details in Chapter 4). As a feed treatment, where sulphur is extracted before combustion, the technology can be applied to augment any sulphur control strategy.

Table 14 shows the results of the DryFining™ trial at Coal Creek Station comparing raw to dry lignite operation. The main finding is that 30% of the original inorganic sulphur present in lignite was removed by the DryFining™ process prior to combustion. The operation of the plant at Coal Creek station enhanced the SOx reduction to 43% by using less feedstock, improving plant efficiency and by reducing gas bypass flow rate at the SOx scrubber plant.

Table 14 DryFining™ SOx emission data (Bullinger, 2015a,b)

Lignite raw/dried	SOx lb/million Btu (ppmv)	Comments
Raw wet coal 37.1% moisture	0.605 (260)	Reference
Dried coal 32.1% moisture	0.346 (149)	43% less SOx emission Approximately 30% of inorganically bound sulphur removed Additional benefit from reduced stack bypass operation More efficient combustion of dry coal lowers SOx by ~3%

7 Mercury removal

Recognition of the gradual rise in background levels of mercury and its harmful effects to the environment, is leading to new legislation which affects the power generation industry. Lignite coals can contain significant levels of mercury of up to 0.34 mg/kg (Mercury Convention, 2013). There are two principle methods to remove mercury currently available and some NOx/SOx treatment units also partially reduce mercury emission.

The latest legislation on mercury emission is summarised in Table 15. China is implementing a limit for existing plants of 0.03 mg/m^3 while the USA has set a stringent target of 0.006 mg/m^3. The EU is currently considering action on mercury emission in accordance with the UN Minamata Convention (Expert Group on BAT/BEP (nd)) while India intends to introduce legislation commencing in 2017, with the focus initially on plants commissioned after 2003.

Table 15 Mercury emission standards for China, European Union and the USA (IEA CCC emissions standards database, 2016)

		China	European Union*	USA†
Mercury, mg/m^3	New plants	0.03	–	0.005 (lignite)
	Existing plants	0.03	–	0.006 (lignite)

* for power plants >500 MW in size
† units in the standards have been converted to concentrations

The removal of mercury may be partly achieved using typical pollutant removal techniques (termed co-benefit) that are commonly deployed on a plant, thus alleviating specific measures to remove mercury. The Minamata Convention has prepared guidelines on such techniques to remove mercury and following Table 16 has extracts from their assessment of the effectiveness of existing methods aimed at lignite combustion applications; the study utilised actual plant experience (Mercury Convention, 2013).

Of the co-benefit technologies shown in Table 16 that can partially remove mercury, the most effective is a combination of an SCR NOx catalyst and low temperature ESP (HEX+LLT ESP) with wet gas scrubbing.

Table 16 Extract from 'Overview of co-benefit mercury removal in APCSs' (Mercury Convention, 2013)**. Control equipment combinations offering moderate mercury recovery for low rank coals**

ESPc (cold side)	SCR + ESPc
SCR + ESPc + wFGD	SCR + HEX/LLT-ESP + wFGD (most effective)
SCR + hot ESP + wFGD	SCR + FF + wFGD

The formation of soluble mercury oxide is maximised by the SCR with mercury vapour condensed and removed by a low temperature ESP unit. Although a FF improves fine particulates removal, surprisingly this unit has proved to offer only a marginal co-benefit for lignite fuels, whereas for hard coals the mercury recovery by FF is significant.

In contrast to hard coals, for low rank fuels the co-benefit capture of mercury by current methods is hampered by the absence of significant chlorine content. While chlorine is not normally a desirable constituent in the fuel, it acts to catalyse the oxidation of mercury to soluble mercury oxide.

Overall the recovery of mercury from lignite fuels by co-benefit treatment is highly variable and may range from 30% to 70%. This degree of recovery may be insufficient in itself to meet new legislation and specific measures are likely to be required (IED, 2010).

The principal method for mercury removal is the addition of powdered activated carbon (PAC or halogen treated PAC) to the effluent stream to absorb mercury metal. The carbon is normally injected immediately upstream of a fabric filter unit or into the final stage of an ESP. The method fits well with other technologies that add absorbent for SOx recovery such as DSI, SDA and CFBS.

For the future, activated carbon injection has been shown to have an added side benefit of removing a significant portion of poly-aromatic (72% PAH) and oxy-poly-aromatic hydrocarbon (40% OPAH) contaminants (Griggs, 2015).

A potential alternate means to remove mercury is to oxidise mercury metal to mercury oxide (HgO) which is then captured in a wet scrubber. Ozonolysis acts to oxidise NO to soluble nitrogen pentoxide and simultaneously can efficiently oxidise mercury to soluble mercury oxide for removal in a wet scrubber.

Pre-treatment of the feed to remove mercury can reduce the amount of post boiler treatment required. DryFining™ (Chapter 4) performs a gravity segregation step on the fuel which can remove a significant fraction of mercury prior to the boiler.

7.1 Activated carbon

Mercury absorption by activated carbon injection (ACI) is a similar method to DSI, and uses either powdered activated carbon (PAC) or brominated powdered activated carbon (BPAC). The carbon sorbent is injected before or after the preheater with good mercury recovery achieved in either location. The presence of a halogen is beneficial in catalysing the oxidation of mercury and for lignite fuels which possess low chlorine content the BPAC may be preferred. If located after the preheater (<180°C), then the sorbent can be added into the third stage of an ESP avoiding extensive contamination of the fly ash with carbon.

Injection rates are ~1 kg of PAC/15,000 m^3 of flue gas; if the more effective BPAC is used then injection rates are typically 15% of the PAC level where an ACI is followed by a FF unit. The cost of the carbon injection system, excluding the Fabric Filter, is relatively low and the main cost arises from consumption of reagent (Fischer, 2012).

Hamon Research-Cottrell has released figures for the commercial Toxecon™ activated carbon injection system using a FF, and also offers the cheaper Toxecon II™ technology that injects carbon into a pre-existing ESP.

The Toxecon™ technology is the preferred version and comprises a sorbent injection system and a compact pulse jet fabric filter to collect the sorbent. The build-up of sorbent on the fabric filter forms a cake on the surface enhancing efficient removal of mercury. The sorbent applied consists of activated carbon or brominated activated carbon, with removal efficiencies of up to 90%. The cost of retrofitting a Toxecon™ unit is estimated at 154 $/kW (US$ 2009) translating to $46 million for a 300 MW plant, with the majority (94%) of capital cost relating to the FF unit.

The alternate ToxeconII™ technology may be installed as a lower cost retrofit into an existing ESP unit avoiding the additional expense of a baghouse. Fly ash would predominantly be recovered from the first stage of the ESP with the final stage consisting of the remaining fly ash and carbon containing mercury subsequently sent to landfill.

Operation and maintenance of Toxecon™ and ToxeconII™ is similar as the majority of the operating cost is for the sorbent.

As the presence of sulphur trioxide (SO_3) has an impact on the efficiency of mercury removal, increasing the amount of sorbent required, low sulphur fuels are more easily treated. If significant levels of SO_3 are present in the flue gas then this competes with mercury for absorption on activated carbon. Alkaline sorbents such as hydrated lime may be needed to remove SO_3 to avoid excessive consumption of carbon. Consequently it is more challenging to recover mercury from high sulphur lignite fuels, with lower recoveries if the less effective ESP technology is applied. For an ESP injection system in the USA, the mercury recovery for high sulphur fuels was limited to 50% which meant that much higher carbon injection rates were required. This compared to 80% recovery for low sulphur lignite under similar conditions using ACI/ESP (Sjostrom, 2012).

7.2 Lignite segregation

The DryFining™ technology developed by GRE has been described in Chapter 4, and features gravitational separation of mineral matter from the raw lignite feed. The Dryer includes a segregation stage chiefly to remove iron pyrite but also has the added benefit of removing higher density mercury. The density of iron pyrites is six times that of lignite (about 800 kg/m^3), whereas mercury possesses a density 17 times that of lignite.

The data in Table 17 was supplied by GRE from testing at the Coal Creek lignite plant. The station has no specific mercury treatment measures and comprises boilers fitted with low NOx burners, an ESP unit and wFGD operated in partial bypass mode.

Table 17 DryFining™ mercury emission data (Bullinger, 2015)

Lignite raw/dried	Mercury, mg/Nm^3	Comments
Raw wet coal – 37.1% moisture	0.014*	
Dried coal – 32.1% moisture	0.009*	35–40% Hg reduction due to segregation of inorganically bound mercury enhanced mercury oxidation and removal in FGD

* dry gas basis at 3% O_2 in stack gas

The main benefit of gravitational segregation is the removal of approximately 35% to 40% of mercury in the fuel that is inorganically bound to iron pyrites. A secondary benefit arises from the increase in oxygen partial pressure from using a dried feedstock that promotes mercury oxidation as first proposed by Lehigh University (Bullinger, 2016)

The measurement of mercury emission proved complex as although there is a clear reduction due to the removal of mineral matter from the raw feed, the reduction in moisture content of the stack gas means that the remaining components, including oxygen, are more concentrated. Lignite pre-treatment is a technology that can be used in conjunction with all other technologies to reduce chemical demand.

7.3 Mercury oxidation

Ozonolysis is a NOx abatement strategy which utilises oxidation rather than the more typical reductive methods such as SCR (Chapter 5). The method involves the low temperature oxidation of NOx to nitrogen pentoxide by ozone; the reaction conditions also permit oxidation of mercury to soluble mercury oxide. The technology is offered by vendors including LoTOx™ and NeuStream®-N&S Lextrans, with the LoTOx™ technology described in Section 5.4. Applying this system for mercury reduction is only practical if the unit is already fitted to treat NOx emissions.

The results of mercury Ozonolysis by LoTOx™ are shown in Table 18. For a typical raw lignite fuel only 10-30% of the total mercury content of lignite will be present in the soluble form Hg^{2+} that can be removed simply by scrubbing. In contrast, bituminous coals that contain high chlorine content have over 70% of mercury present as Hg^{2+} which is easily removed in the FGD scrubber. The predominance of organically bound mercury in lignite means that removal by scrubbing is relatively inefficient at only ~20%.

Table 18 LoTOx™ mercury removal data for various coal types (UNEP, 2010)

Coal Type	Typical Hg^{2+} as % of total Hg	Hg removal with FGD alone, %	Hg removal with LoTOx™ and FGD, %
Bituminous	70–85	76	94
Subbituminous	15–45	33	92
Lignite	10–30	19	91

The data show that addition of an Ozonolysis reactor to oxidise NOx can also be effective for mercury. High conversion to mercury oxide leads to a recovery of mercury in excess of 90%. The formation of soluble mercury oxide means that this can be washed from the stack gas in the flue gas desulphurisation unit. The relatively low level of mercury present in stack gas (for example 15 mg/m³ Hg compared to 200 mg/m³ NOx) means that increasing ozone production to oxidise mercury would only have a modest impact (~10%) on the power demand from the Ozonolysis unit over that needed for NOx oxidation.

8 Particulates: ESP or fabric filters

The growing concern over the effect of fine particles ($PM_{2.5}$) on health is causing energy companies to consider the installation of fabric filtration (FF) instead of, or in addition, to electrostatic precipitators (ESP). Both FF and ESP are currently classed as 'best available technology', and are capable of meeting the latest emissions standards for particulates (IED, 2010). Both methods can achieve 99% mass particulate removal. The current limits are shown in Table 19; the USA and China set particulate limits below ~30 mg/Nm^3, while the European Union allow a higher level of 100 mg/Nm^3 for lignite fuels. There are no specific restrictions on sub 2.5 micron particles ($PM_{2.5}$) in current standards. Draft regulations for India indicate that new plants from 2017 will need to meet emissions levels of 30 mg/Nm^3, although older facilities will have less stringent targets, likely to be a 25% reduction on current average emissions of 150 mg/Nm^3. In Australia although each state sets its own standards, the goal is to implement a specific day average limit for fine particulates ($PM_{2.5}$) of 25 µg/m^3 (IEA Clean Coal Centre, 2015b).

Table 19 Particulate emission standards for China, European Union and the USA (IEA Clean Coal Centre emissions standard database, 2016)

		China	**European Union***	**USA†**
PM, mg/Nm^3	New and existing plants	30	50, with an exception of 100 for low quality coal, such as lignite	22.5

* for power plants >500 MW in size
† units in the standards have been converted to concentrations

8.1 Electrostatic precipitation, ESP

Historically, electrostatic precipitation (ESP) is the preferred particulate removal treatment to remove fly ash from the effluent stream. The method uses high voltage electrodes to charge particles and attract them to collection plates which are then periodically disturbed (rapped) to dislodge the particles into a hopper for disposal or sale. The advantages and also limitations of the ESP system to be considered are:

- capable of handling large dust laden gas flows with low pressure drop;
- fixed operating parameters established at design stage limit flexibility;
- high collection efficiency, less effective for fine particulates;
- handles corrosive and wet materials, can operate at elevated temperature;
- changes to particle electrical resistivity can affect recovery efficiency;
- low operating costs, but high installation costs;
- long service life.

An ESP unit would be expected to remove over 99% of particle emissions that exceed 8 microns, with lower efficiency for fine sized particles. An ESP is found to be most effective for high sulphur fuels, as sulphur reduces the resistivity of fly ash enabling higher collection efficiency (Mercury Convention, 2013).

The main factors affecting the collection efficiency include: particle resistivity, size distribution, structure, density, composition, concentration and agglomeration. The condition of the stack gas also affects collection, for example gas flow rate, moisture and temperature. Studies on Indian coals showed that the presence of high alkali (Na_2O, K_2O), and iron oxide Fe_2O_3 beneficially reduce resistivity of the fly ash (Andrabi, 2013). Conversely calcium and magnesium oxides increase resistivity due to absorption of SO_3. Thus the effectiveness of an ESP will be significantly affected by the lignite feed composition.

For mercury recovery by ACI, activated carbon may be injected into the last stage of an ESP to avoid contaminating the main fly ash collection.

8.2 Fabric filter technology and cost comparison with ESP

Fabric Filter (FF) technology is becoming preferable to ESP due to its higher performance in removing fine particulates. The Fabric filter can remove a broader range of particle distribution due to the build-up of a filter cake on the filter material that captures fine particles. Where ESP is effective for particles >8 micron, Fabric filter units have proved effective at removing sub-micron particulate, and is a potential means to alleviate growing concern over emissions containing particles under 2.5 microns, $PM_{2.5}$ (EPA, 2015b).

Fabric filters (baghouses) collect dust onto a fabric that is supported by wire cages. The fabric may be made from polyacrylonitrile or, for higher temperatures, polyphenylene sulphide polyimide. Gas enters the fabric cylinders (for tubular systems) leaving dust on the surface to form a filter cake. The gathered dust layer is then periodically removed by either reverse flow through the fabric, or, preferably, by using pulsed compressed air blowpipes to create a shock wave to dislodge the filter cake attached to the filter.

Previously, fabric filters were installed in plants that used semi-dry FGD sulphur removal units rather than wet scrubbers (wFGD). Smaller plants (<250 MW) where dry sorbent injection (DSI) is used for sulphur treatment would normally possess a FF baghouse (IED, 2010).

The fabric filter unit is a large installation that, dependent on the plant scale, may comprise 20 to 40 thousand filter bags of approximately 8 to 12 m in length and 150 mm in diameter. This installation provides up to 80,000 m^2 surface area for a 600 MW scale plant. The filter bags last for several years but must be replaced at 20,000–30,000 hours (Hansen, 2006).

The capital cost of a fabric filter suitable for a 660 MW boiler design is of the order of US$10-20 million (15–25 $/kW) dependent on the target emission level, whereas the cost of an ESP is higher at approximately $20–30 million (>25 $/kW) while a wet ESP version is priced at $26–46 million (>40 $/kW) (Metah, 2013; Reynolds, 2012).

Although an FF unit has a lower installation cost, over the life of the system, the operating costs are somewhat higher than for the equivalent ESP which requires less maintenance and also has a lower power demand. The total operating cost for a fabric filter unit, averaging bag changeover is approximately 50% higher than for ESP dust removal, although this is affected by the fly ash composition and condition.

9 Multi-component pollutant removal

A number of technologies already discussed are capable of removing more than one component from the effluent stream. For example:

- SOx removal technology wFGD has the co-benefit of washing mercury oxide from the stack gas, as well as scrubbing acidic components.
- LoTOx™ ozone technology combined with wFGD oxidises NOx to nitric acid and also oxidises mercury which can then be washed out of the stack gas.
- Lignite drying with mineral segregation reduces the inorganic content of sulphur and mercury in the fuel as well as lowering moisture levels.

A number of processes are under development to efficiently remove two or more pollutants. Table 20, contains a list of multicomponent technologies, a brief summary of the technique, pollutants removed and their current state of development.

Table 20 Multi-pollutant control processes – commercially available technologies (extract from Carpenter, 2013)

Process	**Description**	**Pollutants removed**	**Status 2015**
Wet scrubbing			
Limestone wet scrubbers	Wet scrubbing with limestone slurry. Gypsum by-product	95–>99% SO_2, <60% SO_3, >98% HCl + HF, 75–99% oxidised Hg (>50% total Hg), >70% PM	Dominant commercial technology for SOx
Airborne™ Process	Dry, regenerable sodium bicarbonate injection combined with wet sodium carbonate scrubbing and oxidant wash. Saleable fertiliser by-product	99.9% SO_2 + SO_3, 99% NOx, 99% Hg	Commercial: 3 projects in China 12 to 200 MW
NeuStream®-MP	Ozone injection for NO oxidation before dual-alkali flat jet scrubber followed by CO_2 capture. Solvents are regenerated. Saleable by-products	97% SO_2, 98% HCl, >90% NOx, >90% oxidised Hg (~80% total Hg), <95% PM, 70–90% CO_2	Commercial demonstration installing at Martin Drake 6 & 7
Semi-dry scrubbing			
Spray dry scrubbers	Scrubbing with lime slurry. May incorporate a Hg sorbent	90–98% SO_2, 95–98% SO_3 + HCl, >95% PM, 0–95% Hg	Commercial
Circulating fluidised bed scrubbers	Scrubbing with dry hydrated lime and water in a circulating fluidised bed. May incorporate a Hg sorbent	>98% SO_2, 99% SO_3, HCl + PM, >95% Hg	Commercial
Dry technologies			
ReACT™	Activated coke fluid bed absorption with sorbent regeneration. Ammonia injection upstream of absorber. Saleable by-products	99% SO_2 + SO_3, 20–80% NOx, >90% Hg, ~50% PM	Commercial: 2 coal power plants Japan & WPS Weston 3 to install 2016

Table 20 continued			
SNOX™	Regenerable catalytic reduction followed by acid condensation. Saleable by-products	99% SO_2 + SO_3, 99% NOx, >99.9% PM	Commercial: installation in 1999 at 300 MW plant Denmark
Catalytic ceramic filters	NOx catalyst embedded in ceramic filter. Upstream injection of sorbents for removal of SO_2 and Hg	>95% NOx, >99.8% PM, 80–95% SO_2, SO_3 + HCl, >90% Hg	Commercial: but not yet demonstrated on large-scale power plants
Max-9™	Injection of Hg sorbent and electrostatically stimulated fabric filter	99.99% fine PM, >90% Hg	Commercial
TOXECON II™	TOXECON™ injects activated carbon before compact pulse jet filter. Hot- or cold-side ESP first removes 99% PM. TOXECON II™ injects mercury sorbent into back portion of cold-side ESP	TOXECON™ >85% fine PM, >90% Hg TOXECON II™ >95% PM, >90% Hg	Commercial
Non-thermal plasma technologies			
Pulse corona discharge	Ammonia injection and plasma reactor. Saleable fertiliser by-product	95% SO_2, 40–70% NOx	Small-scale demonstration
ECO™ + ECO2®	Dielectric barrier discharge, Ammonia-based wet scrubber and wet ESP (ECO™), integrated with ammonia-based scrubbing with solvent regeneration (ECO2®). Saleable by-products	95–99% SO_2, >90% NOx, >85% oxidised Hg, >90% CO_2	Tested on 50 MW (ex 156 MW boiler slipstream) at First Energy Burger Plant (2005)
Gas phase oxidation			
Eco Power Solutions' (EPS) system	Oxidation (ozone and H_2O_2 solution) and condensation. Saleable by-products	99% SO_2, SO_3 + HCl, 98% NOx, 95% Hg, 30–>90% CO_2, 99% PM	Tested at 5 MW pilot scale
Lextran	Ozone injection and regenerative wet scrubbing with organic sulphoxide catalyst. Saleable by-products	99% SO_2 + SO_3, 85–90% NOx, some Hg	Commercial
LoTOx™	Ozone injection and wet scrubber. Saleable by-products dependent on scrubber technology	>95% SO_2, 90–95% NOx, >90% Hg	Commercial (in petroleum refineries) growing interest as secondary NOx treatment in PCC
Amine scrubbing			
Shell Cansolv®	Regenerable amine scrubbing in packed absorber towers. Saleable by-products	>99.9% SO_2, ~50% SO_3, 90% CO_2	Commercial demonstration
Gasification retrofit			
Castle-Light gasifier	Boiler re-engineering replacing existing burners with add-on gasifiers. No SCR or FGD needed	<110 ppm NO 105 ppm SO_2	Commercial demonstration

The following techniques are capable of removing at least three key pollutants including NOx and SOx to current emission standards, utilising an integrated processing unit:

REACT™ – regenerable activated coke absorption with ammonia injection

SNOX™ – regenerable catalyst reduction

Catalytic ceramic filter – DSI for SO x and Hg, coupled with NOx catalyst embedded in filter

ECO™ – plasma discharge technology utilising ammonia injection

Airborne™ – sodium bicarbonate pollutant treatment.

These Advanced Quality Control Systems (AQCS) have significant potential to lower the cost of pollutant treatment, but there are questions over the commercial demonstration as there is limited evidence from operation at full plant scale.

The SNOX™ system was originally installed on a 300 MW plant in 1999 and has now operated for over 15 years. It has proved efficient at removing NOx, SOx and particulates, but the technology has not been deployed elsewhere.

The catalyst membrane technology shows excellent recoveries but has yet to be implemented on a full-scale plant. Similarly the ECO™ technology has been limited to a 50 MW slipstream.

The activated carbon technology REACT™, an activated carbon fluidised bed reactor, is to be installed on two coal plants in 2016 and good recoveries of SOx and Hg are claimed, although NOx recovery is somewhat lower.

The Airborne™ method has recently been applied to three coal plant projects of up to 200 MW scale. The chemistry of the technology is well known and employs sodium bicarbonate (SBC) to recover both NOx and SOx in a single step; the significant development a method to substantially reduce reagent cost. The Airborne™ method has been trialled more extensively at full scale and is described more fully in the next section.

A novel retrofit technology entitled Clean Combustion System CCS(g) is also described, that involves a combination of coal beneficiation, dry sorbent injection and the replacement of boiler burners with an external coal gasifier. This radical new design aims to lower main pollutant emissions below 110 ppm and avoid the need for SCR and FGD.

9.1 Airborne™ process: a single reactor solution

The Airborne™ process uses sodium bicarbonate (SBC) to remove SOx and NOx in a single reactor that possesses an additional stage to remove mercury. Although SBC technology has been applied in the past, the addition of SBC regeneration overcomes the major commercial barrier of high chemical cost. The technology has recently been applied at three coal power plants in China; the power capacity of the plants ranges from 12–210 MW (Mortson, 2015a). The recovery of NOx, SOx, PM and potentially mercury in one unit allows this method to compete with other more established processes.

Previously the high cost of sodium bicarbonate has prevented significant deployment of this technique as SBC is more expensive to use than alternatives such as limestone in wet scrubbers. The recent addition of a regeneration plant, using lower cost ammonium bicarbonate as the regeneration agent, has halved the SBC cost. Sodium nitrates and sulphates are now converted to saleable fertiliser products in a regeneration plant which partially offsets the SBC cost.

The following diagram, Figure 20, shows a schematic of the Airborne™ process inserted as a retrofit into a coal power plant. In this example the SBC scrubber and baghouse are located after an SCR and ESP unit. In terms of practical installation the SBC scrubber can be added in a relatively short time and the plant operated in non-regenerable SBC ($NaHCO_3$) mode. The regeneration plant, using ammonium bicarbonate to react with sodium sulphate to make sodium bicarbonate, can be added the following year. Where there is an existing wet FGD plant then it is possible that it may be adapted to the Airborne™ process. The use of a more reactive alkaline solution results in a simple vessel design made from standard materials that is about one-third of the height of a typical wFGD unit.

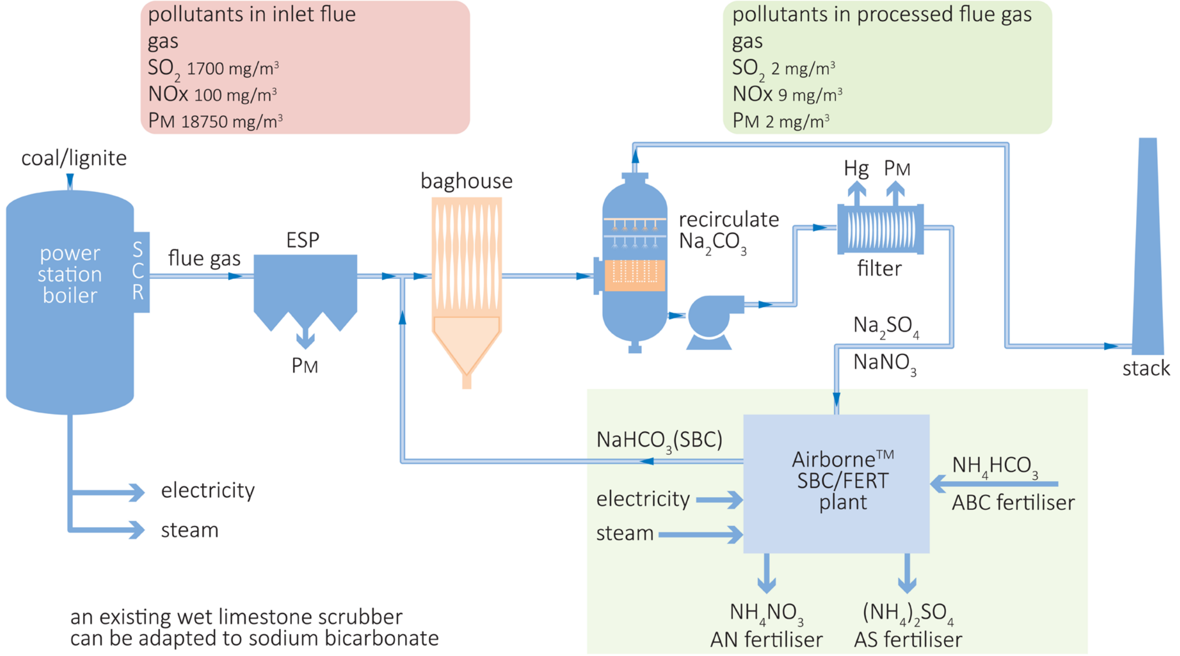

Figure 20 Schematic of the Airborne™process showing the sodium bicarbonate SBC scrubber and baghouse and, in the green section the SBC recovery and fertiliser plant (Mortson, 2015b)

In Figure 20, the sodium bicarbonate plant replaces a wFGD unit in an otherwise standard plant configuration. Operated in this manner, with an SCR catalyst in place, the NOx emission can be lowered to ~10 mg/m^3, well below current standards. The SO_2 and particulates are each reduced to ~2 mg/m$^{3.}$ Effectively the SBC plant has removed 100 mg/m^3 of NO_x making the plant attractive to other retrofit scenarios where an SCR may not be present. The regeneration plant is depicted in the green section.

The reaction of sodium bicarbonate parallels that of the limestone process for SOx in that where a calcium salt ($CaSO_4$) is formed in wFGD, a sodium salt (Na_2SO_4) is formed in SBC. The main difference is the additional reaction of SBC ($NaHCO_3$) with NOx to form sodium nitrate; that is effectively only one reagent to treat SOx and NOx. The reaction mechanism is outlined in Table 21, showing the reaction of SBC injected as a dry powder into the flue gas stream, with recirculating sodium carbonate scrubbing solution. The bicarbonate reacts with sulphur dioxide to form sodium sulphate. In the case of NO, the presence of sulphur oxides is needed to promote the reaction with NOx, converting NO to NO_2.

Table 21 Reaction of NOx and SOx with sodium bicarbonate $NaHCO_3$ SBC	
Oxidation of SO_2 by SBC in presence of oxygen	$2NaHCO_3 + SO_2 + ½O_2 \rightarrow Na_2SO_4 + 2CO_2 + H_2O$
Oxidation SO_2 with sodium carbonate (scrubbing solution)	$Na_2CO_3 + SO_2 + ½O_2 \rightarrow Na_2SO_4 + CO_2$
SBC oxidation of SO_3	$2NaHCO_3 + SO_3 \rightarrow Na_2SO_4 + 2CO_2 + H_2O$
Sodium carbonate (scrubbing solution) reaction with SO_3	$Na_2CO_3 + SO_3 \rightarrow Na_2SO_4 + CO_2$
SBC reaction with NO forming NO_2 (requires SO_2)	$2NaHCO_3 + SO_2 + NO + O_2 \rightarrow Na_2SO_4 + NO_2 + H_2O + CO_2$
SBC reaction with NO_2 to form sodium nitrate	$2NaHCO_3 + 2NO_2 + ½O_2 \rightarrow 2NaNO_3 + H_2O + 2CO_2$

Above the NOx/SOx recovery section of the scrubber additional proprietary oxidants are injected in a second zone fitted with bubble cap trays to convert mercury metal to mercury oxide. Heavy metals are then removed by filtration from the solution.

The filtered products formed from the flue gas treatment are then reacted in the regenerator with ammonium bicarbonate to form ammonium sulphate and ammonium nitrate; these products are recovered from solution by crystallisation and sold as a commercial grade fertiliser for an additional revenue stream; a specific advantage of the technology. For the comparable calcium salts from wFGD, the products are supplied to the cement industry if suitable or else sent for disposal in landfill.

The parasitic power consumption of the SBC plant was previously reported as 3% of plant output for a hard coal plant (Carpenter, 2013), but that figure has now been revised to a lower value of <1.5% as shown in Table 22 (Mortson, 2015). However, it should be noted that power consumption is dependent upon the heating value of the coal and the sulphur content; the higher gas flow for lignite will lead to a higher electrical load than for an equivalent hard coal of the same sulphur content.

Table 22 Power load for a theoretical 1000MW capacity hard coal plant based in China		
Airborne™ absorber	50841 MWh/y	0.58%
SBC regeneration facility	56466 MWh/y	0.64%
Fertiliser facility	13823 MWh/y	0.16%
Total electrical load	121,130 MWh/y	1.38%

Using a theoretical reference hard coal plant of 1000 MW capacity, the following Table 23 shows projected costs for the main elements of the Airborne™ process: pollution scrubbing system, SBC regeneration, and fertiliser plant. However, the predicted costs exclude the required fabric filter baghouse. The total cost for a 1000 MW equivalent plant located in China is then estimated at ~$35 million (Mortson, 2015).

Table 23 Airborne™ process: capital and operating charges – plant scale 1000 MW, 0.7% sulphur in coal located in China (Mortson, 2015)	
Pollution control scrubbing system	125 million RMB ($20 million)
SBC regeneration system	55 million RMB ($8.8 million)
Fertiliser co-production	41million RMB ($6.6 million)
Total plant cost	221 million RMB ($35 million)
Annual operating charges including all chemicals , power, utilities	34 million RMB ($5.4 million)
Based on 6.25 RMB to 1 USD	

For a plant smaller than 1000 MW the installation cost will not be reduced pro-rata but will require a scale factor. Operating charges are sensitive to sulphur content as this directly affects chemical consumption, and although the sulphur content of the coal in this example is similar to many lignite supplies, the higher throughput of lignite feed would lead to higher chemical demand.

Airborne™ Technology has the potential to augment an existing facility, possibly reusing an underperforming FGD plant, to lower the emission of all main pollutants using a single reactor. Although the current projects for Airborne™ use hard coals, there is no particular property of lignite that should present new technical issues for a lignite plant application; although equipment size must increase for higher gas rates with an impact on cost (Mortson, 2015). The overall cost of the installation to address SOx, NOx, Hg and particulates appears competitive with current processes, and may be particularly attractive to those plants with limited existing effluent treatment.

9.2 Clean combustion system – Add-on gasification reactor

An alternative to installing new equipment to remove NOx and SOx is to re-engineer a PC boiler to incorporate a set of gasification reactors, replacing the existing firing equipment (Moore, 2016). The gasification section of the clean combustion system (CCS(g)) is intended as a 'bolt on' addition with the boiler retained as a secondary oxidation zone. The gasifier creates 'fuel rich' reaction conditions through partial combustion of the fuel avoiding the formation of nitric oxides from fuel nitrogen. Addition of limestone with the coal or lignite feed directly converts sulphur to calcium sulphide in an air deficient atmosphere. The emission reduction demonstrated on a 1940's stoker furnace is comparable to that achieved by an SCR/wFGD installation at considerably lower cost.

Addition of limestone into the reaction zone forms sulphides rather than sulphates as in typical DSI technology that can then be removed as part of the molten slag. The reducing atmosphere prevents the formation of SO_3, a significant source of corrosion. The formation and removal of molten solids prior to the main boiler, leads to cleaner heat transfer surfaces an important consideration for high ash lignite fuels.

With the primary combustion relocated to external gasifiers, the existing boiler is re-configured with access ports cut through the water wall, while original burner ports are sealed or converted to supply over fire air. Combustion products from the gasifier section that include carbon monoxide, hydrogen and carbon in fly ash are fully oxidised in the original boiler. The formation of thermal NOx in the existing boiler may be avoided by careful control of the temperature profile, staging additional air after partial heat removal between the gasification and secondary air addition.

To improve the quality of the coal feed, boiler exhaust gas is diverted prior to the air preheater in a coal beneficiation stage, whereby surface moisture and other volatile components may be removed from the fuel.

Figure 21 shows the main process steps within the gasifier and boiler sections with fuel nitrogen forming nitrogen gas, carbon oxidised to carbon monoxide, and sulphur to sulphide. Hydrogen is obtained from hydrocarbons present in the fuel and from water gas shift chemistry equilibrating CO and H_2. Following partial heat removal by the boiler, hydrogen is oxidised to water and carbon monoxide to carbon dioxide completing the combustion process utilising air staging and with the final gas composition and flow rates as per the original boiler design.

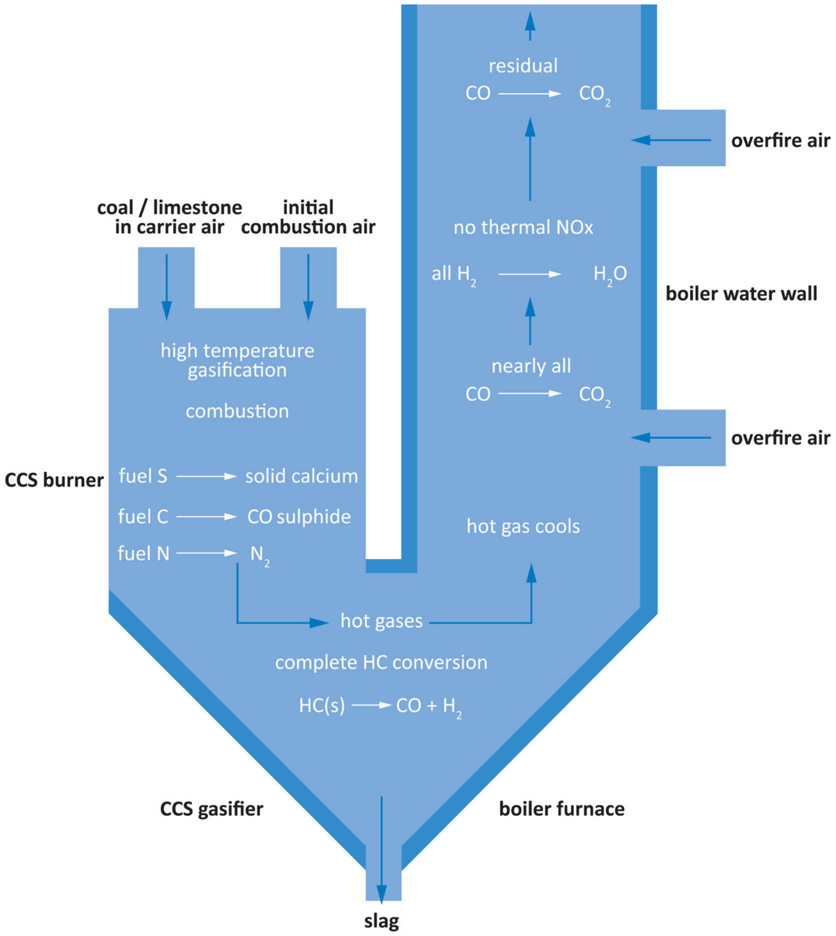

Figure 21 Schematic of the Clean Combustion System hybrid reactor showing the 'add-on' gasification first stage followed by the boiler converted to a secondary oxidation reactor (Moore, 2016)

Current trials are at modest scale of 15 t/h hard coal (2.5% S); equivalent to approximately 30 t/h lignite. However, to introduce the gasifier onto a 600 MW capacity boiler would require only a limited scale-up of the demonstration 'add on' reactor technology, as this would involve installation of six gasifier chambers each possessing four clean combustion system burners, with the gasifiers arranged either side of the boiler.

The estimated cost of a gasifier retrofit project is comparable to an SCR retrofit project or a quarter of the cost of a combined SCR and FGD installation. Applying the gasifier in recent trials on a 2.5% S coal produced emissions of <110 ppm NOx and 105 ppm SO_2. The total project timescale to implement re-engineering of the boiler is approximately 18 months with plant outage limited to less than 14 weeks for installation, with the majority of the preparatory work and construction undertaken off-site.

10 Output flexibility: plant operability, thermal storage and gas co-feed

In Germany the recent growing contribution from renewable power has impacted upon the operation of lignite power plants for the first time (Figure 4). A number of German lignite stations have been assigned to reserve capacity; while remaining plants will experience periods of load sharing with a need to rapidly respond to changing demand and perhaps operate under sub-optimal conditions. Although German power stations are among the first to be affected by the introduction of renewable energy sources, this is likely to affect power generation in other countries in the near term.

Lignite plants are less flexible than hard coal units due to the nature of the drying and firing systems; for existing plants the minimum operation is typically at ~50% capacity, and for new state-of-the-art stations ~35–40% output (Agraniotis, 2015). The more technically advanced units possess high pressure and temperature parts that may be more vulnerable to transient or unstable conditions. The transient conditions arise due to the limited time available for plant start-up and shutdown, and the need to quickly raise the ramp rate where the plant is required to respond at short notice.

The efficiency of the plant falls substantially as the load is reduced and the plant moves further from the optimal design point, with supercritical (SC) plants shown to be more sensitive to partial load operation than subcritical plants; heat rate rises more rapidly with reduced loading of the plant (Figure 22).

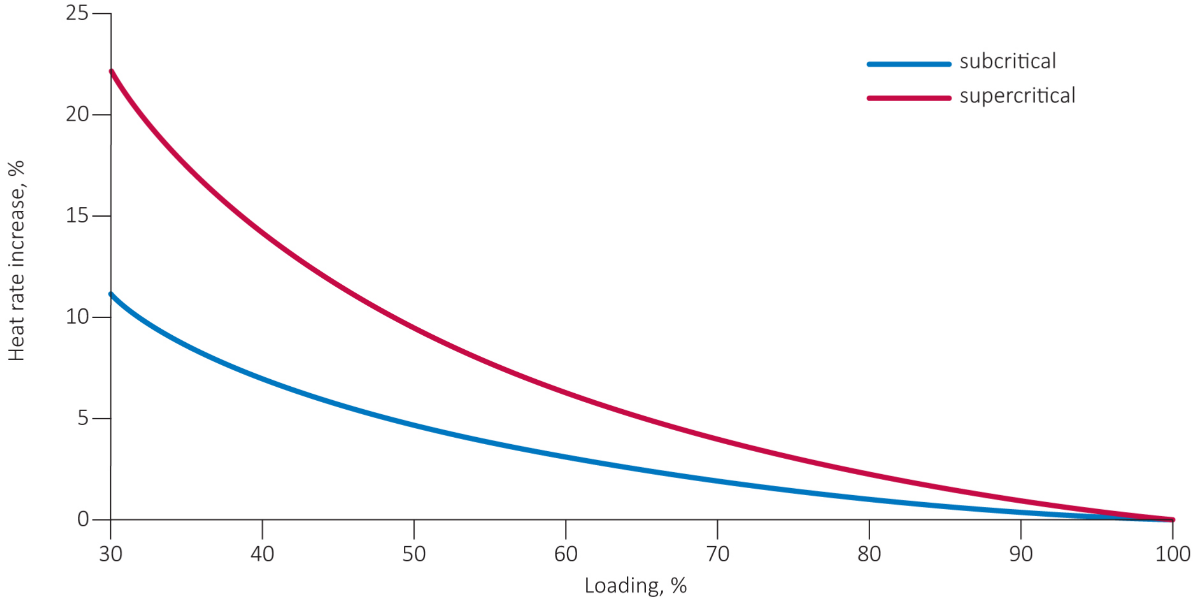

Figure 22 Effect of loading on the heat rate of subcritical and supercritical power plants shows a rise in heat rate for subcritical and supercritical plants (Jones, 2010)

For example, at 50% load in Figure 22 the heat rate increase by 9% for SC plants, while subcritical plant is less affected with a 5% rise.

The main short-term focus for flexible operation is to minimise the demand response time and maximise efficiency of the plant at modest loading; but a number of issues may be encountered that affect both boiler heat exchange equipment and turbine assemblies thus shortening the useful life of the plant:

- metal fatigue from increased temperature cycling, causing cracking in steam headers and turbine rotor damage;
- enhanced creep deformation within the boiler;
- differential thermal expansion, affecting the heat exchanger tubes and headers, support framework and ducting;
- lower temperatures leading to corrosion due to acid gas condensation;
- SCR catalyst performance may be impaired due to low reaction temperatures limiting effective NOx reduction;
- variability in boiler feed quality.

If a plant is assigned as a reserve station, then operation may consist of rapid load cycling where variable generating capacity is required; the following terminology is applied to describe operation from various states of readiness, accompanied by the approximate times needed to mitigate thermal stress during transient conditions (Domenichini, 2013):

- hot start – the plant may be shut down and restarted after a short period of <12 hours, taking less than 1 hour;
- warm start – shut down for an intermediate period for 12–72 hours allows restarting in ~4 hours;
- cold start – starting from cold the most arduous case taking up to 7 hours.

A primary aim of reducing the minimum operating load as far as practicable is to maintain the plant running to avoiding a cold start. Once the load demand rises then the plant has to be ramped up in the minimum timescale which is enabled if maintained under ‘hot start’ conditions.

10.1 Options to improve plant flexibility

There is a need to respond to variable power demand and plant flexibility measures are primarily aimed at limiting thermal stress, expanding the operable load range and allowing for a more rapid start-up and shut down. In addition the rate of change of loading has to be increased; the load rate increase is currently limited to <3% on state-of-the-art plants, taking over 30 minutes to achieve full plant operation (Schiffer, 2015). Potential measures for enhancing flexibility are listed in Table 24.

Table 24 Options to improve flexibility of lignite power plants (Henderson, 2014; Agraniotis, 2015)

Technical options: boiler and turbine	Description	Benefit
Variable number of lignite mills in operation	Reduce number of mills in operation to match desired loading, currently limited to ~40%	If can operate on fewer beater mills then that allows lower load operation, minimising cold start demand
Indirect firing systems	Storage for milled lignite means that lignite supply is not limited by the mill operation	Provides a supply of milled lignite independent of the mills raising potential ramp rates, preferably based on dry lignite to improve combustibility and replace start up oils
Enhanced furnace monitoring and advanced control	Optimisation of the combustion process at part load from CO, O_2 and T measurements	Ensuring boiler operates at optimum conditions for combustion stability, turbine operation and to limit emissions
Re-design of high pressure systems	Installation of high temperature alloys that allow thinner components	Potential for load rate change rates of up to 10% for new alloys compared to 3% for conventional steels
Variable speed components	Variable speed control of ID and FD fans	Reduce parasitic load and improve part load efficiency
Heat storage systems	Steam storage for low or high pressure feedwater	Increase steam flow to the turbine for up to 30 minutes
Multiple boilers	Lower capacity boilers serving a common turbine	Allows optimum operation of one boiler while others are idled until required
Integrated gas turbine	Installed to heat feedwater or as a fully integrated conventional combined cycle plant	Improve efficiency of the plant and gas power has lower carbon footprint
Sliding pressure turbine control	Match steam and turbine metal temperatures by adjusting pressure	Earlier steam flow to the turbine allows a more gradual temperature ramp
Turbine repowering	To use modern designs that are more suitable for flexible operation	To improve ramp rate and efficiency
Optimise load ramp rates, depending on load segment	Adjust start up conditions depending on hot/warm or cold starts, and load sector for example 40–50% / 50–60%	Reduce thermal stresses on turbine parts

A range of measures suitable for plant retrofits are listed and form four broad categories: management of the feed system; modifications to the boiler and turbine; integration of a natural gas turbine; and energy storage systems.

The lignite feed system is normally operated with all beater mills in operation. Each mill supplies a set of burners, and reconfiguration for operation on fewer mills while maintaining uniform combustion in the boiler will improve efficiency. Indirect firing using a separate dry lignite supply is a means of starting and running the boiler at low loading avoiding the use of expensive oil burning.

The management of boiler and turbine can be optimised to reduce thermal stress by controlling the rate of load increase, applying sliding pressure steam control and using an updated control system that closely aligns boiler and turbine operation. Actual plant modification may include replacing the turbine for designs that offer improved durability to temperature transients, and replacing thick walled heat exchange parts by thinner walled high temperature alloys.

A natural gas turbine operated in parallel with the lignite plant can potentially be introduced as a fully-integrated steam system, with the natural gas turbine always in operation maintaining minimum steam conditions in the lignite boiler.

The concept of energy storage is to maintain a heat reservoir that can be built during a period of off-peak operation and then supplied to the plant to support flexible operation. A hot water system is readily integrated, while alternate energy storage systems, such as liquid air energy storage systems (LAES) are under development (Agraniotis, 2015).

The upgrade of steam turbines and the introduction of an advanced control system, that would incorporate boiler strategies to minimise thermal stress, are described earlier in the report. Indirect firing is an exclusive option for lignite plants and this technology together with hot water energy storage and gas turbine re-powering, which have been successfully implemented on hard coal plants, are discussed more fully in the following sections.

10.2 Indirect firing

During normal operation lignite is dried by hot exhaust gases drawn from the boiler. Generally, oil is burned first to heat the boiler and support stable combustion of wet lignite at low flow rates. This procedure is acceptable for short periods during start-up where the plant operates as a base load station, but may become prohibitively expensive for a flexible plant operating under variable load conditions with frequent restarts.

An alternative is to feed pre-dried lignite which has been treated in a dryer and stored in a vessel adjacent to the boiler ready for use; the supply of prepared lignite is independent of beater milling. Indirect firing of dry lignite has already been applied in two German plants for start-up and support firing, with the dry feed passed to dedicated burners as shown in Figure 23. A portion of the lignite fuel is dried, sufficient to provide low load operation in off-peak periods for several hours (Bergin, 2014). At the Vattenfall Jänschwalde plant in Germany the silo contains 650 tonnes of dry lignite, equivalent to 1 hour‘s supply at full rate, sufficient to sustain operation at low loading (Heimann, 2015). The use of dry lignite as the start-up fuel has enabled the Jänschwalde station to reduce the minimum plant load to 20% during commissioning trials. An enhanced load range of 20–100% instead of the previous 40–100% enables the plant to remain on-stream for longer periods avoiding warm or cold restarts.

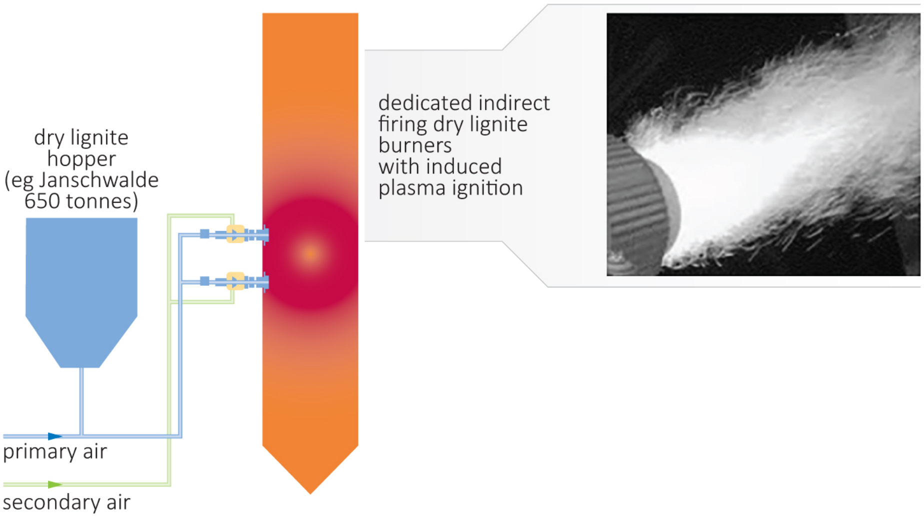

Figure 23 Indirect firing concept: pre-dried lignite for fast start up (Agraniotis, 2015). **Plasma induced ignition of lignite – photograph** (Czernichowski, 2014)

The production of dry lignite at this scale could be carried out in rotary or tubular dryers, normally located at the plant using steam or flue gas to dry a portion of the lignite. Earlier in the report (*see* Chapter 4) the drying of a large fraction or all of the plant lignite feed using fluidised bed drying technology is discussed as a means to improve plant efficiency and those methods would also be suitable for this application. Dried lignite could then be fed to all burners but with dedicated lignite ignition present at the start-up burners and the addition of dry lignite storage to delink the plant operation from lignite milling.

10.3 Gas turbine repowering

Integration of a gas turbine into a lignite plant may be an option in locations that benefit from low natural gas prices. In Germany, retrofitting of gas turbines equivalent to about 20% of the existing power plant capacity has been carried out at some PC coal plants; although in these cases the economics have proved less favourable due to high gas cost. Meanwhile in the USA, the favourable gas price has led to complete repowering of several plants from hard coal to natural gas. For lignite stations that remain cost effective, the repowering option may provide a means of improving flexibility, lowering greenhouse gas and other emissions and improving plant heat rate, all requirements of new proposed legislation. For a repowering project the gas turbine may be incorporated either in the form of a conventional combined cycle or by providing additional feedwater and steam heating (Agraniotis, 2015).

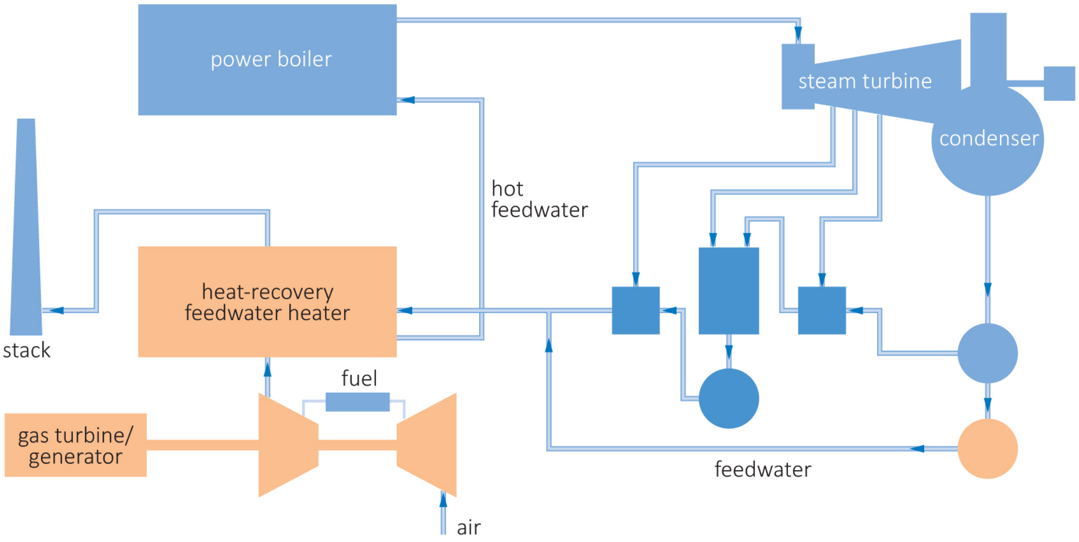

Figure 24 Feedwater heater repowering uses energy recovered from a gas turbine to heat feedwater to main boilers (Stoll, 1996)

A gas turbine can be incorporated in the main plant by using the flue gas to heat the boiler feedwater in 'recovery preheaters' termed 'feedwater heater repowering' as shown in Figure 24. Steam can also be generated in a Heat Recovery Steam Generator (HRSG) to offset or fully replace the steam from the existing power boiler with a direct feed upstream of the steam turbine termed 'heat recovery or full repowering'. Additionally the boiler can be operated in 'hybrid' mode with the gas turbine designed to maximise the capacity of the existing steam turbine.

The gas turbine's ability to ramp up quickly on start-up, independent of the main plant steam cycle, allows the plant early synchronisation to the grid, and the hot flue gas can heat feedwater in the steam cycle reducing the cold start time. In bypass mode the gas turbine can also be operated independently of the main plant, the overall power output of the plant can be increased by up to 20% through the direct contribution from the gas turbine and preheating of water in the steam cycle. Plant emissions can be reduced by ~10% per MW at full load due to the reduced contribution to carbon from the gas feed.

The energy efficiency of the additional natural gas unit can potentially exceed that of a dedicated natural gas-fired combined cycle power plant at ~60% (Henderson, 2014). Cofiring natural gas to reduce the carbon footprint of the plant may be significant for countries setting CO_2/MWh targets, such as the USA.

10.4 Energy storage

A number of energy storage systems are under development to improve plant flexibility, storing energy for direct use or to improve the response time of a fossil fuelled plant. Large-scale energy storage has been achieved using: pumped water (hydro), compressed (CAES) and liquid air (LAES), large-scale batteries, heated ceramic bricks, molten salts and hot water (HWES). Of these options the hot-water storage system, HWES, perhaps offers a simpler integration for energy storage into an existing lignite plant.

The addition of hot condensate storage is a means of storing energy during periods of low power demand which can then be released when required. Figure 25 (Schuele, 2013) shows an example of one variant of a thermal storage device. Upstream of the turbine LP heaters a bypass route can feed high temperature condensate to an array of insulated storage tanks. During periods of low power demand hot condensate is taken from the outlet of the deaerator/feedwater storage tank that supplies the economiser and passed to the thermal storage unit, with hot condensate displacing the cooler contents of the vessel.

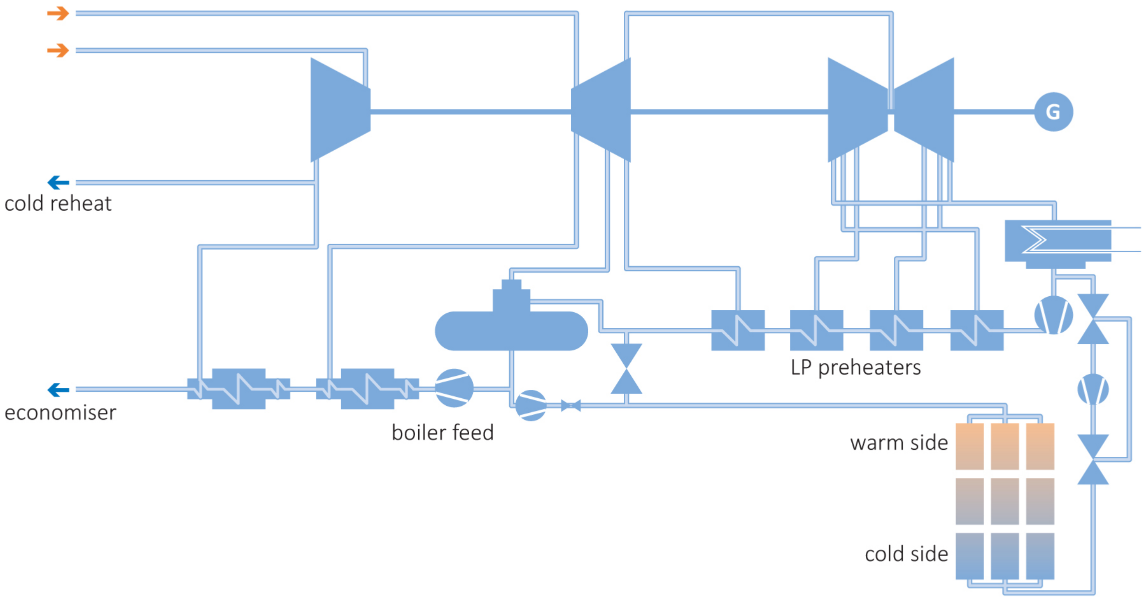

Figure 25 Thermal storage systems for increasing plant flexibility (Schuele, 2012)

During this period the condensate mass flow through the LP preheaters and the feedwater tank is increased. This causes increased extraction of steam from the IP and LP turbines, reducing power output, while building a thermal store, and maintaining the plant at minimum loading.

When power is needed, the hot condensate, which is at the same temperature as the feedwater tank, can be drawn from the store, the LP preheaters are bypassed and so less steam is extracted from the IP/LP turbine raising the steam flow for generation. Overall a system such as this is anticipated to raise 5% additional power from the plant when needed.

For costs, the capital charge for a thermal storage system is currently less than for alternative systems such as battery or compressed air storage, while the efficiency is greater. The thermal storage system has additional benefits of extending the plant load range and enhancing the ramp rate. Although designed for hard coal plants, similar technical issues apply to lignite plant.

11 Carbon mitigation

The most significant action a lignite fuel plant can take to minimise carbon emission is to optimise the efficiency of the plant. A number of the options that are suitable for established plants have already been discussed and include: drying feedstock, optimising the boiler, and upgrading steam turbines. Operating at high efficiency, applying ultra-supercritical steam systems for example can dramatically lower carbon dioxide emission, but even for the most advanced technologies the emissions will exceed those of the lowest emitting fossil fuel, natural gas.

The current options to further reduce carbon emissions are to partially replace lignite by a low emission fuel or to apply carbon capture and storage (CCS) technology. The main fuel alternatives include raising the hydrogen-carbon ratio by co-feeding natural gas and partial replacement of lignite by a renewable, low emission biomass feedstock. The two variants for carbon dioxide capture are enhanced oil recovery (EOR) or storage underground.

The use of bio-waste feedstock, possessing a low emission rating, is not straightforward as these feedstock supplies tend to be seasonal. Furthermore the presence of trace elements can be problematical for the boiler. However, unlike hard coal plants, the energy content of lignite fuel is similar to many waste bio-feedstocks making a direct feed replacement more suitable. Issues involved in the use of bio-waste feeds are explored in Section 11.1.

The use of a natural gas co-feed is discussed in the section on plant flexibility (10.2). Installation of an integrated gas turbine into a lignite plant forming 20% of the overall feed rate, results in an overall plant carbon reduction of 10%, benefitting from the relatively low emission factor for natural gas (about half that of lignite). This modification may be attractive where the natural gas price is competitive, and there are specific emission targets to attain, such as the Clean Green Power Plan, USA.

There are pioneering demonstration programmes underway to develop CCS technology. The methods aim to extract carbon dioxide from dilute low pressure streams using chemical bonding agents, or apply gasification or oxy-combustion techniques to concentrate CO_2 followed by absorption methods. Removal of approximately half of the CO_2 in the stream could make lignite power stations on a par with natural gas plants, although most projects currently aim to remove 65–95% of the CO_2. The latest developments in the capture of CO_2 from an existing lignite power plant are outlined below.

11.1 Evaluating the use of renewable feedstock

There has been a move towards the use of bio-feedstocks in order to lower carbon footprint, but this method has had limited use in lignite PF technology. Under certain circumstances it is thought that bio-waste feedstocks (wood, maize residue, nut kernels, grasses) could constitute up to 20% of the feedstock (Tillman, 2010). Where agricultural waste is rated as low or zero carbon emission then there is the potential to substantially reduce the carbon footprint of the power station.

The preferred reactor technology for bio-feedstock is a fluidised bed combustor (FBC) as this reactor is more suitable for handling fuels that may be more prone to slagging and fouling in a conventional PC boiler. It is possible to directly control sulphur levels in a FBC boiler where there may be an increased risk from sulphur trioxide production at the boiler. An FBC can also tolerate the variability in composition and supply of biomass which is a seasonal product, and the optimal processing conditions can vary with each feedstock

Lignite fuel plants have the advantage in that the boiler is already designed for high moisture content fuels, and so wood waste for example which has a moisture content of about42% would be compatible with typical lignite boiler flows and conditions. The mass of wood would be similar to lignite for the same energy output, whereas for a hard coal almost double the mass of material would be needed to achieve the equivalent energy output to coal which would require modification of feed handling and of boiler loads to accommodate higher gas flow.

There are concerns over the composition of bio-feedstock as a direct replacement for lignite where the reactor has not been specifically designed for them. The chloride content of some bio-feedstock is of particular concern as this can pose significant corrosion problems when hot chloride salts are formed in the combusted gas, whereas chloride is largely absent from lignite fuels. The effect of chlorine is mitigated somewhat where the lignite fuel contains higher levels of sulphur which can displace chlorine from its salts as the temperature falls, preventing excessive corrosion.

A concern is the higher vanadium content of some bio-feedstocks, which results in a low ash melt temperature as this can lead to fouling of the boiler. In addition, the reaction of vanadium pentoxide with alkalis form an alkali vanadate that deposits on heat exchange surfaces, accelerating the rate of corrosion of the super-heater. The higher content of iron oxide may be an issue as that also promotes slagging by association with calcium. The most favourable bio-feedstock is considered to be wood waste as the composition is similar to lignite.

Bio-feedstock has the potential to reduce the amount of fossil carbon from the plant by up to 20%, lowering emissions from 983 to 788 tonnes CO_2 per GWh (2170 to 1740 lbs CO_2 per MWh); this latter figure assumes that the agricultural waste is accounted as zero emission. There are certain combinations of bio-feedstock that could work well in the boiler and other combinations which could lead to significant issues of slagging, fouling and corrosion. A careful analysis would be required before processing an opportunistic feed, given that agricultural waste supply is highly seasonal (Mills, 2014).

11.2 Lignite power plants and carbon capture

The international coal industry is seeking methods to lower carbon emission in compliance with ever tighter emission targets. Carbon capture and storage (CCS) may provide the means to lower emissions, and there are a number of hard coal trials underway. Up till now CCS has been considered as a potential retrofit option primarily for the most technically advanced coal stations because of the high power demand of the capture plant. However, a commercial demonstration plant using lignite fuel and subcritical boiler technology has been commissioned and is now operational.

Canada has set challenging emission targets; Canadian power plants over 50-years old must emit less than 420 tonnes CO_2/GWh (925 lbs CO_2 per MWh), less than half of that emitted by a typical lignite PC plant. Failure to comply with these measures would lead to closure of the plant. In response, SaskPower have revamped the Boundary Dam lignite power station in Saskatchewan in order to capture carbon dioxide from the stack gas. The facility retained subcritical steam technology, although boilers were substantially refitted and a new carbon dioxide capture plant was introduced using amine solvent absorption technology. The CO_2 is then piped off-site and either utilised for enhanced oil recovery (Carbon Capture Utilisation and Storage, CCUS), or pumped to a storage reservoir (CCS) (Massachusetts Institute of Technology, 2015).

In CCUS there are four stages involved in the processing of carbon dioxide:

1. Recovery and compression of CO_2 from the stack gas. The concentration of CO_2 in the stack gas is important for the efficiency and cost of recovery by amine solvent extraction.
2. The transport of liquid compressed carbon dioxide by pipeline to the user.
3. Injection of carbon dioxide into an oil reservoir for enhanced oil recovery, or for storage in a depleted natural gas reservoir with proven properties of gas containment.
4. Continuous monitoring of the reservoir to detect leaks which would negate the carbon reduction scheme.

Although the Boundary Dam plant is not using the most advanced steam technology, project economics benefit from the low cost of lignite fuel compared to a comparable hard coal project and the sale of carbon dioxide at 25 $/ton, projected to earn $20 million per year when producing 800,000 tons CO_2 at full capacity. To further improve cash flow, fly ash is sold for cement manufacture and the SOx is captured and converted to sulphuric acid for sale to fertiliser plants.

The quoted cost to adapt the 110 MW subcritical lignite plant for carbon capture is $500 million with a further $800 million for the carbon capture plant and associated pipeline. The retrofit modifications to the boiler plant led to an increase in power output from 110 to 120 MW despite the additional energy use of the carbon capture plant. The CC unit is energy intensive and may require 20–25% of the station output.

Since commissioning in November 2014, the capture plant has demonstrated significant CO_2 emission reductions; the emissions were a quarter of those from a 'state-of-the–art' natural gas station (Monea, 2015). Although operational for a relatively short period, the project has demonstrated the feasibility of removal of 95% of CO_2 from lignite plant stack gas. However in normal operation the recovery rate would be 80%. To date the facility has captured 300,000 tonnes CO_2 to be utilised in EOR projects (Massachusetts Institute of Technology, 2015).

The capture facility has experienced mechanical problems since commissioning. The issue has not been with the capture plant itself, but from conventional units, notably with leakage from a 1 Mt amine storage vessel. Plant issues and modifications have consequently had an impact on current operations, limiting capture to 50% of the intended rate, which results in lignite emission comparable to that of natural gas (Martel, 2015).

Due to the low cost of feed, lignite stations are cost competitive with hard coal stations but the emission of carbon dioxide is higher per megawatt. The use of low quality lignite has a significant impact on the quantity of CO_2 to be captured and consequently on the economics of lignite–CCUS facilities. The efficiency improvements outlined earlier in this report and preferably the use of higher severity steam systems may reduce the difference in efficiency between lignite and hard coal, substantially lowering the quantity and cost of CO_2 recovery from a new lignite CCUS plant.

Sask Power are currently exploring retrofit opportunities for the technology, and have already identified substantial cost reductions of the order of 30% for the next retrofit to an existing installation. This is the first commercial demonstration project for lignite/CCUS at the beginning of a technology optimisation process and this project will define future CCS retrofit lignite plants.

There is a second lignite-CCS project under construction at Kemper County, USA. The project aims to capture 65% of the CO_2 using a bespoke lignite air gasification technology with pre-combustion capture. The decarbonised product syngas is then used to generate electricity utilising a gas turbine in an Integrated Gasification Combined Cycle (IGCC) facility. The capture plant uses physical absorption methods to recover CO_2: SELEXOL™ – polyethylene glycol dimethyl ether solvents. The original design was limited to the gasification-IGCC plant, and CO_2 capture has been introduced as an add-on treatment plant.

Lignite gasification is a new technology and over the five year construction period cost overruns and unexpected technology issues have led to a current project cost of $5 billion for the 582 MW station. However, despite the high cost, and extended installation time this remains a potentially breakthrough development in the deployment of lignite-CCS. Technical analysis of the gasification technology, excluding CCS, indicates potential efficiencies that exceed those of a USC PF lignite plant.

12 Conclusions

International legislation to reduce greenhouse gas emission together with the introduction of more stringent emission limits for key pollutants is having a substantial impact on the lignite power industry. In particular, low efficiency plants are coming under significant pressure to improve performance, both to lower emissions and to reduce plant heat rate, or face closure. The latest HELE technology applied to new lignite plants can achieve performance approaching that of hard coal power stations. The established treatment units achieve emission targets but are expensive to retrofit. For existing plants under threat of closure there is a need to improve efficiency and reduce emissions utilising technologies which ideally require both lower investment and short installation times.

The majority of the lignite plant fleet utilises subcritical steam systems which will require suitable retrofit adaptations. Given the disruption and cost, it is unlikely that a subcritical boiler would be upgraded to supercritical steam conditions, and so plant modification is likely to be limited to add-on and direct replacement units. For subcritical facilities there is a substantial gap between the lowest performing stations and 'best in class' units, and consequently there is an opportunity for upgrading technologies to make a significant difference to performance and emissions.

Lignite pre-treatment

The quality of the feedstock is a significant consideration for lignite power performance, as high moisture/low energy content results in increased greenhouse gas emissions together with lower efficiency. Of the numerous technologies available for lignite drying this study has focused on two commercially available fluidised bed technologies that use low-grade heat streams to dry the fuel. One technology uses gravity segregation to remove sulphur and mercury, easing post boiler emissions treatment. The limiting factor to the benefit of lignite drying is likely to be the impact on minimum gas flow rate requirements of the boiler design, as steam derived from the lignite fuel is reduced.

Combustor design and advanced instrumentation and control

Where the combustion within the boiler is uneven or unstable then the lignite plant is forced to operate with higher air ratios, departing from optimum process conditions, to safeguard equipment and avoid slagging and fouling. In these circumstances, improved instrumentation and associated reactor control can offer a significant benefit. Advanced low-NOx combustion equipment and the recent introduction of wireless instrumentation, avoiding costly wiring, combine to offer a route to more efficient boiler operation.

Steam turbines

The gradual decline in efficiency of 1990's era steam turbines is well-established, and replacement of part or all of the turbine sets, perhaps within original casings, has proved a successful retrofit strategy. New turbines are more durable and exceed original design performance, with reported station power output rising by up to 15%, depending on the condition of the pre-existing turbine facility.

The installation of a revised emissions treatment plant to meet regulatory requirements tends to lower efficiency impacting on the power output of a station. Therefore efficiency improvements will be necessary, even to maintain the current performance, while legislation in some countries requires a reduction in heat rate.

Power plants that have been configured for a further 25-years operation are likely to be already fitted with an established emissions treatment plant incorporating selective catalytic reduction (SCR), electrostatic precipitators or baghouses (ESP/FF), and flue gas desulphurisation (wFGD). For facilities with a shorter lifespan seeking to reduce emissions there are alternative technologies possessing lower installation costs that can match the performance of these established systems.

Nitric oxide (NOx)

There are a number of technologies available to treat NOx emissions that can compete with SCR. A combination of inexpensive selective non-catalytic reduction (SNCR) together with ozone NO oxidation or a compact SCR, can achieve the required NOx reduction. These hybrid technologies require lower initial investment and avoid extended down time.

Mercury

Mercury is treated by activated carbon injection (ACI); the quantity of activated carbon may be reduced by combining with other ‘co-benefit’ technologies that promote mercury oxidation, such as ozonolysis. The established technology for particulates is either ESP, fabric filters FF or a combination of both. Fabric filters are required for a number of sorbent injection methods, and are now favoured for the removal of $PM_{2.5}$ particulates.

Sulphur dioxide (SOx)

The lowest cost method to treat sulphur dioxide is direct sorbent injection (DSI) where reagent is injected into the ductwork after the boiler. It is also the least efficient method showing modest sulphur recovery (50–80%). Spray dry absorption (SDA) and circulating fluidised bed scrubbing (CFBS) SOx technology offer an alternative to the established wFGD method for lower investment, and can be configured to recover mercury efficiently.

Multicomponent treatment

New multicomponent technologies entering service offer a means to remove all the pollutants in a single treatment unit. This approach would be of particular interest to those plants possessing limited emissions control. The Airborne™ process which can remove SOx and NOx using one reagent, can be configured for mercury removal and fitted with a baghouse for particulate filtration, has the advantage that it can be retrofitted into an existing underperforming FGD plant. This technology uses relatively expensive sodium bicarbonate but has overcome the issue of reagent cost by incorporating a regeneration unit in the plant. A feature of this technology is the conversion of pollutants to ammonium sulphate and nitrate products for sale as fertiliser.

Re-engineering of the boiler to incorporate an add-on gasification reactor is an alternative means to achieve low NO and SO_2 emissions, with additional benefits of cleaner boiler surfaces, corrosion reduction and improved efficiency through lignite drying and reduced parasitic load from emissions control equipment.

Flexibility

Power stations increasingly have to respond to variation in demand due to the growing contribution from renewable energy sources. Plant modifications may be required to respond to this change from base load operation; this includes measures to minimise thermal stress during transient operation while upgraded control systems can optimise combined operation of the boiler and steam turbine to mitigate temperature gradients. Technologies specifically aimed at enhancing flexible operation of the plant include: co-combustion of natural gas where lower priced gas is available; energy storage solutions such as hot water storage HWES; and indirect firing of dry lignite to allow extended operation at low rates.

Greenhouse gases

Maximising efficiency is the best means to lower greenhouse gas emissions from lignite fuel, but efficiency measures alone will be insufficient in the future. The latest developments at Sask Power's Boundary Dam project involves the retrofit of a carbon capture plant to an 110 MW subcritical lignite power station. The initial project results indicate that technical hurdles for lignite-CCUS plants have been overcome with CO_2 recoveries demonstrated at up to 95%. The main objective is to reduce the cost of integrating carbon capture while also showing the stability of deep storage in saline aquifers as an alternate to EOR.

Co-feeds

An alternative to CCUS is to partially replace lignite with a biomass co-feed such as wood waste. However, practical implementation of this is not entirely straight forward in a pulverised fuel plant due to the possible seasonal supply and presence of impurities such as vanadium, chlorine and iron in agricultural waste stock. Natural gas has been used as a co-feed for coal stations as part of flexibility measures, but could be considered as a potential co-feed for lignite plants to moderate CO_2 emission.

This report reviews examples of the commercial implementation of available techniques to improve efficiency and meet the latest emission standards. Alternate commercial emissions treatment techniques are described which can compete with established technologies on performance and cost. Although these have yet to be widely implemented on lignite plants, the industry is gaining from first-hand experience on hard coal plants, of especial relevance in retrofit to established facilities.

A number of countries including Germany, USA and the UK have recently announced the closure of less efficient hard coal and lignite plants, even though that means generation capacity shortages. The adoption of high efficiency technology, effective pollutant emission control and the development of technologies to reduce greenhouse gas emissions have never been more relevant to the lignite power industry.

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14 Appendix

Summary of lignite drying technologies

A listing of lignite drying technologies showing the manufacturer, a short description of the technique applied and an update on their status as of 2015.

Table A1 Listing of lignite pre-drying technologies under development or commercialised for lignite power plants (Zhu, 2012)

Dryer name	Company	Technology	Status 2015
WTA	RWE (Germany)	Fluidised bed using steam (eg sourced from low pressure turbine) drying at 110°C	Demonstration plant 210 t/h removing 100 t/h water on high moisture lignite, operational since 2008 at Niederhausen power station, >6 years. Proven most efficient for fine particles (<2 mm)
Dryfining™	Great River Energy (USA)	Drying and partial dense minerals removal including iron sulphides and mercury	Commercial scale demonstration from 2010 on medium level moisture lignite, >4 years
PFBD	Vattenfall (Germany)	High pressure steam fluidised bed dryer	10 t/h Demonstration plant operated from 2008
Tubular dryer Eg AST, Zemag etc.	Number of suppliers	Low pressure steam drying in rotating drum, lignite in air stream	Drums of 8 m x 5.6 m can dry 25 t/h. aimed at dry lignite support burners
Integrated drying gasification combined cycle IDGCC	HRL (Australia) Dual Gas	High pressure hot air (from gasifier) blown fluidised bed dryer	Successful pilot. Victoria Govt. project grant for a 600 MW plant cancelled in 2013, seeking alternate support
Superheated steam rotating dryer SHSD	Keith Engineering (Australia)	Superheated steam dryer (>300°C)can reduce mineral content and moisture	Tested on 8 mm particles. Small-scale batch pilot that removed 80% moisture. Sulphur and sodium (>50%) level sin the lignite reduced.
Coldry™	Environmental Clean Technologies Ltd (Australia)	Lignite water mixture agitation removes water, from lignite followed by drying at 40°C. Waste heat streams used	At 4t/h* scale with dried product used by generators. Patent issues in India for a black coal equivalent BCE product from lignite 2015.
Microwave drying Drycol™	DBA Global (Australia)	Water in the lignite is directly heated and evaporated from the coal mass	Some issues with hot spots from impurities and ignition during drying. Can achieve up to 94% drying as all water in lignite energised.
Microwave drying CoalTek	CoalTek Inc (USA)	Removes water and contaminants	40–50% moisture removal typical 24 t/h* facility
High velocity air drying Windhexe	Vortex Dehydration Technology (USA)	High velocity air used to shatter lignite particles to remove water trapped in pores	Tested by International Power at Hazelwood station
High velocity air DevourX	DevourX (Malaysia)	Aero-acoustic drying and grinding technology covert lignite to a dry powder	Machine capacity is 100–150 t/h, available under licence
High velocity air Lamiflo	LF Pumping (Europe)	Air cyclone dryer targeting surface moisture	Electrically powered units up to 250 t/h, sand dryer

Table A1 continued

Dryer name	**Company**	**Technology**	**Status 2015**
Hydrothermal dewatering HTD	K-Fuel (USA)/Evergreen Energy	High pressure heating to crush the lignite releasing water.	Removes >50% water and Hg. 150 t/h* plant operated in 2005 led to a redesign by Bechtel offered commercially.
Continuous hydrothermal dewatering CHTD	Exergen	High pressure and temperature autoclave to de-carboxylate lignite.	4 t/h Pilot scale demonstration, aiming for 50 t/h
Hot water drying	Energy and Environmental research Centre	High pressure and temperature drying of lignite water mixture by expansion/expulsion mechanism	7.5 t/d pilot plant
Mechanical Thermal expression (MTE)	CRC Lignite	Dewatering a hot lignite slurry in a compression cylinder	Pilot trial showed drying to 30% moisture. Water remediation an issue due to the high contaminant level in waste streams.

based on 5000 hours per year