Techno-economics of modern pre-drying technologies for lignite-fired power plants

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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, Canada, China, the European Commission, Germany, India, Italy, Japan, New Zealand, 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

Lignite is an important fuel for power generation in many parts of the world. In conventional lignite-fired power plants, the high moisture content of lignite can result in low plant thermal efficiencies. Drying the lignite prior to combustion in the boiler is thus an effective way to increase the thermal efficiencies and reduce the CO_2 emissions from lignite-fired power plants. Modern pre-drying technologies, which can continuously dry run-of-mine lignite, have been developed in Germany and the USA. RWE's WTA dryer and GRE's DryFining™ system have been successfully demonstrated at commercial scale, while Vattenfall's PFBD dryer has reached pilot scale. The technical details of these modern lignite pre-dyers have been discussed in detail in the literature, while their cost and techno-economic information is limited in the public domain. This report examines such information on modern pre-drying technologies gathered from relevant publicly available literature and analyses their techno-economic implications for lignite-fired power plants. The capital costs of modern pre-drying processes are likely to be in the range of US$ 33–50 million (currency in the year of reporting). Such costs may be largely offset by the gains in plant thermal efficiencies and the power savings due to reduced flue gas flows and fuel handling equipment. The actual capital costs depend both on the properties of the fuel and the operational parameters. Modern pre-drying processes can result in about 1 percentage point (LHV) increase in the plant thermal efficiency when retrofitted to existing lignite-fired power plants; they could increase the plant thermal efficiency by 4–5 percentage points (LHV) in dry lignite-fired power plants and a further 0–3 percentage points of efficiency improvement can be expected if 700°C advanced steam conditions are adopted. The pre-dryers can deliver similar benefits to future lignite-fired power plants that capture CO_2.

Acronyms and abbreviations

AUSC	advanced ultra-supercritical
BoA	lignite-fired power station with optimised plant engineering
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
CCS	carbon capture and sequestration
DECC	Department of Energy and Climate Change (UK)
ENBIPRO	Energie-Billanz-Program (Germany)
EPC	engineering, procurement and construction
ESP	electrostatic precipitator
FGD	flue gas desulphurisation
GRE	Great River Energy
HHV	higher heating value
HP	high pressure
IEA CCC	IEA Clean Coal Centre
IED	Industrial Emissions Directive (European Union)
IGCC	integrated gasification combined cycle
LCOE	levelised cost of electricity
LHV	lower heating value
LP	low pressure
MHI	Mitsubishi Heavy Industry
MTE	mechanical thermal expression
MWh	megawatt hour
NETL	National Energy Technology Laboratory (USA)
O&M	operation and maintenance
OPEX	operational expenditure
PF	pulverised fuel
PFBD	pressurised fluidised bed dryer
SC	Supercritical
US DOE	Department of Energy (USA)
WACC	weighted average cost of capital
WTA	fluidised bed drying with internal waste heat utilisation
ZEP	zero emissions platform

Contents

List of Figures

List of Tables

1 Introduction

Around half of the world's estimated recoverable coal reserves comprise coals of low quality, predominantly lignites, subbituminous coals and high-ash bituminous coals. By rank on a tonnage basis, lignite and subbituminous coals account for 18% and 32% of the world's recoverable reserves, respectively (Mills, 2011). Despite their abundance and geographically wide availability, low-rank coals find limited use due primarily to their high moisture contents and the attendant low calorific values as well as their high propensity for spontaneous combustion. Reducing the moisture content of low-rank coals is necessary to enhance their heating values and safety during transportation and storage and to reduce greenhouse gas emissions from their combustion. Moreover, drying is an integrated step in almost all low-rank coal upgrading processes, which convert these low-value coals into higher-value products that can capture market opportunities distant from where these coal are produced.

There exist a variety of technologies for drying or upgrading low-rank coal, which have been reviewed in detail in a previous IEA CCC report (Dong, 2011). However, it is challenging, if not impossible, to find one technology that is cost-effective and efficient in all aspects. A range of factors, including particle size and size distribution, energy consumption, material handling capabilities, throughput, safety, carbon footprint, capital and operational costs, and return on investment, need to be taken into account. Most of the previous work found in the literature focuses on the design and technical aspects of low-rank coal drying and upgrading processes. There is little information available on the cost/economics of these processes due largely to the confidentiality that technology developers place on their processes. This is not difficult to understand considering that at this stage there is no clear market winner among the different drying/upgrading technologies and that those technologies have been applied only to a limited number of commercial projects.

Information is more readily available on the technologies used to continuously pre-dry low-rank coals before they are burned in the boiler furnace. The development of most of these technologies has been jointly funded by governments, which require disclosure and sharing of the R&D work and results. In contrast, there is little information on coal upgrading technologies that are based on proprietary R&D efforts due to the need to protect intellectual property.

The use of lignites for electricity generation entails many differences in boiler design and ancillary equipment in comparison with hard coal power plants as a result of the distinct properties of lignites. Such differences can lead to higher capital costs. In particular, the high moisture content (30–70% on as-received basis) of lignites necessitates drying immediately prior to combustion to enable ignition and stable flames. In conventional lignite-fired units, this is generally achieved through simultaneous milling and drying in beater wheel mills in which hot furnace gas of ~1000°C drawn from the upper part of the boiler furnace is circulated. In this method, the energy used for drying lignite is the high grade heat in the hot flue gas; the evaporated moisture is carried by the flue gas through the boiler furnace. The moisture laden flue gas makes the boiler furnace temperature several hundred degrees lower than that of comparable hard coal-fired units. As illustrated in Figure 1, a larger boiler furnace is thus needed to accommodate large volumes of moisture-laden flue gas and to increase the radiant heat exchange surface to make up for the decrease in the flue gas temperature. A larger boiler not only incurs higher capital costs but also higher operational and maintenance costs as a result of increased demand for coal handling and milling as well as flue gas clean-up.

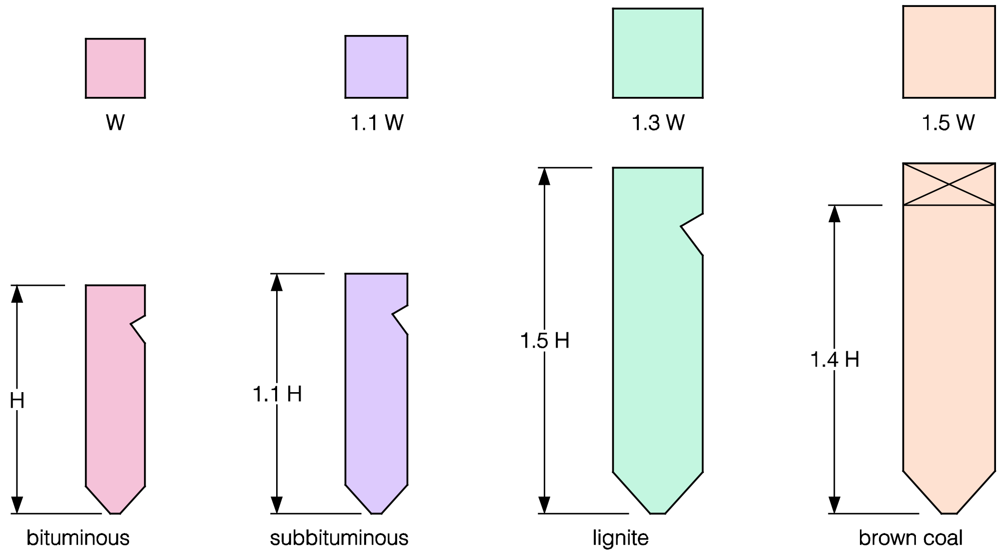

Figure 1 Effect of coal rank on the boiler size (St Baker and Juniper, 1982)

More importantly, the integrated mill drying results in significant plant efficiency penalties in conventional lignite-fired power plants as a considerable amount of energy in the lignite feed is used to provide heat needed for evaporation of the moisture. The efficiency of a coal-fired plant can drop by about 4 percentage points and 9 percentage points when coal moisture content increases from 10% to 40% and 60%, respectively (Burnard and Bhattacharya, 2011). Consequently, lignite-fired power plants emit considerably more CO_2 than hard coal power plants of same power ratings.

The integrated mill drying principle is used in Australian and German lignite/brown coal-fired power stations with similar basic designs. In contrast, it is not used in lignite-fired power plants in the USA, where the lignites have lower moisture contents. Nevertheless, it is reported that Texas Utilities uses Parry entrained flow evaporative dryers to prepare dry lignite that is burnt at Alcoa's generating plant in Rockdale, Texas (Willson and others, 1992).

Higher power plant efficiencies and lower capital costs can be achieved if the run-of-mine lignite is dried and the evaporated moisture is removed from the flue gas prior to combustion, preferably using low grade heat that is otherwise wasted on the power plant. Modern pre-drying processes, based on this design principle, typically use the sensible heat of cooled flue gas, recover the latent heat from the dryer effluent, and/or remove the moisture without evaporation. One common feature of these modern pre-dryers is the employment of a fluidised bed with steam as the fluidising media, which is considered the most practically feasible technology for drying lignite at large scale. These modern pre-dryers offer the greatest potential for efficiency improvement of lignite-fired power plants in the immediate future (Henderson, 2013).

This report examines the techno-economic information available in the public literature on modern pre-drying technologies that can be integrated into lignite-fired power plants and are capable of continuously drying the fuel feed. Chapter 2 discusses techno-economic considerations related to retrofitting these pre-drying processes to existing lignite power plants. Chapter 3 analyses the application of modern pre-dryers to new build lignite power plants as proposed in a number of concept studies. Finally, Chapter 4 summarises the key findings and the techno-economic implications of installing modern pre-drying processes for lignite-fired power plants.

2 Pre-drying retrofit to lignite-fired power plants

Global production of low-rank coals is currently around 950 Mt/y (Mills, 2011). The bulk of these coals are used for power generation at mine-mouth power plants, which mostly have low efficiencies due to the high moisture contents and/or the low heating values of these coals. Retrofitting modern pre-dryers to these existing power plants can improve their thermal efficiencies and thus reduce their carbon footprints. For example, in the USA, where there are 35 lignite-fired units with a total capacity of 15 GW, a reduction of 10 percentage points in the lignite moisture content could result in a reduction of more than 10 million tonnes (Mt) of CO_2 emissions annually from these units (Burnard and Bhattacharya, 2011). In addition, firing dried low-rank coal in these power plants can also reduce NOx, SO_2 and mercury emissions.

The R&D work undertaken on efficient modern pre-drying processes on power plants has been reviewed in detail in previous IEA CCC reports (Dong, 2011; Henderson, 2013). It is technically possible to retrofit modern pre-drying systems to existing lignite-fired power plants, but only part of the total fuel input can be replaced by dried coal (up to 30% for pf units; CFBC units can take more). The retrofit can produce about one percentage point gain in the plant thermal efficiency and a CO_2 reduction of about 2.5% (Henderson, 2013). This chapter discusses the implications of retrofitting these pre-drying systems for the capital and operational costs of existing pf lignite-fired power plants.

2.1 WTA

In Germany, RWE Rheinbraun has developed a proprietary pre-drying process, WTA, which in German stands for fluidised bed drying with internal waste heat utilisation (Wirbelschicht-Trocknung mit interner Abwämenutzung). As shown in Figure 2-a, lignite is dried in the fluidised bed with the heat for drying provided almost exclusively by the tubular heat exchanger immersed in the fluidised bed and only to a small extent by the fluidising media (coal moisture vapour). The heating steam in the heat exchanger can come either from an external source (open cycle), such as the bleed steam from the low-pressure (LP) steam turbine of the associated lignite unit, or from the recompressed vapour evaporated from the raw lignite (closed cycle). In the open cycle, the vapour coming out of the dryer may be condensed to preheat boiler feed water or vented to the atmosphere as a low cost option. A detailed discussion can be found in a previous IEA CCC report (Dong, 2011).

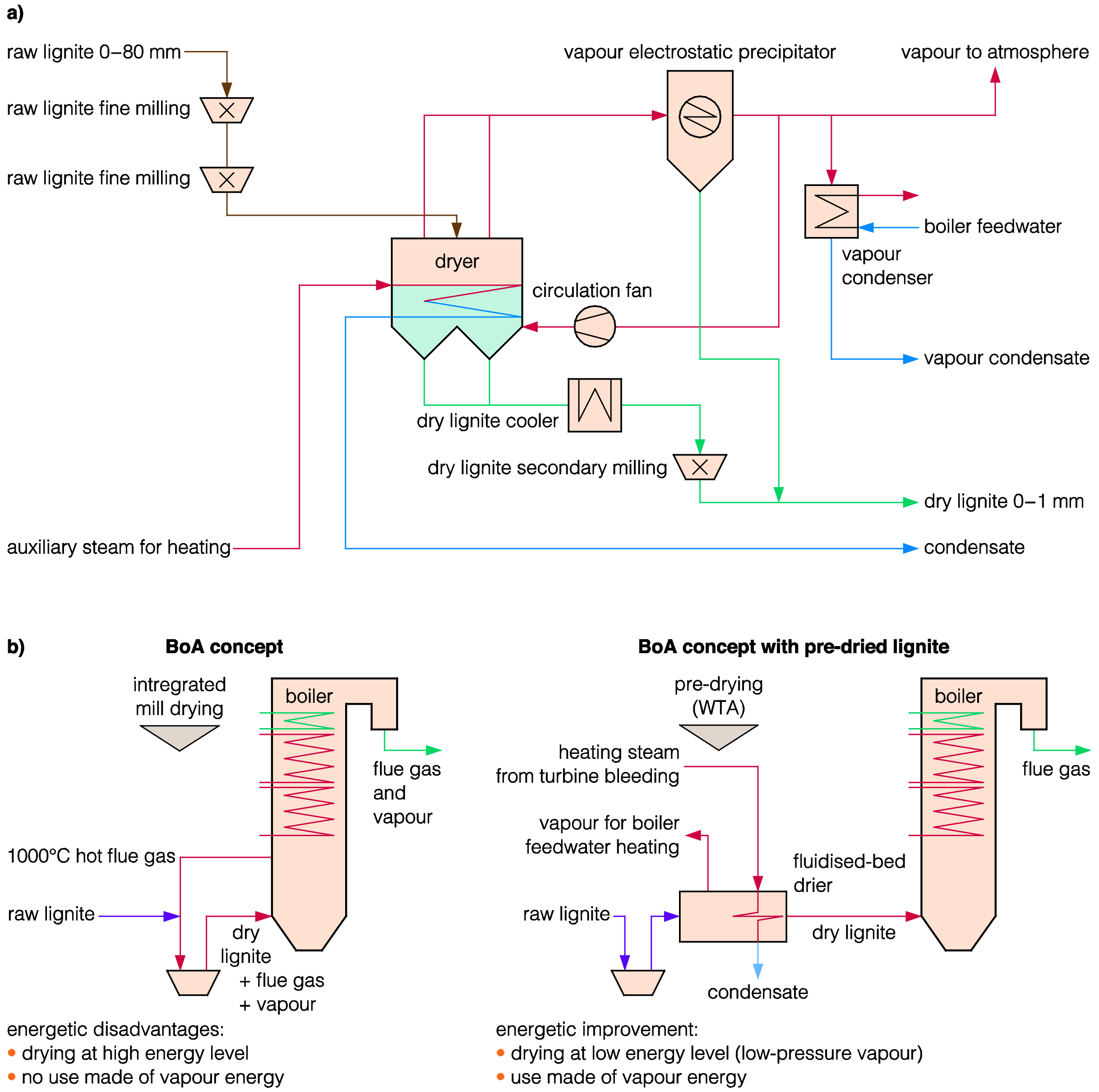

Figure 2 (a) WTA with vapour condensation (open cycle); (b) WTA integrated in a BoA lignite power plant (modified from Burnard and Bhattacharya, 2011)

2.1.1 Process optimisation

Extensive R&D work has been carried out to determine the optimum operational conditions of the WTA dryer. The operational parameters considered for optimisation include the lignite particle size, the fluidised bed pressure and the heating steam pressure, which together determine equipment costs and energy consumption for the pre-drying process.

The heat transfer and fluid dynamics of the fluidised bed dryer are significantly influenced by the lignite particle size. The heat transfer process between the fluidised bed and the tubular heat exchanger immersed in the bed is determined by gas convection, particle convection and radiation. As the particle size decreases, particle convection dominates the heat transfer process. The particle convective coefficient increases with decreasing particle size, so that finer particles increase the heat transfer coefficient and thus reduce the design workload of the heat exchanger (such as surface area and temperature difference). In addition, finer particles fluidise more readily and consequently need lower fluidising velocities. RWE has demonstrated the advantage of finer particles in operation of the WTA-1 (feed coal size 0–6 mm) and WTA-2 (feed coal size 0–2 mm) test plants at Frechen, Germany. The heat transfer coefficient of the immersed heat exchanger in WTA-2 was 70–80% greater than that of WTA-1 with coarser coal feed, while the fluidising velocity required above the bed bottom was reduced by approximately 65% (Klutz and others, 2010).

Thermodynamics determine that at a constant bed pressure, the residual moisture content of dried lignite is dependent only upon the temperature of steam present in the fluidised bed (that is the bed temperature). The study by Klutz and others (2010) shows that at a bed pressure of approximately 1.1 bar, an equilibrium moisture content of approximately 12 wt% is achieved at 110°C bed temperature for Rhenish lignite and at 107°C for an Australian lignite. A lower equilibrium residual moisture content can be obtained at higher temperatures, but this heat-to-dry effect tends to level off as determined by the thermodynamics. Therefore, it is an important economic consideration to balance the desired residual moisture content and the acceptable bed temperature, which is largely controlled by the heating steam pressure, *see* discussion below.

The heating steam pressure determines the heating steam temperature and thus the temperature difference across the wall of the heat exchanger tubes. Utilising heating steam with higher pressures reduces the surface area of the heat exchanger and thus the size of the dryer, which results in reduced capital outlays for the pre-drying system. However, this benefit comes at a cost because using higher pressure steam means consuming more energy that could have been used to produce electricity. This could lead to a reduced efficiency of the associated power plant if the pressure of the steam is too high. At constant heat transfer and evaporation rates, the upper limit of the heating steam pressure is set by fluid dynamic requirements, whilst the lower limit is determined by the maximum size of the dryer that can be fabricated and transported economically as a complete unit or in modules. Within these limits, the dryer can be optimised in both technical and economic terms.

In addition to the heating steam pressure, the equilibrium moisture content of dried lignite is also controlled by the fluidised bed temperature (or pressure). Assuming a temperature difference of 30°C between the fluidised bed and heat exchanger, the required heating steam pressure for the heat exchanger needs to rise from 3.7 bar to 13.7 bar to achieve an equilibrium moisture content of 12 wt% if the fluidised bed pressure is increased from 1 bar to 6 bar (Klutz and others, 2010).

The fluidised bed pressure also affects the heat transfer between the bed and the heat exchanger; the gas convective coefficient is proportional to the square root of the bed pressure. However, this positive effect diminishes as the particle size reduces because particle convection comes to dominate the heat transfer process. For fine particles, the fluidised bed pressure is more of concern with respect to the bed fluidisation. At a constant evaporation rate, an increase in the bed pressure is associated with a reduction in the superficial velocity of the fluidising media. With only a slight change of fluidisation point (the minimum velocity of the fluidising media at which coal particles no longer rest on each other) with pressure, a higher bed pressure leads to a considerably reduced volumetric bubble flow rate, and hence reduces the mixing intensity of cohesive raw lignite and easily fluidised dried lignite. This is adverse to the operation of the WTA dryer with a high specific surface load.

With these parameters taken into account, the size of the dryer, vapour dust collector, fluidising fan and connection pipes can be optimised so that the entire dryer is compact with low electric power consumption. The sole heat transfer consideration determines that the size of the WTA dryer can be reduced only to the point that the heat exchange surface area cannot be further reduced by improving the heat transfer coefficients. In addition, the increased costs for high pressure equipment/machinery need to be taken into account for system optimisation. A large pressure difference at the coal feed and discharge systems can lead to increased wear and leakages that have to be safely managed, necessitating further process-related outlay of capital.

2.1.2 Technology development and cost consideration

The development of the WTA dryer has been made through a series of four test plants: initially the two WTA-1 plants at Frechen and Niederaussem using 0–6 mm coarse particles (as is common in coal upgrading processes and necessary for the High-Temperature Winkler gasification technology) and subsequently the two WTA-2 plants based on fine grain, 0–2 mm size, also at the two sites.

Klutz and others (2010) compared the investment costs on a normalised basis for the Frechen WTA-2 plant (fine grain: 0-2 mm), the Niederaussem WTA-2 plant (fine grain: 0–2 mm), and Vattenfall's DDWT (the abbreviation for Druckaufgeladene Dampf-Wirbelschicht Trocknung, which means pressurised steam fluidised bed drying) plant (system pressure 6 bar; coarse grain 0–6 mm). No heat recovery from the evaporated moisture was made on either the Frechen WTA-2 plant (as built) or the DDWT plant, whilst the Niederaussem WTA-2 plant included a vapour condenser. The investment costs for DDWT were based on a press release by Vattenfall in November 2007 and there for the two WTA-2 plants based on the actual total plant costs inclusive of engineering and assembly. All costs were escalated to 2010 levels based on German Federal Statistic Office indices. Regression analysis was used to normalise the plants to the same unit size to eliminate the size-dependent cost effects. The comparison showed that the investment costs of DDWT, which used coarse grains, were 3.2 times higher than those for the Frechen WTA-2 plant and 1.9 times higher than those for the Niederaussem WTA-2 plant. This indicates that the increased investment costs associated with utilising higher system pressures cannot be offset by any gains in other areas. RWE also confirmed in another report (Reinartz, 2006) that fine grain drying reduced the size of dryer, ESP and fluidisation blower by half and the size of the vapour recompressor by one third. Supplementary equipment optimisation allowed the specific investment costs of the entire WTA pre-drying system to be cut by 60% to 70 €/kW, compared to those for WTA coarse grain drying (*see* Figure 3). Those findings have led RWE Power to decide in favour of reduced lignite grain size for future development of the WTA dryer.

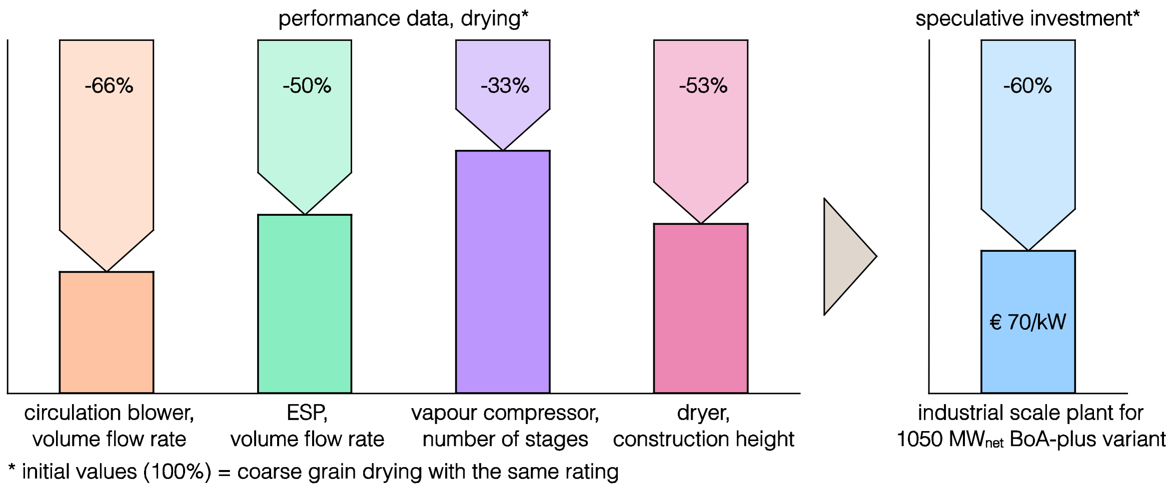

Figure 3 **WTA fine grain drying permits significant reduction in the dryer size and investment costs** (modified from Reinartz, 2006)

Klutz and others (2010) also revealed that considerable gains in efficiency could be obtained from energy recovery of the evaporated vapour. Three recovery processes were considered by RWE: mechanical recompression in an open heat pump process, direct condensation in a process heat sink, and expansion of the vapour in a condensing turbine. The first two options have been pursued by RWE while the last option was abandoned due to considerable outlays for machinery and equipment and no efficiency advantages over vapour compression. Vapour condensation could serve two purposes: firstly for preheating boiler feed water and secondly for producing secondary steam; this process is an attractively priced option for lignite with relatively low moisture contents and a sufficient number of heat sinks available on the associated power plant. If the power plant offers no, or only small, heat sinks, mechanical vapour recompression is advantageous, particularly for lignite with relatively high moisture contents. In principle, the WTA dryer system could be virtually self-sufficient in steam if the vapour condensate from the embedded heat exchanger is used to preheat the raw lignite.

WTA has reached the full-scale commercial demonstration stage with the erection of the prototype WTA-2 plant at RWE's 1050 MW (net) Niederaussem K supercritical unit. The prototype dryer is of the open cycle variant, and extracts LP steam from the turbines to provide heat into the dryer. It was designed to dry 210 t/h of 50–55% moisture lignite to produce 110 t/h of dried product, which corresponds to 30% of the fuel requirement of this BoA unit at maximum continuous rating (Henderson, 2013). As the largest lignite dryer in the world, the prototype dryer incurred a total investment of some €50 million for erection and operation (RWE, 2009). Since it was designed for full commercial-scale operation, future commercially supplied WTA dryers would be no larger. This prototype dryer now achieves 83% of the design throughput, limited only by the raw coal feed path. The dried lignite has a 12% moisture content with variation within just 0.5 percentage points. Availability of this dryer was 94% during continuous operation in 2011. The initial difficulties in achieving acceptable performance with a very cohesive and xylite-rich coal (Garzweiler lignite) have been resolved by process modifications in 2012 and the WTA plant is now operating stably and responds well to load ramping (von Bargen, 2013). The dried lignite was initially fed to the existing dry lignite start-up burners on the unit, but this resulted in slagging issues (Kluger and others, 2012). In 2013, a modification was made to introduce the dried lignite at a lower position into the combustion chamber through the eight wheel beater mills rather than through the dry lignite start-up burners, and the initial experience with this modification has been positive (von Bargen, 2013).

RWE's WTA pre-drying technology is being licensed to Linde, ThyssenKrupp Uhde and other companies. RWE will provide tests, basic design and support, while the licensed suppliers will be responsible for detailed design, erection and commissioning and provide the commercial guarantees for clients. WTA is also used as a key component of RWE's BoA Plus power plant concept, which is discussed in Section 3.1.

2.2 Vattenfall PFBD dryer

Vattenfall Europe AG developed a pre-drying process, which is similar to WTA (operating at atmospheric pressures) but operates under higher pressures. As shown in Figure 4, Vattenfall's pressurised fluidised bed dryer (PFBD) is intended to deliver a better cost/benefit ratio than the atmospheric variants (Leidich and others, 2005). This is largely due to the increased heat transfer coefficients for heat transfer between fluidised lignite particles when the fluidised bed operates at higher pressures. The higher pressures also reduce the superheating of evaporated moisture as the boiling point of coal moisture increases accordingly. High pressure drying improves the opportunity to recover the energy in the evaporated moisture by means of, for example, a steam expander, which then reduces the cooling load of the dryer. Moreover, the pressurised dryer is more compact in size as volume flows are smaller under higher pressures. Nevertheless, changes need to be made to the coal feeding, mills and boiler layouts, which will add to the capital outlay. Leidich and others (2005) made a cost comparison between an atmospheric pre-drying plant and a pressurised pre-drying plant. They found that a clear cost advantage of about 20% might be expected from the pressurised variant. When being retrofitted to an existing power plant, the pressurised variant could be 7–10% cheaper potentially than the atmospheric variant.

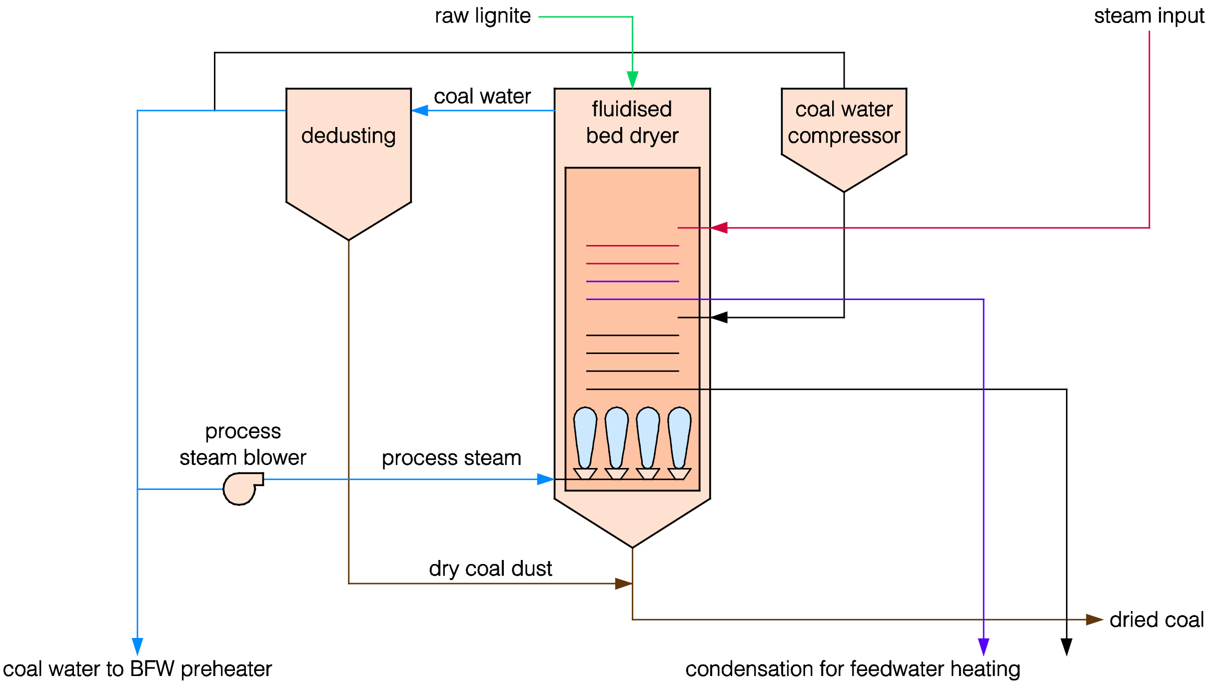

Figure 4 Schematic of Vattenfall's pressurised fluidised bed dryer (Vattenfall, 2012)

Vattenfall's PFBD drying technology has moved from a small prototype of 0.5 t/h in 2006 to a pilot-scale test plant of 10 t/h at Schwarze Pumpe power station since 2008. This pilot plant is now part of Vattenfall's FlexGen programme. In this pilot plant, lignite is dried under 1–6 bar to a moisture content of 8–17% from 55–60% in the raw lignite (Vattenfall, 2012). The lower heating value (LHV) of lignite is thus increased from 8.5 MJ/kg to 20.2 MJ/kg (ADEME, 2012). The vapour produced from the dryer is at the pressure prevailing in the fluidised bed, so can be used in the power plant cycle for energy production. The pilot plant results showed the potential of increasing the power plant efficiency by several percentage points and reducing CO_2 emissions by up to 5–10%. A large demonstration facility was planned to be integrated into the Vattenfall's oxyfuel combustion demonstration plant in Schwarze Pumpe, Germany in 2013. This project, however, is not going forward as Vattenfall abandoned all its research on CCS in May 2014.

2.3 DryFining™

DryFining™ was developed and patented in the USA by Great River Energy (GRE) with the involvement of Lehigh University's Energy Research Centre. As suggested by the name, it combines drying and beneficiation in one process. It utilises waste heat available in a power station to partially dry the feed coal in a fluidised bed dryer. Meanwhile, denser materials present in the coal such as pyrites and stray rocks can be separated from coal and removed from the dryer, thereby improving the quality of coal fed to the boiler.

2.3.1 Process development

Development of DryFining™ was funded by the first round of the US Department of Energy Clean Coal Power Initiative with additional support from the National Energy Technology Laboratory (NETL) (NETL, 2011). Over the last decade, GRE has proved the technical feasibility of the technology concept firstly in a 2 t/h pilot-scale dryer, then in a 75 t/h prototype-scale dryer integrated into GRE's Coal Creek Station in North Dakota (2006–2009), and finally in the complete conversion of the 2 x 546 MWe Coal Creek Station to dry coal firing (that is the dried coal from the DryFining™ accounts for all the coal feed to this station). The full-scale coal drying system at the Coal Creek station includes four commercial-sized (125 t/h feed rate) moving fluidised bed dryers per unit. The system was commissioned in December 2009 and fully-instrumented for process monitoring and control. Tests to gain preliminary information on operation and performance of the dryer and baghouse were subsequently carried out in 2009 and 2010.

Figure 5 shows the overall integration of the DryFining™ dryer at Coal Creek Station. The major source of waste heat for DryFining™ is from the flue gas system. This heat is extracted using flue gas coolers installed at a convenient location downstream of the air heater and particulate removal equipment. Another heat source is the cooling water. Extracting low grade heat from the hot water fed to the cooling tower not only benefits the DryFining™ process but also lessens the heat rejection load on the cooling tower.

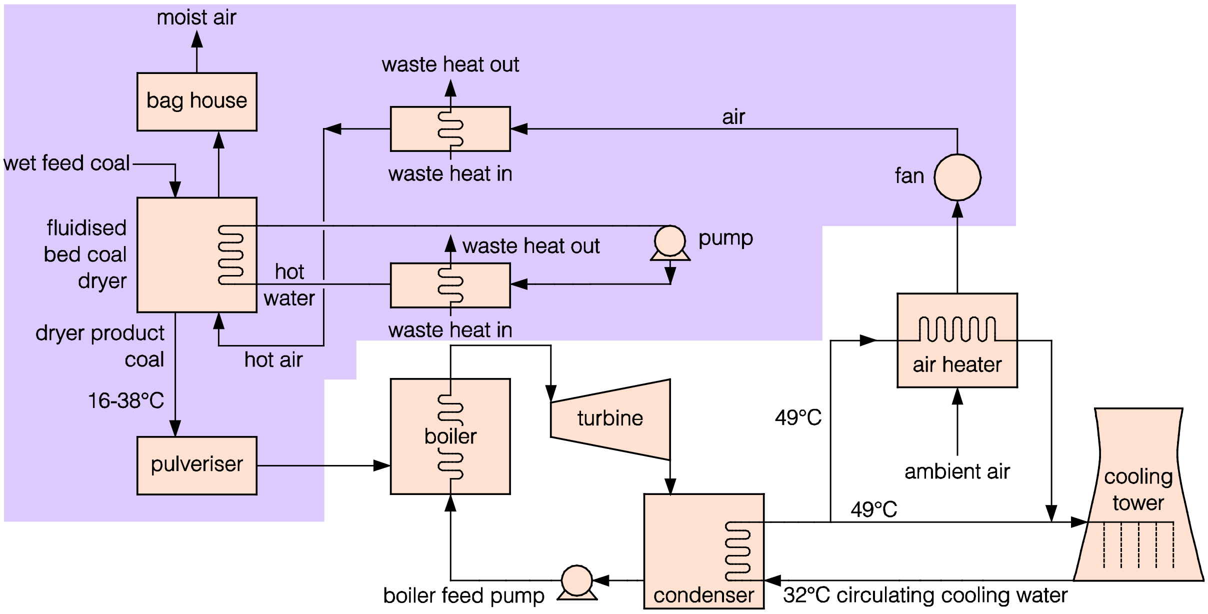

Figure 5 Schematic of integrated DryFining™ dryer at the Coal Creek Power Station (modified from NETL, 2011)

Figure 6 below shows the prototype design for the DryFining™ dryer, which is equipped with coal crushers, a conveying system to handle raw lignite, segregate and product streams, a baghouse for particulate control, and an electronic control system. Raw lignite is fed to the two-stage moving FBD from crushers, where the coal particle size is reduced to ~6.35 mm suitable for fluidisation. Heavier material tends to gravitate to the bottom of the first stage of the dryer and is removed by a GRE patented segregation device. Since the heavier material is richer in S and Hg, its removal in the first stage leads to reduced emissions of relevant air pollutants from subsequent coal combustion. The first stage also ensures a more uniform flow of coal to the second stage where the coal is heated and dried to a desired moisture level.

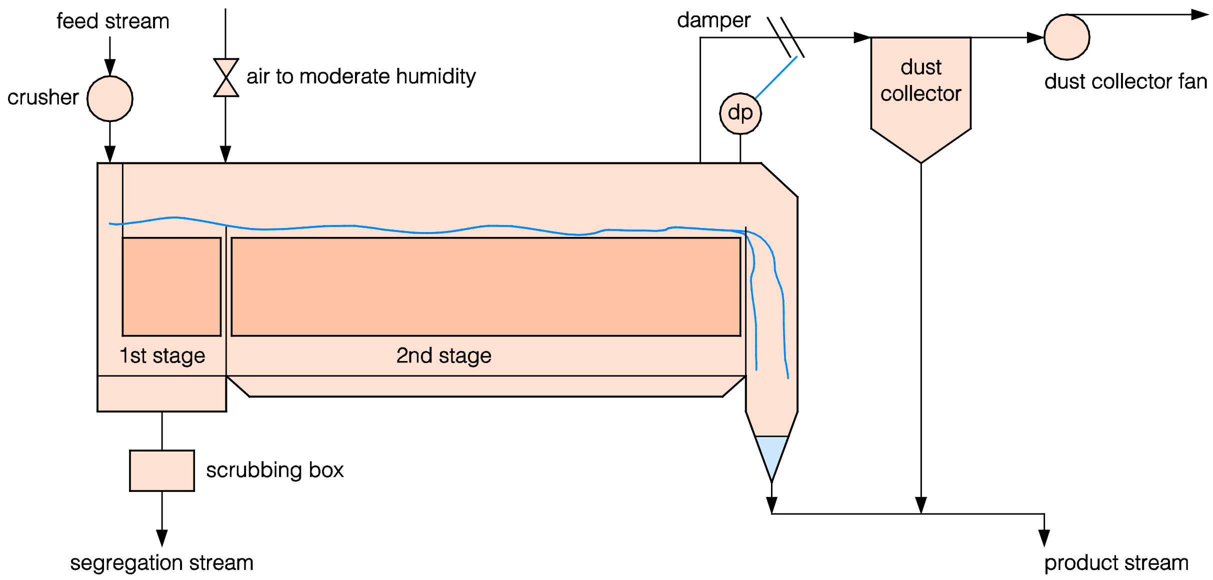

Figure 6 The prototype design of DryFining™ dryer (modified from NETL, 2011)

The bed of lignite is fluidised by hot air that has been heated by the waste heat mentioned above. The hot fluidising air supplies a portion of the heat needed for drying the lignite and carries away the evaporated moisture. This moisture-laden air is then passed through a baghouse to remove entrained coal fines before being discharged to the atmosphere. Additional heat for drying is provided by a heat exchanger immersed in the fluidised bed, which carries a circulating hot water stream heated by interchange with another source of low grade heat from the station. The partially dried coal is discharged from the moving FBD dryer into a bunker, from which it is fed to the mills. The full-scale dryer installed on Coal Creek Station uses a three stage FBD design. The first stage is similar to the prototype dryer and occupies approximately 20% of the total volume.

The full-scale tests at Unit 1 of Coal Creek Station demonstrated the ability of the DryFining™ dryer to reduce moisture by the target amount of 8.5%. This resulted in an HHV improvement from 14.62 MJ/kg to 16.38 MJ/kg (NETL, 2011). The tests also demonstrated that mercury emissions were reduced by 41% due to some removal in the first stage and increased oxidation of mercury which allowed for greater removal in the FGD system. NOx and SO_2 emissions were reduced by 32% and 54% respectively. NOx reduction was largely due to improved boiler performance resulting from improved fuel quality. Reduced SO_2 emissions resulted both from substantial removal of S in the first stage and the reduced flue gas volume that the FGD system needs to process.

The US DOE contributed US$13 million through the Clean Coal Power Initiative for the full-scale demonstration project in which four full-scale DryFining™ dryers were retrofitted to Unit 2 of Coal Creek Station and commissioned in 2009. GRE upgraded the front-end coal handling systems for both units with its own funds in order to provide uniform coal quality for all dryers. The costs related to upgrading both coal handling systems, the dryers on Unit 1, and processing of separated refuses from dryers of both units are solely provided by GRE and are therefore considered proprietary by GRE. GRE disclosed in a recent report that the first commercial installation incurred an investment costs of 240 $\$/kW_{net}$, but said these costs could be reduced to 80–100 $/kW$_{net}$ for future retrofit installations (Dene, 2013). These need to be added with other site-specific costs and owners' costs to calculate the total capital costs for future retrofit projects. The O&M costs for the dryers at Coal Creek Station were estimated at 0.35 $ per wet tonne of lignite processed or 350,000 $/y for a 113 t/h dryer. But pre-drying of coal at both units reduced expenses by more than $20 million annually in fuel, auxiliary power consumption and other O&M costs.

2.3.2 Retrofit consideration

GRE has entered into a commercial agreement with WorleyParsons, which is the exclusive licensor and process integrator, to market the DryFining™ technology. In a recent thermodynamic modelling case study undertaken by WorleyParsons for the Global CCS Institute, the role of DryFining™ in improving the efficiency of power plants with post-combustion CO_2 capture and bringing about additional CO_2 reduction was investigated (WorleyParsons, 2013). Although this study did not present a detailed cost and techno-economic analysis, it did shed some light on the cost implications of retrofitting DryFining™ to an abated power plant, a scenario likely to apply to most coal power plants remaining in operation in the future.

The case study was framed around retrofitting an existing sub-critical brown coal-fired pf power station with a coal pre-drying plant and a commercial-sized (5000 t/d) post-combustion capture plant for partial capture of CO_2. The power station selected for modelling was the Loy Yang A Power Station in Victoria, Australia. The station produces about 40% of Victoria's electricity demand. Electricity generation at this station requires over 60,000 t brown coal a day, supplied exclusively by a dedicated opencast mine. The brown coal has a high moisture content (approximately 60%) but a low ash content (average of 0.9% wet basis). The station has four units; each unit comprises a boiler and a turbine generator, auxiliary plant and pipework, with a rating above 500 MW. Each boiler is a balanced draught tower unit type, with superimposed recirculation. The superheaters, reheaters and economisers are stacked in the furnace enclosure above the combustion chamber. The case study adopted the post-combustion CO_2 capture process supplied by Mitsubishi Heavy Industry (MHI).

The software selected for modelling the power plant was GateCycle™, which utilises a component-by-component approach and advanced macro capabilities to model the energy system, but does not provide equipment sizing and cost estimation details. The post-combustion capture plant model was built by the technology IP proprietor, MHI, using their own software, and provided the relevant performance for feeding into WorleyParsons' modelling work. Validation of MHI's modelling results was carried out using a third party model for the integration of the post-combustion capture plant to the brown coal-fired power station.

The coal drying process is simulated using a proprietary MS Excel based model developed by Lehigh University for GRE. Validation of this proprietary model was carried out using intensive design checks of the integration of the drying plant to the power station.

Five cases were investigated, as shown in Table 1. The base case is the Loy Yang A Power Station. The differences between the five cases are indicated in the top part of Table 1. It shows that capturing CO_2

inevitably entails an efficiency penalty to the power station. However, such a penalty could be reduced if the brown coal is pre-dried using the DryFining™ technology. A comparison between Case 1 and Case 2 shows that pre-drying increased the plant efficiency by 1.3 percentage points to 25.97%. However, this efficiency gain came with reduced power output of 0.6 MWe. In Case 2 where pre-dried brown coal was fired in the boiler, the heat flux within the boiler furnace strengthened so as to reduce the heat transfer load in the boiler backpass. Such a change in heat flux distribution increased feed water flow through the boiler membrane wall, but reduced the steam flow to superheaters and reheaters. Consequently, the gross generation in the steam turbine decreased, but the steam cycle efficiency increased due to reduced steam condensation duty.

Table 1 Summary of the thermodynamic modelling results of Worley Parson's study (2013)

System configuration	Base	Case 1	Case 2	Case 3	Case 4	Case 5
Base plant	X	X	X	X	X	X
PCC plant		X	X	X	X	X
Coal drying			X	X		X
Plant optimisation				X	X	X
Air-cooled						X
Power generation summary	kW	kW	kW	kW	kW	kW
Main steam turbine generation	568,960	530,810	527,700	528,840	549,390	528,840
Expander generation				5,320	3,130	5,320
Total gross power generation	568,960	530,810	527,700	534,160	562,620	534,160
Net power generation	521,380	446,460	445,840			
Net power output reduction	–	74,920	75,540	69,000	53,110	68,900
Gross plant efficiency, %	31.46	29.35	30.74	31.12	30.53	31.12
Net plant effeciecy, %	28.82	24.68	25.97	26.36	25.88	26.36
Auxiliary load power summary, kW						
Base plant auxiliary load	47,580	47,450	44,350	44,270	47,350	44,170
PCC plant auxiliary load	–	36,900	34,500	34,500	*36,900	*34,500
Coal drying plant auxiliary load	–	-	3,010	3,010	–	3,010
Total plant auxiliary load power	47,580	84,350	81,860	81,780	*84,250	*81,680
CO_2 capture summary	Base	Case 1	Case 2	Case 3	Case 4	Case 5
CO_2 captured, t/d	–	5,000	5,000	5,000	5,000	5,000
CO_2 produced, t/d	14,831	14,831	14,081	14,081	14,854	14,081
CO_2 emitted, t/d	14,831	9,831	9,081	9,081	9,854	9,081
Gross specific emissions, kg/kWh	1,086	0,772	0,717	0,708	0,743	0,708
Net specific emission, kg/kWh	1,185	0,917	0,849	0,836	0,877	0,836
Electricity output penalty, kWh/tCO_2	–	419,89	274,70	233,60	284,36	233,60

Note: The actual PCC plant auxiliary lad and hence the lotal plant auxiliary load for Cases 4 and 5 will be either equal or less than the figures shown. For the purpose of this study a detailed assessment of the PCC auxiliary load has not been carried out

The table also illustrates that the auxiliary power consumption of the coal drying plant was about an order of magnitude smaller than that of the post-combustion capture plant. However, the coal drying plant reduced the CO_2 emissions significantly by 0.75 t/d or 0.068 kg/kWh net. Moreover, pre-drying alleviated the penalty of reduced power output due to CO_2 capture, from 419.89 kWh/tCO_2 in Case 1 to 274 kWh/tCO_2 in Case 2. Nevertheless, such benefits arising from pre-drying the brown coal, as suggested by the thermodynamic modelling study, have to be judged against the capital outlay for the CAPEX and OPEX of the drying plant, which were not analysed in this study.

2.4 Summary

This chapter discusses three modern pre-drying technologies for retrofitting to existing low-rank coal power plants. RWE's WTA dryer is the most developed pre-drying technology, and has been successfully demonstrated at full commercial scale at the Niederaussem Unit K. Operational parameters, including coal particle size, the fluidising bed pressure and the heating steam pressure, have been optimised to strike a balance between reduced dryer size and acceptable energy consumption as well as complexity of operation. The prototype WTA dryer at Niederaussem incurred a total investment of €50 million for erection and operation as reported in 2009. RWE reported a specific investment cost of 70 €/kW for the open cycle variant of WTA in a report published in 2006. There is little information on Vattenfall's PFBD dryer, which is in principle similar to WTA but operates at higher pressures. There is contradiction between RWE and Vattenfall with regard to whether using higher fluidised bed pressures can bring about cost benefits. The actual cost/benefits balance will depend not only on the properties of coal to be dried but also on the detailed thermodynamic configuration, such as whether or not the heat from the evaporated moisture is recovered and used for drying. GRE's DryFining™ employs a totally different drying principle. It utilises the low grade heat contained in the flue gas downstream of air preheaters and particle control equipment as well as in the cooling water, which would otherwise be wasted in the cooling towers. Despite also being based on fluidised bed operation, DryFining™ uses a two- or three-stage moving fluidised bed, which needs low fluidising velocity and is capable of removing unwanted pyrites and stray rocks in the first stage. DryFining™ therefore combines drying and beneficiation in one process to give the dual benefits of increased coal heating value and reduced emissions of air pollutants. The US DOE invested $31.5 million through its Clean Coal Power Initiative into retrofitting four DryFining™ dryers into Unit 2 of Coal Creek Power Station. GRE went on to retrofit the Unit 1 as well using its own funds, but the cost information is proprietary to GRE.

3 Pre-drying on new build power plants

Pre-drying of low-rank coal is not only important for existing power plants, but also, and more importantly, for maintaining the competitiveness of future low-rank coal-fired power plants. These power plants will need to compete with other power generation plants in increasingly liberalised markets with ever tightening environmental pollution control requirements. The literature suggests that the plant design conceived so far for future new builds will be based on dried coal firing. This chapter discusses the technical concepts for future new build lignite plants reported in the public literature and the techno-economic implications of the pre-drying systems for these plants.

3.1 BoA Plus

RWE Power developed a modern lignite power plant concept termed BoA (Braunkohlekraftwerk mit optimierter Anlagentechnik, the German abbreviation for lignite-fired power station with optimised plant engineering). The first BoA plant was the supercritical Unit K at Niederaussem, which started continuous commercial operation in 2003. This unit has a gross output of 1000 MW and achieves a maximum efficiency of 43% (LHV) and a reduction of CO_2 emissions up to 3 Mt/y compared to conventional lignite power plants with the same rating (RWE, 2013). Two more BoA units were commissioned at Grevenbroich-Neurath in August 2012; it was reported that RWE invested €2.6 billion in these two units (BoA 2&3). The BoA units have high operational flexibility; each of the units can ramp up or down its output by more than 500 MW within 15 minutes (RWE, 2013).

The quality of the feed coal has considerable implications for the capital costs of the BoA power plants. Coal quality mainly concerns the boiler and flue gas clean-up systems such as FGD and ESP; together these account for approximately 40% of the total capital costs of the BoA power plant. RWE's benchmark capital costs of its BoA plant have been based on Rhenish lignite, which typically has a moisture content of 53%, ash 5%, sulphur 0.4% and a net calorific value 8.70 MJ/kg (or 2078 kcal/kg). The capital cost of a 1100 MW (gross) BoA unit firing Rhenish lignite was reported to be 1100 €/kW (in 2006 Euro) (Reinartz, 2006).

If a lignite with a lower heating value is used, for instance Greek lignites, which have high ash contents (typically 16–17%) and thus lower heating values than Rhenish lignite, a greater amount of fuel needs to be burnt in order to reach the same rating. Consequently, the flue gas mass flow will increase. RWE's study showed that a 30% increase in the flue gas mass flow would increase the capital costs of the boiler by 17% (Note that there is no linear effect of the flue gas mass flow on the investment costs; the study assumed an exponential effect with an exponent of 0.6) (Reinartz, 2006). This corresponded to a 7% increase in the total capital costs of the power plant (increased from 1100 €/kW to 1177 €/kW).

The capital costs of a BoA power plant also depend critically on its size. The specific capital costs increase for a smaller capacity BoA unit due to the inverse and non-linear scaling effect of unit size on capital costs. RWE's study showed that the total unit specific capital costs increased to 1359 €/kW for Rhenish lignite and to 1455 €/kW for Greek lignite when the unit downsized from 1100 MW to 600 MW (Reinartz, 2006).

Based on the BoA technology, RWE Power developed a new dry lignite power plant concept termed BoA Plus. This new concept integrates the WTA pre-drying system to the BoA power plant with necessary modifications to the boiler in order to allow for combustion of dried lignite. As shown in Figure 7, the BoA Plus concept includes four lignite pre-drying/milling lines and two vapour cleaning lines. This concept is based on the demonstration at the Niederaussem K unit, as discussed in Section 2.1.1, where one pre-drying/milling line with vapour cleaning has been demonstrated successfully. The concept includes secondary dry coal milling to reliably achieve fine lignite size distribution (only 1% greater than 1 mm and 60% greater than 90 μm). The pre-drying system of the BoA Plus concept is capable of feeding raw coal at 890 t/h or dried coal at 460 t/h, which is sufficient for a 1000 MW unit.

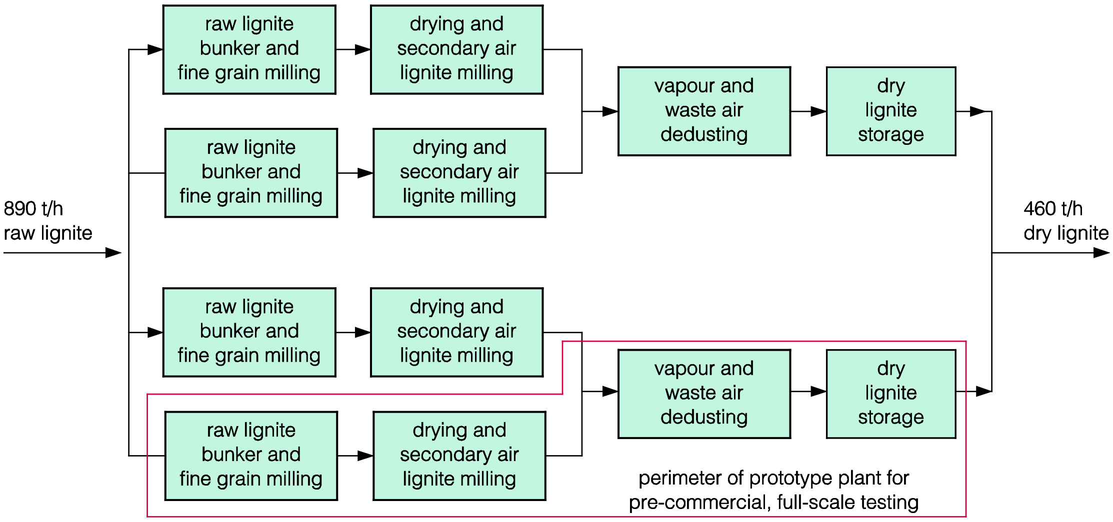

Figure 7 The BoA Plus fuel feeding diagram (modified from Reinartz, 2006)

Since the BoA Plus plant burns dried lignite, a number of key modifications need to be made to the boiler design. It is noted that the flue gas temperature at the boiler furnace exit depends only on the ash properties of the coal. However, the adiabatic combustion temperature becomes higher for dried lignite in the absence of large amounts of moisture. This increases the heat flux within the combustion chamber of the boiler, which consequently has a considerable impact on the furnace design:

- the burner arrangement is changed from wall fired to tangential firing. Tangential firing allows for symmetric feeding of coal, even during partial load operation, and consequently more balanced heat flux and temperature distribution across the cross-section of the combustion chamber of the boiler. Since the burners are arranged in the corners, more of the chamber volume can be utilised. Such an arrangement also minimises the back-flow zones of the individual burners and results in more uniform heat flux and temperature around the burner area. The slagging problems are thus reduced;

- the oil burners for boiler ignition are integrated into the dry lignite burners; they are centred within the dry lignite burners and equipped with a swirl. The burner array on each corner consists of six dry lignite burners arranged one on top of another. Each of these dry lignite burners is allocated a wall air opening for staged firing in order to control NOx and CO production. Tests at dry lignite plants demonstrated that NOx and CO emissions could be controlled below the regulatory permitted limits;
- boiler tube cleansing devices, including water lance and water jet blowers, are installed in the combustion chamber to prevent slagging, particularly in the principal burner areas.

RWE together with Alstom Power undertook a detailed study of the economics of the BoA Plus concept (Reinartz, 2006). The methodology was to compare a 1050 MW BoA unit with a BoA Plus unit that was modified from the BoA unit for firing pre-dried lignite. As such, these two plants had the same net power output, comparable thermodynamics and process engineering, and the same requirements for plant machinery and equipment other than the pre-drying system.

Compared to the BoA unit, the BoA Plus unit was more efficient by 4–5 percentage points, dependent upon the feed lignite quality. The BoA Plus unit incurred additional capital costs of approximately 70 €/kW for the pre-drying system (arising from construction of dryers and modifications made to the overall plant design). This, however, was offset by savings that were made in the BoA Plus plant. Savings of approximately 52 €/kW were achieved on the boiler, primarily due to the fact that the raw coal bunkers, the eight raw coal mills and the flue gas recirculation shafts could be dispensed with at the BoA Plus plant. An additional 15 €/kW was saved from a multitude of minor process optimisations and a reduction in piping (*see* Figure 8). The overall investment costs of BoA Plus thus barely increased, while a significant improvement in the plant thermal efficiency was achieved.

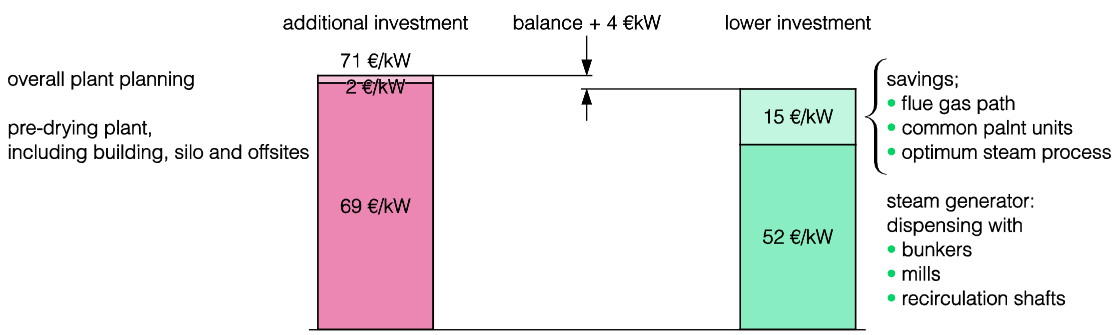

Figure 8 Additional specific costs and savings of the BoA Plus unit compared to the reference BoA unit (modified from Reinartz, 2006)

It is possible to further increase the efficiency of a BoA Plus unit by increasing the steam parameters from currently 275 bar/600°C/605°C to 350–375 bar/700°C. A study has been made to investigate the conceptual design of a 700°C power plant firing poor quality Greek lignite (*see* Section 3.2 below). The development built on a number of research programmes in Europe, which have been (and some are still) developing and testing new materials that could withstand such high temperatures and pressures. Under the E_{MAX} initiative a consortium of large utilities focused on high temperature materials research. The AD700 programme started in 1998 with the aim to develop advanced ultra-supercritical pf power generation technology (abbreviated as AUSC) and continues to 2017. A recent IEA CCC report has discussed the development of AUSC in Europe and other countries (Nicol, 2013). Several key high temperature materials, including Alloy 617, T24, 12 CrCoMo for the steam generator outlet headers and superheater tubes and T91, T92 and VM12 for use in membrane walls, have been qualified and tested for welding performance. There are plans in Europe to build a full-scale AUSC demonstration plant in 2017-21 with operation and feedback in 2022-2626.

3.2 700°C lignite-fired power plant

In the majority of R&D work on the 700°C power generation technology, the fuel taken into consideration is hard coal or good quality lignite (such as Rhenish lignite in western Germany). Kakaras and others (2006) studied the conceptual design of a 700°C power plant using poor quality Greek lignite, which incorporated pre-drying of lignite before combustion in the boiler. This study included an interesting comparison of three drying technologies: WTA, the tubular dryer and the MTE (Mechanische-Thermische Entwässerung or Mechanical Thermal Dewatering) dryer. A detailed introduction to each of these drying technologies can be found in a previous IEA CCC report (Dong, 2011). The integration of each drying technology into the steam cycle of an existing Greek power plant was modelled with modified software code ENBIPRO (ENergie-BIllanz-PROgram) to allow for modelling of an additional flow type representing the fuel input to and output from the dryer. ENBIPRO is a software tool for solving heat and mass balances, efficiency calculation, and exergetic and exergoeconomic analysis of complex heat and power systems.

A number of assumptions were made for this modelling study. The thermodynamic characteristics of the working fluid remained practically unchanged across all test modelling cases. So did the flue gas exit temperature (at approximately 150°C) and the air excess ratio (at 1.29). The energy producing and consuming equipment, including steam turbines, pumps, fans and compressors, was assumed to have a mechanical and electrical efficiency of 97.5% and 99%, respectively. The fuel used for the study was the Greek brown coal from the Ptolemais region, which had a heating value as low as 5.58 MJ/kg. This lignite typically had a moisture content of 55% and an ash content of 15%. The final moisture content of the dried lignite was assumed to be 15% using WTA or the tubular dyer, while in the case of the MTE dryer a 22% moisture content was assumed to reflect its different drying principle from the other two drying technologies.

The results of the modelling study are summarised in Table 2. Compared to lignite drying using hot flue gas as in conventional lignite units, a 20% reduction of fuel consumption was achieved across all three pre-drying technologies integrated to the power plant due to substantial efficiency increases. However, the net power output was reduced because the steam, extracted to provide heat for the pre-drying process, did not produce electricity in the steam turbine. This is an important factor to consider when retrofitting a pre-dryer to an existing power plant; for new build units, this can be factored into the power output rating in the design stage.

Table 2 Comparison of three cases modelled for the three pre-drying technologies (modified from Kakaras and others, 2006)

Test case (drying method)	Raw fuel consumption, kg/s	Drying medium consumption, kg/s (% total)	ΔP_{gross}, MW	ΔP_{net}, MW	Δη, %
Flue gas	162.30	190.0 (24.16%) 100.0 (21.81%)	–	–	–
Tubular dryer 1	130.15	74.87	–35.5	–32.4	4.71
Tubular dryer 2	132.10	73.62	–41.1	–38	3.33
Tubular dryer 3	131.56	72.39	–66.1	–61.9	0.24
WTA dryer 1	130.10	68.08	–	–16.6	6.90
WTA dryer 2	134.95	74.24	+4.4	–21.9	4.61
MTE dryer 3	132.50	10.53	–8.8	–7	7.39

The tubular dryer has already been applied at industrial scale for power generation. However, the study showed that this technology produced the smallest efficiency improvement because it used steam bleed of higher temperature and pressure for pre-drying the lignite compared to the other two technologies. For instance, in the tubular dyer – Case 3 where steam of 20 bar/470.1°C was used, the efficiency gain was negligible, but the net power output was reduced considerably. In contrast, WTA and MET have proven to be more efficient. MET, compared to the WTA process, had a higher net power output due to its lower energy consumption. Nevertheless, the MET dewatering operation was not continuous and the product moisture content was higher.

Figure 9 shows the impact of steam pressure on the overall efficiency improvement of the power plant. Higher steam pressure means more energy that could have been used to produce power is diverted to pre-drying the lignite. Consequently, the overall efficiency gain was smaller. This suggests that pre-drying methods involving no steam bleed from the turbine or small amounts would be more efficient. If steam bleed is used for pre-drying, the lower its pressure the higher the overall thermal efficiency improvement will be on the plant. The results of the study show a significant deviation from the previously available literature data, which was due to the different thermodynamic data of the drying steam used in the modelling study (Kakaras and others, 2006). However, the mathematical models used in the respective literature broadly confirm the trend of the results.

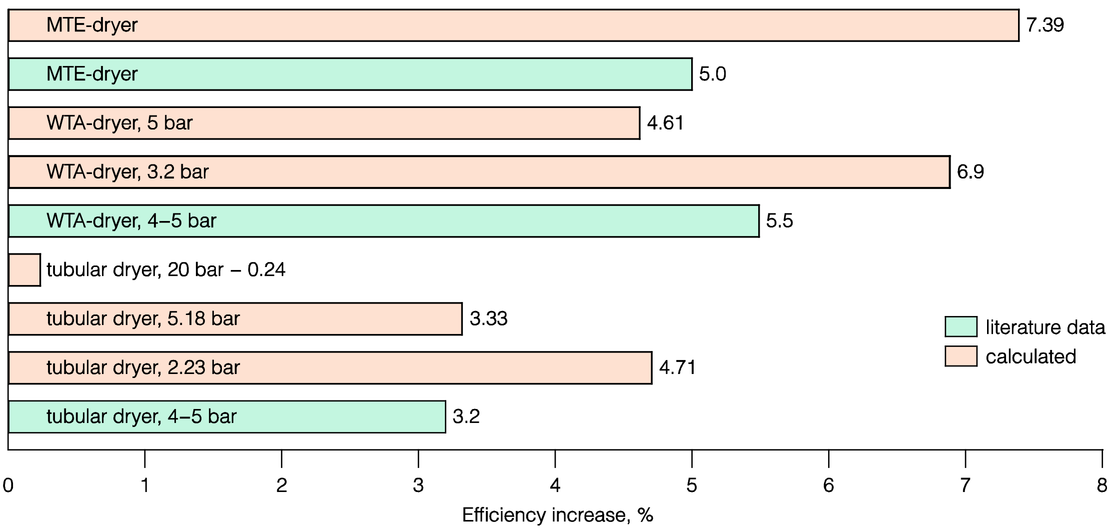

Figure 9 Comparison of the net efficiencies of the modelled cases (modified from Kakaras and others, 2006)

The WTA pre-dryer was then selected for the conceptual study of the AUSC 700°C lignite-fired pf power plant. The closed cycle variant of WTA was employed where the moisture removed from the raw lignite in the form of steam was recompressed up to 3.2 bar and consequently used for drying incoming raw lignite. It was assumed that pre-drying reduced the moisture content of lignite from 55.3% to 12%; this corresponded to a LHV increase from 5.418 kJ/kg to13.025 kJ/kg. The following four cases were examined to provide a comparative view of how the advanced steam parameters impact the power plant's efficiency.

- Case 1: Reference lignite power plant. Gross output 360 MWe with reheat and seven water preheaters, pf supercritical boiler with main steam temperature 540°C and pressure 190 bar;
- Case 2: Reference lignite power plant with WTA pre-dryers;
- Case 3: AUSC 700°C lignite power plant. Gross output 422 MWe. Steam conditions 350 bar/700°C/720°C. The power plant configuration was maintained the same as in the reference Case 1, but higher turbine polytropic stage efficiencies are assumed compared to the reference cases (Cases 1 and 2) in order to take into account the turbine design development;
- Case 4: AUSC 700°C lignite power plant with WTA pre-dryers.

The results are illustrated in Table 3. It is clear from the table that pre-drying brought about benefits of reduced power consumption by fans, mills and ESP. This was due largely to smaller flue gas flows through the boiler. Another main benefit was the significant fuel savings (~22% on LHV basis) that resulted from more efficient use of energy in the lignite for power production. Consequently, the net efficiency of the power plant increased by 7–8 percentage points. These benefits, however, were obtained at the expense of additional power consumption by the pre-drying system, which was comparable to the total power consumption of all other components. The pre-drying application also reduced the net power output by 5–6% as some steam was diverted to provide heat for the pre-dryers.

The total estimated installation costs of the AUSC 700°C lignite power plant with WTA pre-drying were €537 million and split into the following cost components: boiler €250 million, coal and ash handling €40 million, ESP €16 million, FGD €63 million, steam boiler €82 million, and the rest of plant €86 million. However, no cost estimates for other cases were discussed in the study, which makes it difficult to infer information on costs with respect to the pre-drying system.

Table 3 Main data of the modelling results (modified from Kakaras and others, 2006)

Power consumption by components	Unit	Case 1	Case 2	Case 3	Case 4
Forced draft fans	MWe	1.60	1.27	1.60	1.27
Induced draft fans	MWe	3.20	1.98	3.20	1.97
Lignite mills	MWe	11.52	9.06	11.52	9.05
ESP	MWe	0.57	0.45	0.57	0.45
Feed water pumps	MWe	9.22	9.24	15.68	15.69
Condensate pumps	MWe	0.50	0.50	0.84	0.84
Circulating and cooling water pumps	MWe	2.15	2.16	1.86	1.86
Pre-drying system	MWe	–	24.75	–	24.71
Total	MWe	28.76	49.41	35.27	55.84
Fuel flow	kg/s	170.1	133.87	170.1	133.67
Heat input (on raw fuel LHV)	MWe	921.6	725.31	921.6	724.22
Gross power output	MWe	361.17	361.93	422.53	422.77
Net power output	MWe	332.41	312.52	387.26	366.93
Net efficiency	%	36.07	43.09	42.02	50.67

3.3 Zero Emissions Platform cost study

The European Technology Platform for Zero Emission Fossil Fuel Power Plants (known as Zero Emissions Platform, or ZEP) commissioned a study into the costs of complete CO_2 capture and storage (CCS) value chains estimated for new build coal- and natural gas-fired power plants that are located at a generic site in Northern Europe and enter into operation in the early 2020s. This ZEP study used new, in-house data provided by ZEP member organisations to establish a reference point for the costs of CCS with all investment costs referenced to the second quarter of 2009 (ZEP, 2011a).

The investment costs were determined for three main first-generation capture technologies (post-combustion, pre-combustion and oxyfuel) applied to hard coal, lignite and natural gas-fired power plants; two main transport options (pipelines and ships) and two main storage options (depleted oil and gas fields, and deep saline aquifers) both onshore and offshore were considered. Both a base case and an optimum case were considered for each combination examined in this study. The base case with CO_2 capture represented the technology choices and full economic risk, margins, redundancies and proven components for the first units to be built following the CCS demonstration phase, which constituted conservative cost levels expected in the early 2020s. The optimum case (OPTI) provided a cost estimation of the units commissioned (around 2025) after the first full-size CCS plants have been in operation, incorporating technology improvements, refined solutions, improved integration and other experience gained from the commercial operation of the first full-size CCS plants. The difference between the base case and the optimum case thus represented the normal learning curve and indicated the magnitude of the resulting cost reduction.

This study covered the entire CCS value chains and consisted of three parts; each part focused on the capture, transport and storage of CO_2, respectively. The costs for CO_2 capture are most relevant to this report. The capture part included the compression and processing of the captured CO_2 stream (and liquefaction in the case of shipping transport). This enabled any benefits arising from the integration of streams between the compression/processing island, capture plant and the power plant to be taken into account, as well as those synergies arising from using common plant infrastructures. This methodology also ensured that all the internally consumed electricity required for CO_2 compression and processing was part of the capture penalty.

Both the levelised cost of electricity (LCOE) and CO_2 avoidance costs were calculated in this study. The LCOE takes into consideration plant capital costs, operation and maintenance (O&M) costs, fuel costs, site location, and financial assumptions over the lifetime of the power plant to calculate the break-even cost of electricity. The CO_2 avoidance cost of a capture technology is determined by comparing the LCOE and CO_2 emissions of a power plant with CO_2 capture (abated plant) against a reference power plant without CO_2 capture. It is the minimum price of CO_2 that can justify undertaking CO_2 capture on a power plant.

Both the reference plants and the corresponding abated plants analysed in this study were designed to comply with the future European Union's Industrial Emissions Directive (IED), which will replace the current Large Combustion Plant Directive in 2016. The IED stipulates more stringent limits for NOx, SOx, CO and particulates that power plants may emit and thus determines the flue gas clean-up technologies that must be employed. All power plants were assumed to operate as base load, operating for 7500 hours per year. Other assumptions adopted in this study, such as plant site ambient conditions and CO_2 stream qualities, can be found in the original report and are not discussed in any detail herein (ZEP, 2011b).

All the investment costs in the ZEP study were referenced to the second quarter (Q2) of 2009. Cost data on plant and equipment referenced to a different time period were adjusted to 2009–Q2 costs by applying the Cambridge Energy Research Associates (CERA) cost index. The total investment costs included the engineering, procurement and construction (EPC) costs of the power plant, as well as the owner's costs to develop the project. The owner's costs were those incurred during the planning, designing and commissioning phases of the power plant, and also included a contingency for any deviation. The owner's costs in this study were added as a percentage of the EPC costs as follows:

- 10% for CCGT power plant;
- 10% for hard coal pf power plants (15% for OPTI-case oxyfuel power plant);
- 20% for the lignite power plant.

The O&M costs were divided into fixed and variable costs. The fixed O&M costs (€/y) included personnel and administration costs, spare parts and planned maintenance overhauls, while the variable O&M costs ($/MWh) included the costs of consumables and disposal costs (such as ash and gypsums). The annual O&M cost escalation was assumed to be 2% in all cases.

The fuel costs used in this study were the best estimation by ZEP of representative fuel prices in 2020. To take into account the considerable uncertainty of the fuel price, it was decided to use low, middle and high prices for both natural gas and hard coal, whilst the price of lignite was kept the same, as shown in Table 4. The price ranges were selected during the fourth quarter of 2010 and were consistent with other projections including the European Commission's Second Strategic Energy Review of November 2008 for the year 2020 and the 2010 UK Electricity Generation Updates by DECC (ZEP, 2011a).

The weighted average cost of capital (WACC) took into account the equity/debt ratios, inflation and the required rate of return on equity, and was assumed to be 8% in this study. The inflation rate was assumed to be the same for all costs and incomes during the project life. Other common financial boundary conditions used in the study are summarised in Table 4.

Table 4 Financial and other boundary conditions assumed in the ZEP CCS Study (ZEP, 2011a)

Assumptions	Unit	Hard coal plant			Lignite plant	CCGT (F-class)		
Depreciation period	year	40			40	25		
Fuel price	€/GJ	2	2.4	2.9	1.39	4.5	8	11
Fuel price escalation	%/y	1.5%			1.5%	1.5%		
Standard emission factor	t/MWh thermal	0.344			0.402	0.210		
Common inputs								
O&M cost escalation		2%						
Debt/equity ratio		50%						
Loan interest rate		6%						
Interest during construction		6%						
Return on equity		12%						
Start of debt service		Commercial operation of the power plant						
Tax rate		35%						
WACC		8%						
Discount rate		9%						

3.3.1 Effects of pre-drying of lignite

An interesting comparison was made in this study between three reference state-of-the-art unabated ultra-supercritical (USC) lignite-fired power plants, whose technical parameters and economic data are given in Table 5. The reference lignite power plant A burnt run-of-mine lignite, whilst the other two reference lignite plants (B and C) burned dried lignite produced by the pre-drying system integrated to these plant.

There were considerable differences between the total investment costs of the two reference plants that burned pre-dried lignite. There was no explanation of such differences in the report (ZEP, 2011b). Thus it was assumed by the author to represent two distinct investment climates: plant B represented a more favorable investment climate than plant C. Such a difference in capital costs was also reflected in the fixed O&M costs, while the variable O&M costs largely remained constant across three plants.

Nevertheless, some useful insights can be drawn from Table 5. Pre-drying resulted in a considerable increase in the net full load efficiency from 43% (LHV) to 48–49% (LHV). This improvement in efficiency was due to the avoidance of energy consumption for evaporation of coal moisture within the boiler furnace. The CO_2 emissions were therefore reduced from 0.930 t/MWh to 0.816–0.833 t/MWh.

Pre-drying lowered the levelised fuel costs from 13.6 €/MWh to around 12 €/MWh. It was however not credible to draw any conclusion on the LCOE as this cost measure was also dependent on both investment costs and fixed O&M costs. The LCOE could be much lower than that of run-of-mine lignite-fired power plant if the investment climate was favourable, but also could be modestly higher if the EPC and O&M costs were high.

Table 5 Parameters and economics of the two reference lignite-fired power plants with post-combustion CO_2 capture (modified from ZEP, 2011b)

Parameters	Unit	Reference pf lignite-fired power plant A without capture and pre-drying	Reference pf lignite-fired power plant B without capture but with pre-drying	Reference pf lignite-fired power plant C without capture but with pre-drying
Net electricity output/plant capacity	MWe	989	920	1100
HP turbine steam inlet pressure	Bara	280	280	–
HP turbine steam inlet temperature	°C	600	600	–
IP turbine inlet steam reheat temperature	°C	620	620	–
Net full load plant efficiency	LHV	43%	49%	48%
Plant load factor	h/y	7500	7500	7500
Plant life	year	40	40	40
CO_2 emissions calculated from fuel carbon content	t/MWh	0.930	0.816	0.833
Economics				
Investment cost				
EPC cost	million €	1680	1167	2017
EPC cost, net	€/kW	1699	1268	1834
Owner's cost incl. contingencies	% of EPC	20	20	20
Total investment cost	million €	2016	1400	2420
Fuel cost	€/GJ (LHV)	1.39	1.39	1.39
Operating cost				
Fixed O&M	€/MWh	37.2	30	50.4
Variable O&M	€/MWh	1	1.09	1
Levelised CAPEX	€/MWh	22.7	16.9	24.5
Levelised O&M	€/MWh	7.4	6.7	8.8
Levelised fuel cost	€/MWh	13.6	12.0	12.2
Levelised cost of electricity	€/MWh	43.7	35.6	45.5

3.3.2 Effects of CO_2 capture

The following CO_2 capture technologies were considered for lignite-fired power plants entering into operation in the early 2020s:

- BASE-case lignite-fired pf ultra-supercritical (280 bar/600°C/620°C) power plant with post-combustion capture using advanced amines, but without lignite pre-dryers;
- BASE-case lignite-fired oxygen blown IGCC with full quench design, sour shift and CO_2 capture, F-class gas turbine (diffusion burners with syngas saturation and dilution), and lignite pre-dryers;
- OPTI-case lignite oxyfuel combustion pf power plant with ultra-supercritical steam conditions (280bar/600°C/620°C) and lignite pre-dryers.

The LCOE and CO_2 avoidance costs are given in Table 6. The LCOE of the abated power plant increased considerably with any of the CO_2 capture technologies, compared to the respective reference unabated power plant: 72% for pf post-combustion capture, 48% for IGCC pre-combustion capture and 39% for pf oxyfuel combustion. This was because the CO_2 capture system incurred additional EPC and O&M costs. Capturing CO_2 also imposed efficiency penalties as a result of additional steam and electricity consumption: 10 percentage points for pf post-combustion capture, 8 percentage points for IGCC pre-combustion capture and 7 percentage points for pf oxyfuel combustion.

The results suggested that the pf post-combustion capture had a higher CO_2 avoidance cost than the other two capture technologies. However, this was at least partly due to pre-drying of lignite on both reference and captured plants in the case of IGCC pre-combustion capture and oxyfuel combustion capture. This suggests that pre-drying can reduce the degree of cost increase resulting from CO_2 capture. This was not surprising as firing pre-dried lignite produced less CO_2 per MWh of electricity (0.816–0.833 t/MWh compared to 0.930 t/MWh).

Table 6 The LCOE and CO_2 avoidance costs for three CO_2 capture technologies (modified from ZEP, 2011b)

Capture technology		LCOE €/MWth	CO_2 avoidance costs, €/t CO_2
Lignite pf post-combustion capture	Reference lignite pf USC plant with no pre-drying	43.7	38.9
	BASE early commercial	75.2	
Lignite IGCC with pre-combustion capture	Reference lignite pf USC with pre-drying	45.5	29.9
	BASE early commercial	67.4	
Lignite pf oxyfuel capture	Reference lignite pf USC with pre-drying	35.6	19.3
	OPTI early commercial	49.5	

3.3.3 Cost comparison between unabated hard coal, lignite and natural gas CCGT power plants

The ZEP study also compared reference unabated power plants burning lignite, hard coal and natural gas. These reference plants were used as a benchmark to derive the CO_2 avoidance costs of the abated power plants. They thus represented the best cost estimates of the unabated power plants entering operation in the early 2020s.

Three different fuel price levels have been assumed for hard coal and natural gas in order to account for fuel price variation. In the case of natural gas combined cycle gas turbine (CCGT) power plant, both a base case and an OPTI case were examined. The base case represented the technology available in 2009, while the OPTI case represented the optimised plant technology with enhanced integration between various parts of the entire plant, based on first commercial experience in base case plant operation in the early 2020s.

The results showed that the lignite-fired pf power plant was more costly to build than hard coal power plants. The levelised CAPEX of a lignite power plant was 22.7 €/MWh compared to 19.0–19.1 €/MWh for hard coal power plants. This was due both to higher EPC costs resulting from the larger boiler required to burn lignite and doubling of the owner's costs. The fixed O&M costs of the lignite pf power plant were also 41% higher than those of hard coal pf power plants, while the variable O&M costs were at the same level of the hard coal plant. The levelised O&M costs were therefore slightly higher for lignite pf power plants than for hard coal pf power plant.

However, the lignite-fired power plant was more economical to run than the hard coal-fired power plant. The primary reason was the low cost of lignite. The hard coal could be ~35% more expensive (levelised fuel cost) than the lignite in the low fuel-cost case (2 €/GJ) and nearly 100% more expensive in the high fuel-cost case (2.9 €/GJ). This translated into LCOE of 44.4–44.6 €/MWh in the low end of fuel cost and 52.7–52.8 €/MWh in the high end for hard coal pf power plant, compared to 43.7 €/MWh for lignite pf power plant.

A natural gas CCGT power plant was much cheaper to build than either a lignite pf power plant or hard coal pf power plant. The levelised EPC cost of the CCGT power plant was just 43% of that of the lignite pf power plant and about half that of the hard coal pf power plant. The natural gas CCGT power plant also had much lower levelised O&M costs than the lignite and hard coal pf power plants. The lower capital costs of a natural gas CCGT power plant resulted from the simpler plant design and less demanding needs for air pollutant emission control.

Natural gas was however a more expensive generation fuel than lignite and hard coal. According to the assumption of the ZEP study, its price could be 3–8 times higher than lignite and 1.5–5.5 times higher than hard coal. Higher gas prices mitigated the benefits of lower capital costs of natural gas CCGT plants, and actually resulted in a higher LCOE than the lignite or hard coal-fired power plants. Nevertheless, if gas prices were as low as 4.5 €/GJ and hard coal prices were above 2.4 €/GJ, natural gas CCGT plants could be more competitive for power generation.

3.3.4 Cost comparison between hard coal, lignite and natural gas CCGT power plants with CO_2 capture

Figure 10 shows the LCOE and CO_2 avoidance costs across three first generation capture technologies and three types of fuel, assuming the Middle fuel cost level for hard coal (2.4 €/GJ) and natural gas (8 €/GJ) power plants. The respective reference plants are given in Table 7. For IGCC pre-combustion capture and oxyfuel combustion capture, the reference plant was also the state-of-the-art unabated pf supercritical power plant. This was different from other cost studies in the literature. In the case of lignite, it must be noted that the post-combustion capture option was the only case where pre-drying of lignite was not included either in the reference unabated plant or the abated plant. In other words, the capture options of IGCC pre-combustion and oxyfuel combustion for lignite were studied with reference to a pf supercritical lignite-fired power plant that incorporated lignite pre-drying.

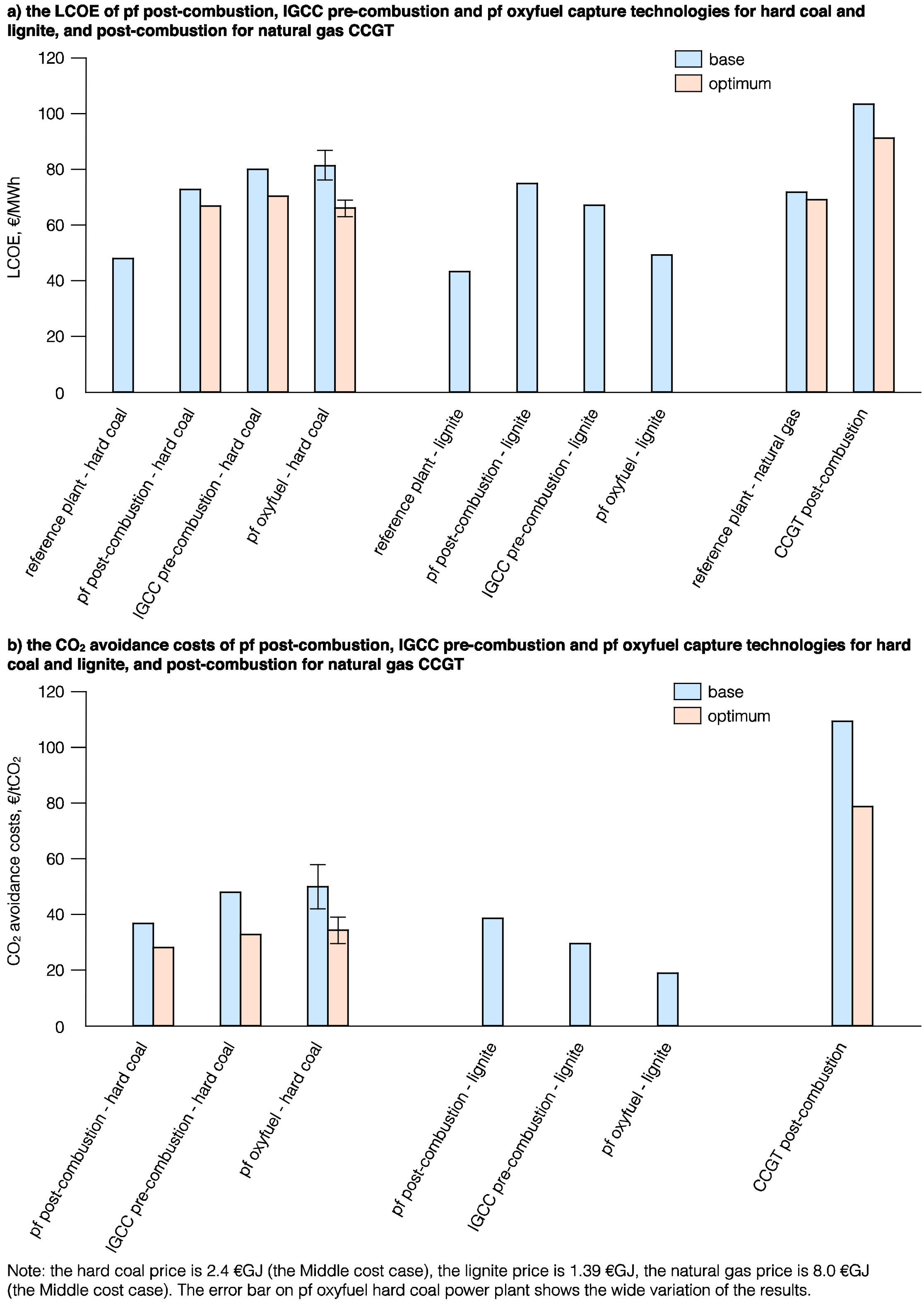

Figure 10 (a) the LCOE of pf post-combustion, IGCC pre-combustion and pf oxyfuel capture technologies for hard coal and lignite, and post-combustion for natural gas CCGT; (b) the CO_2 avoidance costs of pf post-combustion, IGCC pre-combustion and pf oxyfuel capture technologies for hard coal and lignite, and post-combustion for natural gas CCGT. Note: the hard coal price is 2.4 €/GJ (the middle cost case), the lignite price is1.39 €/GJ, the natural gas price is 8.0 €/GJ (the middle cost case). The error bar on pf oxyfuel hard coal power plant shows the wide variation of the results.

Table 7 Parameters and economics of the reference lignite pf, hard coal pf and natural gas CCGT power plants without CO_2 capture technologies (ZEP, 2011b)

Parameters	Unit	Reference pf lignite-fired power plant without capture and pre-drying	Reference pf hard coal power plant without capture	Reference CCGT power plant without capture
Net electricity output/plant capacity	MWe	989	736	420
HP turbine steam inlet pressure	Bara	280	280	113.8/27.7/3.99
HP turbine steam inlet temperature	°C	600	600	549
IP turbine inlet steam reheat temperature	°C	620	620	549
Net full load plant efficiency	LHV	43%	46%	BASE 58% OPTI 60%
Plant load factor	h/y	7500	7500	7500
Plant life	year	40	40	25
CO_2 emissions calculated from fuel carbon content	t/MWh	0.930	0.759	BASE 0.347 OPTI 0.335
Economics				
Investment cost				
EPC cost	Million €	1680	1141–1152	300
EPC cost, net	€/kW	1699	1550–1565	714
Owner's cost incl. contingencies	% of EPC	20	10	10
Total investment cost	Million €	2016	1255–1267	330
Fuel cost	€/GJ (LHV)	1.39	Low 2.0 Mid 2.4 High 2.9	Low 4.5 Mid 8.0 High 11.0
Operating cost				
Fixed O&M	€/MWh	37.2	26.2	9
Variable O&M	€/MWh	1	1	BASE 2 OPTI 1.4
Levelised CAPEX	€/MWh	22.7	19.0–19.1	9.8
Levelised O&M	€/MWh	7.4	7.1	BASE 5.8 OPTI 5.1
Levelised fuel cost	€/MWh	13.6	Low 18.3 Mid 2.0 High 26.6	Low/Mid/High BASE 31.7 56.4 77.5 OPTI 30.6 54.5 74.9
Levelised cost of electricity	€/MWh	43.7	Low 44.4–44.6 Mid 48.1–48.3 High 52.7–52.8	Low/Mid/High BASE 47.2 71.9 93.0 OPTI 45.5 69.3 89.7

The results suggest that it was slightly more expensive to apply post-combustion capture to lignite plant than to hard coal plant. This was attributed to higher levelised CAPEX and levelised fixed O&M costs of lignite pf power plants. Lignite seemed more attractive than hard coal to adopt IGCC pre-combustion and oxyfuel combustion for CO_2 capture. This might be partially due to the fact that pre-drying of lignite was applied to those plants, which improved their economics as mentioned in Section 3.3.1. Compared to hard coal and lignite power plants, post-combustion CO_2 capture on the natural gas CCGT power plant was substantially more expensive.

For hard coal, the CO_2 avoidance costs were in the range of 37–58 €/tCO_2e in the base-case plants, and 29–39 €/tCO_2e in the OPTI-case plants. It was noted that there was considerable variation in the estimated cost of the oxyfuel combustion technology. This reflected the fact that oxyfuel combustion was the least developed CO_2 capture technology.

Figure 10 also shows that at the Middle fuel price level, natural gas CCGT plants were a more expensive option for power generation than hard coal plants or lignite plants, both with and without CO_2 capture. However, the LCOE of an abated lignite pf power plant could be comparable or even cheaper than that of an unabated natural gas CCGT plants. The carbon price must be no less than 110 €/t for the BASE-case plant and at least 79 €/t for the OPTI-case plant to justify CO_2 capture on natural gas power plants.

3.4 Summary

This chapter discusses proposed plant design concepts for future lignite-based power generation. These concepts range from RWE's BoA Plus, the 700°C AUSC technology, to the first generation lignite-fired power plants with CO_2 capture. As such, these concepts represent the technology development roadmap for lignite-based power generation.

The BoA Plus technology builds on the experiences of three existing BoA power plants and the full commercial-scale demonstration of the WTA pre-dryer at the first BoA unit, Niederaussem K. The capital costs of a BoA unit depend heavily on the size of the plant and the quality of the lignite. The specific unit capital costs (€/kW) have an inverse and non-linear scaling relationship with the unit size. The quality of the lignite mainly affects the boiler and the flue gas clean-up systems such as FGD and ESP, which together account for about 40% of the total capital costs of a BoA unit. A number of modifications need to be made to the burners and combustion chamber cleaning system when changing from the BoA concept to the BoA Plus concept. This is because firing dried lignite produces higher adiabatic combustion temperatures and thus increases the heat flux within the combustion chamber. RWE's economics study showed that the additional capital costs of approximately 70 €/kW incurred by installing the WTA dryers could be offset by savings that were achievable on the BoA Plus plant. The overall investment costs of a BoA Plus unit therefore barely rise, but a 4–5 percentage points increase in the unit thermal efficiency could be achieved.

The 700°C AUSC technologies are under development in Europe, Japan and the USA, and more recently in China and India. Most of the development activities have involved hard coal or good quality lignite. It is envisaged that application of 700°C AUSC technologies to low quality lignite necessitates pre-drying of the fuel. Kakaras and others (2006) compared three pre-drying technologies (tubular dryer, WTA dryer and MTE dryer) to select a pre-dryer for their conceptual lignite-based 700°C AUSC power plant. Their modeling results showed that WTA was the best choice in terms of thermal efficiency gain versus additional energy consumption as well as ease of operation. With the WTA dryer, a thermal efficiency gain of 7–8 percentage points could be obtained for a 700°C AUSC lignite unit. The efficiency gains resulted from reduced loads on fans and mills as well as considerable fuel savings. Nevertheless, the additional power consumption of the WTA dryer, comparable to the total power consumption of fans, mills and pumps, reduced the net power output from the respective units. Moreover, the study estimated that the total installation costs were €537 million (as reported in 2006) for a 422 MWe 700°C AUSC lignite-fired unit with WTA pre-drying. However, it was not possible to infer the cost of the WTA dryers from the study.

The ZEP CCS study provides the latest and most comprehensive cost estimates of the entire CCS value chains for new build hard coal, lignite and gas power plants. Although it did not explicitly report the costs of lignite pre-drying, some useful insights could be inferred from the costs data.

A comparison between reference plants burning pre-dried lignite and one burning run-of-mine lignite showed a considerable efficiency increase from ~43% (LHV) to 48–49% (LHV) and a reduction of CO_2 emissions from 0.930 t/MWh to 0.816–0.833 t/MWh. Lignite pre-drying lowered the levelised fuel costs from 13.6 €/MWh to around 12 €/MWh. It was however not credible to draw any conclusion on the LCOE, which was influenced by the investment climate (such as interest rate) that determines the actual EPC and fixed O&M costs.

CO_2 capture significantly increased the LCOE of the lignite-based power generation: 72% for pf post-combustion capture, 48% for IGCC pre-combustion capture and 39% for pf oxyfuel combustion. Capturing CO_2 also imposed considerable efficiency penalties: 10 percentage points for pf post-combustion capture, 8 percentage points for IGCC pre-combustion capture and 7 percentage points for pf oxyfuel combustion. The post-combustion capture was also found to have a higher CO_2 avoidance cost than the other two capture technologies which incorporated pre-drying. Since firing pre-dried lignite reduced the CO_2 emission from 0.930 t/MWh to 0.816–0.833 t/MWh, pre-drying reduced the degree to which LCOE costs rose due to CO_2 capture.

The unabated lignite-fired power plant (levelised CAPEX cost 22.7 €/MWh) was more costly to build than unabated hard coal power plants (levelised CAPEX cost 19.0–19.1 €/MWh) due to higher EPC costs and fixed O&M costs. However, the low price of lignite made the unabated lignite-fired power plant more profitable to run. The LCOE of the hard coal-fired pf plant could be 44.4–44.6 €/MWh in the low fuel-cost case and 52.7–52.8 €/MWh in the high fuel-cost case as opposed to 43.7 €/MWh for the lignite pf power plant (the study assumed that the lignite price was stable).

Unabated natural gas CCGT power plant was much cheaper to build than either unabated lignite pf power plant or unabated hard coal pf power plant. The CCGT plant's levelised EPC cost was just 43% that of the lignite pf power plant and about half that of the hard coal pf power plant. The levelised O&M costs were also lower for the natural gas CCGT plant than for the other two types of power plant. However, since natural gas is more expensive than hard coal or lignite, the LCOE of the natural gas CCGT plant was generally much higher. Natural gas CCGT plant could be competitive only if gas prices were as low as ~4.5 €/GJ and hard coal prices were above 2.4 €/GJ.

The ZEP study also compared 3 first generation CO_2 capture technologies for hard coal, lignite and natural gas, assuming the middle-fuel-cost level for hard coal (2.4 €/GJ) and natural gas (8.0 €/GJ). The results suggested that post-combustion capture was a more expensive option for lignite plant than for hard coal plant, due primarily to higher levelised CAPEX and levelised fixed O&M costs of the lignite plant. IGCC pre-combustion capture and oxyfuel combustion seemed attractive for lignite; part of the reason might be lignite pre-drying was incorporated into these two capture technologies. Natural gas CCGT plants were a more expensive option for power generation than hard coal plants and lignite plants, regardless of CO_2 capture. Nevertheless, abated lignite power plants could be cost-comparable or even cheaper than unabated natural gas CCGT plants. The CO_2 price must be higher than 110 €/t to justify CO_2 capture on a natural gas CCGT plant that operates in the early 2020s, and be no less than 110 €/t for an optimised natural gas CCGT that operates after 2025.

4 Summary

As an effective way to improve the thermal efficiencies of lignite-fired power plants and thus decrease their CO_2 emissions, modern pre-drying technologies have been developed over the last decade. RWE's WTA dryer and Great River Energy's DryFining™ have been demonstrated successfully at full commercial scale, while Vattenfall's PFBD dryer has reached pilot scale with larger-scale demonstration planned. The technical aspects of these modern pre-drying technologies have been reported in detail in the literature. In contrast, little information on investment costs and techno-economics are publicly available.

This report gathered and extracted relevant cost information available from the public literature and presented an overview of the implications of modern pre-drying technologies to the techno-economics of power plants that fire lignite or brown coal.

Development of RWE's WTA dryer has been directed to strike a balance between compact dryer size, high drying efficiency, and acceptable energy requirement and operational complexity. To this end, it was necessary to optimise three key operational parameters: coal particle size, the fluidised bed pressure, and the pressure of the heating steam fed into the embedded tubular heat exchanger. No complete techno-economic analyses are available, but RWE reported in 2009 that the prototype WTA dryer at Niederaussem incurred a total investment of €50 million for erection and operation. In another earlier assessment in 2006, RWE claimed a specific investment cost of 70 €/kW for the open cycle variant of WTA. Please note that the reported costs are in the currency of the reporting year.

Vattenfall's PFBD dryer is similar in principle to RWE's WTA, though operating at a higher fluidised bed pressure. There was very limited cost information available. RWE and Vattenfall have different views in respect of whether fluidised bed drying at higher pressures delivers better economics. The actual cost/benefits balance will depend not only on the properties of lignite to be dried but also on the detailed thermodynamic configuration, such as whether or not the heat from the evaporated moisture is recovered and used for drying.

GRE's DryFining™ is based on a different technological principle to the WTA and PFBD dryers. It recovers very low grade heat contained in the flue gas downstream of the particle control equipment as well as in the hot cooling tower water flowing out of the boiler water condensers. Such low grade heat is normally not recovered and wasted as the flue gas is vented and the cooling water is condensed in the cooling towers. Moreover, DryFining™ combines drying and beneficiation in one process by means of a two- or three-staged moving fluidised bed. No detailed cost information is available, apart from that the US Department of Energy reported a $31.5 million investment through its Clean Coal Power Initiative into retrofitting 4 DryFining™ driers into Unit 2 of Coal Creek Power Station.

Modern pre-drying processes are also considered a key part of future lignite-based power generation technologies. RWE's BoA Plus technology integrated the WTA pre-dryers to the BoA lignite power plant technology. As for a BoA unit, its capital costs were found to depend heavily on the size of the unit and the lignite quality. The unit size had a non-linear inverse relationship with the unit's capital costs, while the lignite quality affected the design of the boiler combustion chamber and the flue gas clean-up equipment. In addition, firing dried lignite necessitated some modifications to the burners and boiler furnace cleaning system because the flame temperature increased and heat flux within the combustion chamber thus became greater. Such modifications incurred extra capital outlay (approximately 70 €/kW), but could be largely offset by the benefits gained from reduced fuel consumption and flue gas flow. The overall investment costs of a BoA Plus thus barely rose compared to a BoA unit of equivalent net power output, but the thermal efficiency could increase by 4–5 percentage points.

Modern lignite pre-drying was also included in a 700°C AUSC technology concept proposed by Kakaras and others (2006). The performance of three pre-dryers, including the tubular dryer, WTA dryer and MET dryer, were modeled to select an appropriate pre-dryer for the concept. WTA was found to be the best choice in terms of unit thermal efficiency improvement versus additional energy consumption and ease of operation. With the WTA dryer, a unit thermal efficiency gain of 7–8 percentage points could be expected for a 700°C AUSC lignite unit. The study estimated that the total installation costs were €537 million (as reported in 2006) for a 422 MWe 700°C AUSC lignite-fired unit with WTA pre-drying. However, it was not possible to infer the costs of the WTA dryers from the study.

The ZEP CCS cost study provided informative insights into the role of pre-drying in supercritical lignite-fired power plants both with and without CO_2 capture (the abated SC lignite power plants were expected to be operating in the early 2020s). Pre-drying could increase the thermal efficiency of an unabated lignite supercritical unit from ~43% (LHV) to 48–49% (LHV), which corresponded to a reduction of CO_2 emissions from 0.930 t/MWh to 0.816–0.833 t/MWh. It was also found that the impact of pre-drying on the levelised cost of electricity (LCOE) depended somewhat on the investment climate, because the investment climate determined the actual EPC and fixed O&M costs.

The ZEP study compared the generation costs when three types of first-generation CO_2 capture technology are applied to lignite power plant, and illustrated the cost implications of pre-drying for these abated lignite power plants. The study found that post-combustion capture was a relatively more expensive option (in terms of LCOE) and also imposed a greater plant efficiency penalty of 2–3 percentage points than IGCC pre-combustion capture or pf oxyfuel combustion. The post-combustion capture also demanded a higher CO_2 price to justify CO_2 capture. Such a difference was partially due to the fact that pre-drying of lignite had been included in the IGCC pre-combustion capture plant and the pf oxyfuel combustion plant in the ZEP study.

The ZEP study also examined the relative cost advantages of hard coal, lignite and natural gas for power generation. Since lignite is a much cheaper fuel and its price is almost unaffected by factors outside the production area, it represents a more affordable fuel of generation with a stable price. The study showed unabated lignite-fired power plant was the most profitable plant to run despite the fact that the higher EPC costs and fixed O&M costs made its levelised CAPEX (22.7 €/MWh) considerably higher than that of unabated hard coal power plants (19.0–19.1 €/MWh). The LCOE was found to be very sensitive to the fuel costs. The LCOE of hard coal-fired pf plant could be 44.4–44.6 €/MWh in the low fuel-cost case (2.0 €/GJ) and 52.7–52.8 €/MWh in the high fuel-cost case (2.9 €/GJ) as opposed to 43.7 €/MWh for the lignite pf power plant (lignite fuel cost 1.39 €/GJ). Unabated natural gas CCGT power plant was much cheaper to build than either unabated lignite pf power plant or unabated hard coal pf power plant. However, it was more costly to run gas plants due to the high prices of natural gas (4.5–11 €/GJ). Natural gas CCGT plants could be competitive with hard coal plants only if the gas price became as low as ~4.5 €/GJ and hard coal prices were above 2.4 €/GJ.

Moreover, the generation cost advantages of each type of the first-generation CO_2 capture technologies were compared across the three generation fuels. The results suggested that post-combustion capture was a more expensive option for lignite plants than for hard coal plants, due primarily to higher levelised CAPEX and levelised fixed O&M costs of the lignite plants. IGCC pre-combustion capture and oxyfuel combustion seemed attractive for lignite; part of the reason might be that lignite pre-drying was incorporated into these two capture technologies. Natural gas CCGT plants were a more expensive option for power generation than both hard coal plants and lignite plants, regardless of CO_2 capture. Nevertheless, abated lignite power plants could be cost-comparable or even cheaper than unabated natural gas CCGT plants. The CO_2 price must be higher than 110 €/t to justify abatement on a natural gas CCGT plant in operation in the early 2020s, and be no less than 110 €/t for an optimised natural gas CCGT plant that operates after 2025.

In summary, the investment cost and techno-economic information on modern pre-drying processes is scarce and incomplete in the literature. Their capital costs, as indicated in the literature, are likely to be in the range of US$33–50 million (currency in the year of reporting). Such costs may be largely offset by the gains in plant thermal efficiencies and power savings due to reduced flue gas flows and fuel handling equipment. The actual cost level, however, depends both on the properties of the lignite in question and the operational parameters. Modern pre-drying processes can produce about 1 percentage point (LHV) gain in the plant thermal efficiency when retrofitted to existing lignite-fired power plants to replace part of the fuel feed. An increase of 4–5 percentage points (LHV) in the plant thermal efficiency can be realised in supercritical dry lignite-fired power plants; a further 0–3 percentage points (LHV) efficiency improvement could be achieved if the 700°C advanced steam conditions are adopted at dry lignite-fired power plants. These modern pre-drying processes will also benefit future lignite power plants with CO_2 capture.

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