Water conservation in coal-fired power plants

Anne M Carpenter

CCC/275

February 2017

Water conservation in coal-fired power plants

Author:	Anne M Carpenter
IEACCC Ref:	CCC/275
ISBN:	978–92–9029–598-3
Copyright:	© IEA Clean Coal Centre
Published Date:	February 2017

IEA Clean Coal Centre
Apsley House
Third Floor
176 Upper Richmond Road
London SW15 2SH
United Kingdom

Telephone: +44(0)20 3905 3870

www.iea-coal.org

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, China, the European Commission, Germany, India, Italy, Japan, Poland, Russia, South Africa, Thailand, the UAE, the UK and the USA. The Service provides information and assessments on all aspects of coal from supply and transport, through markets and end-use technologies, to environmental issues and waste utilisation.

Abstract

The vulnerability of the power generation industry to constraints in water availability is widespread and growing, and this is increasing the pressure on power plant operators to conserve water. This report discusses where water can be conserved or recovered within pulverised coal-fired power plants. It includes ways of saving water in bottom ash handling, pollution control, and cooling systems. Cooling typically accounts for the largest usage of water (where water is the coolant), and wet flue gas desulphurisation is the second largest use at wet-cooled plants. Techniques for recovering water from the pulveriser and pre-dryer exhausts, and from the flue gas are also discussed. If sufficient water can be economically recovered from the flue gas, then a dry-cooled power plant could become a supplier of both electricity and water.

Acronyms and abbreviations

ACC	air-cooled condenser
CCS	carbon capture and storage
CDS	circulating dry scrubbers
COC	cycles of concentration
DSI	duct sorbent injection
EPRI	Electric Power Research Institute (USA)
ESP	electrostatic precipitator
ESI	economiser sorbent injection
EU	European Union
FGD	flue gas desulphurisation
FSI	furnace sorbent injection
GWFL	Getting Water from Lignite
IEA	International Energy Agency
L	litres
NDDCT	natural draught dry cooling tower
NETL	National Energy Technology Laboratory (USA)
NSF	National Science Foundation (USA)
PCM	phase change material
PM	particulate matter
SCR	selective catalytic reduction
SDS	spray dry scrubbers
TMC	transport membrane condenser
TSC	thermosyphon cooler
USDOE	United States Department of Energy
WESP	wet electrostatic precipitator
WTA™	Wirbelschicht-Trocknung mit interner Abwämenutzung (fluidised bed drying with internal waste heat utilisation)

Conversions

1 m^3 = 1000 litres

1 t water = 1 m^3

Contents

List of Figures

1 Introduction

Water and energy are basic necessities of human well-being and prosperity. They are mutually dependent, with energy production requiring large volumes of water and the water infrastructure requiring large amounts of energy. For example, the water system in the USA consumes over 12% of national energy production (Hightower, 2014), whereas thermal power generation alone was responsible for 45% of water withdrawals in 2010 (although most of this water is returned to the source) (Maupin and others, 2014). This interdependency has been called the 'water-energy nexus', and is explored more fully in an earlier report from the IEA Clean Coal Centre (Carpenter, 2015). The demand for energy and water is increasing as a consequence of population and economic growth, and higher living standards. Water demand worldwide has been projected to grow by 55% between 2000 and 2050, principally due to rising demand from manufacturing, thermal power generation, and domestic use (OECD, 2012). Global energy demand has been projected by the International Energy Agency (IEA, 2012) to rise by 35% between 2010 and 2035, with the demand for electricity expanding by some 70%. This projection is in their New Policies Scenario, which takes into account existing and planned government policies.

Withdrawal of water for power generation (which accounts for over 90% of energy-related water withdrawals) is projected by the IEA (in the New Policies Scenario) to rise by 3.7%, from 540 billion m^3 in 2010 to 560 billion m^3 in 2035. However, water consumption, that is, the amount of water that is withdrawn and not returned to the source, could increase by almost 40% (IEA, 2012). These two trends are the result of a shift towards higher efficiency power plants with advanced cooling systems that reduce withdrawals. Cooling accounts for the largest usage of water at a wet-cooled coal-fired power plant (*see* Chapter 6). The more efficient wet-cooled supercritical and ultrasupercritical plants typically use 15-20% less water than subcritical ones.

The vulnerability of the power generation industry to constraints in water availability is widespread and growing (Carpenter, 2015). Significant areas of almost every continent face a high level of water stress, including large areas in China, India, South Africa, and the USA – the four top thermal coal consuming countries in the world. Regions where water is scarce face obvious risks, but even regions with ample resources can experience constraints due to droughts, heat waves, seasonal variations and other factors. For example, a number of power plants in India had to shut down temporarily during 2016 due to a lack of water, including five units (totalling 1600 MW) at the Farakka coal-fired power plant in West Bengal, and four units (2600 MW in total) at the Tiroda plant in Maharashtra (Power, 2016). The power generation industry in the water-abundant north-east region of the USA is facing issues of water quality and temperature. Power plants have had to close down at times to ensure they do not exceed the permitted water discharge temperature.

The number of plants affected is likely to increase in the future, with serious economic consequences. Furthermore, ground water supplies are diminishing with an estimated 20% of the world's aquifers already over-exploited (WWAP, 2015), and the quality of the water is deteriorating. Consequently, competition between power plant operators and other water users is likely to escalate, and climate change could further exacerbate the situation. Regulatory restraints by governments may impose limits on, or increase the cost of, fresh water usage by power plants. All of these factors are increasing the pressure on power plant operators to reduce water consumption and/or to look for alternative or supplementary non-fresh water sources.

This report continues a series relating to water and the power generation industry. The first one looked at where water stress is occurring in the world today, before it examined the availability and consumption of water within China, India, South Africa and the USA. It also discussed central government energy, climate and water policies and how they affect the coal-fired power generation sector in these four countries (Carpenter, 2015). The second report discussed alternative non-fresh water sources in the same four countries (Carpenter, 2016). The sources were municipal waste water, brackish and sea water, mine water, produced water from oil and gas wells, and water extracted from saline aquifers during CO_2 storage. An earlier report covered low water flue gas desulphurisation (FGD) technologies (Carpenter, 2012). This report looks at how water can be conserved within a pulverised coal-fired power plant. A report published recently by the Asia-Pacific Economic Cooperation (APEC) reviews technology developments, best practices and current policy measures related to coal power generation and clean coal technologies in APEC countries (DNV GL, 2016).

Water is essential for power generation. Heat (from the combustion of coal) is used to convert water into high pressure, high temperature steam, which is expanded through a turbine to produce electricity. There are many different designs for pulverised coal-fired power plants. One design and its associated water-steam and flue gas paths are illustrated in Figure 1. Water exits the system in various ways. These can be broadly classified as:

- unavoidable losses, such as through the evaporation of recirculated water in wet cooling towers, and minor steam leaks;
- losses to the formation of products, such as gypsum from the wet FGD scrubber;
- deliberate blowdown from various recirculating streams, including boiler feedwater, FGD streams and cooling water. Blowdown is necessary to preserve water quality and remove impurities; and
- handling products, such as ash sluicing.

The main places where water is lost and added (water make-up) are indicated in Figure 1.

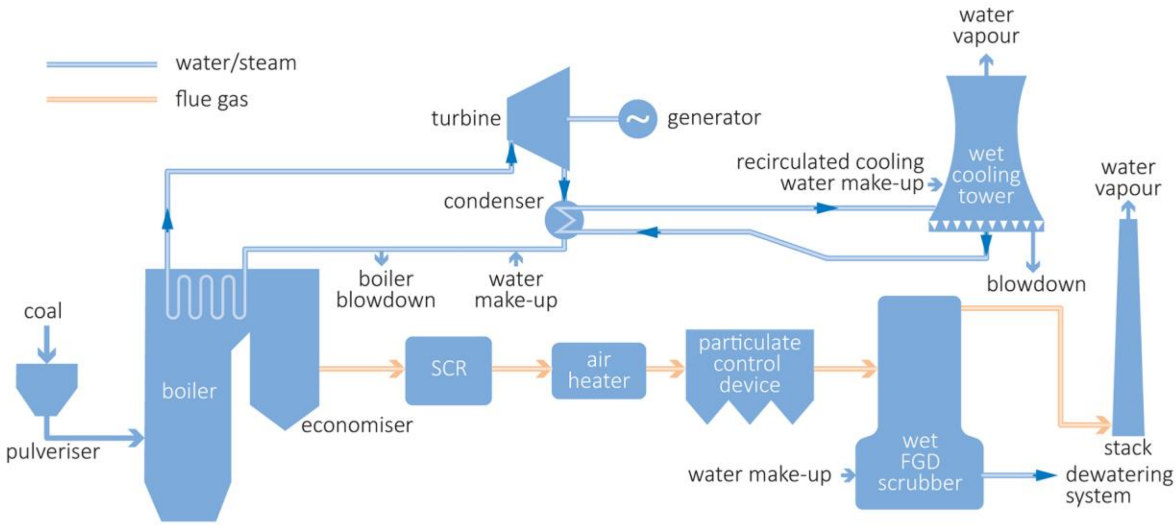

Figure 1 Schematic of a power plant showing where water is lost and added

Figure 2 shows the water balance for a 500 MW subcritical, bituminous coal-fired power plant; it gives an indication of the amount of water consumed. The plant layout is basically that shown in Figure 1. The particulate control device is a fabric filter (baghouse) and it uses a wet limestone forced oxidation FGD system (wet FGD scrubber).

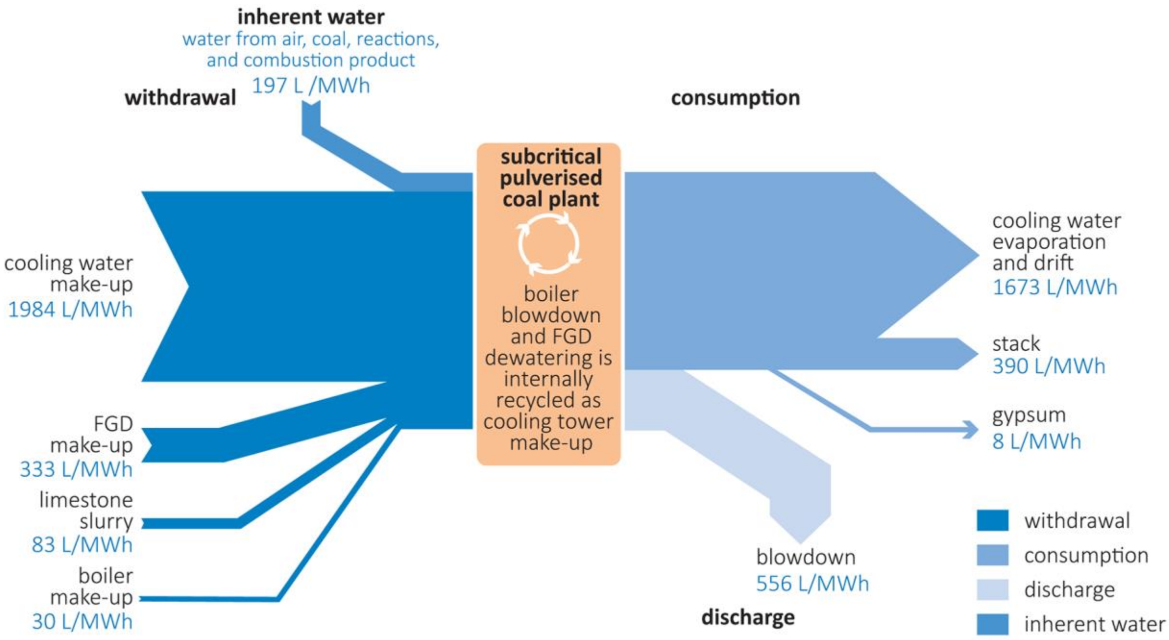

Figure 2 Water balance on a subcritical 500 MW power plant (Carney and Shuster, 2014)

The report begins by describing techniques for recovering water from coal. Low rank coals are sometimes dried before combustion to improve power plant efficiency. The evaporated water can be recovered from the mill (pulveriser) exhaust or from pre-dryers. Ash existing the bottom of the boiler can be handled wet or dry, and this is the subject of Chapter 3. The next chapter examines ways of conserving water in pollution control systems, in particular, FGD. Wet FGD systems typically account for the second largest usage of water at a wet-cooled power plant (*see* Figure 2). The flue gas exiting the boiler contains a large amount of water vapour. The 500 MW subcritical plant, whose water balance is shown above, discharges some 390 L/MWh from the flue gas stack. If lignite was fired, instead of bituminous coal, then even more water vapour would be lost if the lignite is not dried prior to combustion. Technologies for recovering water vapour are covered in Chapter 5. Finally, ways of conserving water in cooling systems are examined.

Boiler feedwater is generally a mix of returned steam condensate and fresh make-up water. Make-up water is required to compensate for leakages (very small) and sootblowing steam used to clean the boiler tubes. Blowdown is also necessary to preserve the high purity of the water and steam in the system. Make-up usage accounts for about 1–2% of steam flow, or about 30 L/MWh in a 500 MW subcritical power plant (*see* Figure 2). Although not insignificant, it is much less than for cooling or FGD water make-up. There are smart systems available that can minimise the sootblowing steam consumption. Otherwise compressed air or acoustic sootblowers could be installed. Water recovered from coal or flue gas could be used for boiler feedwater make-up to reduce fresh water consumption. Since much of the water loss cannot be avoided, boiler feedwater make-up is not covered any further in this report.

Improving plant efficiency, for example, by utilising waste heat, reduces the amount of heat rejection required per unit of power produced and therefore, decreases water demand; but this topic is outside the scope of the report, as is water treatment for the reuse of waste water generated within the power plant.

2 Water recovery from coal

Low rank coals are widely used for power generation in a number of countries, including Australia, China, Germany, Greece, India, Poland and the USA. Many of these plants are in water-stressed areas, and so recovering the moisture from the coal could provide water for internal use. Lignites can have inherent moisture contents as high as 70%. The coals can be dried before they are combusted. In conventional power plants, the drying takes place within the mill. Here, the beater wheel mills not only break up the coal, but also draw the hot furnace gas (1000°C) from the boiler to evaporate the moisture and convey the pulverised lignite and water vapour to the burners. The use of such high grade heat for drying and passing all the evaporated moisture through the boiler results in lower power efficiencies and higher CO_2 emissions than from plants firing lower moisture coals at similar steam conditions. Pre-drying lignite before it enters the mill (preferably using low-grade heat) offers the potential to recover the evaporated moisture from the dryer exhaust. Otherwise, the water vapour could be recovered from the mill exhaust. Both options would also result in a lower flue gas volume and consequently, lower water consumption in wet cooling towers (*see* Section 6.2) and wet FGD systems, especially if the temperature of the flue gas has been reduced before it enters the FGD system (*see* Section 4.2.1). Moreover, the plant's thermal efficiency could increase by about 1 percentage point (lower heating value, LHV) when retrofitted to existing lignite-fired power plants; thermal efficiency could increase by 4–5 percentage points (LHV) in new dry lignite-fired power plants (and CO_2 emissions decrease by over 10%), and a further 2–3 percentage points can be expected if 700°C advanced steam conditions are adopted (Dong, 2014; Henderson, 2013). Higher rank bituminous coals have a lower moisture content and therefore, a lower amount of water would be recovered. This chapter will focus on pre-drying low rank coals with water recovery.

A number of technologies for removing water from low rank coals have been developed or are under development. These can be categorised into:

- evaporative processes, where the moisture is driven off as vapour;
- non-evaporative dewatering processes, where the moisture is removed as a liquid. These include thermal dewatering, mechanical thermal expression, and solvent extraction processes. However, the water discharged from these processes often requires expensive treatment before it can be used.

Some of the commercial or near-commercial pre-drying technologies that have been integrated into pulverised coal-fired power plants are described. These evaporative processes use hot air, flue gas or steam from the power plant as the drying medium. Coal drying systems that are operated separately from an on-site power plant will not be covered, although the recovered water could potentially be used by the power plant. The chapter begins with developments in recovering water from the mill exhaust before discussing water conservation from pre-drying the coal before it enters the mill. Technologies for drying were primarily developed to improve the thermal efficiency of power generation rather than for water recovery. The evaporated water vapour is often emitted to the atmosphere but could be recovered for use within the power plant. More information on low rank coal drying technologies are available in the IEA

Clean Coal Centre reports by Dong (2011, 2014) and Zhu (2012), and in more recent reviews by Nikolopoulos and others (2015) and Rao and others (2015).

2.1 Water recovery from mill exhaust

A proposed plant modification from CastleLight Energy Corp. (*see* www.Castle-Light.com) uses a mixture of flue gas from the economiser and the air heater to dry coal within the mill. The wet exhaust (sweep) gas and pulverised coal are separated in a small fabric filter (baghouse), one for each mill. The dried pulverised coal is then conveyed to the coal burners, and water is recovered from the exhaust gas using a heat exchanger. A 600 MW power plant firing Powder River Basin subbituminous coal (<30% moisture) is dried to less than 10% moisture (by removing surface water in roughly one second), and about half of the evaporated water could be recovered for boiler feedwater make-up or other purposes (Moore, 2016).

A new technology being developed in China is the Getting Water from Lignite (GWFL) system (*see* Figure 3). High temperature flue gas extracted from the upper part of the boiler and low temperature flue gas from the rear of the boiler are mixed and transported through a membrane-cooled high temperature pipeline to a drying tube. Here, they pre-dry the raw lignite (>30% moisture), quickly turning the moisture into steam. The steam and coal then enter a fan (beater wheel) mill, where further drying of the coal occurs. The steam and pulverised coal are separated, and the steam is then condensed in a heat and water recovery device (an ultra-low temperature heat exchanger). The pulverised coal passes into a bunker before being delivered to the coal burners. Field tests of the system have been carried out on a 100 MW unit.

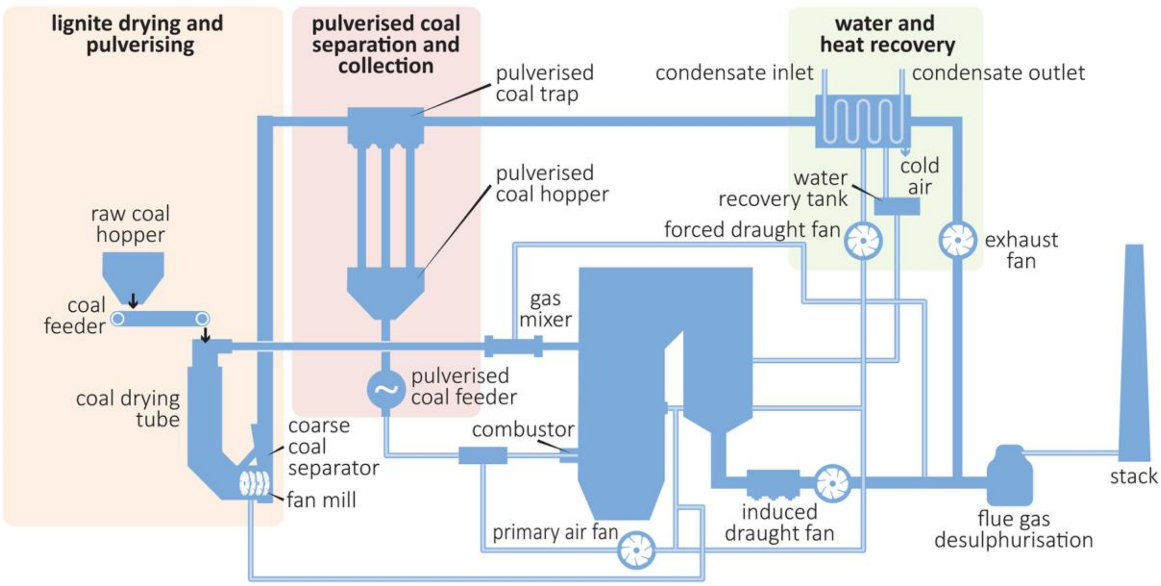

Figure 3 Flowsheet of the GWFL system (Hu and Pei, 2015)

Water is also saved in the FGD system as the cool exhaust gas exiting the water and heat recovery unit reduces evaporation losses. The condensate can be used for make-up purposes after treatment; the water is weakly acidic and the main contaminates are suspended solids. Zero water make-up can be achieved on supercritical or ultrasupercritical units employing dry (air) cooling systems (Hu and Pei, 2015).

Calculations by Ma and others (2013) for a 600 MW supercritical plant employing a version of the GWFL system suggest that some 84% (131 t/h) of the water vapour in the mill exhaust could be recovered with a 39.5% moisture lignite. This is enough to meet the entire water consumption of an air-cooled plant with a wet FGD system. The drying agent is a mixture of hot flue gas from the boiler and mill exhaust gas. Various drying agent options, namely hot air from the air heater outlet, mill exhaust from the pulverised coal collector outlet or hot mill exhaust from the air heater outlet, each mixed with hot flue gas from the boiler, were later investigated by Ma and others (2015). The highest water recovery was achieved with a mixture of hot flue gas from the boiler outlet and hot mill exhaust from the air heater outlet.

Instead of the waste heat and water recovery device shown in Figure 3, Han and others (2017) investigated using a low pressure economiser for wet-cooled units, and a spray tower integrated with a heat pump for air-cooled units. Some 39% of the water vapour from the mill exhaust could be recovered with a low pressure economiser on a 600 MW plant firing 39.5% moisture lignite. As a result, about 110 t/h (0.18 t/MWh) of water could be saved; this would at least be enough to supply the make-up water requirements of the wet FGD system. Some 189 t/h of water (0.31 t/MWh) could be saved with the spray tower system. This reduces to 0.17 t/MWh when the moisture content of the lignite is 30%. These savings mean zero make-up water consumption in dry-cooled power plants. Both schemes were economically feasible with discounted payback periods of around 3 years.

2.2 Pre-dryers

Pre-drying systems, which can continuously dry run-of-mine lignite using waste heat or low pressure steam, have been successfully integrated into power plants. The opportunities for retrofitting these systems are site-specific and depend on the available heat sources, space constraints, and general layout of the plant. More details about the technologies discussed below can be found in the IEA Clean Coal Centre reports by Dong (2011, 2014) and Zhu (2012).

The commercially available DryFining Fuel Enhancement Process (DryFining™, *see* http://greatriverenergy.com/we-provide-electricity/making-electricity/dryfining/) has been demonstrated at Great River Energy's Coal Creek Station near Underwood, ND, USA, and was subsequently installed on both of the plant's two units. It combines drying and beneficiation into one process using a two- or three-stage moving bed Fluidised Bed Dryer system. The first stage removes the heavier particles, which contain significant amounts of sulphur and mercury, from the crushed coal. Thus emissions of sulphur dioxide and mercury are reduced. The lighter particles pass into the second stage where they are fluidised and dried by hot air. The hot air is generated by heating ambient air in the air heater using warm cooling water from the steam turbine condensate. Additional drying is provided by in-bed heat exchangers using heated water. The dried coal is sent to a pulveriser and then to the boiler. The evaporated moisture is currently vented to the atmosphere after passing through a fabric filter (baghouse). Installing tube-type water-cooled condensing heat exchangers could capture some 34,900 kg/h of water from each unit (Yao and others, 2016). Nevertheless, retrofitting DryFining™ has saved an estimated 47,630 kg/h of water at each unit due to the lower volume of flue gas passing through the wet FGD scrubbers and reduced cooling demand on the wet cooling towers. The moisture content of local lignite was reduced from 38% to 28%, increasing thermal plant efficiency by ~4 percentage points (Great River Energy, 2016). Operating experience of DryFining™ at the Coal Creek Station is discussed by Yao and others (2016).

RWE has developed the WTA™ (Wirbelschicht-Trocknung mit interner Abwämenutzung or fluidised bed drying with internal waste heat utilisation) system (*see* http://www.rwe.com/web/cms/en/234614/rwe-technology-international/mining/integrated-solutions/wta-technology/). The heat for drying is provided almost exclusively from heat exchangers immersed in the fluidised bed and only to a small extent by the fluidising medium (coal moisture vapour). The commercial-scale system installed at the Niederaussem power plant in Germany uses fine grained lignite (0–2 mm after milling of the raw 0–80 mm coal), and produces a 0–1 mm dried product after final milling (*see* Figure 4). This product size is more suited to a pulverised coal plant than the coarser feed version; it has reduced fluidising steam requirements and provides better heat transfer, giving equipment size savings (Zhu, 2012). The WTA™ system at Niederaussem is the open cycle variant, which takes low pressure steam from the steam turbine for heat input to the fluidised bed heat exchangers. Part of the evaporated vapour (steam) is recirculated for fluidisation, and the rest is condensed to provide some of the low grade heat for pre-heating the boiler feedwater.

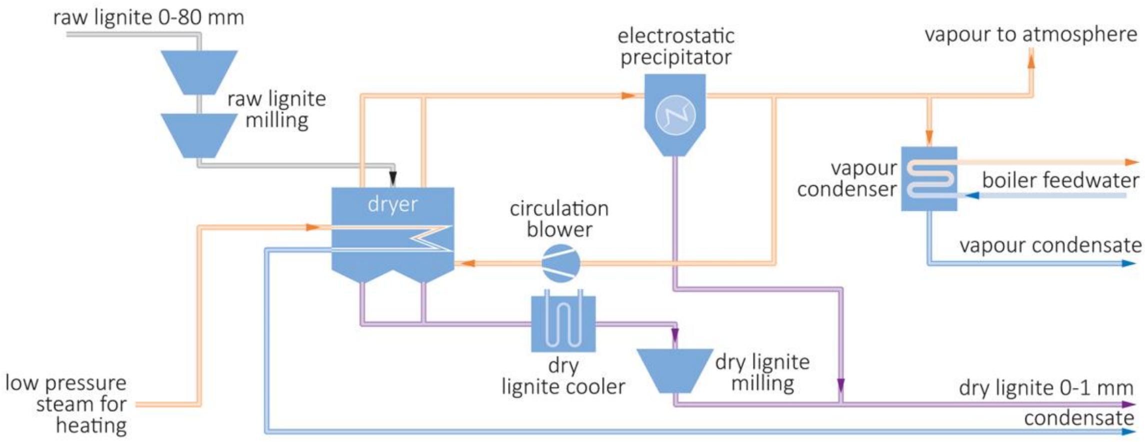

Figure 4 WTA™ lignite drying process as used in the prototype at Niederaussem (Henderson, 2013)

The closed cycle version of WTA™ compresses the liberated vapour for condensation in the heating tubes of the steam dryer, thereby recirculating the heat of evaporation back into the drying process, effectively an open heat pump cycle. The vapour condensate can also be used for industrial applications.

The WTA™ system at Niederaussem was designed to dry 210 t/h of 50–55% moisture lignite to produce 110 t/h of dried product (12% moisture), which corresponds to 30% of the fuel requirement of the 1000 MW ultrasupercritical unit. Some 100 t/h of water is evaporated.

One way of incorporating a steam fluidised bed pre-dryer in an air-cooled power plant is described by Xu and others (2015). It utilises waste heat from the air-cooled condensers. Again, exhaust steam from the low pressure steam turbines is passed through tubes embedded within the fluidised bed to dry the coal, but the fluidising (and additional drying) medium is warm air from the air-cooled condensers. The thermal efficiency of the plant increases, and the levelised cost of electricity is reduced, when compared to an air-cooled plant of similar capacity and without lignite pre-drying.

Vattenfall's PFBD (pressurised fluidised bed drying) system is similar to WTA™ but operates under a higher pressure. This improves the heat transfer efficiency, reduces the superheating of evaporated moisture, and results in a smaller dryer. Since the evaporated vapour from the dryer is at the operating pressure of the fluidised bed, it can be used in the plant's steam cycle. A 10 t/h pilot-scale system at the Schwarze Pumpe power plant in Germany dried 55–60% moisture lignite to 12–17% under a pressure of 0.1–0.6 MPa, and at an operating temperature of 100–160°C. The planned integration of a large-scale demonstration unit at the oxyfuel combustion demonstration plant at Schwarze Pumpe was cancelled when Vattenfall abandoned all its carbon capture and storage (CCS) research (Dong, 2014).

Environmental Clean Technologies Ltd (ECT) in Australia is developing the Coldry Process (*see* http://www.ectltd.com.au/coldry/coldry-overview/). Pellets produced from lignite are dried in a vertical Packed Bed Dryer using waste heat from the power plant to provide the warm air needed for the drying process. The evaporated moisture is condensed and fed to the power plant's cooling circuit. The dried pellets are then pulverised and the resultant product is injected into the boiler. Coal with a moisture content of 30–70% can be dried to 10–14%, depending on the water content and characteristics of the raw lignite, the drying temperature and drying time (which can take hours). The Coldry plant, currently run for testing and demonstration purposes, has a maximum production capacity of 20,000 t/y (Zhu, 2012). The Coldry process has not yet been integrated into a power plant. A demonstration plant is planned in India where it will be integrated with an iron ore plant (Stevens and Plummer, 2016).

2.3 Comments

Commercial systems for drying coal prior to combustion are available, and these could be adapted to recover the evaporated moisture. New systems that have been designed to recover the moisture are available, but have not yet been demonstrated on a full-scale power plant. In some cases, the amount of water recovered may be sufficient to supply all the make-up requirements of an air-cooled plant with a wet FGD unit. Furthermore, water recovery can lower fresh water consumption in wet FGD scrubbers and cooling towers, improve overall plant thermal efficiency and reduce CO_2 emissions.

3 Ash handling systems

The combustion of coal produces unburned residues. These include bottom ash (also called clinker ash) that exits the bottom of the boiler, and fly ash that exits the economiser, air heater and particulate removal system (an electrostatic precipitator or fabric filter (baghouse) – *see* Section 4.1). The amount of ash generated depends on the properties of the coal, particularly its calorific value and ash content. Coals with ash contents of up to ~40% are combusted in power plants in China, India, South Africa and elsewhere. A 500 MW unit burning a typical Indian coal (40% ash) generates some 140 t/h of ash (CEA, 2012a). Bottom ash generally accounts for 10–20% of total ash production, and fly ash for the rest. This ash needs to be collected and disposed of. Wherever possible, the ash is sold for cement and concrete manufacture, as building material, for road construction or for other uses. However, large quantities still require disposal in landfills, large surface impoundments (ash ponds) or other waste sites. Ash management and utilisation are discussed in the IEA Clean Coal Centre reports by Barnes (2010), Couch (2006), Sloss (2007), Smith (2005a,b), and Zhang (2014). This chapter just covers bottom ash handling systems where there is more opportunity for conserving water.

Methods for handling bottom ash can be categorised into:

- wet handling systems that use water to cool and transport the ash to downstream processing equipment;
- semi-dry systems where the ash is dewatered after being cooled with water; and
- dry handling techniques, which use air to both cool and convey the ash.

Fly ash is usually collected as a dry solid. However, water is consumed if it is turned into a slurry for hydraulic transport to an ash pond. In addition, some water is needed if the fly ash requires conditioning before transport.

3.1 Wet ash systems

Traditionally, water has been used to cool and sluice ash away from the bottom of the boiler for final disposal (often called an ash sluicing or water-impounded hopper system). The ash falls into a water-filled hopper where it is quenched and stored. The relatively cold water causes the larger clinkers to fracture into smaller pieces due to thermal shock. The collected ash is then periodically removed from the hopper, ground in a clinker grinder, and pumped via a slurry pipeline to the ash pond.

The hot ash heats the water in the ash hopper, evaporating a portion of it; the rate of evaporation is equivalent to around 7.5% of the rate of bottom ash production (Bassetti and others, 2013). The evaporated water passes into the boiler. Make-up water is needed to replace the loss, some 1.3% of water usage in a 550 MW (net) subcritical plant and 1% in a 550 MW supercritical power plant burning 7.2 wt% ash bituminous coal (Berkenpas and others, 2009). Ash handling systems can account for some 40% of fresh water intake at Indian power plants burning high ash coals (Batra, 2012). Blowdown from the cooling water system is often utilised. Water can also be saved by recycling water from the ash pond back to the plant rather than discharging it into a nearby waterway; some 70% of water can be recovered and reused (CEA, 2012b). Water is lost from the ponds due to evaporation. The water usually requires treatment before reuse.

The bottom ash and fly ash can be transported to the pond as a dense concentrated slurry (over 60% solids by weight) to reduce water consumption. However, if water recovery from the ash pond is taken into consideration, there may not be substantial savings in water compared to low solid slurry disposal (CEA, 2012b).

Ash sluicing systems consume energy because slurry and circulating pumps are required. Maintenance can be costly because of corrosion, erosion (quartz in ash is abrasive) and clogging.

3.2 Semi-dry systems

Semi-dry ash handling systems dewater the collected wet ash either in dewatering bins (batch-type system) or on a continuous removal conveyor system. The water is collected and recirculated (after treatment). Water consumption is lower than wet handling systems, and the need for wet ash ponds is eliminated. However, water could still seep through 'dry' ash impoundments as the ash is not completely dry.

Two bins are needed in a dewatering bin system, used alternately (*see* Figure 5). The bottom ash slurry from the ash hopper is pumped into the top of the bin, and when the ash level is above the conical section, the flow is stopped. Decanting valves are opened, allowing the water to pass through the decanting screens and into a separate settling tank. Here, remaining ash particles are removed and returned to the dewatering bins. The clear water is then stored in the surge tank before eventual return to the ash hopper. The ash removed from the dewatering bin has a moisture content of around 15–18% (Morris, 2011).

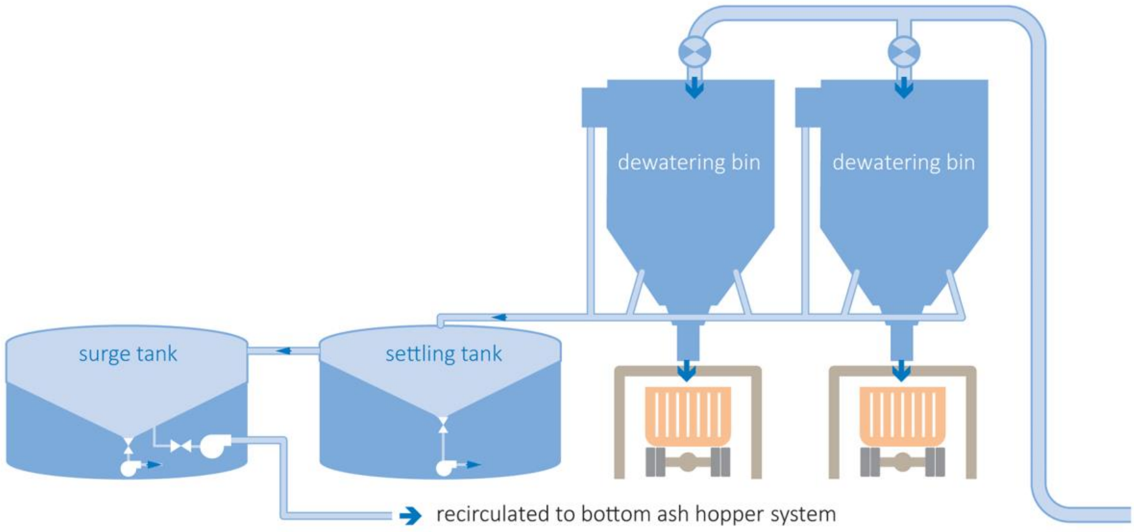

Figure 5 Dewatering bin system (Fleming and Mooney, nd)

The advantages of dewatering bins include a low initial cost and, for retrofits, no outage is required and the wet bottom ash hopper is unaffected. However, lifecycle costs can be high (Morris, 2011).

In a continuous removal and recirculation system, a conveyor submerged in the water trough below the boiler removes the bottom ash as it is quenched. The ash is then dewatered as it travels up the inclined section, and is discharged onto a mechanical conveyor or directly into a storage silo or containers. Crushers or grinders can be installed at the discharge point to decrease the particle size. The final bottom ash moisture content is generally between 15% to 20%, but can be higher. If further dewatering is required, then the ash can be discharged into a dual bin dewatering arrangement (Fleming and Mooney, nd).

The water can be collected and recycled to save water and for zero liquid discharge. Water treatment for pH control and heat exchangers may be needed to minimise corrosion, increasing capital and operating costs. A typical submerged scraper conveyor requires some 130–190 L of water per minute to maintain the water level and temperature in the water trough (Fleming and Mooney, nd). These systems can be retrofitted at plants employing wet handling systems, provided there is enough room. Otherwise the ash slurry can be transported to a conveyor system located away from the boiler. Advantages of conveyor systems over wet handling systems include lower power consumption, less water usage, and reduced operational and maintenance costs (Foster Wheeler Italiana, 2011).

3.3 Dry ash systems

Dry ash systems use ambient air to cool and transport the bottom ash from the boiler, thereby eliminating the need for water. Several dry handling approaches have been developed. In some systems, bottom ash from the boiler falls onto an enclosed moving conveyor belt. The negative pressure in the boiler draws in ambient air, which moves in a counterflow direction over the ash. Sensible heat from the ash is transferred to the air, which is returned to the boiler as preheated air for combustion (improving boiler efficiency); it typically makes up less than 1–1.5% of the combustion air. Moreover, combustion of the unburnt carbon in the ash continues (improving ash quality). The dry ash is sent to an ash silo, storage bin or transfer station. Examples include Drycon™, developed by Clyde Bergemann (*see* http://www.cbpg.com/en/products-solutions-materials-handling-bottom-ash/drycon%E2%84%A2), and MAC® (Magaldi Ash Cooler) and SuperMAC® developed by Magaldi Power (*see* http://www.magaldi.com/en/products-solutions/#coal-fired-power-plants). In the SuperMAC® design (for high ash coals), part of the cooling air is forced across the belt to maximise the cooling process. Large clinker pieces can be crushed before (Drycon™) or after cooling (MAC®).

United Conveyor's VAX™ (Vibratory Ash Extractor) system (*see* http://unitedconveyor.com/vax/) uses the toss-and-catch motion of a vibrating deck to move the ash from under the boiler to a crusher, where it is fed to a secondary conveyor. Cooling air is forced up from under the vibrating deck to surround each particle. This promotes more efficient combustion than the moving belt approach where the air tends to flow over the ash layer. Up to 90% of all the heat contained in the bottom ash is recovered and delivered to the boiler.

Other dry systems include United Conveyor's PAX™ (Pneumatic Ash Extractor) in which the bottom ash is collected in a dry refractory-lined hopper under the boiler and cooled by percolating air. As the ash cools, it is fed and crushed into a pneumatic conveying line.

Advantages of dry handling systems over wet and semi-dry ones include higher boiler efficiency, better quality ash (lower unburnt carbon), no water treatment costs, lower power consumption, lower operating and maintenance costs, and smaller space requirements (Bassetti and others, 2015; Clyde Bergemann, 2016). However, investment costs are higher (Bullock, 2010). Returning preheated air to the boiler increases boiler efficiency by some 0.1–0.5 percentage points, depending on coal properties (such as ash content), the carbon content of the ash and other factors (Bassetti and others, 2013). High ash coals result in higher boiler efficiencies. Furthermore, the efficiency increase reduces coal usage and, consequently, lowers CO_2 emissions. Calculations for a 300 MW unit fitted with a MAC® system and burning Indian coal with an ash content up to 45% could recover 4.96 MWth (net) of heat and increase boiler efficiency by 0.63 percentage points. Converting a 300 MW unit from a submerged chain conveyor (once-through) handling system to a dry one (assuming a capacity factor of 80%) could save 10,320 t/y of coal, reduce CO_2 emissions by 13,240 t/y, save 159,900 m^3/y of water and reduce auxiliary power consumption by 1,850 MWth/y (Bassetti and others, 2013). Calculations for a 500 MW unit burning a 13% ash coal and its conversion to a fully dry handling system are given in Bassetti and others (2015). Dry handling systems have been successfully retrofitted.

The dry bottom ash with its lower unburnt carbon content increases the possibility of its use by the concrete and cement industry. If necessary, the dry-cooled bottom ash is pulverised to a fine size, so that it can be mixed with the dry fly ash, increasing the potential for more ash sales revenue. Otherwise the dry-cooled bottom ash can be converted into fly ash (a more valuable combustion by-product) by returning it to the boilers through the coal pulverisers (Bassetti and others, 2015). If the bottom ash is not sold, the landfill costs for dry ash are lower than those for wet ash.

3.4 Comments

Wet handling systems consume a not insignificant amount of water. Dewatering the ash (semi-dry systems) and recycling the water can result in zero liquid discharge from the ash handling system, as well as saving water. Dry ash handling systems have been available for over 30 years. As well as eliminating the need for water and wet ash ponds (which can contaminate ground water, if unlined, and can fail without adequate safeguards), these systems increase boiler efficiency, improve the quality of the bottom ash (lower carbon content) and can reduce ash disposal costs. Mixing dry bottom ash with the dry fly ash could potentially increase revenue from ash sales; this is largely limited by proximity to the end market and the availability of cheap transport.

4 Pollution control systems

Pollutants, such as nitrogen oxides (nitrogen dioxide (NO_2) and nitric oxide (NO)), sulphur dioxide (SO_2), sulphur trioxide (SO_3), particulate matter (PM), mercury (Hg) and carbon dioxide (CO_2) are formed when coal is combusted in a power plant boiler. Concerns over the environmental and health consequences of these pollutants has led to legislation and regulations limiting the amounts of SOx, NOx and PM that can be emitted to the atmosphere. The legislation and regulations have become increasingly stringent over the years, and this continues to be the case today. In addition, regulators are now setting limits for pollutants that were not previously regulated, such as mercury (in China) and CO_2 (in Canada). The national emission limits are given in the IEA Clean Coal Centre's emission standards database (*see* http://www.iea-coal.org.uk/site/2010/database-section/emission-standards).

This chapter looks at pollution control systems designed to control particulates, sulphur oxides, or carbon dioxide. NOx control systems are not discussed since they do not involve more water usage, except for the ones that use selective catalytic reduction. The catalyst in this system needs periodic cleaning and this is often done using sootblowers, which generally use steam. NOx control systems are discussed in the IEA Clean Coal Centre report by Nalbandian (2009). Some mercury can be captured as a co-benefit or by injecting a dry sorbent (which is not covered here since no water is involved). Mercury capture is discussed by Sloss (2012, 2015).

4.1 Particulate control

Coal-fired power plants typically install electrostatic precipitators (ESP) or fabric filters (also called baghouses) to control particulate emissions. The majority use dry ESP (over 90% of coal-fired power plants in China), although fabric filters (which are also dry) are relatively common. Dry ESP and fabric filters have similar overall PM removal efficiencies of more than 99.9%, but fabric filters are better at abating fine PM ($PM_{2.5}$), and are less sensitive to particulate loading and fly ash characteristics. Wet electrostatic precipitators (WESP) are not often employed on their own for PM control as they are not economically viable on large coal-fired power plants (Nicol, 2013). But they are increasingly being used as a final polishing device (after the wet FGD unit) to capture fine PM (filterable and condensable) and control acid gas mist. This is the case in China, where WESP are being retrofitted to meet the stringent 5 mg/m^3 emission limit for $PM_{2.5}$ (Silva and others, 2015). Fine particulates are removed more effectively in a WESP as the humidity in the flue gas stream reduces the resistivity of the particles. In addition, there is virtually no re-entrainment of particles. Particulate-bound mercury and some oxidised mercury are also removed as a co-benefit. Plants with a WESP are 'CO_2 capture ready' (provided there is enough space for the CO_2 capture unit) as CO_2 scrubbing requires very low inlet levels of PM, sulphuric acid and other pollutants. This section discusses WESP and how water can be conserved. More information on particulate control systems, including WESP, can be found in the IEA Clean Coal Centre reports by Nicol (2013) and Zhang (2016).

In a WESP, the particles are charged, collected on the collection electrodes, and removed using an intermittent or a continuous washing system to prevent any build-up of particulates on the collecting electrode surface. In the continuous washing process, atomised water is continuously sprayed into the gas passage or onto the collector plate to create a film of water that flows down, keeping the plate wetted. Since the amount and size of the water droplets sprayed is small, power levels in the WESP are not affected – this allows it to be energised at all times. However, a bus section is out of service during intermittent washing as it has to be de-energised to protect the transformer/rectifier sets. The wash water containing the particulates is collected, and can be recycled after neutralisation and blowdown. The blowdown stream can be sent to the wet FGD scrubber, if present, as make-up. The collected water could be directly sent to a limestone wet scrubber, where it is neutralised by the limestone slurry (Silva and others, 2015). The authors also discuss the design of WESP and the parameters that can affect their performance.

A continuous wash generally uses more water than an intermittent wash. Water consumption was 1.7 L/min/m^2 in a continuous thin water film WESP with enhanced hydrophilic collection plates. The plates were coated with TiO_2 nanoparticles to increase water film uniformity and lower consumption (Kim and others, 2014). The WESP (400 m^3/h capacity) was downstream of a dry ESP and flue gas condenser that had removed particles from a 0.7 MW oxy-fired combustion plant to a level of ~1 mg/m^3. Modified rigid collectors are also being developed with lower water and energy consumption (Xu and others, 2016).

Membrane collecting electrodes (instead of plate electrodes) are made from a material that readily absorbs water, such as a polypropylene mesh, and are placed over a material, such as fibreglass reinforced plastic (Silva and others, 2015). Du and others (2016) found that a similar particulate collection efficiency could be achieved at a lower water consumption with intermittent washing using water sprays than with a continuous thin film washing system. The intermittent system employed a Venturi nozzle on the front of a tubular WESP. The higher performance is a result of three particulate removal mechanisms, namely the prewashing (scrubbing) effect of the Venturi nozzles, condensation and agglomeration of the fine particle by the interaction of the fine water mist flowing into the electric fields, and the particles collected on the fibre membrane collecting plates.

Water can be dripped onto the membrane collection plate, rather than sprayed, to conserve water. A condensing membrane WESP has been developed where the reduction in the temperature of the saturated flue gas stream enables condensation of the water droplets. This could eliminate the need for make-up water to replace blowdown losses. It also enhances particulate collection efficiency (Shah and Caine, nd).

4.2 Desulphurisation systems

There are a wide range of commercial FGD processes available for removing SOx from flue gas. These can be categorised by their water usage into:

- wet processes (wet scrubbers), which consume the largest amount of water. Wet scrubbing is by far the most common system with over 80% of installed capacity worldwide;

- semi-dry processes, principally spray dry scrubbers (also called spray dry absorbers) and circulating dry scrubbers. These account for less than 10% of global installed capacity, and typically consume some 60% less water than wet scrubbers; and
- dry processes (dry sorbent injection), which consume no water or only a minimal amount. They account for about 2% of installed FGD capacity worldwide.

The wet FGD system is usually the second largest consumer of water in a coal-fired power plant fitted with a wet cooling system (wet cooling systems are the largest consumer, *see* Section 6.2). However, on a site which utilises a dry cooling system for the condensers (*see* Section 6.3), or where it is sea water-cooled (open-loop or once-through cooling – *see* Section 6.1), the use of water in wet FGD units can easily be 40–70% of the total site usage (Couch, 2005).

FGD technologies that reduce water usage are becoming more important due to the large number of systems being installed globally. This chapter looks at wet scrubbers and where water can be saved, before discussing the semi-dry and dry systems. More information on low water FGD technologies can be found in Carpenter (2012).

4.2.1 Wet scrubbers

Limestone is the most commonly used reagent in wet scrubbers to remove SO_2. Although other sorbents, such as lime, magnesium oxide, ammonia and sodium carbonate, are employed, limestone is normally the cheapest sorbent and is available in large amounts in many countries. The limestone slurry is sprayed into the absorber tower where it is atomised into fine droplets (*see* Figure 6). The droplets absorb SO_2 from the flue gas, facilitating reaction with the limestone. Some of the water in the spray droplets evaporates, cooling the gas and saturating it with water. The desulphurised flue gas passes through the mist eliminators to remove entrained droplets and is emitted to the atmosphere via the cooling tower, a wet stack or a dry stack after reheating. The spent sorbent slurry collects in the reaction tank at the bottom of the absorber where compressed air is commonly injected to oxidise the hydrated calcium sulphite into hydrated calcium sulphate (gypsum). The gypsum is dewatered and processed to produce a saleable quality product or it is sent for landfill disposal. Water removed from the gypsum is returned to the process. Fitting mist eliminators, if not installed, in the top section of the absorber tower or directly downstream would conserve water.

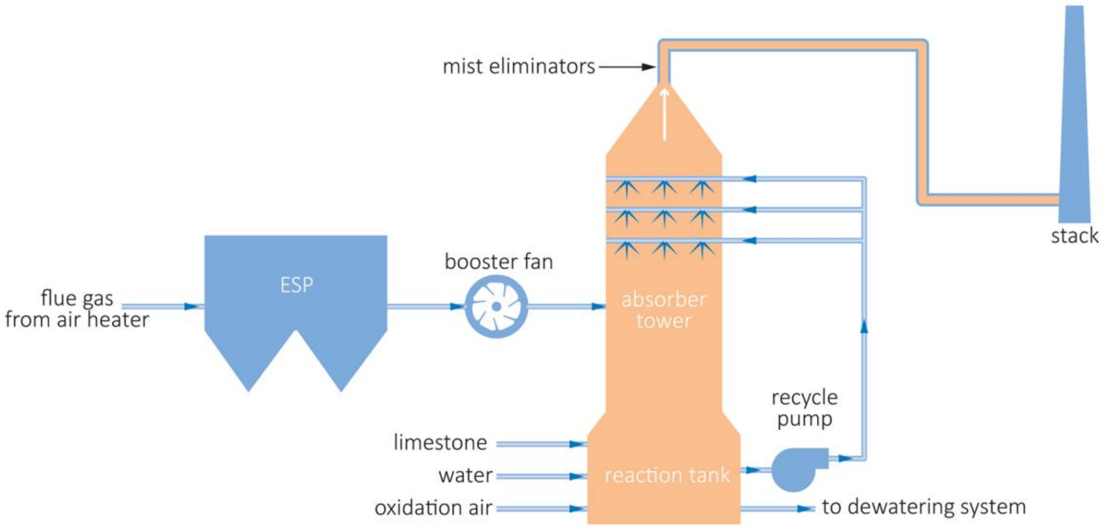

Figure 6 A typical limestone wet scrubber system (Carpenter, 2012)

Wet scrubbers commonly remove 95–98% of the SO_2, with the latest generation capable of removing over 99%, but they do not capture significant amounts of SO_3. They also remove hydrogen chloride (HCl), hydrogen fluoride (HF), and oxidised mercury (but not elemental mercury), and have been installed on units burning low to high sulphur coals. Unfortunately, CO_2 is produced as a result of the reaction of limestone with SO_2 and is emitted with the scrubbed flue gas. Parasitic power consumption is around 1.2-2%, depending on the sulphur content of the coal. Capital and operating costs are relatively high, but operating costs are often lower than the semi-dry processes. Selling the gypsum by-product can offset costs (Carpenter, 2012).

Waste water is generated and is treated before discharge. Treating it to a higher quality to enable its reuse is expensive, but will be required if future regulations mandate zero liquid discharge. The waste water is commonly combined with other water discharges from the plant, such as that from the bottom ash handling and cooling water systems, before it is treated. Wet FGD systems can be made into closed-loop ones to lessen the impact of water treatment and disposal concerns.

Over half the water in the flue gas can be lost in wet scrubbers due to evaporation. A nominal 500 MW subcritical bituminous coal-fired power plant equipped with wet scrubbers loses some 3514 L/min (or 405 L/MWh) of water vapour in the flue gas exiting the wet scrubber; a 500 MW supercritical plant loses some 3096 L/min (359 L/MWh). Water is added to make up for the evaporative water losses (and for water discharged with the gypsum or wet solid waste), some 2162 L/min (249 L/MWh) in the subcritical plant and 1899 L/min (220 L/MWh) in the supercritical plant (Klett and others, 2007). Adding a CO_2 capture (amine-based) system increases the FGD make-up water consumption by ~45–50% for both subcritical and supercritical plants. This is partly because a very low flue gas SOx level (<10 ppm) is needed to avoid contamination of the amine solvent. Consequently, reducing the evaporative water losses and/or recovering water vapour from the flue gas would save a significant amount of water. Recovering water vapour is discussed in Chapter 5.

Reducing evaporative water losses

Cooling the flue gas from a typical ~140°C to 90–100°C prior to its entry to the wet scrubber reduces the amount of water that is evaporated in the FGD absorber and hence, is lost through the exiting flue gas; this can lower its water consumption by ~40–50%. The flue gas exits the scrubber at a temperature of ~50°C and is then reheated. This improves stack gas dispersion and helps avoid condensation (and visible plumes). Typically, the flue gas cooling system is incorporated with the flue gas reheating system to form a regenerative heat recovery system. The regenerative heat exchanger is installed either before or after the particulate control device, which is upstream of the wet scrubber. Heat exchangers for flue gas cooling are often utilised in coal-fired power plants in Japan and Europe. However, regenerative heat exchangers are expensive, and can have high operating and maintenance costs. Corrosion and fouling can occur, and parasitic power consumption increases due to the pressure drop across the heat exchangers (Carpenter, 2012).

Another option is to recover the extracted heat from the flue gas within the steam cycle, leading to an improvement in plant efficiency and reduced water consumption. Low temperature economisers (heat exchangers) are widely used in China to recover waste heat in the flue gas for heating the condensate from the turbine (Li and others, 2016). Alternatively, a low pressure economiser can be installed between the ESP and FGD unit to extract heat for pre-heating the low temperature feedwater condensate. Thus steam that would otherwise be used for this purpose is saved, enabling more power to be generated. An analysis for a 600 MW power plant suggests that some 21–47 t/h of water could be saved in the FGD unit, depending on the location of the low pressure economiser within the feedwater pre-heating system (Wang and others, 2012). Upgrading the regenerative air heater to recover more heat from the flue gas and injecting sodium-based solutions to control sulphuric acid condensation can lower wet FGD water usage due to lower evaporative water losses, as well as increasing power plant efficiency by up to 1 percentage point (Noble and other, 2016).

Cooling the flue gas before it enters the wet scrubber also reduces the flue gas volume, resulting in a smaller FGD system and stack requirements for new plants. For retrofits, the reduced flue gas volume helps to offset the pressure drop associated with the regenerative heat exchanger. Emissions of SO_3 can be reduced through condensation on the fly ash when a heat exchanger is installed upstream of a hot-side particulate collector; SO_3 emissions at the FGD outlet were <0.1 ppm at Japanese power plants (Nakayama and others, 2006).

Li and others (2016) have proposed incorporating a flash evaporation and condensation device to provide low temperature desulphurisation slurry for further cooling of the flue gas. The flash evaporation and condensation device separates the water from the returned desulphurisation slurry. Simultaneously, the sensible and latent heat absorbed by the desulphurisation slurry from the flue gas is recovered by a heat pump. The water collected from the flash evaporation and condensation device can be used in the FGD scrubber to conserve fresh water. An analysis for a 300 MW plant combusting lignite suggests that 21.5 t/h of water could be saved and 99.5 t/h recovered through condensation from the flue gas. For bituminous coal, some 26.1 t/h of water could be saved and 19.56 t/h recovered, whilst 28.57 t/h could be saved and 0.18 t/h recovered when firing anthracite.

4.2.2 Semi-dry processes

Semi-dry FGD processes are the second most common system installed on coal-fired power plants. There are two main types:

- spray dry scrubbers (SDS, also called spray dry absorbers); and
- circulating dry scrubbers (CDS, also termed circulating fluidised bed scrubbers).

The fundamental difference between the two technologies is the manner in which the reagent is mixed with the incoming flue gas to remove the pollutants. A SDS sprays atomised lime (calcium hydroxide) slurry droplets into the flue gas. The droplets absorb the acid gases while simultaneously evaporating into solid particulates, and cooling the flue gas. The particles are then collected downstream, typically in a fabric filter. Part of the dry waste product is mixed with waste water and recycled back to the scrubber to improve sorbent utilisation. A CDS uses a fluidised bed to mix the reagent (typically dry calcium hydroxide) with the pollutants in the flue gas. Just enough water is sprayed into the fluidised bed to both humidify and cool the flue gas to the optimum level for the desulphurisation reactions to occur, but no more than can be fully evaporated. The reaction products, fly ash and unreacted sorbent are then collected in a fabric filter, and continuously recycled back to the scrubber. A small portion of the reaction by-products are removed to keep a constant inventory of solids in the system.

The water consumption of SDS and CDS is similar, and both consume about 60% less water than wet scrubbers. For example, the CDS unit at the 275 MW Seagull power plant (which uses a circulating fluidised bed boiler) in Gansan City, South Korea, is designed to use 35 m^3/h (583 L/min) of humidification water at maximum load (Kim and others, 2016). CDS can use lower quality water than SDS as it is not utilised for lime hydration (Fischer and Darling, 2016). Unlike wet FGD scrubbers, the semi-dry scrubbers produce no waste water (hence no waste water treatment facilities are required). SDS are typically used on small- to medium-sized units burning low to medium sulphur coals. Multiple units are required for plants with a higher capacity. A single CDS unit can be applied to larger plants burning low to high sulphur coals. Single-unit CDS designs of 600 MW are now available (Fischer and Darling, 2016). SO_2 removal efficiency is 90–97% for SDS, and over 98% for state-of-the-art CDS, a value approaching that for wet scrubbers. In addition, semi-dry scrubbers remove nearly 99% of SO_3, over 95% of HCl, HF, and other acid gases, and over 95% of mercury (especially if a mercury sorbent is also used). An advantage over wet scrubbers is that the semi-dry systems capture more SO_3 and oxidised mercury. Wet scrubbers typically capture only about 50–80% of oxidised mercury – a pollutant that is now being regulated. Moreover, emissions of SO_3, HCl and HF are now regulated in the USA. Power consumption of SDS and CDS is similar at less than 1% of a power plant's output. This is lower than the ~1.2% to 2% consumed by wet scrubbers. Although investment costs are lower for SDS and CDS than for a similar-sized wet scrubber, operating costs are generally higher mainly due to the higher sorbent costs; lime is more expensive than limestone. Unfortunately, there is no market for the by-products from the semi-dry technologies, whereas saleable gypsum is produced in the limestone wet scrubbing processes. Disposal of the by-products can be expensive. However, the by-products can be utilised in wet scrubbers, replacing some of the limestone sorbent. This is being done at a Polish industrial plant, which has both wet and semi-dry scrubbers. Consequently, the semi-dry by-products are converted into saleable gypsum (Korhonen, 2016).

4.2.3 Dry technologies

Dry technologies consume no water, or only a minimal amount if the sorbent needs hydrating or the flue gas is humidified to improve SO_2 removal efficiency. The sorbent can be directly injected at several locations, as shown in Figure 7; actual injection locations will be plant specific because not all of the units shown are necessarily present in every power plant. Unlike the wet and semi-dry scrubber processes, the flue gas is not passed through a separate desulphurisation vessel – the sorbent is injected directly into the furnace (furnace sorbent injection, FSI), the inlet to the economiser (economiser sorbent injection, ESI), or duct (duct sorbent injection, DSI). Consequently, there is a smaller footprint and the technology is easier to retrofit. The solid reaction products, unreacted sorbent and fly ash are collected in the downstream particulate control device. Fabric filters generally achieve greater SO_2 removal efficiencies than ESP by virtue of the filter cake on the bags, which allows a longer reaction time between the sorbent solids and the flue gas.

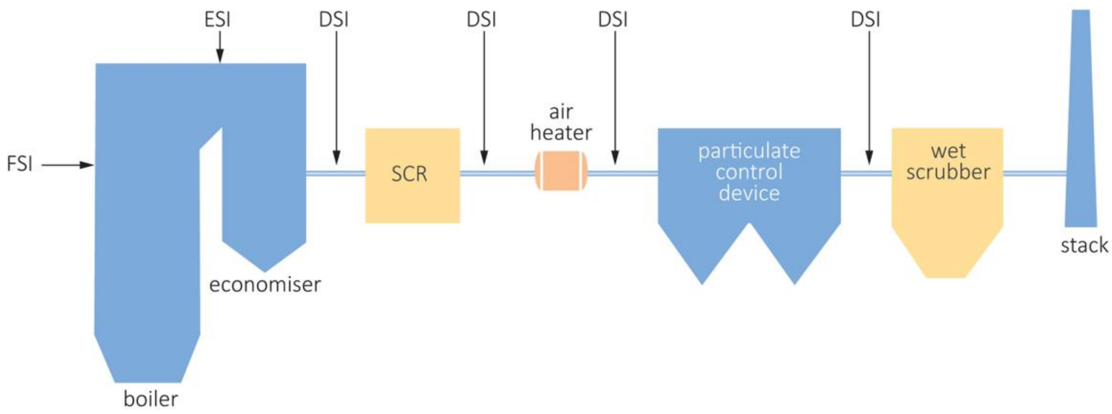

Figure 7 Possible sorbent injection points (Carpenter, 2012)

Sorbent injection systems are one of the simplest and cheapest commercial FGD systems to install and operate. The major cost is the sorbent itself. Limestone, dolomite or hydrated lime (calcium hydroxide) are commonly injected into the furnace as these sorbents can withstand the high temperatures within the furnace. Hydrated lime has been employed for ESI, but the process is little used today. A wider range of sorbents can be used for duct injection. These include calcium- and sodium-based reagents, and various proprietary sorbents. These are injected dry, as a slurry, or as a solution, depending on the reagent used. Generally, sodium-based sorbents are more reactive than calcium-based ones, resulting in a higher SOx removal efficiency. But they are more expensive. A co-benefit of FSI and DSI is the capture of some of the HCl, HF, and mercury in the flue gas, although this does depend on the sorbent used. The by-products are dry, and thus are relatively easy to handle and manage; no waste water is produced.

The main drawback of the sorbent injection processes is their lower SO_2 removal efficiency compared to wet and semi-dry scrubbers. Injecting sodium-based reagents, such as sodium carbonate-based ones, into the duct removes ~70–90% of SO_2, but 90–98% of the SO_3. Removal efficiencies with calcium hydroxide are lower, ~50–60% for SO_2 and >80% for SO_3. Power consumption is low, ~0.2% of the plant's output. Capital costs are less than for semi-dry and wet scrubbers, but operating costs can be high, mainly due to the cost of the sorbents. Research is underway to develop cheaper, and more efficient, sorbents. Sorbent injection systems are best suited to small- or medium-sized (<300 MW) power plants (depending on the sorbent) burning low to medium sulphur coals, and where only a moderate SO_2 removal efficiency is required (Carpenter, 2012).

4.3 CO_2 capture

Although carbon capture and storage (CCS) is not yet commercially deployed on coal-fired power plants, the water consumption of the process has been evaluated. Installing CCS increases the water requirement per net power generation of a plant, due both to a reduction in the plant efficiency, and to the cooling water and process water requirements associated with CO_2 capture and compression. The amount of additional water and energy required depends on the design and size of the CCS system. An analysis by Zhai and others (2011), using the Integrated Environmental Control Model developed for the USDOE National Energy Technology Laboratory (NETL), of a wet-cooled (closed-loop) 550 MW supercritical power plant with SCR, ESP and wet limestone FGD systems withdraws 2400 L/MWh of water, and consumes some 1685 L/MWh. Withdrawal and consumption rates each increase by ~83%, to 4380 L/MWh and 3085 L/MWh, respectively, when an amine-based carbon capture system is installed (with 90% CO_2 removal efficiency). For the same net power output (550 MW), a subcritical plant requires 13% more total water make-up than the base case supercritical plant, whereas the ultrasupercritical one requires 18% less (*see* Figure 8). Other estimates for water use in thermal power plants equipped with CO_2 capture systems published in the literature are summarised by Magneschi and others (2016).

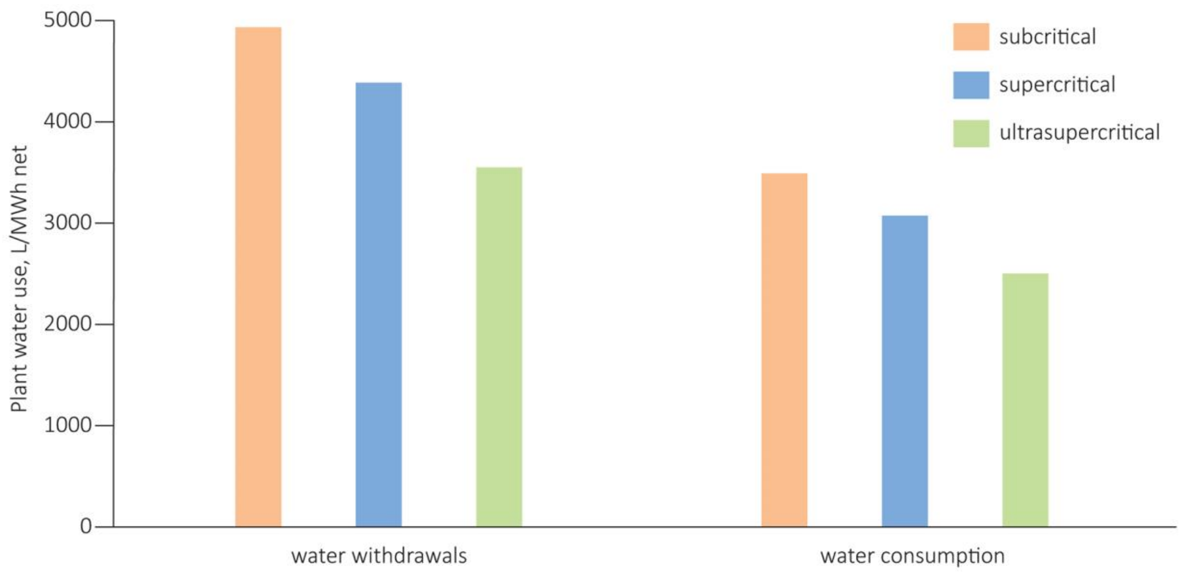

Figure 8 Total water use with CCS (Zhai and others, 2011)

Technologies are available for reducing the water requirements, such as dry cooling (*see* Section 6.3), water recovery from the flue gas (*see* Chapter 5), and waste water treatment (Foster Wheeler Italiana, 2011). Replacing wet cooling towers with air-cooled condensers (dry cooling) decreases total plant water withdrawals by 80% and total plant consumption by 86% in a 550 MW supercritical power plant (Zhai and others, 2011). But adding CCS to the new dry-cooled supercritical Medupi and Kusile power plants (with wet FGD systems) in South Africa is expected to increase water consumption by 0.1 L/kWh to 0.5 L/kWh (Pietersen and others, 2013). Water usage for a plant using a hybrid cooling system is analysed by Zhai and Rubin (2016). Developments in carbon capture technologies may lead to lower water consumption and lower parasitic power consumption. Next generation carbon capture technologies are reviewed in the IEA Clean Coal Centre report by Lockwood (2016).

4.4 Multi-pollutant systems

Multi-pollutant processes remove two or more regulated pollutants in a single reactor or a single system designed for the purpose (rather than as a co-benefit). These may be more cost effective, and may lower water consumption, than installing a series of traditional systems that remove the same number of pollutants. But these systems are not widely employed. Two commercial systems that are essentially dry are the ReACT™ and SNOX™ processes. ReACT™ uses only 1% of the water required by conventional wet FGD systems, and removes over 99% of SO_2 and SO_3, 20-80% NOx, >90% of mercury (both elemental and oxidised) and around 50% of the particulates, when burning low to medium sulphur coals (Peters, 2011). SNOX™ is a dry catalytic process that was designed for high sulphur fuels. Up to 99% of SO_2 and SO_3, 96% of NOx and essentially all the particulates are removed (Schoubye and Jensen, 2007). Both processes produce a saleable by-product. More information on these, and other multi-pollutant systems, can be found in Carpenter (2012, 2013).

4.5 Comments

Semi-dry scrubbers consume some 60% less water than limestone wet scrubbers, but have a lower SO_2 removal efficiency. Modern wet scrubbers can capture 99% of SO_2, SDS 90–97%, and state-of-the-art CDS over 98%. All of the technologies can remove HCl and HF (>95% in SDS and CDS, 98-99% in wet scrubbers), and some mercury as a co-benefit. However, the semi-dry scrubbers can capture more SO_3 (over 99%) and oxidised mercury. On the other hand, wet scrubbers can accommodate low to high sulphur coals. SDS are better suited to low to medium sulphur coals, although CDS have been used with high sulphur coals. Consequently, semi-dry scrubbers may not be able to meet very strict SO_2 emission limits when burning high sulphur coals. The sorbent injection systems have the lowest water consumption but only a moderate SO_2 removal efficiency, and so are unable to meet strict SO_2 emission limits.

Incorporating a regenerative heat exchanger or upgrading the air heater by extending its heat transfer surface lowers the water consumption of wet scrubbers. Air heater improvements may be the better option since heat is added to the cycle, increasing power plant efficiency. No waste water is generated in the dry and semi-dry systems. Power plants on the coast have an advantage in that they can use sea water FGD systems to reduce fresh water consumption. Operating and maintenance costs and power consumption are generally higher for wet scrubbers than for semi-dry and sorbent injection systems. On the other hand, wet scrubbers use a less expensive reagent (limestone) than the semi-dry systems, and can more easily adjust to varying boiler loads.

FGD processes that use a carbonate-based reagent (such as limestone or sodium carbonate) form CO_2 as a by-product of the chemical reactions of the reagent with SO_2, increasing CO_2 emissions from the plant if it is not captured. Although by-product CO_2 is not generated by the lime-based processes, CO_2 is produced during the manufacture of lime. Unless the CO_2 from the on-site lime kiln is captured and stored, overall CO_2 emission from plants with lime-based scrubbers (semi-dry scrubbers) will be similar to those using wet scrubbers (US EPA, 2010). Incorporating conventional amine-based systems to capture CO_2 from the power plants will significantly increase water consumption.

More WESP systems are being installed as a final polishing device to control $PM_{2.5}$ and this will increase overall water consumption. Research is underway to reduce their water consumption. Multi-pollutant control systems that consume minimal water are available, for example, the ReACT™ system on the Isogo power plant in Japan. These could be more widely employed in the future, especially if they are more cost effective than installing a series of traditional systems that remove the same number of pollutants.

5 Water recovery from flue gas

Flue gas discharged from the boiler contains a large amount of water vapour, the main sources of which are the fuel moisture, oxidation of fuel hydrogen, and moisture carried into the boiler with the combustion air. The water content can vary widely, depending on the coal type, plant configuration, and other factors. Lower rank coals have a higher moisture content than higher rank ones and consequently, produce higher moisture flue gases. A typical 400 MW coal-fired power plant in the Netherlands that is equipped with a wet FGD unit uses 30 m^3/h (30 t/h) of demineralised make-up water in the boiler feedwater. At the same time, 150 m^3/h (150 t/h) of water in the flue gas is emitted through the stack; some 90–120 m^3/h (90-120 t/h) is emitted in plants without FGD (Daal, 2011; de Vos and others, 2008). Recovering 20% of the emitted water would enable a plant with a wet FGD unit to fulfil its boiler make-up requirements. But if sufficient water could be captured, then a dry-cooled plant could possibly become a water supplier instead of a consumer. It seems unlikely that enough water could be recovered to supply the cooling make-up requirements for a wet-cooled power plant. Removing water from the flue gas also helps to mitigate corrosion in the flue gas stack.

There are three basic methods for recovering water vapour, namely:

- condensation;
- membrane filtration; and
- desiccant absorption.

5.1 Condensation

Cooling the flue gas to below 50°C (the water dew point) would not only condense the water vapour, but also enable the recovery of latent and sensible heat that could be used to increase net unit power output, and hence lower CO_2 emissions. Moreover, condensing the flue gas moisture after the flue gas has passed through the pollution control systems can further lower emissions.

Condensation can be achieved by:

- direct contact coolers, where the flue gas and cooling fluid are in direct contact with each other; or
- indirect contact coolers, where an intervening wall separates the cooling fluid from the flue gas.

Condensation efficiency is influenced by a number of factors, including the moisture content and temperature of the flue gas, the cooling fluid temperature, and whether the condensation system is installed before or after a wet FGD system (when present). It is higher with lower flue gas temperatures (less cooling required) and colder cooling fluids (higher heat transfer rate).

5.1.1 Direct contact coolers

In a direct contact cooler, flue gas is cooled as it passes up through the heat exchanger (a vertical column) by a stream of water that is sprayed into the top (*see* Figure 9). Part of the water in the flue gas is condensed and collected at the bottom of the column. Some of the condensate is then cooled in a separate dedicated heat exchanger and recirculated to the spray nozzles at the top of the column. The excess is sent for treatment or to another destination.

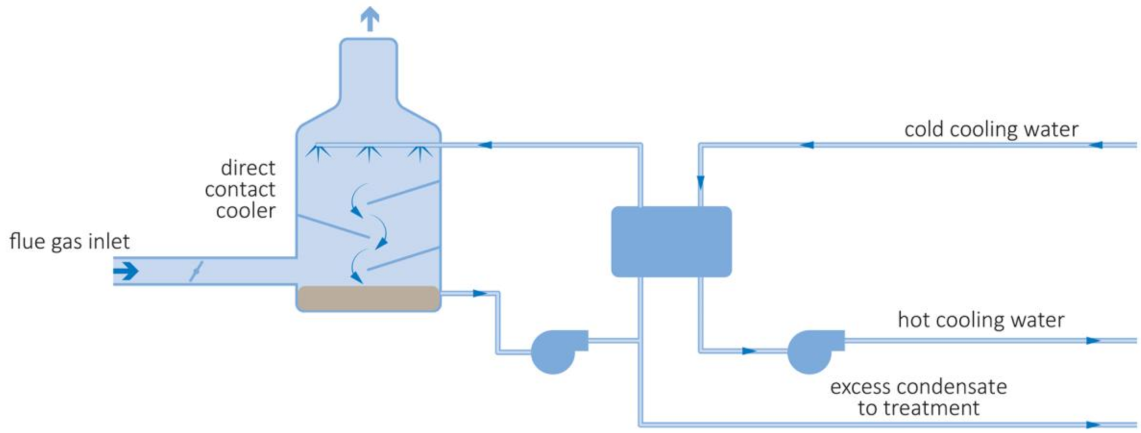

Figure 9 Direct contact flue gas condensing system (Foster Wheeler Italiana, 2011)

Instead of a water-cooled heat exchanger (as shown in the Figure), an air-cooled one could be used. However, air is a less efficient cooling medium than water, especially on hot days. Trays or packed beds can be included in the column to increase contact between the gas and water; this enables the flue gas and water to approach thermodynamic equilibrium conditions. Although more condensate is produced, the drawback is an increase in flue gas pressure drop, and consequently, higher fan power consumption. An advantage with direct contact coolers is that there is no heat exchange surface to be fouled or corroded.

5.1.2 Indirect contact coolers

The use of indirect contact condensing heat exchangers has been investigated at pilot-scale (using a slipstream from three coal-fired power plants) by Lehigh University in the USA; the project was funded by the USDOE NETL. Water vapour is condensed by cold water flowing through the tubes of the heat exchanger. The cooling water is taken from the power plant's cooling circuit. For plants without FGD systems, the heat exchanger is located between the ESP/fabric filter and the stack. For plants with FGD units, one heat exchanger could be located between the ESP/fabric filter and FGD unit to capture the sensible heat, and additional heat exchangers after the wet scrubber and before the stack to condense the water vapour (latent heat transfer) (Levy and others, 2008). Heat exchangers could also be placed after the CO_2 capture unit to recover moisture from the flue gas before it is compressed for transport to a storage site.

Calculations for a 585 MW plant indicate that flue gas moisture rates range from over 90 t/h for units firing bituminous coal to over 270 t/h for those firing high moisture lignite. Extracting all of the flue gas moisture (which is unlikely) could provide ~10% (bituminous coal), ~18% (Powder River Basin subbituminous coal) or ~29% (lignite) of the plant's cooling make-up water requirements (Levy and others, 2008). The ratio of the cooling water to flue gas flow rate can have a large effect on the rate of water capture. Water vapour capture efficiencies are limited to ~20% when boiler feedwater (from the cooling circuit) is used as the cooling fluid and the flow rate ratio of cooling water to flue gas is about 0.5; the heat rate of the plant is improved by 0.5%. But adding an air-cooled heat exchanger after the wet-cooled ones to further condense moisture in the flue gas could increase the water vapour capture efficiency from 20% to 80%; this could supply around 20% of the plant's wet tower cooling make-up requirements (Lehigh University, 2012).

Condensing flue gas moisture requires a large exchange surface area, can cause corrosion and fouling of the heat exchanger tubes, and leads to a pressure drop that is compensated by an induced draught fan. Installing an 'acid trap' reduces the amount of acids in the condensate water. Therefore, relatively low cost corrosion-resistant alloys or plastic-coated tubes could be used. A co-benefit of lowering the flue gas temperature is the removal of mercury. Vapour phase mercury decreased by 60% between the inlet and exit of the heat exchanger system when the flue gas was extracted downstream of the ESP; the reduction was 30% to 80% when the flue gas was extracted after the wet FGD scrubber (Levy and others, 2011). However, the recovered water requires treatment before it can be used for cooling make-up or other purposes due to the acidity and other contaminants that may be present, and this can be costly. Nevertheless, the availability of low temperature flue gas with reduced acid and water vapour content would lower the cost of capturing CO_2 in amine- and ammonia-based scrubbers.

Cost benefit studies for a 600 MW power plant suggest that placing the heat exchangers downstream of the wet FGD system could be cost effective; but plume dispersion may be an issue. The heat captured from the flue gas is used to heat the boiler feedwater, thus increasing net unit power output (Levy and others, 2011). However, installing condensing heat exchangers upstream of the wet FGD system or at units without FGD may not be cost effective.

A pilot-scale test using a slipstream (50,000 m^3/h flow rate) from a 600 MW lignite-fired unit in Inner Mongolia was conducted using a modified plastic heat exchanger to avoid potential corrosion problems. The slipstream was taken from the wet FGD scrubber and cooled by 5°C. The results indicated that 61.6 t/h of water and 129.5 GJ/h of latent heat could be recovered from the entire flue gas flow (2,500,000 m^3). The water can be utilised in the FGD system, which consumes some 60–80 t/h of make-up water. Cooling the flue gas by 10°C would recover 187.7 GJ/h of latent heat and 73.9 t/h of water, enough in some cases to cover all FGD make-up water requirements (Xiong and others, 2013, 2014).

Stony Brook University, NY, USA, is developing a high performance thermosyphon to condense water vapour from flue gas (*see* https://arpa-e.energy.gov/?q=slick-sheet-project/water-recovery-cooling). It will be air-cooled and the polymer construction will minimise corrosion problems. The condensate can be stored and used for subsequent evaporative cooling when the ambient temperature exceeds acceptable operating limits in dry-cooled power plants.

5.2 Liquid desiccants

A liquid desiccant-based process has been developed, and tested at pilot-scale, by the University of North Dakota's Energy and Environmental Research Center in the USA; it recovers 50–70% of the water in the flue gas from a wet scrubber (Folkedahl and others, 2006). The technology is already used in air conditioning systems in buildings and for the dehydration of natural gas, but has not yet been demonstrated in a coal-fired power plant.

The process involves cooling the flue gas before it is sent to an absorption tower into which the liquid desiccant (such as an aqueous solution of calcium chloride, lithium bromide or triethylene glycol) is sprayed. A packed bed configuration was also tested. The flue gas exiting the absorber passes through a mist eliminator to remove any entrained desiccant droplets and is discharged through the stack. The wet desiccant is heated before entering the regenerator, as the hotter the desiccant the easier it is to separate the water. The resultant water vapour is then condensed. The regenerated hot desiccant solution is filtered to remove insoluble contaminants, cooled and injected back into the absorber; the colder the desiccant solution, the more water it can pick up. About 0.3–0.9 L/min of water was recovered in subbituminous coal tests with a desiccant (calcium chloride) flow of 151–416 L/min (Carney and others, 2008).

Low grade heating and cooling sources available in a power plant could be utilised to minimise the power needs of the process. Depending on the amount of water to be removed, the system can be designed with no parasitic power consumption, other than pumping loads, by taking advantage of the heat of absorption and heat of vaporisation to provide the necessary temperature changes in the desiccant between the absorber and the regeneration tank (Folkedahl and others, 2006). Pilot-scale tests indicated that the presence of sulphur in the flue gas was not detrimental, and that the process could act as a final polishing step for SO_2 removal. The recovered water has a similar quality to that from reverse osmosis treatment, which is normally used to produce boiler make-up water.

An economic analysis by Folkedahl and others (2006) for a 250 MW coal-fired power plant treating a flue gas slipstream in the desiccant system (capacity 284 L/min) put the investment costs (equipment and installation) at US$5,837,762, and annual operating costs at US$503,860. Auxiliary power consumption would be ~1,051 kW. About 123 million litres of water would be produced per year, resulting in a price of 0.0053 US$/L of pure water. Whether this is economically viable depends on the location of the plant. The calculations were carried out for a power plant located in Wyoming, USA.

Questions remain as to the long-term interaction of the desiccant with the flue gas, contamination of the desiccant solution by flue gas constituents, and precipitates that may form and how to handle them. Corrosion could be an issue with salt-based desiccants (such as calcium chloride), but can be largely mitigated through proper material selection. Glycol-based systems have the disadvantage of atmospheric losses of glycol with the flue gas.

A system using liquid LiBr desiccant for recovering heat and water from industrial boiler flue gas is described by Wang and others (2016a). The liquid desiccant absorbs waste heat and moisture contained in low temperature flue gas in a packed tower, and is then regenerated using high temperature flue gas as the heat source. The water vapour from the regenerator is then condensed after releasing heat to the heating water system. Bench-scale experiments recovered 1.05 kg/h of water and 5.51 kW of heat in a simulated coal-fired boiler.

The desiccant concept has been further tested in a USDOE Advanced Research Projects Agency – Energy (ARPA-E) project, which found that the heats of absorption and desorption of water on the desiccant increased the cost of water (Carney, 2017).

5.3 Membranes

The main advantage of membrane separation technology is the ability to produce high quality water that is mineral free, and therefore can be used for boiler make-up, as well as for FGD or cooling water make-up, without any further treatment. Contaminants, such as CO_2, NOx and SO_2, are inhibited from passing through the membrane by its high selectivity for water molecules. The latent heat in the flue gas can also be recovered, depending on the plant layout.

A modular polymer-based composite membrane system has been developed under the EU-funded CapWa project (Capture of evaporated Water with novel membranes), coordinated by DNV GL (formerly known as KEMA). The membrane consists of microporous hollow fibres coated with a water-selective material. Water vapour permeates through the membranes and is transported to a condenser by applying a vacuum.

The pressure drop that occurs over the membrane unit is compensated with an induced draught fan. Energy is also required to run the vacuum pumps and for condensation of the recovered water vapour. The net electric efficiency of a power plant could decrease by 0.1–1.1 percentage points, depending on the heat exchanger lay-out and power plant characteristics (Daal and others, 2012). Modelling studies found that energy consumption is ~7 kWh/m^3 of water produced when water is used to condense the vapour, and ~35–40 kWh/m^3 for air cooling. However, energy savings can be made as reheating the flue gas before it is emitted through the stack is no longer necessary, and the latent heat of water vapour can be reused to preheat the condensate water (de Vos and others, 2013).

Pilot tests on a slipstream from a coal-fired power plant and other industrial plants in the Netherlands and Germany have indicated that at least 40% of the water in the flue gas can be recovered; this may be enough to turn a dry-cooled power plant from a consumer into a water producer. The recovered water was of a high enough quality to meet power plant demineralised water and potable water specifications. Combining the water capture membranes with CO_2-selective membranes could lower CO_2 emissions at the same time.

A larger scale pilot test was conducted at the Rutenberg coal plant in Israel over a period of three months in 2013 using 30 modules that each had an effective surface area of 1 m^3. An air-cooled condenser was used, and some 1.5–1.6 kg/m^2 (1.5–1.6 L/m^2) of water was produced per hour (Daal, 2013; de Vos and others, 2013). Water production per day was 0.7–1 m^3 (700–1000 L). The main parameter influencing water production was the feed temperature, which is affected by ambient conditions. Some fouling of the membranes occurred. This could be mitigated at power plants by installing 'cleaning in place' units that spray water to clean the fibres. The amount of broken fibres was 0.5‰ of all fibres.

An economic analysis of the membrane system, based on a membrane lifetime of 3 y and a water flux of 2 L/m^2/h, quotes a cost of 1.24–1.38 €/m^3 for the recovered demineralised water, dependent on the configuration of the power plant (de Vos and others, 2008). The price is based on existing power plants and so the price could be lower for new plants. In addition, further savings are possible since the calculations did not include the savings when flue gas reheating is rendered obsolete. The average cost for water from a conventional demineralisation plant in the Netherlands is around 2 €/m^3. A more up-to-date cost benefit analysis is given in DNV GL (2016).

Research is being carried out in Australia to find polymer membranes that have the potential to recover high purity, low pressure steam from high temperature brown coal flue gas. Victorian brown coals have a low sulphur content and therefore FGD units are not required; consequently, the flue gas is at a higher temperature. The recovered steam would be recycled as boiler feedwater; latent heat could also potentially be recovered. A study of Nafion 115 at 70–150°C found that although a permeate pH of 3.3–4 was achievable at 150°C, the permeate would need treatment (pH adjustment) before it could be used as boiler feedwater (Azher and others, 2014).

The Gas Technology Institute in the USA is developing a nanoporous ceramic membrane, the Transport Membrane Condenser (TMC), which is based on commercial technology that was developed for industrial gas-fired boilers. Water vapour from the flue gas condenses inside the nanopores of the membrane tubes and passes through in direct contact with low temperature water flowing inside the tubes. Particulate fouling is prevented by a smooth, and slippery, coating on the outside of the tubes.

A two-stage TMC system is being developed (partly funded by the USDOE NETL) for coal-fired power plants that uses two separate cooling water streams to maximise recovery of both the water and latent heat in the flue gas (*see* Figure 10).

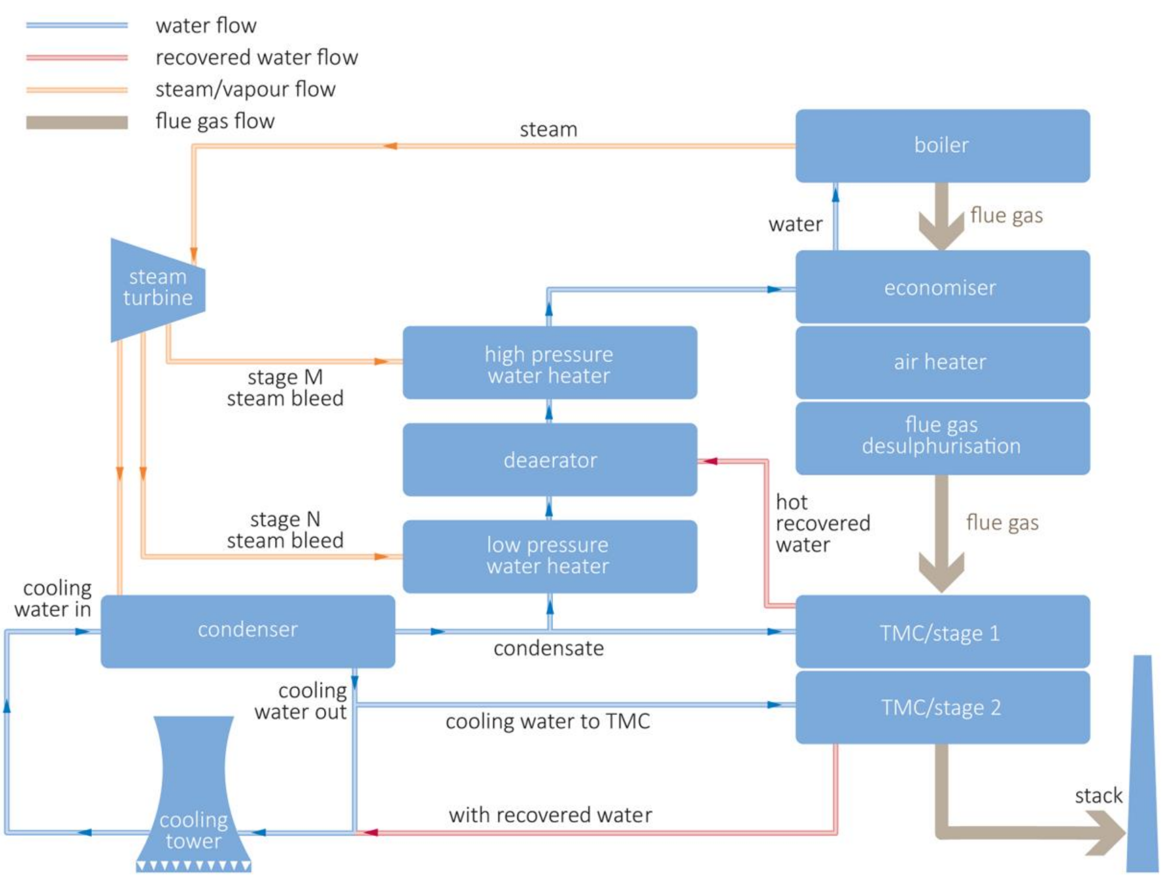

Figure 10 Two-stage TMC integration in a coal-fired power plant (Wang and others, 2016b)

The inlet water for the first stage TMC unit is obtained from condensate from the steam turbine condenser, whilst the second stage TMC inlet water is from the condenser cooling water stream. The outlet water from the first TMC unit, with recovered water vapour and associated latent heat from the flue gas, passes to the deaerator for boiler water make-up. The second TMC unit's outlet water and recovered flue gas water is returned to the condenser cooling water stream. The TMC unit is placed between the FGD unit and stack (Wang, 2012; Wang and others, 2016b). The system was tested over 5 weeks in 2011 on a slipstream from a coal-fired power plant in Baltimore, MD, USA. Good heat and water recovery performance was achieved.

Preliminary analysis (using Aspen modelling/software) showed that the first stage of TMC (stage 1) could increase the cycle efficiency by 0.72 percentage points from a baseline of 36.3 percentage points, and save 2% of make-up water (which is ~500 kg/min for a 550 MW unit), if it is integrated into the steam cycle. The second stage (stage 2) could recover about 3506 kg/min of water for cooling water make-up (Carney, 2016). A high pressure modular version is being developed for future commercial-scale pressurised oxyfuel combustion power plants.

5.4 Comments

The three basic technologies for recovering water vapour from flue gas are at different stages of development. None has yet been demonstrated at full-scale on a coal-fired power plant. Nevertheless, they have been shown to be potentially economically viable, depending on factors such as plant configuration, location and the cost of water. Where water is cheap, the technologies will be harder to implement. The technologies can be particularly beneficial for coal-fired power plants that use high moisture coals and/or a wet FGD system. A drawback with condensing heat exchangers is the need to treat the recovered water before it can be reused. However, latent and sensible heat recovery and reuse could increase the thermal efficiency of the plant. Both membrane and desiccant systems can produce high quality water that could, in principle, be utilised without further treatment. The main drawback with desiccant systems is the parasitic power consumption. The energy consumption of membrane systems can be reduced when the separated water vapour is cooled by water and the latent heat in the flue gas is recovered and reused. Recovering water vapour from flue gas could provide an opportunity for a dry-cooled power plant to become a supplier of both electricity and water, if sufficient water can be economically recovered.

6 Cooling systems

In a coal-fired power plant, the exhaust steam from the low pressure section of the turbine passes into the condenser. The condensed water is then returned to the boiler to be turned back into steam (*see* Figure 1 on page 10). The main condenser is a heat exchanger that uses coolant to absorb the large amount of latent heat that is released from the steam as it condenses. The turbine has to work against the backpressure in the condenser. Lower backpressure on the turbine results in higher efficiency because more of the energy in the steam is released in the turbine. Coolant properties are one of the factors that affect backpressure – a lower coolant temperature results in lower backpressure and consequently, a higher efficiency. If insufficient cooling is available, the plant will not be able to operate. Moreover, the steam is produced using highly purified (demineralised) water. Condensing as much of the steam as possible can help save water, as well as reducing costs, since the production of demineralised water is expensive.

The largest usage of water at coal-fired power plants is for cooling (when water is the coolant); water cooling is the most commonly employed system. There are four main categories of cooling systems:

- open-loop (or once-through), where the water is used once before being returned to the water source;
- wet closed-loop (or wet closed-cycle or wet recirculating), where the warm cooling water is cooled and reused;
- dry systems, which use ambient air as the coolant. These can be further categorised into direct (standalone air-cooled condenser) and indirect (water-cooled condenser and dry tower) types; and
- hybrid systems, which have both dry and wet elements. Each element can be used individually or together to achieve the best features of each – wet cooling performance on the hottest days, and the water conservation ability of dry cooling when it is cooler. The two components can operate together at times of intermediate ambient conditions. The dry and wet elements can be arranged in series or parallel as separate structures, such as air cooling in tandem with wet towers. The dry and wet components can also be combined in a single unit, such as a hybrid tower. Hybrid systems are not widely used.

Each of these systems involves trade-offs in terms of water use, impacts on water quality, plant efficiency and cost. This chapter looks at water conservation within the cooling systems. Some of the emerging technologies are also outlined. More information on cooling systems can be found in the IEA Clean Coal Centre report by Couch (2005).

6.1 Open-loop cooling

Open-loop or once-through cooling systems withdraw water from a natural water body (such as a river, lake or manmade reservoir) and pump it once through the tubes of a steam condenser (*see* Figure 11). As the steam condenses on the outside of the tubes, the heat of condensation is absorbed by the water flowing through the tubes (a shell and tube heat exchanger). The heated water is then discharged back into the original source. This may be detrimental to aquatic life and ecosystems. Moreover, withdrawal of water can cause impingement and/or entrapment and mortality of aquatic organisms on the intake screens as the water is withdrawn. Smaller organisms, such as larvae and juvenile fish, can pass through the screens into the plant's cooling system where they may die. Care must be taken so that the warmer discharge water does not recycle back into the intake, thus raising its temperature and lowering power plant efficiency.

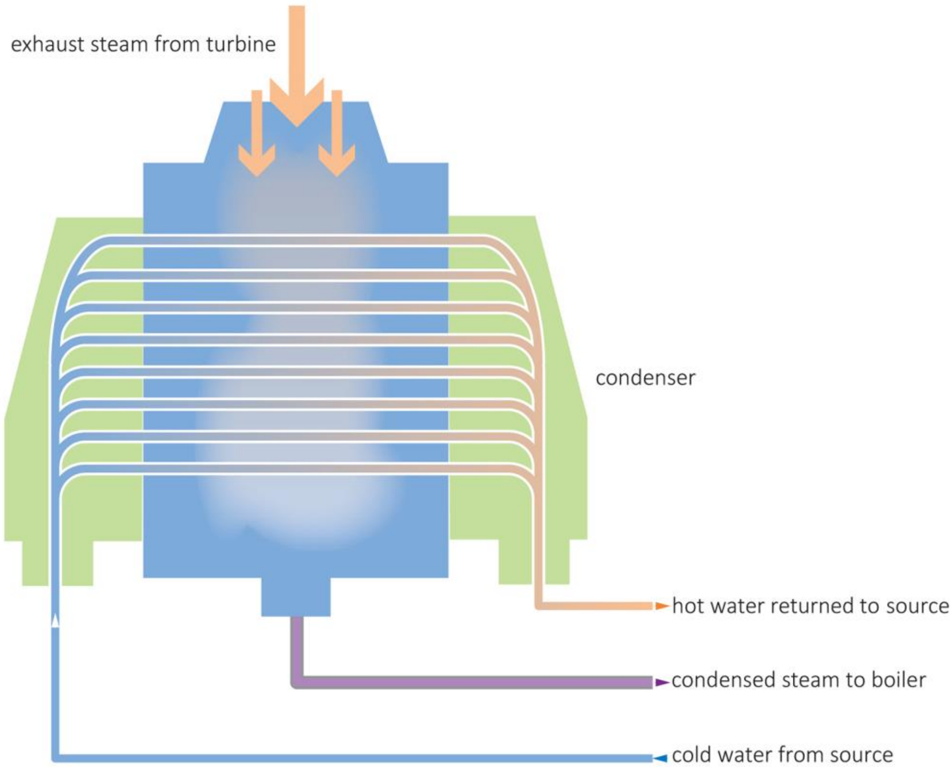

Figure 11 Water flow in a steam condenser (Bushart, 2014)

Water withdrawal requirements are the highest of the cooling systems, but capital costs are the lowest. The amount of water withdrawn varies from 95–190 m^3/MWh. Although none of the water is consumed within the plant, some consumptive loss occurs due to evaporation of the receiving water body by the heated discharge. This loss is site-specific and has been variously estimated to be 0.5–2% of the withdrawn amount, or 0.38–1.5 m^3/MWh (Bushart, 2014). Power plants with these fresh water cooling systems are more exposed to fluctuations in water availability because of their high water withdrawal needs. Open-loop systems are not often used for new power plants, except when the coolant is sea water. Some states in the USA, for example, only allow new plants to install closed-loop systems, whilst countries, such as China, have issued policies to promote dry cooling as a way of relieving pressure on water resources (Carpenter, 2015).

6.1.1 Steam condenser developments

Water-cooled steam condensers are employed in closed-loop, indirect dry and some hybrid cooling systems, as well as in open-loop systems. Depending on the surface wettability of the material, steam condensation on the surface of the condenser tube can be divided into filmwise or dropwise condensation. In filmwise condensation, the layer of water (or film) acts as an additional barrier to the heat transfer process. Forcing the condensate to form droplets, which can be swept off the surface by the steam flow (dropwise condensation), enhances the heat transfer efficiency, resulting in more power output and higher plant efficiency. Smaller and/or cheaper condensers are in prospect, based on this principle. Hydrophobic coatings that generate dropwise condensation and can be applied to the shell side of existing heat exchangers are commercially available and more are under development. These include polymers (such as Teflon), grafted polymers (Paxson and others, 2014), self-assembled monolayers, which form one molecular layer thick coatings (Lee and others, 2013; Zheng and others, 2015), and nanotextured surfaces (Bisetto and others, 2014). Thinner, and more durable, coatings are becoming available since these have a higher rate of heat transfer than thicker ones. A one atom thick chemical vapour deposited graphene coating, for example, can enhance the rate of heat transfer by a factor of four compared to filmwise condensation (Preston and others, 2015). Other advanced hydrophobic coatings and methods of applying coatings are under development, such as the European Union funded MATChING project (Cumbo, 2016; http://matching-project.eu/), and Electric Power Research Institute (EPRI) (Bushart, 2014; EPRI and Maulbetsch Consulting, 2012) and the Small Business Innovative Research (https://www.sbir.gov) funded projects in the USA.

6.2 Closed-loop cooling

The most common cooling system employed in modern power plants is wet closed-loop cooling using cooling towers. These withdraw less water than open-loop systems and avoid thermal pollution of the water source. Like open-loop cooling, steam is condensed in a steam condenser. However, instead of the heated water being returned to the water source, it is pumped to a cooling tower, where it is sprayed over the tower fill (*see* Figure 12). As ambient air passes through the warm water, a portion (~1–2%) of the water evaporates, cooling the remaining flow. The cooled water is collected at the bottom of the tower and pumped back to the condenser tube inlets.

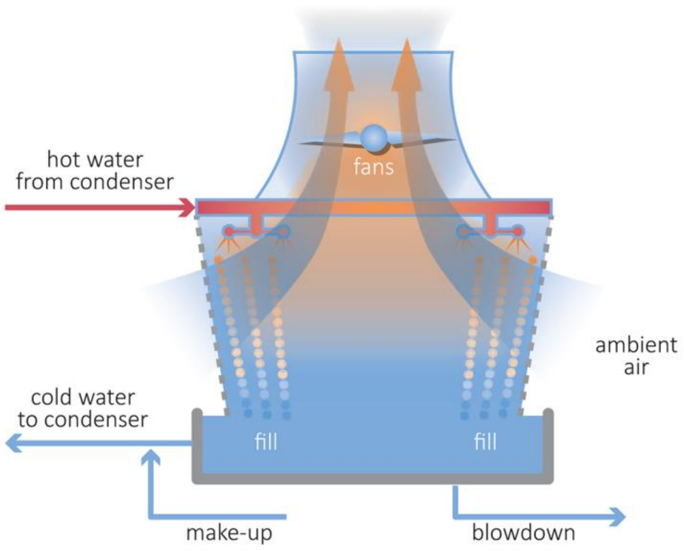

Figure 12 Water flow in an induced draught cooling tower (Bushart, 2014)

There are two types of cooling tower:

- natural draught towers, which utilise the differing densities between the cooler outside (ambient) air and warm moist air within the tower. The warm air rises up the tower because of its lower density, drawing cool ambient air into the bottom portion. These towers are usually taller than mechanical draught ones; and
- mechanical draught towers, which use motor-driven fans to force or draw air through them. Induced draught towers employ a fan at the top to draw air up through the tower, whereas forced draught towers use a fan at the bottom to force air into the tower. Induced draught towers tend to be larger than forced draught ones.

Capital costs of wet cooling systems are higher than for open-loop ones, and mechanical draught towers typically have a higher parasitic load due to power consumption of the fans.

The amount of heat that can be rejected from the water to the air is directly related to the relative humidity of the air. Air with a lower relative humidity has a greater ability to absorb water through evaporation, simply because there is less water in the air. Therefore, wet towers are more effective in dry climates. Although cooling towers withdraw less water than open-loop ones, consumption is higher – make-up water is needed to replace that lost through evaporation (~1–2% of the recirculating water flow rate), blowdown (~0.1–1%), drift (<0.01%) and leaks (Maulbetsch, 2004). Average make-up water consumption usage, normalised by net plant size, is 2139 L/MWh for subcritical coal-fired plants in the USA, 1915 L/MWh for supercritical plants, and 1590 L/MWh for ultrasupercritical ones (Berkenpas and others, 2009).

The water evaporated in the process forms a water vapour plume and exits through the top of the tower. The evaporative water losses lead to the build-up of minerals and dissolved solids in the water that can adversely affect performance. To prevent this build-up, a portion of the water (termed blowdown) is periodically discharged from the system. Drift is water droplets carried out of the tower with the exhaust air. Blowdown can contain chemicals used in the cooling towers to control biofouling, scaling and corrosion. Consequently, blowdown requires treatment before it can be reused or discharged (where allowed). In addition, the make-up water usually requires treatment before use.

Water can be saved by reducing the amount lost through evaporation, blowdown, drift and leaks. Decreasing the heat load on the cooling tower can lower make-up water requirements. This can be achieved by improving the energy efficiency of various processes within the power plant; this is outside the scope of the report. Computer models are being developed and refined to help analyse and design wet cooling towers from the viewpoint of water management. This includes improving air flow design, such as using wind breaks at the inlet of natural draught cooling towers (which is again outside the scope of this report). Improvements to the steam condensers were discussed in Section 6.1.1.

6.2.1 Evaporation

The opportunity to reduce the evaporation loss in wet cooling towers is restricted, since the amount of water evaporated is essentially set by the heat load on the tower. However, a small part of the heat load is carried by sensible rather than latent heat, in the form of increased temperature of the air stream as it passes through the tower. Changes in the water-to-air ratio, for example, can lead to small variations in the sensible/latent heat ratio, and could be exploited to save water; this is limited to a few per cent (EPRI and Maulbetsch Consulting, 2012).

The warm water in the cooling tower is cooled to a value close to the wet bulb air temperature, which is the limiting factor for process cooling. Cooling to below this temperature could be achieved through pre-cooling of the warm water and/or the inlet air.

Pre-cooling the air

Sub-wet bulb cooling can be achieved through the cooling of the incoming ambient air before direct evaporative cooling begins. When a portion of air is cooled, the saturated water vapour pressure decreases, reducing its wet bulb temperature and thus increasing its evaporative cooling potential. Incoming air can be cooled through several means (Anisimov and others, 2014), including:

- mechanical refrigeration. But energy costs and high parasitic cooling loads generally make it unviable;
- indirect-direct evaporative staged cooling where the air is pre-cooled in external evaporative units. Only moderate cooling temperatures are achieved and evaporative water losses also occur in the pre-cooling unit;
- energy recovery from exhaust air (waste heat recovery). This technique is only useful in hot, dry climates; and
- pre-cooling with cold water from the tower collection basin, which leads to partial consumption of the cooled condensate water and consequently, higher make-up water consumption.

EPRI and the Gas Technology Institute in the USA are developing a dew point cooling tower in which the incoming air is cooled within the tower fill. Dry channels are constructed between the wet channels in the tower fill using a thin-walled fill material (*see* Figure 13). This allows the incoming air to be pre-cooled in the dry channels to about the dew point temperature (by water evaporation in the adjacent wet channels) before the air turns into the adjacent wet channels to remove the heat from the water. The lower temperatures and decreased evaporative losses, compared to conventional wet cooling towers, could result in 15% to 20% less cooling and make-up water usage.

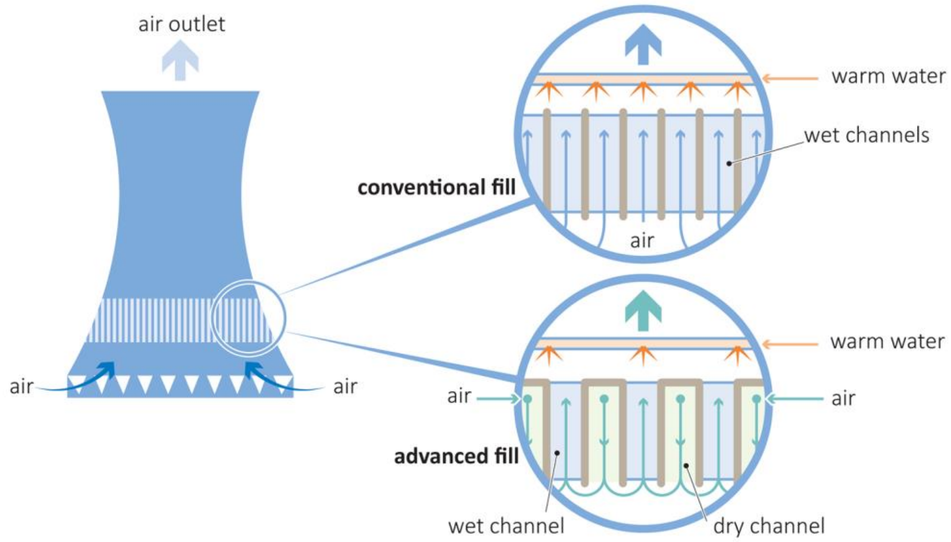

Figure 13 Schematic of proposed fill arrangement (EPRI and Maulbetsch Consulting, 2012)

Preliminary estimates indicated that make-up water requirements for a 500 MW power plant could be reduced from 20,146 L/min to 16,114 L/min, blowdown from 4024 to 3221 L/min, and evaporation and drift losses from 16,118 to 12,893 L/min (Chudnovsky, 2013). The cold water return temperature is lowered to 13°C instead of 24°C. Power production could increase by up to 4% due to the lower turbine backpressure (EPRI and Maulbetsch Consulting, 2012). The system can be retrofitted to existing wet towers or to hybrid systems which include a wet tower.

Pre-cooling the water

Pre-cooling the warm water exiting the steam condenser before it enters the wet tower reduces the heat load in the tower, and hence evaporative water loss. In the Thermosyphon Cooler (TSC) Hybrid System from Johnson Controls, the TSC transfers the heat from the warm water leaving the condenser to a refrigerant in the evaporator and then to the ambient air in an air-cooled condenser without water evaporation. The naturally recirculating refrigerant operates in a closed loop. Thus a TSC combined with a wet tower could be classified as a hybrid wet/dry system.

The TSC hybrid system could potentially reduce annual evaporative losses, make-up water requirements and blowdown volumes by up to 75%, without sacrificing electrical output on the hottest days. It can be retrofitted to existing power plants (Bushart, 2014; EPRI and Maulbetsch Consulting, 2012). Significant water savings (monthly averages of 32% to 78%) compared to a cooling tower only system were achieved at a 1 MW equivalent size test unit (Carter and Vucci, 2015). However, maximum water savings were attained at the cost of increased power consumption due to the higher fan speeds. Design and modelling research is addressing issues of scale-up, cooling tower integration, and cost and performance relative to other cooling configurations for conceptual 500 MW plants at five US locations with differing climates. Findings suggest that TSC hybrid systems (of varying sizes in series with the wet cooling tower) and hybrid cooling systems (air-cooled condenser of varying sizes in parallel with a wet cooling tower) offer a cost effective way to reduce water consumption and insure against even minor constraints (<5%) on water availability, even at fully burdened water costs of just 1 US$/1000 US gals (0.26 US$/1000 L). At water costs between 3 and 5 US$/1000 US gals (0.79 and 1.32 US$/1000 L), the TSC hybrid, hybrid and all dry air-cooled condenser systems are more cost competitive than all wet systems, even with no water constraints (Carter and others, 2014).

Research is at the early stages for employing thermoelectric coolers (heat exchangers) to take up some of the heat load of the evaporative cooling tower, thereby lowering water consumption. Thermoelectric coolers can cool the cooling water below the wet bulb temperature, thus reducing steam condensation temperature and increasing power production. However, the size and operating parameters of the system must be carefully adjusted because thermoelectric coolers also need an energy input. The mass production of thermoelectric materials at an economic cost is a key to the success of the application. New thermoelectric materials, such as non-toxic molecular-scale, complex metal oxide nanostructures, are being developed that have a higher coefficient of performance than current materials (EPRI and Maulbetsch Consulting, 2012).

Ifaei and others (2016a,b) have proposed integrating a vapour compression refrigeration (VCR) system or a water/LiBr absorption heat pump (ABHP) to reduce the cooling load on natural draught wet cooling towers and hence, lower water losses. They found that the VCR configuration increased water losses, as well as annual capital and operating costs, and fuel consumption. On the other hand, the ABHP configuration could save 1–18% of water, depending on the absorber temperature and pressure. It also reduced costs, but fuel consumption increased.

Coolants

The addition of nanoparticles (nominally less than 100 nm) to the circulating cooling water (termed nanofluids) is being investigated as a means to reduce cooling tower evaporative losses and improve thermal performance, without the need for significant capital expenditure. It could provide a cost effective and relatively simple retrofit option to increase water efficiency at coal-fired power plants, as well as a low-cost alternative for reducing water requirements of new power plants using closed-loop or hybrid cooling systems. However, a number of issues need to be addressed, including any health concerns over the emission of nanoparticles from the cooling tower, any environmental impact on air and water quality, capturing the nanoparticles from cooling tower blowdown, and abrasion and erosion from fine particles. Controlling the size and shape of the nanoparticles is important, as well as evenly distributing them in the cooling water. A variety of nanoparticles have been investigated, including aluminium oxide (Tora, 2013) and other metal oxides, carbides (such as silicon carbide), carbon nanotubes and graphene (Askari and others, 2016).

Cooling water incorporating nanoparticles with phase change material (PCM) cores that melt to absorb heat from the steam condensate and solidify as cooling proceeds could reduce overall water consumption by as much as 20% in power plants with closed-loop towers. The PCM increases the coolant's heat capacity, allowing the same volume of coolant to absorb more heat. In addition, the improved thermal properties of the nanoparticles could decrease coolant flow rates by about 15%, helping to lower the associated pumping loads and thus parasitic energy losses. Argonne National Laboratory in the USA is developing a metallic or ceramic encased PCM (EPRI, 2012; EPRI and Maulbetsch Consulting, 2012).

Coatings

Improved coatings that can enhance evaporative cooling on the surface of cooling tower fills could result in a lower cooled water temperature and/or reduce water mass flow rate, thus improving the performance of the cooling tower and plant efficiency. Alternatively, a smaller and thus less costly fill could be made to achieve the same cooling effect. Several types of surface treatment and coatings have been developed to improve the wettability of the relevant surfaces, including hydrophilic polymer coatings (which promote filmwise condensation) and superhard nanocomposites to improve wettability (EPRI and Maulbetsch Consulting, 2012), and other nanotechnology based materials (*see* Section 6.1.1).

6.2.2 Drift and plume abatement

Drift consists of droplets of water entrained in the air leaving the top of the tower, or blown from the sides by crosswinds. Louvres and drift eliminators are commonly used to minimise water loss; the louvres also help to direct air flow into the base of the tower. These need to be properly maintained to ensure optimal water usage. Drift eliminators are commonly installed in the top part of the tower to capture the entrained droplets. Retrofitting towers with these systems, where absent, or with more efficient designs will reduce make-up water consumption. Although less than 0.1% of the recirculating flow is typically lost through drift, this is still a significant amount of water, some 50–90 m^3/h for a 500 MW unit without eliminators. Drift eliminators can reduce this loss to below 0.01%, whereas state-of the-art eliminators reduce the losses to 0.002–0.0005% of the circulating water flow (Bushart, 2014; Miller, 2012). Drift losses in a typical 500 MW plant in the USA with drift eliminators is some 0.56 m^3/h (EPRI and Maulbetsch Consulting, 2012). There are various types of drift eliminators on the market, all based on the underlying mechanism of inertial impaction. The collected water is drained back into the wet section of the tower.

The use of water collection devices installed just beneath the cooling tower fill (instead of ground level) could save the small amount of water lost from the rain zone between the fill and the water collection basin (and drift) in conventional natural draught towers. The water collection devices comprise of multiple parallel sloping panes, each with its own water collection gully. Nonetheless, the main advantage of these high level collection devices is the reduced pumping power consumption of the circulating water pump (a reduction of about 33% in a 1000 MW unit), and hence improved power plant efficiency. High level water collection devices have been installed on several coal-fired power plants in China, including the 1000 MW units at the Anqing and Jurong power plants (An and others, 2015; Zeng and others, 2015; Zhao and others, 2016).

Studies have been carried out to collect the fog droplets within the plume on a fine mesh. Ghosh and others (2015) propose mounting the meshes at the exit plane of the cooling tower cells. They carried out a pilot study using single-layer woven wire meshes at an operating induced draught cooling tower. Analysis of the collected water showed that only drift droplets were collected. The study indicated that implementation of the system could recover about 40% of water from drift loss, amounting to a saving of nearly 10.5 m^3/h from a 500 MW unit.

Sontag and Saylor (2016) suggest tethering the mesh over the cooling tower, called a 'collection parachute'. The orientation of the parachute would be maintained by the buoyancy of the upward directed plume. Collection efficiencies ranging from 5% to 50% were obtained in a laboratory-scale experiment collecting salt water fog droplets (2–8 μm in size) on cotton, nylon or Teflon meshes. The mesh could collect both drift droplets and some of the droplets in the plume vapour.

Another option for recovering the water is to send the vapour/drift exiting the wet tower to a sorption/desorption refrigeration system. The recovered water is returned to the tower. Yang and others (2016) have proposed using a microemulsion (a surfactant in oil) as the absorbent. After passing through the absorber tower (which is cooled by ambient air), the microemulsion containing the sequestrated water droplets passes into the desorption chamber (a heat exchanger). The water droplets are released using waste heat from the steam generator as the heat source, and separated from the used microemulsion in a separation tank. The regenerated microemulsion is returned to the sorption tower, and the liquid water is passed back through the heat exchanger to the wet tower.

The use of membrane condensers to recover water from the plumes will be tested at the Montpellier power plant in France as part of the EU-funded MATChING project (Cumbo, 2016).

Waste heat in the water vapour exiting the cooling tower could be utilised as a heat source in a combined heat pump and system for storing energy. A large amount of water would condense and be recovered, therefore, reducing water loss (EPRI and Maulbetsch Consulting, 2012).

Water savings from plume abatement in hybrid towers (essentially wet cooling towers with an air-cooled heat exchanger) is covered in Section 6.4.1.

6.2.3 Blowdown

The quantity of blowdown required for a wet tower is determined by a parameter known as the 'cycles of concentration' (COC, or concentration ratio), which is the ratio of dissolved solids in the recirculating water to that in the make-up water. Increasing the number of COC saves water as essentially it means that water is being recycled longer before it is blown down. Make-up requirements were reduced by 20% in a tower with an evaporation rate of 2271 L/MWh when COC was increased from 3 to 6 (EPRI and Maulbetsch Consulting, 2012). Unfortunately, the potential for scaling and corrosion increases because of the resulting higher levels of dissolved minerals. The number of COC that can be achieved will be dependent on the quality of the make-up water, the water treatment programme, and the construction materials.

Make-up water is commonly treated before use, and chemicals are added to inhibit scaling, corrosion and fouling. Determining the optimal amounts to enable the system to operate at maximum COC (for example, through computer modelling) without adversely affecting performance can reduce the amount of water blown down. There is typically a breakeven point where additional chemical addition is not cost effective when compared to the water saved.

Treating blowdown (for example, by reverse osmosis) to enable its reuse in the cooling tower or elsewhere in the plant can be expensive. In the USA, the NETL has funded research on innovative methods for removing contaminants in the recirculating cooling water, including precipitation with an electrical pulse spark and mechanical filtration, which can reduce blowdown by about 25% (Cho and Fridman, 2012), precipitation with electrodeionisation, allowing higher COC (Carney and Shuster, 2014), and various sorbents to filter out the impurities. Advanced continuous nanofiltration technologies may be able to reduce water consumption for blowdown by as much as 40% (Altman and others, 2010; Bauer and others, 2014). Blowdown can be combined with other waste water generated in the plant before it is treated.

6.3 Dry cooling

Dry cooling systems use air instead of water as the cooling medium, and are classified as either direct or indirect. Direct cooling utilises a large standalone air-cooled condenser (ACC). Steam exiting the turbine is condensed within finned tube heat exchangers, which are externally cooled by ambient air. The finned tubes are commonly arranged in an A-shaped frame over a forced draught fan (*see* Figure 14). A system can consist of several rows of heat exchanger cells. Otherwise the heat exchangers can be installed inside a cooling tower and cooled by the natural buoyancy of air (a natural draught dry cooling tower). The lowest steam temperature achievable is limited by the dry bulb temperature of the cooling air.

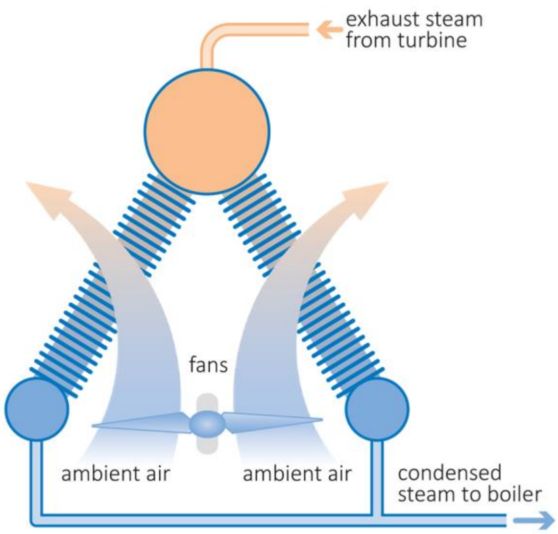

Figure 14 Direct dry cooling with mechanical draught ACC (Bushart, 2014)

In indirect cooling, steam is first condensed in a conventional water-cooled condenser (as used in open- and closed-loop systems). Heat is then conducted from the warm water as it flows through finned tube heat exchangers in a dry cooling tower by upward flowing ambient air. The cooled water is then returned to the water-cooled condenser (*see* Figure 15). There is no evaporative water loss since it is a closed system. Natural draught cooling towers are more commonly employed than mechanical draught ones. Indirect cooling could be classified as a hybrid system since it includes both wet and dry cooling components.

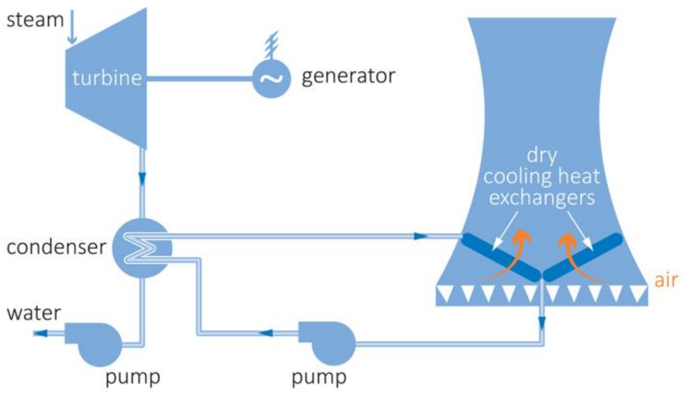

Figure 15 Indirect dry cooling (Couch, 2005)

Water savings are significant for power plants employing dry cooling systems since there is no water loss from cooling. The direct dry-cooled (mechanical draught ACCs) Matimba power plant in South Africa, for example, uses about 3.5 million m^3 of water per year for power generation (~0.1 L/kWh or 0.1 m^3/MWh) compared to an equivalent wet-cooled plant usage of ~50 million m^3/y. Water consumption for power generation is about 0.08 L/kWh at the indirect dry-cooled Kendal power plant, which employs six natural draught cooling towers (Bushart, 2014). For comparison, the wet-cooled coal-fired power plants consumed 1.9–2.1 L/kWh (The Green House, 2011). Capital and operating costs of indirect dry cooling systems are higher than direct ones for plants with a similar capacity, and their footprint is smaller. An indirect-cooled system is more easily retrofitted into an existing power plant than a direct-cooled ACC system.

The main disadvantages of dry cooling are higher capital costs (some four to five times higher), lower power efficiency and a larger footprint than a closed-loop wet cooling system of comparable capacity. This is because the lower heat transfer coefficient of air necessitates massive heat exchangers that are costly and require more space (Bushart, 2014). The total annualised cost for a closed-loop wet cooling system at a 500 MW coal-fired power plant in Yuma, AZ, USA, was calculated to be US$3.56 million, compared to US$18.1 million for a direct-cooled system, US$31 million for indirect cooling, and $US13.5 million for a hybrid system (Maulbetsch, 2011). The levelised cost-of-electricity for 550 MW coal-fired plants (subcritical, supercritical and ultrasupercritical) with direct dry-cooled systems are 3–6 US$/MWh (US$2007) higher than a comparable wet-cooled plant. However, expected higher water usage costs could eliminate this gap. Increasing water costs from the baseline of 0.26 US$/$m^3$ to 1.61 US$/$m^3$ would result in equivalent costs (Zhai and Rubin, 2010).

Dry cooling lowers overall plant efficiency by about 2 to 7 percentage points (more on hot days), depending on the type of plant, since air is a less efficient cooling medium than water (IEA, 2012) – the turbine exhaust steam cannot be cooled to as low a temperature as that achieved in a wet cooling tower. Lower efficiencies mean more coal is needed per unit of electricity, which, in turn, can lead to higher CO_2 emissions. Energy consumption of direct cooling also tends to be higher than a mechanical draught wet cooling tower because of the power requirements of its fans. The performance of ACCs is particularly affected by the direction of the wind, and high, gusty winds can adversely affect their performance.

Another indirect dry cooling system is the Heller System, which uses a direct contact condenser instead of a steam surface condenser. No condenser tubes are needed as the turbine exhaust steam is in direct contact with the cold water spray. The resultant hot condensate and water mixture is pumped to an external air-cooled heat exchanger, which can be a mechanical draught, natural draught or fan-assisted natural draught type. There is no evaporative water loss since it is a closed system. An advantage of the direct contact condenser is the lower terminal temperature difference (the temperature difference between the saturation steam and cooling water outlet temperatures) and thus lower turbine backpressure (Tsou and others, 2013). A 900 MW supercritical power plant equipped with a Heller system and a natural draught dry cooling tower (NDDCT) would generate 1.08% more electricity than a comparable plant equipped with direct-cooled ACCs (Balogh and Szabó, 2008). The tower may be equipped with a peak cooling system that sprays water onto part of the heat exchangers or with parallel delugable peak coolers in the tower to improve plant availability on the hottest days, as with ACCs and dry cooling towers (*see* Sections 6.3.2 and 6.3.3). Water consumption would still be less than a wet cooling tower. Power plants using the Heller system include two 660 MW units at the supercritical Baoji power plant (NDDCT with direct contact jet condensers) in China.

Technologies are being developed to mitigate the disadvantages of dry cooling. The following sections begin by looking at systems that are already in use to enhance power output on hot days (namely, pre-cooling the inlet air and deluge cooling). They then outline improvements to conventional ACCs that could reduce the size (and footprint) of ACCs/heat exchangers, and hence their cost. Alternative dry cooling systems are briefly examined. These have the ability to cool below the dry bulb temperature limit, and could supply supplementary cooling on hot days.

Two research and development programmes in the USA that specifically target dry cooling are the Advanced Research In Dry cooling (ARID) programme (part of the USDOE funded Advanced Research Projects Agency – Energy (ARPA-E) programme, *see* http://arpa-e.energy.gov/?q=arpa-e-programs/arid) and the jointly funded National Science Foundation (NSF)-EPRI power plant dry cooling science and technology innovation programme (Shi and Acharya, 2014; Shi and Chen, 2015).

6.3.1 Cleaning

Debris (such as pollen and leaves) drawn onto the standalone ACCs by the fans, or into dry cooling towers, can clog the spaces of the finned tubes, lowering the heat transfer coefficient and increasing unit operation costs. Compressed air can be employed to clean the surfaces instead of high pressure water jets. A site simulation test for a 600 MW coal plant with direct-cooled ACCs indicated that 1.47 kg/m^2 (1.47 L/m^2) of water could be saved each year (Zhao and others, 2013).

6.3.2 Pre-cooling the inlet air

Pre-cooling the incoming ambient air before it reaches the condensers in direct and indirect dry cooling systems can enhance power output on hot days. This can be achieved by spray cooling or with wetted media.

These methods use water to cool the air to near its wet bulb temperature, which improves the thermal performance of the ACC. The systems are only operated when needed on hot days.

Spray cooling

In this system, a small amount of water is sprayed into the inlet air stream of an ACC where it evaporates and cools the air. The main advantages are the modest use of water, ease of operation and maintenance, and low capital costs. It can be retrofitted to existing power plants. Nevertheless, water consumption at high ambient temperatures can reach over 5 m^3/MWh, and the maximum inlet cooling available is limited by the ambient relative humidity (Bustamante and others, 2016). Spray cooling is more effective than deluge cooling (*see* Section 6.3.3) due to the higher heat and mass transfer contact area; it also uses less water (Sadafi and others, 2015). Disadvantages include the increased potential for scaling, fouling and corrosion of the heat exchanger tubes from unevaporated water droplets, and rainback caused by droplets falling onto the floor or ground below the units. Rainback can contaminate surface and ground water. The inclusion of drift/mist eliminators help to eliminate droplet carryover to the heat exchangers.

Spray cooling in the direct dry-cooled supercritical Kogan Creek power plant near Chinchilla, Qld, Australia, consumes 140 L of water per second on hot days to improve total power production from 720 to 740 MW (Sadafi and others, 2015). Calculations for a 300 MW coal-fired power plant in Luoyang, China, suggest that a spray cooling system in a NDDCT (also called natural draught hybrid cooling tower) could save more than 95% of water if it replaced the natural draught wet cooling tower – it would consume some 163,254 t/y and increase earnings by US$968,419. However, annual power generation would decrease by some 10% (Li and others, 2015a).

Spatially controlled ultra-fine water droplets or jets could be sprayed into the dry cooling channels of the heat exchanger in dry towers. The entrained droplets in the air flow impinge on the surfaces of the fins, where they rapidly evaporate. A hydrophilic fin surface would further improve droplet spreading, and thus enhance evaporative heat transfer (EPRI and Maulbetsch Consulting, 2012).

Sadafi and others (2015, 2016) have proposed using saline water in order to conserve fresh water resources. The NDDCT would need to be designed to avoid contact between the droplets and metal surfaces of the heat exchangers to prevent corrosion and salt deposition. Otherwise, corrosion-resistant materials, surface treatments or surface coatings can be used for the heat exchangers.

Wetted media cooling

Wetted media is less commonly applied than spray cooling in thermal power plants. In this method, the inlet air is cooled and humidified by direct contact with water as it passes through the wetted medium at the base of the dry cooling tower. Excess water is collected and recirculated. Various wetted media that could potentially be used in NDDCTs are reviewed by He and others (2015). These include fibre pads, rigid medium pads, and packages or fills (such as trickle films made from plastic or metal grids).

A disadvantage with wetted media in a NDDCT is the extra pressure drop introduced by the medium, which reduces the air mass flow rate passing through the tower, and therefore impairs tower heat rejection. Hence there is a trade-off between evaporative cooling and the extra pressure drop. This is not an issue for mechanical draught towers since fans are used to drive the air flow (He and others, 2013). There is also a critical ambient temperature below which pre-cooling does not benefit NDDCT performance; this temperature is a function of the tower design and the wetted media (He and others, 2013, 2014). Modelling suggests that a pre-cooled NDDCT consumes 70% less water for every MW of heat rejection than a natural draught wet cooling tower (He and others, 2016).

Brackish water could be used instead of fresh water, but care has to be taken to minimise biofouling and clogging of the packing. A certain amount of blowdown is necessary to maintain water quality within acceptable levels of dissolved solid content (Ashwood and Bharathan, 2011).

6.3.3 Deluge cooling

In a deluge cooling system, water is introduced onto the finned side of the heat exchanger tubes. It runs down the fins as a thin film, and the excess water is collected and recirculated. The system makes use of both sensible and latent heat transfer. The air flowing over the water film causes evaporation (latent heat transfer) and lowers the air-water interface temperature. The resultant increase in temperature difference between the internal fluid and external deluge film increases the rate of heat transfer. This enhances the performance of the ACC. In one design, the tubes are horizontal and the fin surfaces are vertical (Maulbetsch and DiFilippo, 2003).

Deluge systems require more water than wetted media and spray cooling systems. The main disadvantage is that scaling, fouling and corrosion can occur. This can be mitigated by the use of corrosion-resistant materials. Brackish water could be used instead of fresh water, but a certain amount of blowdown is needed to keep the water within acceptable levels of dissolved solid content (Ashwood and Bharathan, 2011).

6.3.4 Conventional ACC developments

Improvements in conventional ACCs/heat exchangers are aimed at enhancing their performance and reducing their size (and footprint), and cost. Low cost materials would also decrease capital costs.

The University of Stellenbosch in South Africa is developing a hybrid dry/wet dephlegmator that uses a small amount of water to enhance cooling performance on hot days. An ACC with this system in a direct air-cooled power plant would use some 20% less water than an ACC using water sprays to pre-cool the inlet air (Heyns and Kröger, 2012). Retrofitting the hybrid system in an existing power plant could increase annual energy output by 1.33%; the cost could be recovered in 3 to 6 years, depending on energy and water prices (Owen and others, 2015).

Conventional ACC design is limited by both air flow rate and air-side heat transfer coefficient. Methods for increasing these parameters, without significantly increasing pressure drop and consequent additional fan requirements, are being developed. A high rate of heat transfer will also reduce heat exchanger size, resulting in reduced capital cost and lower pumping load, provided the accompanying increase in pressure drop is limited. Bustamante and others (2016) review a number of emerging heat transfer enhancement techniques that could improve ACC performance by introducing flow disturbances to promote mixing, without large frictional losses, as the air flows across the heat transfer surfaces. Some of these techniques also extend the heat transfer area of the ACC. These include winglet vortex generators, inter-fin vortex generators (Hrnjak and Jacobi, 2014), passive chaotic mixing, mechanical mixing (for example, using oscillating reeds (Glezer and others, 2014)), electrohydrodynamic enhancement, and acoustic enhancement. Coating the tubes with a thin layer of metal foam, in place of conventional fins, extends the heat transfer surface of heat exchangers (Asheghi and others, 2015). However, an assessment in Australia found that although foams improve heat transfer, the rise in pressure drop makes the system unfavourable for coal-fired power plants (Hooman and others, 2013).

Steam-side heat transfer can be enhanced by incorporating hydrophobic nanostructures inside the condensation tubes of an ACC to enhance jumping droplet steam condensation. These could include copper oxide nanoblades, zinc oxide nanorods, titanium oxide nanowires, and polymer, silane or other coatings (Sack and others, 2015).

The use of polymer heat exchangers offers a number of advantages over metal ones. These include their lower cost, better corrosion resistance, less fouling, less weight for the same surface area of heat transfer, and ease of cleaning. But their thermal conductivity is low and they may not last as long as metal ones (Smart Water Fund, 2012). Plastic heat exchangers which incorporate high thermal conductivity fibres (such as aluminium, copper or carbon fibres) to improve thermal conductivity are under development (for example, *see* http://arpa-e.energy.gov/?q=slick-sheet-project/advanced-heat-exchangers and http://arpa-e.energy.gov/?q=slick-sheet-project/advanced-heat-exchangers-0).

6.3.5 Alternative dry cooling technologies

A number of alternative dry cooling technologies are being investigated. These have the ability to cool below the dry bulb temperature limit, and could replace conventional dry-cooled systems or supply supplementary cooling on hot days. Some of these developments are at an early stage. They include novel heat exchangers, such as the Direct-contact Liquid-on-String Heat Exchangers for indirect dry cooling (Ju and others, 2014, 2015), and incorporating thermosyphons (Benn and others, 2016) or heat pipe condensers (Li and others, 2014, 2015b). One technology uses spray freezing of phase change materials to decouple steam condensation and heat rejection processes to reduce steam condensation temperature (Sun and others, 2014, 2015). Another indirect air-cooled design features a rotating mesh heat exchanger comprised of discs of polymer tubes with encapsulated phase change materials, such as wax (paraffin) particles (DrexelNow, 2015; http://arpa-e.energy.gov/?q=slick-sheet-project/enhanced-air-cooled-heat-exchanger). A liquid desiccant dry cooling system has been tested at the pilot scale as a heat transfer medium (Carney and Shuster, 2014; Martin and Pavlish, 2013). In the Hygroscopic Cycle system, the ACC or steam condenser is replaced with a steam absorber or mixing condenser in which the steam is absorbed and condensed in a highly concentrated solution of water and hydroscopic compounds. A test plant has been built in Gijón, Spain (http://www.hygroscopiccycle.com/; Rubio Serrano, 2016).

Sorption/desorption cooling technology driven by waste heat from the power plant could be used to condense steam with near zero water consumption, and increase power production (EPRI and Maulbetsch Consulting, 2012). These systems are more easily integrated in an indirect dry cooling configuration. A project at the University of Maryland in the USA, for example, is developing a microemulsion absorbent that absorbs water vapour (refrigerant) and releases the water as a liquid during desorption, without vaporisation or boiling (http://arpa-e.energy.gov/?q=slick-sheet-project/advanced-absorption-cooling; http://www.arpae-summit.com/paperclip/exhibitor_docs/16AE/University_of_Maryland_671.pdf). The use of a vapour compression refrigeration system to condense the steam has been proposed by Hegazy and others (2016). The use of a turbo-compressor with high-performance heat exchangers could provide supplementary cooling that will help to maintain the thermal efficiency of an air-cooled power plant (*see* http://arpa-e.energy.gov/?q=slick-sheet-project/ultra-efficient-turbo-compression-cooling). An alternative to mechanical compressors is a low grade waste heat (or solar energy) driven ejector refrigeration system, which uses an ejector to compress the refrigerant vapour from the evaporator to the condenser. Recent developments in ejectors, their performance enhancement, and applications of ejector refrigeration systems, when combined with other systems, are reviewed by Chen and others (2013). An NSF-funded project is combining an ejector with an innovative evaporation/condensation compact condenser and low cost oscillating heat pipes (Ma, 2014, 2015).

The use of radiative cooling to provide supplementary cooling during the day and at night is being investigated (http://arpa-e.energy.gov/?q=slick-sheet-project/radiative-film-supplemental-cooling-0; http://arpa-e.energy.gov/?q=slick-sheet-project/radiative-film-supplemental-cooling). Radiative cooling may not be practical to dissipate large heat loads in a standalone solution due to the relatively low heat flux.

The efficiency of dry cooling systems on hot days can be enhanced by incorporating a thermal energy storage system to store the heat during the day when the ambient temperature is high, and to release it during colder periods at night (or to another heat recovery system). Another approach is to employ a cool storage system where the condenser water is cooled at night and stored for use during the day at peak temperatures. Both of these approaches would enhance power output and efficiency. A number of projects in the USA are investigating variations on these approaches (*see* http://arpa-e.energy.gov/?q=slick-sheet-project/air-cooled-condenser-and-storage-system; http://arpa-e.energy.gov/?q=slick-sheet-project/cool-storage-supplemental-cooling; http://arpa-e.energy.gov/?q=slick-sheet-project/cooling-using-thermochemical-cycle; http://arpa-e.energy.gov/?q=slick-sheet-project/radiative-cooling-and-cold-storage).

6.4 Hybrid cooling

Hybrid systems are dual cooling systems that have both dry and wet cooling elements, as described at the beginning of the chapter. The differing configurations allow a range of trade-offs in water consumption, plant performance, cooling system cost, operating (pumps and fans) power, flexibility of operation, ease of control, and maintenance requirements. Water consumption, capital costs, energy usage and environmental impacts of hybrid systems are generally in-between those of wet and dry cooling systems. They are also subject to all of the operation and maintenance issues of both cooling systems.

Hybrid cooling systems could benefit from improvements in the dry or wet cooling elements discussed in the previous sections. For example, reductions in the cost of ACCs or heat exchangers (*see* Section 6.3.4) will allow hybrid systems to be designed for lower water use targets for the same cost and power requirements as present designs. This section will concentrate on hybrid towers (also called wet-dry towers). They can reduce water use by 20–50% (or more) compared to evaporative wet cooling systems, while at the same time reducing energy use by 30–60% compared to dry cooling, depending on hybrid technology, weather conditions and how often the wet cooling system is employed (Libert and others, 2015a). Libert and others (2015b) have proposed a method for standardising the calculation of hybrid water savings that will allow all cooling equipment and technologies to be assessed on a level field. They then compared the water use of a hybrid cooling tower to that of the benchmark cooling tower.

6.4.1 Hybrid cooling towers

Hybrid cooling towers combine wet evaporative cooling with dry sensible cooling within the same unit. The dry cooling element is commonly a coil-based heat exchanger (air-to-water cooling) or an air-to-air heat exchanger. The early commercial systems were designed primarily for the abatement of plumes rather than water conservation, but can still save a small quantity of water. The systems essentially reduce the humidity in the air leaving the tower to a sufficiently low level to prevent the formation of visible plumes. More recent designs have focused on water conservation, as well as achieving plume abatement.

Coil-based systems

There are many configurations of hybrid cooling towers. One configuration places the finned coils vertically along the sides of a counterflow tower, above the spray distribution system and below the fans (in the plenum section). A portion of the hot water from the steam condenser passes through the coil tubes before being sprayed over the cooling tower media. The ambient air passing over the coils provides some sensible cooling of the water. Water savings range from 5% to 20% (depending on system operating conditions and local weather conditions), with a 10–20% power use penalty compared to a wet cooling tower (Libert and others, 2015a).

Another design locates the coils across the plenum (above the wet fill section and below the fans). All of the hot water from the steam condenser passes through the coils before it is sprayed over the evaporative heat exchanger. Ambient air first passes through the wet section before it is heated by the hot coils. An advantage in hot dry climates is that the dry bulb temperature of the evaporative exhaust may be lower than the ambient dry bulb temperature, which allows additional dry cooling, and thus more water savings than the vertical coil design (Libert and others, 2015b). The height of the tower is also lower, but there is less operational flexibility on the air side. The proximity of the coils to the fill section can lead to impingement, scaling problems and restricted air flow.

A different configuration replaces some of the cooling media in the wet section of a counterflow tower with sparsely finned coils that are in the same air stream. The coils are positioned on the outside, with the wet fill in the centre. On hot days, the coils are used as a splash fill (no fluid in the coils), with a portion of the recirculating water sprayed over them. On cooler days, the circulating water flow can be redirected to flow through the coils (no spray), allowing dry cooling. The amount of water saved is directly related to the surface area of the coils in the unit – some 20–30% could be saved with almost no impact on energy use. The tower is also shorter than the two configurations described above, since the dry coils are on the same level as the evaporative section. The footprint is only slightly larger than a conventional wet cooling tower (Libert and others, 2015a,b).

Higher water savings can be achieved in a dual coil closed-circuit hybrid tower. The hot water first passes through the tubes of an upper dry coil section before entering the lower wet coil, which is cooled by water sprays. The water sprays are switched off when operating in the dry mode. In another arrangement, the two finned coil sections can be installed side by side in a single structure (*see* Figure 16). Here, both coils can be sprayed with water (wet mode) or without water (dry mode), or one coil with water and one without (wet-dry mode). The water is collected beneath the coils and recirculated to the spray nozzles above the coils. The water is supplied from an external source and requires treatment to prevent biofouling and to inhibit corrosion and scaling. A portion is blown down to control the buildup of dissolved solids (as in conventional wet cooling towers).

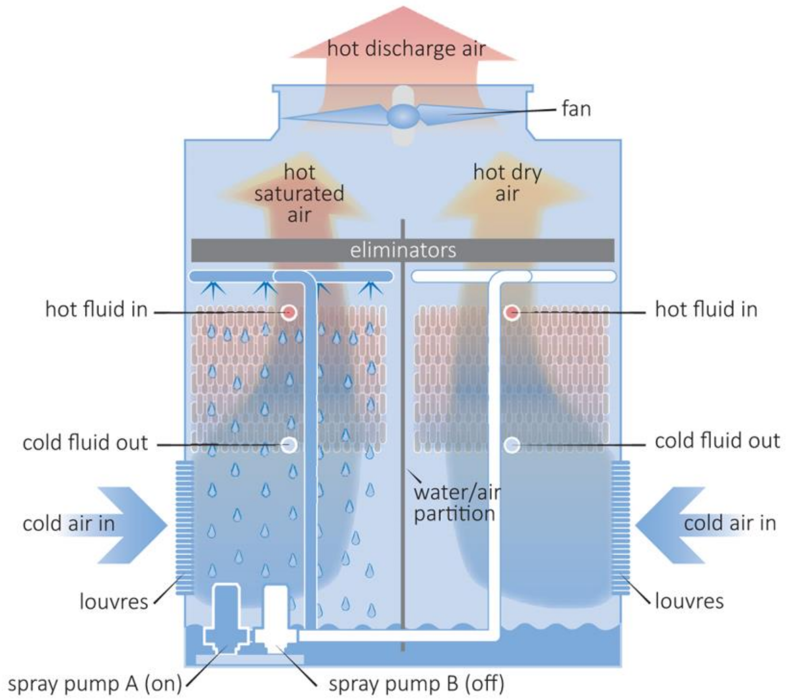

Figure 16 A dual coil closed-circuit cooling system (Libert and Nevins, 2011)

The dual coil design by Evapco uses spiral wound elliptical finned tubes. This allows closer tube spacing, resulting in a higher surface area per plan area than round tubes, and without the air-side pressure drop increase. Multiple coils would be used at power plants, without adding to the tower height or fan power requirements. Water savings are over 60% compared to conventional wet cooling towers. This is accomplished by providing a higher switchover temperature that enables totally dry operation for much of the time each year. However, capital costs are higher. A unit is undergoing tests at the EPRI Water Research Center at Georgia Power's coal-fired Bowen plant (Libert and Nevins, 2011; Libert and others, 2015a). The technology could be retrofitted easily into plants using all wet cooling (Bushart, 2014).

Air-to-air heat exchanger systems

Water can be recovered from the vapour leaving the wet counterflow tower by installing air-to-air heat exchangers in the tower plenum. The moist exhaust air from the wet section passes on one side of the heat exchanger whilst ambient air passes on the other side. The cool ambient air condenses a portion of the evaporative exhaust air. The condensate is high purity water, which can be returned to the cooling tower basin or collected for other power plant use (such as boiler make-up). The system can be retrofitted to existing power plants. Advantages over coil-type hybrid towers include reduced auxiliary power usage, lower installation and maintenance costs, and no concerns over freezing (Lindahl and Mortensen, 2010).

A prototype air-to-air PVC heat exchanger (Air2Air® from SPX Cooling Technologies) was tested at the San Juan Generating Station at Farmington, NM, USA, in a project funded by NETL. Water savings of about 18% were achieved (Mortensen, 2009). The net make-up water requirement of the cooling tower is reduced by both the quantity and quality of the returned water. The higher quality enables operation at fixed COC with less blowdown (Lindahl and Mortensen, 2010). A follow up NETL project redesigned the heat exchanger to make it smaller and to improve the efficiency and cost of the technology (Carney and Shuster, 2014; Mortensen, 2012). This resulted in the SPX ClearSky® Plume Abatement System. It has been estimated that the current model will pay for itself in water savings in about seven years. With further development, it is thought that the hybrid tower could condense 40–50% of the water from the cooling tower. Modularisation of the heat exchangers could decrease the size and lower costs.

6.5 Comments

A number of approaches are being taken to reduce the fresh water requirements for cooling. For wet cooling systems (typically the largest usage of water at coal-fired power plants), these include more efficient open-loop designs, reducing water loss in cooling towers, and more efficient and compact water-cooled condensers and heat exchangers. For example, water loss can be lowered by pre-cooling the air or water, or incorporating nanoparticles in the recirculating water. Otherwise water savings can be made by capturing the water vapour exiting the tower, or treating the blowdown for reuse (as is already done at a number of power plants). Hybrid cooling systems will benefit from improvements in both the wet and dry cooling technologies.

The pressure on water resource availability and conservation is increasing the employment of dry cooling systems, despite power capacity reductions and efficiency penalties during periods of hot weather; these increase operating costs and CO_2 emissions per MW of output. Hence, research and development are focussed on mitigating these drawbacks. They include reducing condensing temperatures by enhancing air- and water-side heat transfer without significantly increasing ACC size (footprint), pressure drop, power consumption or cost. The use of low cost materials (such as polymers) for heat exchangers would also decrease costs. Novel heat exchanger designs are being devised. The efficiency of dry cooling systems on hot days can be enhanced by incorporating a thermal energy or cool storage system. There are a number of alternatives to air-based techniques, such as thermosyphons, heat pipes, desiccants, sorption/desorption, magnetic refrigeration, thermoelectric cooling, electrocaloric cooling, and thermoacoustic cooling. These technologies are at different stages of development for use in thermal power plants.

7 Discussion and conclusions

Water conservation in power plants is becoming more important as fresh water becomes scarcer and regulations on water use more stringent. The cost of fresh water is likely to rise in the future, and competition with other users for limited water resources will increase. The power generation sector is typically the largest industrial user of fresh water within a country. Fortunately, there is an array of opportunities and technologies available to conserve water within a power plant.

The cooling system accounts for the largest usage of water (when water is the coolant). More advanced coatings that promote filmwise or dropwise condensation are being developed that can enhance the rate of heat transfer in the water-cooled steam condensers. More efficient designs can reduce the amount of water withdrawn in open-loop (once-through) systems. In closed-loop (recirculating) systems, water can be saved by reducing the amount lost from the cooling tower through evaporation (the largest loss), blowdown and drift. Technologies are commercially available, or are being developed, to reduce these losses. These include reducing evaporative losses by pre-cooling the inlet air or the water from the steam condenser before it enters the tower.

Installing state-of-the-art drift eliminators can reduce drift losses to 0.0005–0.002% of the circulating water flow. Treating the blowdown water for reuse can be expensive, but is already being carried out at a number of power plants. Waste heat from the cooling tower could be used to concentrate other waste water streams to lower the cost of treatment. The introduction of zero liquid discharge regulations will force more power plants to treat blowdown.

The early designs of hybrid cooling towers (which contain wet and dry cooling elements) were primarily concerned with abating plumes. More recent designs have focused on water conservation. Hybrid cooling towers can reduce water usage by 20–60% compared to evaporative wet cooling systems, whilst at the same time reducing energy use by 30–60% compared to dry cooling (depending on hybrid technology, weather conditions and how often the wet cooling system is employed).

Dry cooling systems, which use air instead of water as the cooling medium, could save substantial amounts of water. Some national governments and states are therefore promoting dry cooling as a way of relieving pressure on water resources. In some water-stressed regions in China, for example, the local government has set compulsory requirements for new coal-fired power plants to install these systems. This is despite the drawbacks, which include higher capital costs and lower power efficiency compared to a similar capacity power plant with a wet cooling tower. Overall plant efficiency is lowered by about 2 to 7 percentage points (more on hot days), depending on the type of power plant and other factors. Lower efficiencies mean more coal is needed per unit of electricity, which, in turn, can lead to higher CO_2 emissions. Ways of enhancing power output on hot days include pre-cooling the inlet air and deluge cooling. These methods consume fresh water. With a suitable design, non-fresh water sources, such as brackish water, could be employed instead. A considerable amount of research is being conducted to mitigate the drawbacks of dry cooling and on the development of alternative dry cooling technologies, such as heat pipes, desiccants, sorption/desorption, and thermoelectric cooling. It includes two major research programmes in the USA, namely the Advanced Research in Dry Cooling (ARID) and joint National Science Foundation–Electric Power Research Institute power plant dry cooling science and technology innovation programmes.

The wet FGD system is the second largest consumer of water in wet-cooled power plants – the scrubbers are responsible for around 10–15% of the evaporative water losses. However, they can account for 40-70% of total water usage at plants with dry or sea water (once-through) cooling systems. Cooling the flue gas before it enters the wet scrubber can lower water consumption by some 40–50%. This is commonly carried out in power plants in Japan and Europe with regenerative heat exchangers. Low temperature or low pressure economisers (heat exchangers) are widely used in China to recover waste heat in the flue gas for heating the condensate. This improves plant efficiency and consequently, reduces water consumption. Upgrading the air heater by extending the heat transfer surface and injecting a sodium-based solution to prevent sulphuric acid condensation can also reduce water usage in wet scrubbers and increase net efficiency by 0.5 to 1 percentage points.

Although semi-dry scrubbers (spray dry scrubbers and circulating dry scrubbers) consume some 60% less water than limestone wet scrubbers, and produce no waste water, they account for less than 10% of global FGD capacity. SO_2 removal efficiency is generally lower than the over 99% achieved with wet scrubbers; spray dry scrubbers can capture some 90–97% and circulating dry scrubbers just over 98% of SO_2. Nevertheless, semi-dry scrubbers can capture more SO_3 (over 99%) and oxidised mercury as a co-benefit than wet scrubbers, pollutants that are now starting to be regulated. Semi-dry scrubbers are better suited to low to medium sulphur coals, although circulating dry scrubbers have been used with high sulphur (3.5%) coals. Wet scrubbers can accommodate low to high sulphur coals. Operation and maintenance costs, and power consumption, are generally higher for wet scrubbers. On the other hand, wet scrubbers use a less expensive sorbent (limestone) than semi-dry scrubbers, and can more easily adjust to varying boiler loads.

Systems which inject sorbents into the furnace or duct consume no water, or only a minimal amount if the sorbent needs hydrating or the flue gas is humidified to improve performance. These are one of the simplest and cheapest commercial FGD systems to install and operate. They are best suited to small- or medium-sized (<300 MW) power plants (depending on the sorbent) burning low to medium sulphur coals, and where only a moderate SO_2 removal efficiency is required. These systems are also used to control SO_3, other acid gases, and mercury (with the appropriate sorbent).

Incorporating amine-based CO_2 capture systems will significantly increase water consumption. Carbon capture technologies that could lower water consumption and parasitic power consumption are under development. Water consumption will also increase if wet ESP are installed – they are increasingly being used as a final polishing device (after the wet FGD system) to capture $PM_{2.5}$. Commercial multi-pollutant control systems are available that consume little, or no water, but these are not yet widely used.

Recovering water vapour from the mill or pre-dryer exhausts, prior to coal combustion, or from the flue gas, after combustion, can save a substantial amount of water. Calculations have shown that capturing 84% of the vapour in the mill exhaust when firing a 40% moisture lignite is enough to meet the entire water requirements of a 600 MW dry-cooled power plant with a wet FGD system. In some cases, enough water could possibly be recovered from the flue gas to enable a dry-cooled power plant to become a co-producer of electricity and water. Commercial systems which dry coal in the mill or pre-dryer could be adapted to recover the evaporated water vapour that is currently sent through the boiler. New processes are being developed that are designed to capture the evaporated vapour for reuse, but have yet to be demonstrated at a full-scale plant. Pre-combustion drying with evaporative water recovery also improves the plant's thermal efficiency and leads to lower CO_2 emissions per unit of electricity.

None of the systems for recovering water vapour from flue gas (condensing heat exchangers, membranes and desiccants) have been demonstrated at full-scale on a coal-fired power plant; only small-scale tests using a slipstream from the power plant have been carried out. Full-scale demonstrations are needed to prove the technology, and this requires funding. Nevertheless, the systems have been shown to be potentially economically viable, depending on factors such as plant configuration and location. Water recovered from membrane and desiccant systems is, in principle, of a high enough quality to be used without further treatment, but water from condensing heat exchangers will need treating.

Another way to save water is to replace the wet bottom ash handling system (such as ash sluicing) with a semi-dry (where the ash is dewatered and the collected water recycled) or completely dry system (which would conserve more water). Furthermore, a dry ash handling system improves the quality of the bottom ash (lower carbon content) and increases thermal efficiency of the boiler. Mixing this ash with the dry fly ash could potentially improve revenue sales.

To sum up, the vulnerability of power plants to water shortages is likely to increase in the future with the demand for energy and water growing, and water becoming a scarcer commodity due to overexploitation, droughts, heat waves, and other factors. Consequently, operating power plants will need to retrofit water saving technologies, and new power plants should be designed to conserve water. Technologies are commercially available or are being developed to conserve water, but more research is needed, particularly on alternative dry cooling systems.

8 References

Altman S J, Cappelle M, Sattler A, Everett R, Holub W, Anderson H, Mayer T, McDonald F (2010) *Nanofiltration treatment options for thermoelectric power plant water treatment demands. Final report*. Available from: https://www.netl.doe.gov/research/coal/crosscutting/environmental-control/water-and-energy-interface/power-plant-water-management/non-traditional-sources/nano-filtration Morgantown, WV, USA, National Energy Technology Laboratory, 62 pp (2010)

An Y, Feng J, Li L (2015) Technical research and economic analysis for cooling tower with water collecting device of 1000 MW coal-fired power plant. In: *Proceedings of the 17th IAHR international conference on cooling tower and heat exchanger*, Gold Coast, Qld, Australia, 7-11 Sep 2015. Brisbane, Qld, Australia, The University of Queensland, pp 13-20 (Sep 2015)

Anisimov S, Kozlov A, Glanville P, Khinkis M, Maisotsenko V, Shi J (2014) Advanced cooling tower concept for commercial and industrial applications. Paper presented at: *ASME power conference: POWER2014*, Baltimore, MD, USA, 28-31 Jul 2014. 8 pp (2014)

Asheghi M, Santiago J, Goodson K (2015) Porous structures with 3D manifold for ultra-compact air side dry cooling. In: *Program on technology innovation: Proceedings of the 2015 NSF-EPRI power plant dry cooling science and technology innovation program annual review meeting*, Crystal City, VA, USA, 13-14 May 2015. Report 3002006555, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-121 – 2-148 (2015)

Ashwood A, Bharathan D (2011) *Hybrid cooling systems for low-temperature geothermal power production*. NREL/TP-5500-48765, Golden, CO, USA, National Renewable Energy Laboratory, 74 pp (Mar 2011)

Askari S, Lotfi R, Seifkordi A, Rashidi A M, Koolivand H (2016) A novel approach for energy and water conservation in wet cooling towers by using MWNTs and nanoporous graphene nanofluids. *Energy Conversion and Management*; **109**; 10-18 (2016)

Azher H, Scholes C A, Stevens G W, Kentish S E (2014) Water permeation and sorption properties of Nafion 115 at elevated temperatures. *Journal of Membrane Science*; **459**; 104-113 (2014)

Balogh A, Szabó Z (2008) Heller system: the economical substitute for wet cooling. Presentation at: *EPRI workshop on advanced thermal electric power cooling technologies,* Charlotte, NC, USA, 8-9 Jul 2008. 45 pp (2008)

Barnes I (2010) *Ash utilisation – impact of recent changes in power generation practices*. CCC/176, London, UK, IEA Clean Coal Centre, 51 pp (Nov 2010)

Bassetti F, Carrea A, Ricci D, Maiello M (2013) Improving boiler efficiency by Magaldi dry bottom ash handling systems. Paper presented at: *2nd IEA Clean Coal Centre workshop on upgrading and efficiency improvements in coal-fired power plants*, Ratcliffe-on-Soar, UK, 19-20 Mar 2013. 17 pp (2013)

Bassetti F, Coppola D, Ricci D (2015) MAC® - Magaldi ash cooler. Fully-dry bottom ash removal system for elimination of ponds. Paper presented at: *World of coal ash (WOCA) conference*, Nashville, TN, USA, 5-7 May 2015. 17 pp (2015)

Batra R K (2012) *Enhancing water-use efficiency of thermal power plants in India: need for mandatory water audits.* Policy Brief no 6, New Delhi, India, The Energy and Resources Institute (TERI), 12 pp (Dec 2012)

Bauer D, Philbrick M, Vallario B, Battey H (and others) (2014) The water-energy nexus: challenges and opportunities. Available at: http://energy.gov/downloads/water-energy-nexus-challenges-and-opportunities Washington, DC, USA, Department of Energy, 258 pp (Jun 2014)

Benn S P, Poplaski L M, Faghri A, Bergman T L (2016) Analysis of thermosyphon/heat pipe integration for feasibility of dry cooling for thermoelectric power generation. *Applied Thermal Engineering*; **104**; 358-374 (2016)

Berkenpas M B, Kietzke K, Mantripragada H, McCoy S, Rubin E S, Versteeg P L, Zhai H (2009) *IECM technical documentation updates. Final report*. DE-AC26-04NT41917, Pittsburgh, PA, USA, National Energy Technology Laboratory, 290 pp (Nov 2009)

Bisetto A, Torresin D, Tiwari M K, Del Col D, Poulikakos D (2014) Dropwise condensation on superhydrophobic nanostructured surfaces: literature review and experimental analysis. *Journal of Physics: Conference Series*; **501**(012028); 1-10 (2014)

Bullock A (2010) Ash handling: why dry bottoms are better than wet bottoms. *Power Engineering International*; **18**(5); 180, 182, 184 (May 2010)

Bushart S (2014) Advanced cooling technologies for water savings at coal-fired power plants. *Cornerstone*; **2**(1); 52-57 (Spr 2014)

Bustamante J G, Rattner A S, Garimella S (2016) Achieving near-water-cooled power plant performance with air-cooled condensers. *Applied Thermal Engineering*; **105**; 362-371 (2016)

Carney B (2016) New technology will recover heat and water from flue gas. *Power Engineering*; **120**(8); 18-20, 22, 24 (Aug 2016)

Carney B (2017) Morgantown, WV, USA, USDOE National Energy Technology Laboratory, *personal communication* (Feb 2017)

Carney B, Shuster E (2014) Exploring the possibilities: the NETL power plant water program. *Cornerstone*; **2**(1); 47-51 (Spr 2014)

Carney B, Feeley T J, McNemar A (2008) NETL power plant water research program. Presentation at: *EPRI advanced cooling technology workshop*, Charlotte, NC, USA, 8-9 Jul 2008. 39 pp (2008)

Carpenter A M (2012) *Low water FGD technologies*. CCC/210, London, UK, IEA Clean Coal Centre, 73 pp (Nov 2012)

Carpenter A M (2013) *Advances in multi-pollutant control*. CCC/227, London, UK, IEA Clean Coal Centre, 82 pp (Nov 2013)

Carpenter A M (2015) *Water availability and policies for the coal power sector*. CCC/256, London, UK, IEA Clean Coal Centre, 102 pp (Aug 2015)

Carpenter A M (2016) *Potential water sources for coal-fired power plants*. CCC/266, London, UK, IEA Clean Coal Centre, 97 pp (Jun 2016)

Carter T P, Vucci J (2015) Options for reducing water consumption and improving operational resiliency associated with chiller plant heat rejection systems. Presentation at: *Big ten and friends mechanical and energy conference*, College Park, MD, USA, 20-23 Sep 2015. Available at: https://www.facilities.umd.edu/SitePages/BigTen/abs/ThomasCarter_OptionsForReducingWaterConsumptionAndImprovingOperationalResiliencyAssociatedWithChillerPlantHeatRejection.pdf 44 pp (2015)

Carter T P, Furlong J W, Bushart S P, Shi J (2014) Wet, dry, and hybrid heat rejection system impacts on the economic performance of a thermoelectric power plant subjected to varying degrees of water constraint. In: *Proceedings of the ASME 2014 power conference: POWER2014*, Baltimore, MD, USA, 28-31 Jul 2014. Paper POWER2014-32051, New York, USA, American Society of Mechanical Engineers, 10 pp (2014)

CEA (2012a) *Report on minimisation of water requirement in coal based thermal power stations*. New Delhi, India, Ministry of Power, Central Electricity Authority, 52 pp (Jan 2012)

CEA (2012b) *National electricity plan. Volume 1. Generation*. New Delhi, India, Ministry of Power, Central Electricity Authority, 255 pp (Jan 2012)

Chen X, Omer S, Worall M, Riffat S (2013) Recent developments in ejector refrigeration technologies. *Renewable and Sustainable Energy Reviews*; **19**; 629-651 (Mar 2013)

Cho Y I, Fridman A A (2012) *Application of pulse spark discharges for scale prevention and continuous filtration methods in coal-fired power plant. Final technical report*. Available from: https://www.netl.doe.gov/research/coal/crosscutting/environmental-control/water-and-energy-interface/power-plant-water-management/advanced-cooling-technology/pulsed-electrical-fields DEFC2608NT0005308, Morgantown, WV, USA, National Energy Technology Laboratory, 172 pp (2012)

Chudnovsky Y (2013) Advanced dew point cooling tower fill development. Presentation at: *Gas Technology Institute End-Use Solutions Group meeting*, Houston, TX, USA, 19 Jun 2013. 12 pp (2013)

Clyde Bergemann (2016) *Drycon™. Dry ash conveying solutions for lower emissions, lower costs and increased efficiency.* Wesel, Germany, Clyde Bergemann, 8 pp (Jul 2016)

Couch G (2005) *Use of coal in areas of water shortages*. CCC/103, London, UK, IEA Clean Coal Centre, 88 pp (Nov 2005)

Couch G (2006) *Ash management in coal-fired power plants*. CCC/118, London, UK, IEA Clean Coal Centre, 69 pp (Oct 2006)

Cumbo D (2016) The EU Project MATChING: materials & technologies for performance improvement of cooling systems in power plants. Presentation at: *11th Power Industry Cooling Water Specialists meeting*, Chatou, France, 28-29 Jan 2016. Available from: http://matching-project.eu/links-downloads/conference-presentations/ 20 pp (2016)

Daal L (2011) How the power industry can contribute to reducing the global water shortage. *Power Engineering International*; **19**(5); 62,64,66,68-69 (May 2011)

Dahl L (2013) *Capture of evaporated water with novel membranes. Project final report. Publishable summary*. Available at: http://cordis.europa.eu/result/rcn/146177_en.html 24 pp (2013)

Daal L, Kamphuis H, Stam A, Konings T, Huibers M, van Rijen S, de Ruijter J (2012) Evaluation of different water vapor capture technologies and energy modeling results for membrane technology. Paper presented at: *Power-Gen Europe conference*, Cologne, Germany, 12-14 Jun 2012. 21 pp (2012)

de Vos F G, Heijboer R, van Deelen-Bremer H M (2008) Power plant: from water guzzler to water producer. *Power Engineering International*; **16**(10); 26-28 (Dec 2008)

de Vos F, van Daele P, Daal L (2013) *Capture of evaporated water with novel membranes. D 7.3 End user testing results*. Arnhem, The Netherlands, DNV-KEMA, 40 pp (Sep 2013)

DNV GL (2016) *Water energy nexus: coal-based power generation and conversion – saving water*. Singapore, Asia-Pacific Economic Cooperation, 154 pp (Dec 2016)

Dong N S (2011) *Utilisation of low rank coals*. CCC/182, London, UK, IEA Clean Coal Centre, 92 pp (Apr 2011)

Dong N (2014) *Techno-economics of modern pre-drying technologies for lignite-fired power plants*. CCC/241, London, UK, IEA Clean Coal Centre, 46 pp (Aug 2014)

DrexelNow (2015) *Drexel Engineers: to save water, cool power plants with wax*. Available at: http://drexel.edu/now/archive/2015/June/air-cooling-DoE/ Philadelphia, PA, USA, Drexel University, vp (22 Jun 2015)

Du Q, Su L, Dong H, Gao J, Zhao Z, Lv D, Wu S (2016) The experimental study of a water saving wet electrostatic precipitator for removing fine particles. *Journal of Electrostatics*; **81**; 42-47 (2016)

EPRI (2012) *Multifunctional nanoparticles for reducing cooling tower water consumption*. Palo Alto, CA, USA, Electric Power Research Institute, 3 pp (Jan 2012)

EPRI and Maulbetsch Consulting (2012) *Program on technology innovation: new concepts of water conservation cooling and water treatment technologies*. Report 1025642, Palo Alto, CA, USA, Electric Power Research Institute, 96 pp (Dec 2012)

Fischer M, Darling G (2016) Multi-pollutant control technology assessment: circulating fluidised bed scrubber vs. spray dryer absorber. *VGB PowerTech*; (5); 57-61 (2016)

Fleming C H, Mooney G D (nd) *Bottom ash conversion options and economics*. Malvern, PA, USA, Clyde Bergemann Delta Ducon, 18 pp (nd)

Folkedahl B C, Weber G F, Collings M E, Copen J, Sullivan T, Deen P (2006) *Water extraction from coal-fired power plant flue gas. Final report*. Available from: https://www.netl.doe.gov/File%20Library/Research/Coal/ewr/water/41907-Final.pdf Pittsburgh,PA, USA, National Energy Technology Laboratory, 157 pp (Dec 2006)

Foster Wheeler Italiana (2011) *Evaluation and analysis of water usage of power plants with CO_2 capture*. Report 2010/05, Cheltenham, UK, IEAGHG, 816 pp (Mar 2011)

Ghosh R, Ray T K, Ganguly R (2015) Cooling tower fog harvesting in power plants – a pilot study. *Energy*; **89**; 1018-1028 (Sep 2015)

Glezer A, Garimella S, Mittal R (2014) autoFlutter: efficient, waterless power plant cooling. In: *Proceedings of the 2014 NSF/EPRI power plant dry cooling science and technology innovation program kickoff meeting*, Washington, DC, USA, 15-16 Apr 2014. Report 3002004334, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-150 – 2-159 (Nov 2014)

Great River Energy (2016) *DryFining™ fuel enhancement process*. Bismarck, ND, USA, Great River Energy, 4 pp (2016)

Han X, Yan J, Karellas S, Liu M, Kakaras E, Xiao F (2017) Water extraction from high moisture lignite by means of efficient integration of waste heat and water recovery technologies with flue gas pre-drying system. *Applied Thermal Engineering*; **110**; 442-456 (2017)

He S, Gurgenci H, Guan Z, Alkhedhair A M (2013) Pre-cooling with Munters media to improve the performance of natural draft dry cooling towers. *Applied Thermal Engineering*; **53**; 67-77 (2013)

He S, Guan Z, Gurgenci H, Jahn I, Lu Y, Alkhedhair A M (2014) Influence of ambient conditions and water flow on the performance of pre-cooled natural draft dry cooling towers. *Applied Thermal Engineering*; **66**; 621-631 (2014)

He S, Gurgenci H, Guan Z, Huang X, Lucas M (2015) A review of wetted media with potential application in the pre-cooling of natural draft dry cooling towers. *Renewable and Sustainable Energy Reviews*; **44**; 407-422 (2015)

He S, Gurgenci H, Guan Z, Hooman K, Zou Z, Sun F (2016) Comparative study on the performance of natural draft dry, pre-cooled and wet cooling towers. *Applied Thermal Engineering*; **99**; 103-113 (2016)

Hegazy A, Rothan Y, Engeda A (2016) Feasibility of using vapor compression refrigeration system for cooling steam plant condenser. *Applied Thermal Engineering*; **106**; 570-578 (2016)

Henderson C (2013) *Upgrading and efficiency improvement in coal-fired power plants*. CCC/221, London, UK, IEA Clean Coal Centre, 58 pp (Aug 2013)

Heyns J A, Kröger D G (2012) Performance characteristics of an air-cooled steam condenser with a hybrid dephlegmator. *R & D Journal of the South African Institution of Mechanical Engineering*; **28**; 31-36 (2012)

Hightower M (2014) *By 2030 there may not be enough water for energy production*. Available at: https://www.uschamberfoundation.org/blog/post/2030-there-may-not-be-enough-water-energy-production/42180 Washington, DC, USA, U.S. Chamber of Commerce Foundation, vp (4 Nov 2014)

Hooman K, Chumpia A, Jadhav P, Rudolph V (2013) *Metal foam heat exchanger for dry cooling. Final report for ANLEC project 5-0710-0063*. Barton, ACT, Australia, Australian National Low Emissions Coal Research and Development, 26 pp (Nov 2013)

Hrnjak P S, Jacobi A M (2014) Advanced air-cooled condensers with inter-fin vortex generator arrays. In: *Proceedings of the 2014 NSF/EPRI power plant dry cooling science and technology innovation program kickoff meeting*, Washington, DC, USA, 15-16 Apr 2014. Report 3002004334, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-132 – 2-149 (Nov 2014)

Hu W, Pei Y (2015) Getting water from lignite technology for high-efficiency power generation. Presentation at: *7th international conference on clean coal technologies: CCT2015*, Kraków, Poland, 17-21 May 2015. 24 pp (2015)

IEA (2012) Water for energy. Is energy becoming a thirstier resource? In: *World energy outlook 2012.* Paris, France, International Energy Agency, pp 501-528 (2012)

Ifaei P, Rashidi J, Yoo C K (2016a) Thermoeconomic and environmental analyses of a low water consumption combined steam power plant and refrigeration chillers – Part 1: Energy and economic modelling and analysis. *Energy Conversion and Management*; **123**; 610-624 (2016)

Ifaei P, Ataei A, Yoo C K (2016b) Thermoeconomic and environmental analyses of a low water consumption combined steam power plant and refrigeration chillers – Part 2: Thermoeconomic and environmental analysis. *Energy Conversion and Management*; **123**; 625-642 (2016)

Ju Y S, Warrier G, Dhir V (2014) Direct Contact Liquid-on-String Heat Exchanger (DILSHE) for dry cooling of steam power plants. In: *Proceedings of the 2014 NSF/EPRI power plant dry cooling science and technology innovation program kickoff meeting*, Washington, DC, USA, 15-16 Apr 2014. Report 3002004334, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-81 – 2-91 (Nov 2014)

Ju Y S, Warrier G, Dhir V (2015) Direct Contact Liquid-on-String Heat Exchanger (DILSHE) for dry cooling of steam power plants. In: *Program on technology innovation: Proceedings of the 2015 NSF-EPRI power plant dry cooling science and technology innovation program annual review meeting*, Crystal City, VA, USA, 13-14 May 2015. Report 3002006555, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-77 – 2-91 (2015)

Kim H J, Han B, Woo C G, Kim Y J, Ono R, Oda T (2014) Performance evaluation of dry and wet electrostatic precipitators used in an oxygen-pulverized coal combustion and a CO_2 capture and storage pilot plant. *Journal of Aerosol Science*; **77**; 116-126 (2014)

Kim S Y, Kang Y, Bautsch C, Moser C (2016) A flue gas first for South Korea. *Power Engineering International*; **24**(7); 8, 10-12 (Jul/Aug 2016)

Klett M G, Kuehn N J, Schoff R L, Vaysman V, White J S (2007) *Power plant water usage and loss study*. Available at: https://www.netl.doe.gov/File%20Library/Research/Coal/ewr/water/WaterReport_Revised-May2007.pdf Morgantown, WV, USA, National Energy Technology Laboratory, 104 pp (May 2007)

Korhonen T (2016) Utilizing waste instead of limestone in wet FGD. Presentation at: *11th annual ExPPERTS Europe conference*, Krakow, Poland, 7-8 Sep 2016. 27 pp (2016)

Lee S, Cheng K, Palmre V, Bhuiya M M H, Kim K J, Zhang B J, Yoon H (2013) Heat transfer measurement during dropwise condensation using micro/nano-scale porous surface. *International Journal of Heat and Mass Transfer*; **65**; 619-626 (2013)

Lehigh University (2012) Development of air-cooled heat exchangers for condensing water vapor from boiler flue gas. In: *Program on technology innovation: new concepts of water conservation cooling and water treatment technologies*. Report 1025642, Palo Alto, CA, USA, Electric Power Research Institute, pp 4-28 – 4-30 (Dec 2012)

Levy E, Bilirgen H, Jeong K, Kessen M, Samuelson C, Whitcombe C (2008) *Recovery of water from boiler flue gas. Final technical report*. Available from: https://www.netl.doe.gov/File%20Library/Research/Coal/ewr/water/NT42727_Lehigh_FinalRpt.pdf Morgantown, WV, USA, National Energy Technology Laboratory, 97 pp (Dec 2008)

Levy E, Bilirgen H, DuPont J (2011) *Recovery of water from boiler flue gas using condensing heat exchangers. Final technical report*. Available from: http://www.osti.gov/scitech/servlets/purl/1084027/ Morgantown, WV, USA, National Energy Technology Laboratory, 155 pp (2011)

Li C, Khan J, Farouk T, Huang X (2014) On-demand sweating-boosted air cooled heat-pipe condensers for green power plants. In: *Proceedings of the 2014 NSF/EPRI power plant dry cooling science and technology innovation program kickoff meeting*, Washington, DC, USA, 15-16 Apr 2014. Report 3002004334, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-68 – 2-80 (Nov 2014)

Li J, Lin X, Ma W, Gurgenci H, Guan Z (2015a) Water consumption comparison between a natural draft wet cooling tower and a natural draft hybrid cooling tower – an annual simulation for Luoyang conditions. In: *Proceedings of the 17th IAHR international conference on cooling tower and heat exchanger*, Gold Coast, Qld, Australia, 7-11 Sep 2015. Brisbane, Qld, Australia, The University of Queensland, pp 344-359 (Sep 2015)

Li C, Khan J, Farouk T, Huang X (2015b) On-demand sweating-boosted air cooled heat-pipe condensers for green power plants. In: *Program on technology innovation: Proceedings of the 2015 NSF-EPRI power plant dry cooling science and technology innovation program annual review meeting*, Crystal City, VA, USA, 13-14 May 2015. Report 3002006555, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-54 – 2-76 (2015)

Li Y, Yan M, Zhang L, Chen G, Cui L, Song Z, Chang J, Ma C (2016) Method of flash evaporation and condensation – heat pump for deep cooling of coal-fired power plant flue gas: latent heat and water recovery. *Applied Energy*; **172**; 107-117 (2016)

Libert J P, Nevins S (2011) Cooling tower plume. *CTI Journal*; **32**(2); 14,16,18,20,22,24,26,28,30 (Sum 2011)

Libert J-P, Hamilton J, Bugler T (2015a) Advanced cooling solutions for water conservation. *CTI Journal*; **36**(1); 66-68, 70-72 (Win 2015)

Libert J P, Lane J, Carl A, McCarrell M (2015b) Hybrid cooling towers water savings calculations and measurements. *CTI Journal*; **36**(2); 74-83 (Sum 2015)

Lindahl P, Mortensen K (2010) Plume abatement – the next generation. Paper presented at: *2010 Cooling Technology Institute annual conference*, Houston, TX, USA, 7-11 Feb 2010. 10 pp (2010)

Lockwood T (2016) *Next-generation carbon capture technologies for coal.* CCC/265, London, UK, IEA Clean Coal Centre, 126 pp (May 2016)

Ma H (2014) Ejector cooling system with evaporation/condensation compact condenser. In: *Proceedings of the 2014 NSF/EPRI power plant dry cooling science and technology innovation program kickoff meeting*, Washington, DC, USA, 15-16 Apr 2014. Report 3002004334, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-105 – 2-115 (Nov 2014)

Ma H (2015) Ejector cooling system with evaporation/condensation compact condenser. In: *Program on technology innovation: Proceedings of the 2015 NSF-EPRI power plant dry cooling science and technology innovation program annual review meeting*, Crystal City, VA, USA, 13-14 May 2015. Report 3002006555, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-105 – 2-120 (2015)

Ma Y, Yuan Y, Jin J, Zhang H, Hu X, Shi D (2013) An environment friendly and efficient lignite-fired power generation process based on a boiler with an open pulverizing system and the recovery of water from mill-exhaust. *Energy*; **59**; 105-115 (2013)

Ma Y, Zhang H, Yuan Y, Wang Z (2015) Optimization of a lignite-fired open pulverizing system boiler process based on variations in the drying agent composition. *Energy*; **81**; 304-316 (2015)

Magneschi G, Zhang T, Munson R (2016) *Water use in thermal power plants equipped with CO_2 capture systems.* Melbourne, Vic, Australia, Global CCS Institute, 51 pp (Sep 2016)

Martin C L, Pavlish J H (2013) *Subtask 5.10 – testing of an advanced dry cooling technology for power plants. Final report.* Available at: https://www.netl.doe.gov/File%20Library/Research/Coal/ewr/water/EERC-Dry-Cooling-Final-Report.pdf Pittsburgh, PA, USA, National Energy Technology Laboratory, 37 pp (Sep 2013)

Maulbetsch J (2004) *Comparison of alternate cooling technologies for U. S. power plants: economic, environmental, and other tradeoffs*. Report 1005358, Palo Alto, CA, USA, Electric Power Research Institute, 270 pp (Aug 2004)

Maulbetsch J S (2011) Cost/performance comparisons of water conserving power plant cooling systems. Paper presented at: *ASME 2011 international mechanical engineering congress and exposition: IMECE2011*, Denver, CO, USA, 11-17 Nov 2011. 6 pp (2011)

Maulbetsch J, DiFilippo M (2003) *Spray cooling enhancement of air-cooled condensers*. Report 1005360, Palo Alto, CA, USA, Electric Power Research Institute, 142 pp (Sep 2003)

Maupin M A, Kenny J F, Hutson S S, Lovelace J K, Barber N L, Linsey K S (2014) *Estimated use of water in the United States in 2010*. Circular 1405, Reston, VA, USA, U.S. Geological Survey, 64 pp (2014)

Miller W C (2012) Best practices for minimizing drift loss in a cooling tower. *CTI Journal*; **33**(2); 36, 38, 40, 44, 46, 48, 50, 52 (Sum 2012)

Moore K (2016) Oxnard, CA, USA, CastleLight Energy Corp., *personnel communication* (2016)

Morris L (2011) Ash handling options for coal-fired power plants. *Power Engineering*; **115**(2);26-30 (2011)

Mortensen K (2009) *Use of Air2Air™ technology to recover fresh-water from the normal evaporative cooling loss at coal-based thermoelectric power plants. Final report*. Morgantown, WV and Pittsburgh, PA, USA, National Energy Technology Laboratory, 49 pp (2009)

Mortensen K (2012) *Improvement to Air2Air™ technology to reduce fresh-water evaporative cooling loss at coal-based thermoelectric power plants. Final report*. Morgantown, WV and Pittsburgh, PA, USA, National Energy Technology Laboratory, 37 pp (2012)

Nakayama Y, Nakamura S, Takeuchi Y, Itoh M, Okino S, Honjo S (2006) MHI high efficiency system - proven technology for multi pollutant removal. In: *Power plant air pollutant control 'Mega' symposium*, Baltimore, MD, USA, 28-31 Aug 2006. Pittsburgh, PA, USA, Air and Waste Management Association, vol 3, pp 1215-1225 (2006)

Nalbandian H (2009) *NOx control for coal-fired plant*. CCC/157, London, UK, IEA Clean Coal Centre, 51 pp (Oct 2009)

Nicol K (2013) *Recent developments in particulate control*. CCC/218, London, UK, IEA Clean Coal Centre, 54 pp (Mar 2013)

Nikolopoulos N, Violidakis I, Karampinis E, Agraniotis M, Bergins C, Grammelis P, Kakaras E (2015) Report on comparison among current industrial scale lignite drying technologies (A critical review of current technologies). *Fuel*; **155**; 86-114 (2015)

Noble R, Dombrowski K, Bernau M, Morett D, Maxson A, Hume S (2016) *Heat recovery-use technology assessments. Final report.* Available at: https://www.osti.gov/scitech/servlets/purl/1332489 USA, National Energy Technology Laboratory, 109 pp (26 Sep 2016)

OECD (2012) *Environmental outlook to 2015: the consequences of inaction. Key findings on water*. Available at: www.oecd.org/env/indicators-modelling-outlooks/49844953.pdf Paris, France, OECD Publishing, 6 pp (Mar 2012)

Owen M, Kröger D, Reuter H (2015). Enhancing turbine output at dry-cooled power plants using a hybrid (dry/wet) dephlegmator. In: *Proceedings of the 17th IAHR international conference on cooling tower and heat exchanger*, Gold Coast, Qld, Australia, 7-11 Sep 2015. Brisbane, Qld, Australia, The University of Queensland, pp 460-473 (Sep 2015)

Paxson A T, Yagüe J L, Gleason K K, Varanasi K K (2014) Stable dropwise condensation for enhancing heat transfer via the initiated chemical vapor deposition (iCVD) of grafted polymer films. *Advanced Materials*; **26**(3); 418-423 (22 Jan 2014)

Peters H J (2011) Operating flexibility in the ReACT™ multipollutant control system. Paper presented at: *PowerGen international conference*, Las Vegas, NV, USA, 13-15 Dec 2011. 11 pp (2011)

Pietersen K, Pearce D, Vernon R (2013) *Impacts of carbon capture and storage (CCS) on South African national priorities other than climate change*. Available at: http://www.sacccs.org.za/wp-content/uploads/2013/Quicklinks/03/CCS_Impact_on_South_African_National_Priorities_Report.pdf Sandton, South Africa, South African Centre for Carbon Capture and Storage, 119 pp (Oct 2013)

Power (2016) Indian water crisis shuts down multiple power plants. *Power*; **160**(8); 9 (Aug 2016)

Preston D J, Mafra D L, Miljkovic N, Kong J, Wang E N (2015) Scalable graphene coatings for enhanced condensation heat transfer. *Nano Letters*; **15**(5); 2902-2909 (13 May 2015)

Rao Z, Zhao Y, Huang C, Duan C, He J (2015) Recent developments in drying and dewatering for low rank coals. *Progress in Energy and Combustion Science*; **46**; 1-11 (2015)

Rubio Serrano F J (2016) Saving water in power plants. *Power Engineering International*; **24**(6); 12-15 (Jun 2016)

Sack J, Preston D, Antao D, Barabadi B, Wang E N, Lestina T (2015) Nanostructure enhanced air-cooled steam condensers. In: *Program on technology innovation: Proceedings of the 2015 NSF-EPRI power plant dry cooling science and technology innovation program annual review meeting*, Crystal City, VA, USA, 13-14 May 2015. Report 3002006555, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-174 – 2-188 (2015)

Sadafi M H, Jahn I, Hooman K (2015) Cooling performance of solid containing water for spray assisted dry cooling towers. *Energy Conversion and Management*; **91**; 158-167 (2015)

Sadafi M H, González Ruiz S, Vetrano M R, Jahn I, van Beeck J, Buchlin J M, Hooman K (2016) An investigation on spray cooling using saline water with experimental verification. *Energy Conversion and Management*; **108**; 336-347 (2016)

Schoubye P, Jensen F E (2007) SNOX™ flue gas treatment for boilers burning petcoke … makes petcoke more attractive for power and heat generation. Paper presented at: *Petcoke conference*, Orlando, FL, USA, 23-27 Feb 2007. 13 pp (2007)

Shah H G, Caine J C (nd) *Next generation wet electrostatic precipitators*. Available at: https://www.southernenvironmental.com/assets/membrane-wesp_rev4.pdf Pensacola, FL, USA, Southern Environmental Inc, 12 pp (nd)

Shi J, Acharya S (2014) *Proceedings of the 2014 NSF/EPRI power plant dry cooling science and technology innovation program kickoff meeting*, Washington, DC, USA, 15-16 Apr 2014. Report 3002004334, Palo Alto, CA, USA, Electric Power Research Institute, 234 pp (Nov 2014)

Shi J, Chen R (2015) *Program on technology innovation: Proceedings of the 2015 NSF-EPRI power plant dry cooling science and technology innovation program annual review meeting*, Crystal City, VA, USA, 13-14 May 2015. Report 3002006555, Palo Alto, CA, USA, Electric Power Research Institute, 258 pp (2015)

Silva A A, Moretti A L, Liu T (2015) Wet electrostatic precipitator (ESP) designs to achieve ultra-low particulate emissions. Paper presented at: *Power-Gen Asia*, Bangkok, Thailand, 1-3 Sep 2015. 21 pp (2015)

Sloss L L (2007) *Trace elements and fly ash utilisation*. CCC/122, London, UK, IEA Clean Coal Centre, 54 pp (Mar 2007)

Sloss L (2012) *Legislation, standards and methods for mercury emissions control*. CCC/195, London, UK, IEA Clean Coal Centre, 43 pp (Apr 2012)

Sloss L L (2015) *The emerging market for mercury control*. CCC/245, London, UK, IEA Clean Coal Centre, 75 pp (Feb 2015)

Smart Water Fund (2012) *Water conservation by replacing cooling towers.* Available from: https://www.clearwater.asn.au/resource-library/smart-water-fund-projects/replacing-cooling-towers-to-conserve-water.php 52M-2108, Australia, Smart Water Fund, 41 pp (2012)

Smith I M (2005a) *Cement and concrete – benefits and barriers in coal ash utilisation*. CCC/94, London, UK, IEA Clean Coal Centre, 70 pp (Jan 2005)

Smith I M (2005b) *Land uses of coal fly ash – benefits and barriers*. CCC/96, London, UK, IEA Clean Coal Centre, 30 pp (Apr 2005)

Sontag D S, Saylor J R (2016) An experimental study of the collection of fog droplets using a mesh fabric: possible application to cooling towers. *Journal of Energy Resources Technology*; **138**(2); 024501-1–024501-4 (Mar 2016)

Stevens G, Plummer F (2016) *Valley earmarked for new brown coal tech*. Available at: http://www.latrobevalleyexpress.com.au/story/3705447/valley-earmarked-for-new-brown-coal-tech/ Morwell, Vic, Australia, Latrobe Valley Express, vp (4 Feb 2016)

Sun Y, McCarthy M, Cho Y, Pearlman H, Xie Q (2014) Indirect dry cooling towers with phase-change materials as intermediate coolants. In: *Proceedings of the 2014 NSF/EPRI power plant dry cooling science and technology innovation program kickoff meeting*, Washington, DC, USA, 15-16 Apr 2014. Report 3002004334, Palo Alto, CA, USA, Electric Power Research Institute, pp 2-43 – 2-60 (Nov 2014)

Sun Y, McCarthy M, Cho Y I, Boettcher P, Hu H, Shi B, Xie Q (2015) *Systems and methods of using phase change material in power plants.* US Patent application 2015/0204612 A1, Alexandria, VA, USA, US Patent Office, 9 pp (23 Jul 2015)

The Green House (2011) *Overview of the South African coal value chain. Prepared as a basis for the development of the South African Coal Roadmap*. Available from: http://www.fossilfuel.co.za/initiatives1/ or http://www.sanedi.org.za/coal-roadmap/ 231 pp (Oct 2011)

Tora E A (2013) Nanofluids as a cooling agent for Rankine power cycle. Paper presented at: *2nd international conference on energy systems and technologies*, Cairo, Egypt, 18-21 Feb 2013. 12 pp (2013)

Tsou J L, Maulbetsch J, Shi J (2013) *Power plant cooling system overview for researchers and technology developers.* Report 3002001915, Palo Alto, CA, USA, Electric Power Research Institute, 32 pp (2013)

US EPA (2010) *Available and emerging technologies for reducing greenhouse gas emissions from coal-fired electric generating units*. Research Triangle Park, NC, USA, US Environmental Protection Agency, 48 pp (Oct 2010)

Wang D (2012) *Transport membrane condenser for water and energy recovery from power plant flue gas. Final technical report October 1, 2007 to March 31, 2012*. Available from:

https://www.netl.doe.gov/File%20Library/Research/Coal/ewr/water/5350-FinalTechReport.pdf Pittsburgh, PA, USA, National Energy Technology Laboratory, 79 pp (2012)

Wang C, He B, Sun S, Wu Y, Yan N, Yan L, Pei X (2012) Application of a low pressure economizer for waste heat recovery from the exhaust flue gas in a 600 MW power plant. *Energy*; **48**; 196-202 (Dec 2012)

Wang Z, Zhang X, Li Z (2016a) Evaluation of a flue gas driven open absorption system for heat and water recovery from fossil fuel boilers. *Energy Conversion and Management*; **128**; 57-65 (2016)

Wang D, Bao A, Kunc W, Wang H, Ma Z (2016b) Pilot-scale study of a waste heat and water recovery technology for coal power plant flue gas. Paper presented at: *41st international technical conference on clean coal and fuel systems, the Clearwater clean coal conference*, Clearwater, FL, USA, 5-9 Jun 2016. 10 pp (2016)

WWAP (2015) *The United Nations world water development report 2015. Water for a sustainable world.* Paris, France, United Nations Educational, Scientific and Cultural Organisation, 139 pp (2015)

Xiong Y, Xu W, Liu Y, Wei B, Wang X, Tan H (2013) Pilot study on in-depth water saving and heat recovery from tail gas in power plant. Paper presented at: *International conference on power engineering: ICOPE 2013*, Wuhan, China, 23-27 Oct 2013. vp (2013)

Xiong Y, Niu Y, Wang X, Tan H (2014) Pilot study on in-depth water saving and heat recovery from tail flue gas in lignite-fired power plant. *Energy Procedia*; **61**; 2558-2561 (2014)

Xu C, Xu G, Yang Y, Zhao S, Zhang K, Zhang D (2015) An improved configuration of low-temperature pre-drying using waste heat integrated in an air-cooled lignite fired power plant. *Applied Thermal Engineering*; **90**; 312-321 (2015)

Xu C, Chang J, Meng Z, Wang X, Zhang J, Cui L, Ma C (2016) Wetting properties and performance test of modified rigid collector in wet electrostatic precipitators. *Journal of the Air and Waste Management Association*; **66**(10); 1019-1030 (Oct 2016)

Yang B, Radermacher R, Cao F, Shi B (2016) *Microemulsion-enabled water capture and recovery*. US Patent application 2016/0200591 A1, Alexandria, VA, USA, US Patent Office, 9 pp (14 Jul 2016)

Yao Y, Levy E K, Wang X, Sarunac N, Bullinger C W, Ness M (2016) Low temperature drying process improves heat rate and water balance for power plants. Paper presented at: *41st international technical conference on clean coal and fuel systems, the Clearwater clean coal conference*, Clearwater, FL, USA, 5-9 Jun 2016. 8 pp (2016)

Zeng H, Wu L, Yang Z, Ren J (2015) Economic evaluation of natural draft cooling tower with water collecting devices. In: *Proceedings of the 17th IAHR international conference on cooling tower and heat exchanger*, Gold Coast, Qld, Australia, 7-11 Sep 2015. Brisbane, Qld, Australia, The University of Queensland, pp 674-681 (Sep 2015)

Zhai H, Rubin E S (2010) Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage. *Energy Policy*; **38**; 5653-5660 (2010)

Zhai H, Rubin E S (2016) A techno-economic assessment of hybrid cooling systems for coal- and natural-gas-fired power plants with and without carbon capture and storage. *Environmental Science & Technology*; **50**; 4127-4134 (2016)

Zhai H, Rubin E S, Versteeg P L (2011) Water use at pulverized coal power plants with postcombustion carbon capture and storage. *Environmental Science & Technology*; **45**; 2479-2485 (2011)

Zhang X (2014) *Management of coal combustion wastes*. CCC/231, London, UK, IEA Clean Coal Centre, 68 pp (Jan 2014)

Zhang X (2016) *Emission standards and control of $PM_{2.5}$ from coal-fired power plant*. CCC/267, London, UK, IEA Clean Coal Centre, 80 pp (Jul 2016)

Zhao B, Yang S, Zhang G, Zhang H, Zhang H, Jiang J, Liu Z, Wang W, Hong H, Ma S, Hu Y (2013) A site simulation test on compressed air blowers for ash fouling of air cooled condensers. *Proceedings of the Chinese Society of Electrical Engineering*; **33**(35); 28-35 (2013) (In Chinese)

Zhao Y, Sun F, Long G, Huang X, Huang W, Lyv D (2016) Comparative study on the cooling characteristics of high level water collecting natural draft wet cooling tower and the usual cooling tower. *Energy Conversion and Management*; **116**; 150-164 (2016)

Zheng Y, Chen C, Pearlman H, Flannery M, Bonner R (2015) Effect of porous coating on condensation heat transfer. Paper presented at: *9th international conference on boiling and condensation heat transfer*, Boulder, CO, USA, 26-30 Apr 2015. 9 pp (2015)

Zhu Q (2012) *Update on lignite firing*. CCC/201, London, UK, IEA Clean Coal Centre, 75 pp (Jun 2012)