NATIONAL ENERGY TECHNOLOGY LABORATORY

Reducing Freshwater Consumption at Coal-Fired Power Plants: Approaches Used Outside the United States

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Notation

The following is a list of the acronyms, initialisms, and abbreviations (including units of measure) used in this document.

ACRONYMS AND ABBREVIATIONS

ACC	air-cooled steam condenser
AD700	Advanced 700°C Power Plant
AFD	acoustic fish deterrent
BoA	lignite-fired power station with optimized plant engineering
CFB	circulating fluidized bed
CHP	combined heat and power
CO_2	carbon dioxide
CWA	Clean Water Act
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
FGD	flue gas desulfurization
HHV	higher heating value
IDGCC	Integrated Drying Gasification and Combined Cycle
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
LHV	lower heating value
NDRC	National Development and Reform Commission
NETL	National Energy Technology Laboratory
OECD	Organization for Economic Co-operation and Development
ReACT	regenerative activated coke technology
R&D	research and development
RD&D	research, development, and deployment

ACRONYMS AND ABBREVIATIONS (Cont.)

SCC	submerged chain conveyor
SDA	spray dryer absorber
SO_2	sulfur dioxide
SPA	sound projector array
UK	United Kingdom
WTA	Wirbelschicht-Trocknung mit interner Abwärmenutzung

UNITS OF MEASURE

Btu/pound	British thermal unit per pound
C	Celsius
cfs	cubic feet per second
F	Fahrenheit
gal	gallon(s)
gpm	gallon(s) per minute
h	hour(s)
kWh	kilowatt-hour(s)
l	liter(s)
m	meter(s)
m^3	cubic meter(s)
mgd	millions of gallons per day
mi^2	square miles
MW	megawatt
MWh	megawatt-hour
psi	pounds per square inch
t/hr	tons per hour

Summary

Coal-fired power plants consume huge quantities of water, and in some water-stressed areas, power plants compete with other users for limited supplies. Extensive use of coal to generate electricity is projected to continue for many years. Faced with increasing power demands and questionable future supplies, industries and governments are seeking ways to reduce freshwater consumption at coal-fired power plants. As the United States investigates various freshwater savings approaches (e.g., the use of alternative water sources), other countries are also researching and implementing approaches to address similar—and in many cases, more challenging—water supply and demand issues. Information about these non-U.S. approaches can be used to help direct near- and mid-term water-consumption research and development (R&D) activities in the United States. This report summarizes the research, development, and deployment (RD&D) status of several approaches used for reducing freshwater consumption by coal-fired power plants in other countries, many of which could be applied, or applied more aggressively, at coal-fired power plants in the United States.

Information contained in this report is derived from literature and Internet searches, in some cases supplemented by communication with the researchers, authors, or equipment providers. Because there are few technical, peer-reviewed articles on this topic, much of the information in this report comes from the trade press and other non-peer-reviewed references.

Reducing freshwater consumption at coal-fired power plants can occur directly or indirectly. Direct approaches are aimed specifically at reducing water consumption, and they include dry cooling, dry bottom ash handling, low-water-consuming emissions-control technologies, water metering and monitoring, reclaiming water from in-plant operations (e.g., recovery of cooling tower water for boiler makeup water, reclaiming water from flue gas desulfurization [FGD] systems), and desalination. Some of the direct approaches, such as dry air cooling, desalination, and recovery of cooling tower water for boiler makeup water, are costly and are deployed primarily in countries with severe water shortages, such as China, Australia, and South Africa. Table 1 shows drivers and approaches for reducing freshwater consumption in several countries outside the United States.

Table 1. Drivers and Approaches for Reducing Freshwater Consumption at Coal-Fired Power Plants outside the United States

Country	Electricity Generated by Coal (%)	Drivers for Reducing Freshwater Consumption	Approaches for Reducing Freshwater Consumption
Germany	49%	Coal expected to remain a significant contributor to power generation for several years; a large portion (about half) of coal-fired generation is from low-rank lignite; power plants are aging.	Replacement of old, inefficient plants with new, efficient plants, including ultra supercritical; research into plants with high steam parameters and new materials; lignite drying.
Denmark	50%	No domestic coal resources.	Supercritical and ultra supercritical plants; cogeneration.
Italy	13%	Coal-fired power generation expected to increase because of coal's lower costs relative to other fuels; coal is expected to provide about 1/3 of generation by 2013.	Replace/retrofit old plants with more efficient plants (ultra supercritical).
China	80%	Large coal resources; coal expected to be dominant fuel for decades; China is third driest country in the world; specific policies for reducing freshwater consumption.	Replace, retrofit small, inefficient plants; increase use of supercritical and ultra supercritical units; use dry cooling; explore integrated gasification combined cycle (IGCC); use desalination at power plants.
Australia	70%	Coal is projected to continue to supply more than half the total electrical generating capacity through 2035; many areas are subject to prolonged drought; groundwater use is restricted.	Supercritical steam cycles, dry cooling, turbine upgrades, coal drying, in-plant water recycling.
South Africa	85%	Abundant coal resources; coal resources and power plants are located in dry regions.	Use efficient supercritical technologies, dry cooling, advanced control systems, desalination, participate in water infrastructure development, incentives, water metering, dry bottom ash handling.
Japan	25%	Imports all fuel, often difficult to obtain water from local governments.	Use supercritical and ultra supercritical technologies, low-water-consuming emissions control equipment.
India	70%	High and increasing demand for power; more power is needed than is available; coal expected to remain dominant fuel through at least 2050.	Increase efficiency; used advance supercritical steam parameters; replace/retrofit old inefficient plants; reuse and recycle wastewater; researching IGCC.

Indirect approaches reduce water consumption while meeting other objectives, such as improving plant efficiency. Plants with higher efficiencies use less energy to produce electricity, and because the greater the energy production, the greater the cooling water needs, increased efficiency will help reduce water consumption. Approaches for improving efficiency (and for indirectly reducing water consumption) include increasing the operating steam parameters (temperature and pressure); using more efficient coal-fired technologies such as cogeneration, IGCC, and direct firing of gas turbines with coal; replacing or retrofitting existing inefficient plants to make them more efficient; installing high-performance monitoring and process controls; and coal drying.

The motivations for increasing power plant efficiency outside the United States (and indirectly reducing water consumption) include the following: (1) countries that agreed to reduce carbon emissions (by ratifying the Kyoto protocol) find that one of the most effective ways to do so is to improve plant efficiency; (2) countries that import fuel (e.g., Japan) need highly efficient plants to compensate for higher coal costs; (3) countries with particularly large and growing energy demands, such as China and India, need large, efficient plants; (4) countries with large supplies of low-rank coals, such as Germany, need efficient processes to use such low-energy coals.

Some countries have policies that encourage or mandate reduced water consumption—either directly or indirectly. For example, the European Union encourages increased efficiency through its cogeneration directive, which requires member states to assess their national potential for cogeneration, analyze barriers to achieving the potential, and then establish support schemes to achieve the potential. China's Eleventh Five-Year Plan (2006–2010) has an energy strategy that specifies, among other things, that production should be optimized by promoting the development of large-scale, high-efficiency units, and that air-cooled technologies should be used in areas with water shortages.

The United States lacks many of these drivers. There are no government requirements that mandate more efficient plants. The United States has ample supplies of relatively cheap coal, and U.S. water-short areas are not as extensive as in countries such as China, South Africa, and Australia. Often, other countries have deployed water-savings technologies to a greater degree than the United States. The United States can benefit from the early deployment of water-savings approaches in these countries. It can use the results of non-U.S. RD&D in its own efforts to help ensure that the water needs of coal-fired power plants *and* other users can be met with minimal impacts on energy production or water use.

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1 INTRODUCTION

This report was funded by the U.S. Department of Energy's (DOE's) National Energy Technology Laboratory's (NETL's) Existing Plants Research Program, which has an energy-water research effort that focuses on water use at power plants. This study complements the Existing Plants Program's overall research effort by evaluating water issues that could impact power plants. Across the globe, abundant coal reserves provide accessible energy resources and maintain price stability. Coal also contributes to the economic and social development of many coal-producing countries, including China, India, Australia, South Africa, and the United States. In late 2010, total worldwide installed coal-fired generation capacity was about 1.7 million megawatts (MW) (Table 2). The International Energy Agency (IEA) (2008) reports that coal will continue to be an important energy source for decades to come, due to its abundance, availability, and lack of competitive large-scale alternatives. DOE's Energy Information Administration (EIA) reports that coal-fired generation accounted for 42% of world electricity supply in 2007; by 2035, its share is expected to increase to 43% (EIA 2010).

Table 2. Coal-Fired Generation Capacity, 2010

Country	**Coal Capacity (MW)**	**% of World**
China	650,000	38
United States	350,000	21
Russia	78,000	5
Germany	60,000	4
Japan	40,000	2
South Korea	35,000	2
Other Countries	487,000	28
Total World	1,700,000	100

Source: International Power Engineer 2010

It is widely recognized (USGS 2004; NETL 2009a, d) that coal-fired power plants use and consume huge quantities of water. In the United States, water consumption by all users is projected to increase by about 7% between 2005 and 2030, while water consumption by coal-fired power plants is projected to increase by about 21% over the same period (Elcock 2010). In some water-stressed areas of the United States, water use by coal-fired power plants competes with that of other users. Without actions to decrease freshwater consumption by coal-fired power plants, the ability to meet power demands with existing water supplies could become a major political, technical, and economic challenge for the nation. In many other countries, these problems are often exacerbated by water shortages due to overuse of groundwater, changes in rainfall patterns, and contamination of good-quality water.

Faced with these realities—large and increasing amounts of coal-fired power generation and reduced freshwater availability—policy makers, engineers, and managers will need to implement water-savings approaches to avoid potentially serious conflicts between coal-fired power production and water supply. NETL has supported significant research into this area (see http://www.netl.doe.gov/technologies/coalpower/ewr/index.html) for the United States. This report presents information on how other countries are addressing the coal-water issue—either directly (e.g., by installing dry cooling technologies) or indirectly (e.g., by increasing power plant efficiencies, which decreases water consumption because less energy and therefore less water is needed to produce the same amount of electricity). Information about water-reducing approaches at coal-fired power plants in other countries can be used to help direct near- and mid-term water-consumption R&D activities in the United States. This report summarizes the RD&D status of approaches for reducing freshwater consumption by coal-fired power plants outside the United States that could be applied to reducing water consumption at new and existing U.S. power plants.

Information contained in this report is derived from literature and Internet searches, in some cases supplemented by communications with the researchers, authors, or equipment providers. Because few entities outside the United States conduct (or release publicly) R&D at the level supported by NETL, and because there are few technical articles on the approaches being used, much of the information in this report comes from the trade press and other non-peer-reviewed references.

The report contains three more chapters. Chapter 2 summarizes, for several countries where coal is a significant fuel source, the status of and projections for coal-fired power generation, water-related concerns, and general approaches for reducing freshwater use at coal-fired power plants. Chapter 3 summarizes several approaches for reducing water consumption that have been observed in other countries. These approaches include some that have been fully deployed for several years, some that have been deployed relatively recently, and some that are in the R&D stage. In some cases, these approaches are also being implemented in the United States, but to a much lesser degree. For each approach, information regarding development status, drivers, costs, and deployment incentives and constraints (where available) is included. Chapter 4 provides conclusions. The report does not address decision criteria regarding the implementation of various approaches, because these criteria will depend on plant- and location-specific conditions that are beyond the scope of this study.

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2 COUNTRIES WITH SIGNIFICANT COAL-FIRED GENERATING CAPACITY

This chapter provides the context for adopting various water-reducing approaches in other countries. For nine countries (Germany, the United Kingdom, Denmark, Italy, China, Australia, South Africa, Japan, and India), it summarizes information on the importance of existing and projected coal-fired power production, water supply concerns (if any), and approaches for reducing freshwater consumption by coal-fired power plants in that country. Chapter 3 provides details regarding these approaches and country-specific examples of how and where many of them are used.

2.1 EUROPEAN UNION

About 30% of the electricity generated in the European Union is coal-based. In some member states, for example Germany, coal accounts for nearly 50% of total power generation. Many European Union countries need coal-based power generation to guarantee a secure supply of energy. With rising demand, high oil and natural gas prices, concerns over energy security, and an aversion to nuclear energy, coal is expected to play a major role in maintaining energy security in the European Union. Europe produces about 315 million tons of coal annually, or about 8% of the world's production, and can therefore cover a significant percentage of its coal demand from its own resources (Vattenfall 2008). Between 2008 and 2013, European countries are expected to build about 50 new coal-fired power plants (Rosenthal 2008). Coal-water situations in selected European countries are highlighted below.

2.1.1 Germany

Germany's electricity generation comes from hard coal (about 24% of total generation), lignite (about 25% of total generation), nuclear (22%), gas and oil (13%), and renewables (14%). Although the country plans to increase the share of renewable energy to 30% by 2020, conventional sources will still provide about 70% of generation. Because Germany has large coal deposits, coal-fired power plants will provide a significant portion of the country's electricity for the next several years. The average efficiency of coal power plants in Germany is 38% (worldwide it is 30%) (CCSD 2006). Germany's coal-fired power plants are aging, and it is estimated that about 40,000 MW of capacity will need to be replaced between 2010 and 2030 (Schilling 2005). New, efficient plants are replacing old, inefficient ones. Increased use of coal-fired power is expected, and new, highly efficient power plants are already operating in central and eastern Germany. For example, the world's largest brown-coal power plant opened near Niederaußern in 2002. The 965-MW facility has an efficiency rating of more than 43% (compared with a 600-MW block built in 1974 with an efficiency rating of 35%), and plans call for efficiency to be raised to over 50% by (1) increasing the steam temperature, and (2) implementing a new, energy-efficient coal-drying process (Siemens 2004). Ultra supercritical plants are also being deployed in Germany. The 800-MW hard-coal-fired power plant in Lunen Germany is an advanced ultra supercritical plant designed to have a net efficiency of about 46% (Cziesla et al. 2009).

2.1.2 United Kingdom

Power generation in the United Kingdom (UK) is provided by natural gas (40%), hard coal (35%), nuclear power (16%), hydropower and renewables (6%), and other (3%). The UK has large coal, oil, and natural gas supplies. The UK's coal-fired power plants, which were designed more than 30 years ago, use subcritical combustion processes with efficiencies of about 36–39%.

2.1.3 Denmark

Until the early 1990s, coal was Denmark's dominant fuel for electricity generation. Today about 50% of the country's electricity is generated from hard coal, 20% from gas and oil, 20% from wind, and the rest from other renewable resources. Denmark has oil and gas, but no domestic coal reserves. The coal-fired power plants commissioned since the 1980s were designed for supercritical operation with high efficiency ratings. Today, six supercritical and two ultra supercritical pulverized coal plants operate in the country.

2.1.4 Italy

Roughly 13% of the electricity generated in Italy is from coal. Most is generated by gas (56%) and oil (13%), but because these fuels are relatively expensive, interest in increasing the share of coal-fired generation is growing. As a consequence, oil-fired units are being converted to coal units, and old coal-fired units are being replaced with more efficient new ones that use ultra supercritical technology. By 2013, coal is expected to provide 33% of the power generated in Italy (Rosenthal 2008).

2.2 CHINA

China's growing economy is requiring significant increases in electrical generation capacity. Over the past few years, the country has added an average of 70,000 MW of generating capacity (roughly equal to the entire generating capacity of France) each year (Oster 2009). Reports indicate that China is building a new coal-fired power station every 10 days and that supercritical technology already exists in more than 20 units throughout the country (Callick 2008).

Eighty percent of China's electricity is produced by using coal. China is the world's largest producer and consumer of coal, and many of China's large coal reserves have not been developed. The country ranks third in the world in terms of coal reserves, after the United States and Russia, with 13% of the world's total (EIA 2011). Because of the large amount of reserves, coal is expected to continue to be the dominant fuel for power generation, even as other cleaner fuels increase market share. Of the nearly 1 million MW of coal-fired generation expected to be added worldwide in the next 25 years, China's contribution is projected to be 737,000 MW. As of late 2010, coal-fired power plant capacity in China was estimated to be 646,000 MW, and by 2011, China is projected to have more coal-fired capacity than the U.S. and Europe combined (International Power Engineer 2010).

While China is the world's largest producer and consumer of coal, it is also the world's third driest country (Schneider 2010). By 2030, China's annual water demand is projected to reach 818 billion m^3 (about 216 trillion gallons), of which about one-third would be for industrial demand driven by thermal power generation, about one-half for agriculture, and the remainder for domestic use (McKinsey & Company 2009). (For comparison, total water withdrawals in the United States in 2005 were roughly 150 trillion gallons [USGS 2009].) Estimated water supplies in China for 2030 are about 619 billion m^3 (about 164 trillion gallons), meaning that by 2030 demand would exceed supply by about 52 trillion gallons. Significant industrial and domestic wastewater pollution makes the "quality-adjusted" supply-demand gap even larger—21% of available surface water resources nationally are unfit even for agriculture (McKinsey & Company 2009).

Since 1953, the Chinese government has implemented a series of Five-Year Plans that establish the blueprint and targets for national economic development. China's Eleventh Five-Year Plan (for the period 2006 to 2010), which has been described as "of turning point significance" (Fan 2006) contains an energy strategy that includes the following elements:

- Conservation and efficiency are priorities.
- Coal will be the primary fuel.
- Production should be optimized by
  - Promoting the development of thermal power with the adoption of large-scale, high-efficiency units;
  - Constructing large-scale ultra supercritical power stations;
  - Using air-cooled technologies in areas with water shortages;
  - Promoting clean-coal generation technology; and
  - Upgrading low-efficiency coal-fired boilers.

Recognizing concerns about increased coal consumption and its impact on the environment, China's National Development and Reform Commission (NDRC) commissioned a 5-year project (2005–2010), Environmental Protection in the Energy Industry, to help address these concerns. The project specifically addresses reducing water consumption by thermoelectric power plants. According to the project description, "Chinese coal-fired power plants consume on average 15% more coal than plants in Germany and their water consumption is significantly higher" (see http://www.gtz.de/en/themen/18074.htm). Chinese partners participate in symposiums, workshops, seminars, and study trips on energy and environmental protection policy, with a focus on coal and electricity; technical staff undergo on-site training in efficient and environmentally sound power plant processes in the framework of specific process optimization. Results achieved to date include, but are not limited to, the following:

- Water-saving measures implemented at two pilot power plants in Shandong Province are expected to reduce annual water use by a total of 16 million m^3 (4.2 billion gallons), which is equal to the annual water use of 390,000 people in this region.
- Power plants and flue gas cleaning plants operate more effectively and have a longer serviceable life.
- A "Cleaner Production Handbook" is being compiled that will serve as a guideline to power plant management and staff on efficient, environmentally sound, and economic operation.

In January 2007, China adopted a policy of increasing energy-sector efficiency by closing small, inefficient coal-fired power plants and preventing the construction of new similar ones. Between 2007 and 2011, more than 50,000 MW of small-scale, coal-fired units were scheduled to be closed. As of July 2009, China had already closed 54,000 MW of small, inefficient plant generating capacity, and China's National Energy Administration forecasts that another 8,000 MW will be removed in 2011 (EIA 2011). Between 2011 and 2020, many plants between 100 and 200 MW will also be closed. As a result, the International Energy Agency (IEA) estimates that by 2011, 80% of China's coal-fired power plants will be modern plants above 300 MW in capacity and that by 2020, 90% will be above 300 MW (Seligsohn et al. 2009). In early 2006, plants with capacities below 100 MW composed 30% of China's total generating units. In 2009, these plants composed 14% of the total. Today, generating units with capacities greater than 300 MW now account for 64% of all plants operating in the country. New coal-burning plants are being built at a rate of 70,000 MW per year, and most of the new facilities are significantly more efficient than those they replace (Chan 2009).

In 2008, China's National Development and Reform Commission adopted a standard requiring all new coal-fired power plants use "state-of-the-art, commercially available or better" technology. Where possible, new supercritical and ultra supercritical units are to have capacities of at least 600 MW. As a result, today most of the world's most efficient coal-fired power plants are being built in China. This trend contrasts with that in the United States, where new coal-fired power plants built in the 1980s and 1990s were less efficient than those built in the 1970s (Seligsohn et al. 2009).

As a consequence of the policies set by the national government regarding increasing efficiency and of the severe water availability problem in coal-producing (and electricity-generating) areas, China is implementing several indirect (e.g., by increasing efficiency) and direct approaches to reducing freshwater consumption. Examples include the following:

- Increased use of supercritical and ultra supercritical units. As explained in Section 3.1, ultra supercritical plants are more efficient than supercritical plants, which are more efficient than subcritical (or traditional) coal-fired power plants.
- Dry cooling.
- IGCC.

- Desalination. China has been using desalination to provide process water to power plants, thereby allowing plants to use river water with high dissolved solids contents. It has built desalination plants that use low-energy technologies and waste heat from power plants (see Section 3.10).

2.3 AUSTRALIA

With ample coal supplies, Australia is the world's fourth largest producer and the world's leading exporter of coal (EIA 2011). In 2007, coal-fired power plants supplied 70% of Australia's electricity generation, and coal is expected to continue to supply more than half of its total generating capacity through 2035 (EIA 2010). At the same time, water is a critical issue in Australia, where 80% of the land receives fewer than 24 inches of rainfall per year. To a large extent, the availability of water controls the density of settlement and location of power plants, and water resources in many highly populated areas have become or are becoming unreliable (Knights 2006). In addition, most large sources of groundwater that would be suitable for power plant cooling are restricted or are not available for environmental reasons. Approaches for conserving freshwater at Australia's coal-fired power plants include the following:

- Efficiency improvements, such as efficient supercritical boiler technology; turbine upgrades; and replacement of low-duty pumps, motors, turbine cylinders.
- Large-scale coal drying, including mechanical thermal expression, where coal is heated in a pressurized vessel and water is mechanically squeezed from the coal.
- Dry cooling technologies, which use up to 90% less water than conventional wet cooling technologies.
- Recycling. Most power plants in Australia use some type of water recycling—typically within the power plant—in the form of reclaimed storm water or treatment and reuse of cooling tower blowdown water. Some plants use, and others are investigating the use of, recycled water from sewage treatment plants (Knights 2006).

2.4 SOUTH AFRICA

Coal accounts for about 85% of South Africa's electrical generation capacity. The country has abundant coal reserves (95% of African reserves and 4% of world reserves [EIA 2011]). In the early 1990s, South Africa experienced an electricity supply overcapacity, and several power plants were mothballed. Since then, rapid growth has strained the country's power infrastructure, which is increasingly struggling to cope with demand. To help address this need, the state electricity company is returning to service three coal-fired power stations (Camden, Grootvlei, and Komati) with a combined capacity of 3,800 MW. It is also building a new 4,800-MW power plant (Medupi), which is to begin generation in 2012, and a 5,400-MW plant (Bravo), which is to start generating power in 2013 (EIA 2011).

To minimize coal transportation costs, many of South Africa's coal-fired power plants are located near coalfields. Because these coal fields are located in the dry regions of the country, water for plant operations must be transferred from neighboring regions. Eskom, the state-owned electric utility, is one of largest consumers of water in South Africa—accounting for about 1.5% of the country's total water consumption (Pather 2004).

During the past 20 years, a number of technical and nontechnical approaches for reducing water consumption have been implemented in South Africa's coal-fired power plants. Between 1989 and 2003, the amount of electricity produced increased by 62%, but the corresponding increase in water consumption was only 22%. This improved water use efficiency translated to a savings of 1,020 million m^3 over the time period (Pather 2004). Between 1994 and 2006, the quantity of energy produced increased by 38% compared to an increase in water consumption of 41%. Since 2004, because wet-cooled units are used at the return-to-service sites, water consumption has been increasing faster than electricity production.

Water savings approaches for coal-fired power plants in South Africa include highly efficient supercritical designs, air-cooled condensers, advanced control systems, and desalination. In addition, over the past 40 years, South African power plants have partnered with the South African Department of Water Affairs and Forestry (by contributing funds or by joint involvement in projects) to help develop an extensive network of pipelines and dams aimed at providing a secure water supply to the power plants and their associated mines.

2.5 JAPAN

Japan has the third-largest installed electricity generating capacity in the world (about 279,000 MW in 2007). Coal-fired generation accounts for about one-fourth of this generation (EIA 2011). Because Japan imports all of its fuel, for years, power plants in that country have been designed to be highly efficient. Since the late 1980s and early 1990s, inlet and reheat temperatures at the coal-fired power plants have been 1,100°F (593°C); in the United States, plants operating at these temperatures were introduced in about 2005 (Hansen 2007).

2.6 INDIA

India suffers from a severe shortage of electrical generating capacity. The overall gap between demand and supply is about 11% and the gap between peak demand and supply is about 14%. In some states, the gaps are as high as 19% and 30%, respectively. In 2007, India had approximately 159,000 MW of installed electrical generating capacity (EIA 2010), and that capacity is expected to more than double over the next decade (Revkin 2008). India is both the third-largest consumer and third-largest producer of coal in the world (EIA 2011). Coal-fired power plants generate roughly 70% of the electricity produced in the country, and coal is expected to remain the dominant energy source in India through at least 2050. The World Bank has estimated that about one-third of the coal-fired power plants in India are old and inefficient (Sibley 2009).

Government policy in India is to increase the gross efficiency in power generation. New plants should adopt technologies that improve their gross efficiency from the prevailing 36% to at least 38–40% (Gaba 2009). The government of India plans to help narrow the power deficits by installing Ultra Mega Power projects—large, efficient, coal-fired units that use advanced supercritical steam parameters, each with a capacity of 4,000 MW or above. As of November 2010, 16 such power projects had been planned in nine different states. The government is also supporting research and development of IGCC and supercritical technologies. Old plants are to improve efficiency through renovation and modernization and improved operations and maintenance. The government is also mandating the retirement of inefficient coal-fired power plants. Table 3 shows examples of efficiency gains due to renovation and modernization. While not targeted at reducing water consumption directly, improved efficiency will lead to reduced water consumption.

Table 3. Expected Efficiency Gains from Renovation and Modernization

System	Improvement	Net Efficiency Gain (% points)
Combustion System	Pulverizer and feeder upgrades	0.3
	Air preheater repair or upgrade	0.25
	Soot blower improvements	0.35
	Instrumentation and controls	0.2
Steam Cycle	Feedwater heater repairs	0.4
	Heat transfer tube upgrades	0.6
	Steam turbine blades	0.5
	Cycle isolation	0.5
	Condenser repairs	0.4
Combined total		3.5

Source: Gaba 2009

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3 WATER SAVINGS APPROACHES

This chapter describes several approaches for reducing freshwater consumption at coal-fired power plants in countries outside the United States. These approaches include those that have been implemented or are being implemented and those for which research is underway. For each approach, the following information is provided: an explanation of how the approach reduces freshwater consumption, its status in terms of development and deployment, a technical description, potential implementation concerns (if any), cost information (where available), and examples from one or more countries in which it is being used. Appendix A summarizes the approaches, their development/implementation status, challenges, and reported benefits.

3.1 EFFICIENCY IMPROVEMENTS

The efficiency of the thermodynamic process at a coal-fired power plant refers to the amount of energy input to the cycle that is converted to electrical energy. The greater the electrical output for a given amount of energy input, the higher the efficiency. Higher efficiencies mean that less energy, and consequently less water, is required to produce a given amount of electricity. Successful efforts to increase coal-fired power plant efficiency translate into reduced water consumption. Ratification of the Kyoto Protocol by many European and other countries to reduce CO_2 emissions—while not a direct driver for reducing water consumption—has become a powerful driver for increasing plant efficiency. This is because one of the primary ways to reduce CO_2 emissions from coal-fired power plants is to make those plants more efficient—by developing and deploying new technologies, by retrofitting current technology to older operating plants, or by replacing less-efficient plants with more-efficient plants.

The efficiencies reported in this document should not be considered absolute. This is because efficiency can be based on HHV (higher heating value) or LHV (lower heating value), and in many cases the efficiencies reported in the literature do not indicate whether they are HHV or LHV. HHV assumes that the water is in a liquid state, and LHV assumes that the water is in a gaseous state. LHV produces a higher efficiency value (up to 10% higher depending on the water content of the coal). In Europe, thermal efficiency is generally reported on the basis of the LHV, while in the United States it is generally reported on the basis of the HHV of the coal. As a result, European reported efficiencies can be 5–10% higher than comparable plants in the United States, depending on fuel constituents (Peltier 2010). Many factors affect power plant efficiency. For example, plants with emissions control devices use energy to operate those controls, thus reducing overall efficiency. NETL (2008) estimates that by operating emissions control equipment, average plant efficiency is reduced by about 1 percentage point or less. Other factors that affect efficiency include type and quality of coal, type of cooling system, and perhaps most importantly, the operating steam parameters (temperature and pressure). These factors are summarized below.

3.1.1 Effect of Coal Type on Efficiency

The efficiencies of plants that use lignite (in Europe, brown coal) are lower than those that use hard-coal equivalents. The higher water content of brown coal (up to 45%) requires more energy to burn than the harder sub bituminous coal (20–30% moisture), bituminous coal (less than 20% moisture), or anthracite (has less than 15%). The efficiencies of plants that burn brown coal are a few percentage points less than those that use hard coal. The use of waste heat in a special processing facility to evaporate the water content in brown coal will further increase efficiency (see Section 3.3.2).

3.1.2 Effect of Cooling System on Efficiency

There are two main types of cooling—once-through and recirculating with cooling towers. With once-through systems, cooling is achieved simply by running a large amount of water (fresh or salt) through the condensers in a single pass and returning it to the source a few degrees warmer in almost the same amount. There is hardly any onsite consumption, although some extra evaporation occurs offsite because of the warmer temperature of the discharge water. With recirculating systems, water passes through the condenser to the top of the tower, where it is sprayed downward to a collection basin while being cooled by an updraught that carries heat away, mainly by evaporation. As the cooled water is returned to the condenser, the flow that is lost to evaporation must be continuously replaced. In addition, because evaporation concentrates impurities in the water, some bleeding of the blowdown is required, raising the need for replacement water. NETL (2002) studied the effects of cooling water system on power generation and found that the temperature of the water as it enters the condenser can have significant impacts on turbine performance, by changing the vacuum at discharge from the steam turbine. In general, cooler water will create a larger vacuum, allowing more energy to be generated, while warmer water creates a lower vacuum and impedes generation. This effect is known as the "energy penalty." NETL found that the energy penalty associated with converting a 400-MW coal-fired unit using once-through cooling to one using a wet cooling tower was 0.8–

1.5%—meaning that the plant will produce 0.8–1.5% less electricity with a wet cooling tower than it did with once-through cooling, while burning the same amount of coal. NETL found that the penalty for converting the 400-MW plant to a dry cooling tower was 4.2–8.8%. During peak demands, the penalties for conversion increase to 2.4–4.0% and 8.9–16.0% for wet and dry cooling towers respectively. Turnpenny et al. (2010) found similar results; the reduction in overall cycle net thermal efficiency between a plant with once-through cooling and one with a mechanical draft wet cooling tower was about 2 percentage points. Many countries (China, Finland, Japan, Korea South, Africa, Sweden, the UK) use once-through seawater for cooling, and the efficiency of these plants is higher than those in Australia, for example, where warmer conditions prevail and plants are located inland.

3.1.3 Effect of Steam Parameters on Efficiency

In general, the most effective means of improving plant efficiency is to increase the temperature and pressure of the steam. Over the past 30 years, steam temperatures have increased by an average of 2°C per year. Today steam temperatures of the most efficient fossil power plants are in the 600–610°C range (Enel 2010). Increasing the steam temperatures remains an active research area in the United States and abroad. The evolution of increasing steam parameters is reflected in three types of plants: subcritical, supercritical, and ultra supercritical. Each is summarized below.

Subcritical

In subcritical (also referred to as traditional or conventional) coal-fired power plants, which generally operate at temperatures below 538°C (1,000°F) and pressures below 2,400 psi, water and steam coexist in two phases. Efficiencies of subcritical plants are generally about 30–35%. Most of the plants built before 1970 are subcritical plants, and subcritical technology has prevailed for the past 60 years. During this time, the technology has improved incrementally, by increasing temperatures and pressures. Subcritical plants are relatively simple and reliable, have low costs and low technical risks, and are still being built today.

Supercritical

When the temperatures and pressures are increased above the critical points of 374°C (705°F) and 3,208 psi, the water and steam become indistinguishable, and the cycle is considered supercritical. Supercritical plants, which use extremely hot steam and operate at temperatures of about 538–566°C (1,000–1,050°F) are about 38–42% efficient. Water use by supercritical plants is about 13% lower than that by subcritical plants (Table 4). This is because the lower steam pressure in the subcritical plant means that less energy can be transferred from the boiler to the turbine, so more steam flow, and therefore more cooling water flow, is required to generate the same amount of electricity (NETL 2009a). In addition, supercritical plants, which use once-through boilers (subcritical plants use drum type boilers), do not have boiler blowdown. This means that less condensate needs to be fed into the water steam cycle and less waste water will require disposal (Susta and Seong 2004).

Table 4. Water Use by Subcritical and Supercritical Coal-fired Power Plants (gal/MWh)

Water Use	Subcritical	Supercritical
Water Withdrawal		
Cooling Tower	590	515
Boiler Feed water	8	8
Flue Gas Desulfurization	68	59
Total	667	582
Water Consumption	520	450

Note: Based on a cooling water system using wet recirculating cooling towers.
Source: NETL 2009a

Supercritical technology is well developed, and many plants built in the past decades, particularly in Europe and Asia, use supercritical technology. The 900-MW Callide C power plant in Queensland, Australia, which opened in 2001, was the first plant in that country to use supercritical boilers. The highest concentration of supercritical plants is in Russia and the former Eastern Bloc countries, where more than 240 supercritical plants provide about 40% of the electricity needed in those countries. Advanced supercritical designs are being used in several Asian plants under construction in China, South Korea, and Taiwan. In China, supercritical plants are being built at a rate of about one per month (Wagner 2009). The relatively small number of supercritical plants relative to subcritical plants in the United States can be attributed in part to the relatively low cost of U.S. coals, which limits the justification for the higher capital costs associated with higher-efficiency supercritical plants. In countries where fuel represents a higher fraction of the total cost, supercritical plants lead to lower overall costs (Susta and Seong 2004).

Challenges to using supercritical technology include high thermal stresses and fatigue cracking in the boiler sections, higher maintenance costs, and lower operational availability and reliability of steam turbines compared to subcritical units. Supercritical units are also more sensitive to feedwater quality. However, supercritical units are more efficient and more flexible than subcritical plants. Compared with subcritical power plants, supercritical power plants can maintain higher efficiency at rather low load, and the expected lifecycle costs of supercritical power plants are lower than those of subcritical power plants. In the second half of last decade, supercritical technology clearly prevailed in the Organization for Economic Co-operation and Development (OECD) countries, where more than 20,000 MW of supercritical capacity was installed, compared with 3,000 MW of subcritical capacity. Various collaborative programs (e.g., THERMIE 700 EUROPE, COST 522 EUR) have pushed the technical envelope of supercritical technology in Europe (Susta and Seong 2004).

Ultra Supercritical

Increases in the steam parameters beyond those used in supercritical plants produce ultra supercritical steam. Ultra supercritical plants operate at steam temperatures greater than 593°C (1,100°F) and at pressures that are typically 3,500 psi or higher. A major challenge for deploying ultra supercritical steam technology is the development of suitable alloys for use in the ultra supercritical steam turbines (Susta and Seong 2004). The turbine designs for supercritical plants are similar to those for subcritical plants, but the higher steam temperatures and pressures in the ultra supercritical plants means that the wall thickness and the materials used in the high-pressure turbines must be able to withstand these higher operating conditions. In addition, higher steam temperatures encountered in supercritical and ultra supercritical units make corrosion problems more critical, meaning that coals with corrosion potential are less suitable for supercritical and ultra supercritical plants (Susta and Seong 2004).

Ultra supercritical plants were placed in commercial operation in the United States and the UK in the 1950s, but mechanical and metallurgical problems required the parameters to be downrated to less than 600°C. Most of the problems were due to the use of austenitic steels for thick-section components operating at high temperatures. (Austenitic steels have low thermal conductivity and high thermal expansion, resulting in high thermal stresses and fatigue cracking.) Ultra supercritical plants have been operating since the late 1960s, but reliability issues have limited their widespread commercialization. Efficiency improvements in ultra supercritical plants include numerous incremental improvements, such as advances in steam turbines, beyond those gained through increased temperature and pressure.

Supercritical and ultra supercritical plants that operate with steam conditions up to 600°C (main heat)/620°C (reheat) and 4,355 psi and with efficiencies of about 42–47% exist in China and Japan, and they are being developed in Europe. Two examples illustrate the application and development of ultra supercritical plants in Asia and Europe.

- *Isogo Power Station—Japan*. At this ultra supercritical plant in Tokyo, state-of-the-art materials such as 10% chrome steel for tubes are used to withstand the high temperatures and pressures. The 10% chrome steel is characterized by up to 30% higher creep rupture strength compared with the 12%-chrome materials used previously (according to material creep laws, components that are hot and under tension are subject to inelastic changes) (Quinkertz et al. 2008). In 2008, after 48,000 equivalent operation hours, inspections of the highly stressed components of the turbine indicated that the steam turbine was in very good condition. Blades, casings, and rotors exposed to high steam parameters showed far fewer creep effects, oxidation, and abrasion than expected after 48,000 equivalent operation hours. Such information helps to optimize new components and allows a better assessment of the design limits (Quinkertz et al. 2008).

- *Trianel Power Project—Germany.* This 800-MW, hard-coal-fired power plant is under construction in Lünen, Germany. Its projected 45.6% net efficiency (LHV basis) comes from high steam parameters (600°C main heat/610°C reheat and 3,915 psi), optimized processes, and highly efficient energy conversion in key plant components. Construction of the ultra supercritical plant began in August 2008, and completion is projected for the fall of 2012. Capital cost requirements for the plant and its associated infrastructure are estimated at €2.4 billion (about $3.3 billion U.S.). The plant will burn low-sulfur bituminous coal and will use wet flue gas desulfurization equipment and a natural draft wet cooling tower. The turbine will be based on a reference power plant for advanced steam power plants, which uses modular pre-engineered reference power plant designs to reduce investment costs and provide flexibility to accommodate specific needs. More details on the technology are available from Cziesla et al. (2009).

It is generally assumed that supercritical plants will be about 2–3% more efficient than subcritical plants, and that ultra supercritical plants will be about 3–6% more efficient than subcritical plants (Susta and Seong 2004). Alstom (a leading power generating company based in France that has built 66 supercritical plants since 1957 with a total capacity of 44,000 MW) has calculated that when comparing supercritical and ultra supercritical plants to a reference subcritical plant and considering steam conditions only,

- A supercritical plant operating at 538/566°C (1,000/1,050°F) and 3,515 psi is 3.2% more efficient than a new-build subcritical plant operating at 538°C (1,000°F) and 2,400 psi;
- American Electric Power's John W. Turk, Jr., ultra supercritical power plant operating at 599/607°C (1,110/1,125°F) and 3,515 psi (scheduled to come online in 2012) will be 6.2% more efficient than the subcritical plant;
- Its most efficient ultra supercritical plant, operating at 600/621°C (1,112/1,150°F) and 4,135 psi is 7.3% more efficient than the subcritical plant; and
- Tomorrow's ultra supercritical plant, operating at 699/721°C (1,290/1,330°F) and 5,075 psi will be 14% more efficient than the subcritical plant (Klotz et al. 2009).

It also suggests the following rules of thumb to determine the benefits of ultra supercritical operating conditions versus subcritical steam turbine conditions:

- Raising the main pressure by 100 psi improves the plant net efficiency by about 0.16%.
- Increasing the main steam temperature by 5.6°C (10°F) improves plant efficiency by 0.16%.
- Increasing reheat steam temperature by 5.6°C (10°F) improves plant efficiency by approximately 0.13%.
- A 5.6°C (10°F) increase of the final feedwater temperature improves plant net efficiency by about 0.1% (Klotz et al. 2009).

China has imported the technologies to enable construction and operation of ultra supercritical plants. By the end of 2006, China had more than 40 operating supercritical and ultra supercritical units, totaling 30,000 MW of capacity. Three of those units were ultra supercritical, each with a capacity of 1,000 MW. It is estimated that more than 150 supercritical or ultra supercritical units, with capacities of 600–1,000 MW, have been installed, are undergoing construction, or have been ordered (Qili 2007). A relatively recent example is the Shanghai Waigaoqiao No. 3 Power Generation Co., whose two 1,000-MW ultra-supercritical coal-fired power generating units supply about one-fourth of Shanghai's electricity. Commissioned in 2008 and built at a cost of 8.5 billion Yuan (about $1.2 billion U.S.), the plant reportedly achieved a peak efficiency rate of 46.3% in 2009 (Areddy 2010).

More than half of coal-fired capacity now under construction is based on subcritical technology, with the remainder mainly supercritical. Ultra supercritical technology is projected to become more widespread in the OECD after 2020 (IEA 2008).

Beyond Ultra Supercritical

Efforts are underway to develop systems that operate at higher temperatures (700–760°C) and pressures (5,060 psi) with efficiencies of 50% or more. Such systems would require design modifications and the use of super alloys for all high-temperature parts of the high-pressure and intermediate-pressure turbines. Current state-of-the-art boiler materials limit the boiler outlet steam temperature to about 600°C. The 700°C boiler of the future will need to use nickel-based alloys for the superheaters, turbines, and some parts of the water wall. Today, high-strength ferritic steels for thick-walled components are available for temperatures nominally up to 620°C, and advanced austenitic stainless steels devoted to superheater and reheater tubing are available for long-term service at temperatures nominally up to 650°C (Enel 2010). To raise steam temperatures by 50–100°C over the next 10 years will require the development of manufacturing and welding procedures to enable application of existing or new high-temperature materials (Enel 2010). See Susta and Seong (2004) and Müller (2008) for more information on materials and steam turbine requirements needed for the successful implementation of plants with higher steam parameters.

The Europeans have conducted significant research and development of technologies aimed at increasing efficiency through higher steam parameters—that is, from 600°C to 700°C. Because of the enormity of this task, producers, plant manufacturers, and energy suppliers have formed a number of consortia that are coordinating the development of the 700°C technology. Some of these are highlighted below.

- *KOMET650 (650°C test rig).* In the Komet 650° test rig project (1998–2002), several German companies and institutes investigated materials that could withstand temperatures of 650°C (50°C higher than usual) and pressures of 4,060 psi, which would enable a 47% efficiency rate. To this end, a high-temperature test facility was built at a

Westphalia, Germany, power plant, where nickel-based materials were tested over 16,500 hours of full-capacity operations (Siemens 2004).

- *North Rhine–Westphalia 700°C Power Plant (NRWPP700).* This effort was a pre-engineering study by ten European energy suppliers that focused on technical design concepts (no building or testing) for the boiler, pipe work, and other components of a 500-MW reference power plant designed for an inland location and operating with steam parameters of 4,205 psi and 600/620°C and achieving a net efficiency of 46% (Rosenkranz and Wichtmann 2005).

- *Advanced supercritical power plant operating at 700°C (Advanced 700°C Power Plant, AD700).* Originally started by the Danish power industry, the European project AD700 became an initiative of European Association of Power and Heat Generators in 2004. The purpose of AD700 was to prepare, develop, and demonstrate the next generation of pulverized coal plants using advanced steam parameters. The goal was to achieve operations at 700°C and 5,075 psi, and to increase efficiency from 47% to 55% for a 400- to 1,000-MW plant located on the sea and burning bituminous coal. Forty partners (e.g., European manufacturers and power generators) from 13 countries are working together on this four-phase project to develop proven technology through new materials and to improve efficiency at competitive costs. The four major phases are as follows:

    1. Development and demonstration of materials (1998–2004);
    2. Demonstration of fabricability (2002–2006);
    3. Component demonstration (2004–2009); and
    4. Construction and operation of a full-scale 400-MW demonstration plant, with commercial establishment around 2015.

    Phases 1 and 2 showed positive outcomes, and phase 3 began in 2004 with the installation of a component test facility in the Scholven power plant in Gelsenkirchen, Germany. The facility, named COMTES700, included demonstration of fabricability and operation of several components at 700°C. Between 2005 and 2009, the 30-year-old F Block at the plant used components (a test boiler, main steam lines, and other components currently operating at temperatures of 700°C) that could one day be used in a 700°C power plant. The old turbine was not affected by the tests; after passing through the test section, the steam was cooled to 520°C to avoid potential damage (Müller 2008).

Preparation for the full-scale demonstration plant (Phase 4) began in 2006 and was scheduled for completion in 2010. E.On, a major public utility company in Europe, has expressed interest in building a full-scale (550-MW) demonstration plant based on AD700 technology on the coast in Wilhelmshaven, Germany (Varley 2010). Named Kraftwerk 50+, the project is billed as the first coal-fired power plant in the world with a net efficiency greater than 50%. (Currently, the average efficiency of hard-coal-fired power plants in Europe is about 36%.) To achieve the 50% efficiency rate, the 700°C power plant will use preheated combustion air. It will also use seawater from the North Sea, where necessary quantites of low-temperature cooling water are available year round. The plant is projected to begin operations in 2014. To date, an estimated €1 billion (about $1.4 billion U.S.) have been invested in the project (E.On 2011).

3.2 ALTERNATIVE COAL-FIRED TECHNOLOGIES

While research is underway to improve the efficiencies of traditional coal-fired power plants (including supercritical and ultra supercritical), other coal-burning technologies for power generation—which are more efficient, and therefore consume less water—are also being used and/or researched. These include cogeneration, IGCC, and coal-fired gas turbines. Each of these approaches is discussed in the following sections.

3.2.1 Cogeneration

Cogeneration, also known as combined heat and power (CHP), is an efficient, technically mature approach for generating electricity and providing useful heat. In a CHP system, high-temperature, high-pressure steam from the boiler passes through a turbine to produce power. Then, rather than being expanded in the turbine to the lowest possible pressure and then discharged to the condenser, the steam is exhausted at a temperature and pressure that is suitable for heating purposes. Designed to provide operational flexibility, CHP systems can be run to provide power only (for example, when district heating is not required) or to provide a consistent supply of steam (for example, in an industrial facility) while also producing power. Cogeneration reduces overall primary energy use (and associated water consumption) by about 15–35% when compared with traditional plants that only produce electricity. Cogeneration plants can use a variety of fuels. Generally, when coal is used, the plant produces about one-third electric energy and two-thirds thermal energy. (A CHP plant fueled by natural gas produces about half electric and half thermal energy.)

A constraint to the increased use of CHP is the need for an assured, steady demand for the heat produced. If the heat is used for district heating, those needs generally only occur in the winter months. However, in some countries, such as Spain, CHP plants are now being used to provide cooling as well as heating, making trigeneration a way to further increase efficiency. In addition, if the plant supplies district heating, it must be located near a residential area, where siting issues (e.g., visibility, noise) must be addressed.

Cogeneration systems are not new. In the United States, they were used in the early part of the twentieth century at factories that needed both electricity and thermal energy, but by the end of World War II, they could not compete economically with central station plants, and most were closed (Peltier 2010). Today, there are few large-scale coal-fired CHP plants in the United States; most of the U.S. CHP plants are small, distributed generation units that are powered by small gas turbines. The 230 coal-fired CHP installations in the United States average 53 MW in size (Hayes and Newall 2007).

Cogeneration Use Outside the United States

In Europe, utilities routinely build power plants that supply both electricity and thermal energy to local cities and towns, particularly in northern Europe, where high population densities and low average temperatures favor district heating. Cogeneration accounts for about 11% of Europe's total electricity production, and in some countries the share is much higher. Denmark produces 40% of its energy from cogeneration, Finland about 35%, and the Netherlands 30% (Riddoch 2009). While many of the cogeneration plants in Europe use oil, natural gas, biomass, and wood waste, coal is also used, particularly in Finland and Poland.

The European Union has promoted the use of CHP. The European Parliament and Council of Europe Directive 2004/8/EC (the Cogeneration Directive) outlines an enabling policy framework to expand the deployment of cogeneration in member states. Passed by the European Parliament in 2004 with the policy objectives of securing supply and saving energy, the Directive encourages the use of cogeneration in the production of heat and power, by requiring that member states assess their national potential for cogeneration, analyze barriers to achieving the potential, and then establish support schemes to achieve the potential. Reports are required to monitor progress (Riddoch 2009). Since 2004, the climate agenda has added further impetus to the wider use of cogeneration. Recognizing the ability of cogeneration to enable improved efficiency, the Cogeneration Directive codified for Europe what is meant by high-efficiency cogeneration: any plant carrying this status must save a minimum of 10% primary energy compared to separate production of heat and electricity using the same fuel (CODE 2009). European governments have helped to promote cogeneration by disseminating information enacting member state legislation, and by providing sound regulatory environments and financial support. Examples of coal-fired cogeneration plants in Europe include the following:

> *Denmark.* The Avedøre CHP Power Station, located south of Copenhagen, has two units. Unit 1, built in 1990, uses primarily coal, while Avedøre Power Station's Unit 2 can use a variety of fuels: natural gas, oil, straw, and wood pellets. By using the excess heat from the power production for district heating, Avedøre Unit 1 attains an energy conversion efficiency of up to 91% (for both electricity and thermal power). The 415-MW Nordjyllandsværket Unit 3 is an ultra supercritical CHP unit that began commercial operation in 1998. By 2005, it had recorded 50,000 operating hours, with availability at more than 98%. In the power-production mode, the thermal efficiency achieved is 47.2%; in the CHP mode, efficiency is 90% (Poulsen 2005).
>
> *Sweden.* Until the 1960s, the Vartan cogeneration plant in Stockholm produced only electric power, with coal as the primary fuel. When the district heating system was developed in Stockholm, and less-expensive fuel oil became available, the plant was converted to oil. But as the cost of fuel oil increased in the late 1980s, the plant was converted back to coal, and it became the world's first pressurized fluidized bed combined-cycle cogeneration plant. In 1995, when it started to produce cooling, Vartan became a trigeneration plant. The plant has the capacity to generate 435 MW of electricity, 1,760 MW of heat, and 80 MW of cooling (Power-Gen Worldwide 2000).
>
> *Germany.* Germany has several cogeneration units and continues to build more. These include the following:
>
> - The 600-MW Reuter West coal-fired CHP plant, built in 1989 in Berlin, has been retrofitted with state-of-the art process controls to improve combustion efficiencies. The 3,000-MW Janschwalde Power Plant in Eastern Germany is a coal-fired CHP plant that is connected to the grid and pipes heat produced during the electricity generating process to neighboring towns.

- In 2008, plans were announced to build an 800-MW hard-coal-fired CHP plant in Mainz. In addition to producing electricity, the plant will produce 200 MW of district heat for up to 40,000 households and 30 MW of process steam for industrial plants in Mainz. The overall efficiency will be 60%, and that of the power plant will be 46%. The project has an expected completion date of 2013 (Power-Gen Worldwide 2008).

- The new Moorburg CHP plant is under construction on a site that was previously used for electricity generation alone. When it becomes operational, the new power plant will provide about 85% of Hamburg’s electricity needs and 40% of its district heating needs, and will have an electrical net efficiency of 46.5%.

3.2.2 Integrated Gas Combined Cycle (IGCC)

IGCC plants use coal to generate electricity, but unlike traditional coal-fired power plants, which burn coal directly, IGCC plants burn a synthetic gas that is produced by the gasification of coal. In the gasification portion of an IGCC plant, coal (or other solid fuel) is combined with oxygen to produce the synthetic gas (syngas), which is mainly hydrogen and carbon monoxide. After impurities are removed, the hot syngas is burned in a combustion turbine (similar to a natural gas turbine) to generate electricity. The hot exhaust heat from the combustion turbine and some of the heat generated in the gasification process are then used to convert water to steam through a heat recovery steam generator. The steam produced through this heat exchanger then passes through a steam turbine to power another generator to produce more electricity. The dual source of electric power, the combined cycle, is more efficient than a conventional coal-fired power plant, because it reuses waste heat to produce more electricity. Gasification was developed primarily for gas and chemicals production, and its application for power generation is not yet a mature technology. IGCC plants consume less water than conventional plants because the gas turbine, which requires minimal cooling water relative to the steam cycle, produces about 60% of the combined cycle power plant’s entire electrical output (NETL 2009a). Actual water consumption will be determined by the type of cooling system used, but cooling requirements for IGCC plants are roughly 35–40% less than those of pulverized coal plants (Table 5). Current IGCC power plants typically operate with efficiencies comparable to new pulverized coal plants (35–42%), but because they have many processes where efficiency could be improved (turbine design, gas clean-up, and air separation systems), the next generation of IGCC plants is expected to have efficiencies of 40–45%, and over the long term efficiencies could be 45–50% (Wibberly et al. 2006). Today, IGCC plants are much more expensive than pulverized coal plants, but as more IGCC plants are constructed, more experience is gained, and reliability issues are resolved, the costs may decrease.

Table 5. Water Use Factors for Pulverized Coal and IGCC Plants* (gal/MWh)

Water Use	Sub-critical	Super-critical	IGCC (slurry fed)	IGCC (slurry fed) % Change from Subcritical	IGCC (dry fed)	IGCC (dry fed) % Change from Subcritical
Water Withdrawal						
Cooling Tower	590	515	382	–35	320	–45
Boiler Feed water	8	8	5	–37	4	–50
Flue Gas Desulfurization	68	59	0		0	
Gasifier	0	0	19		53	
Total	667	582	406	–39	376	–44
Water Consumption	520	450	310	–40	Not Available	

*Based on a cooling water system using wet recirculating cooling towers.
Source: NETL 2009a

Two IGCC demonstration plants built in the United States as part of DOE's Clean Coal Technology program are still operating. The 262-MW Wabash River Coal Gasification Repowering Project Joint Venture, in West Terre Haute, Indiana, began operations in 1995. Capital costs were $1,680/kW and it operates at 39.5% efficiency (Rosenberg et al. 2004). The 250-MW Polk Power Station in Polk County, Florida, was built on a greenfield site in 1996. Its capital costs were $1,790/kW, and it is 37.5% efficient (Rosenberg et al. 2004).

IGCC plants are in various development stages in other countries as well. Examples include the following:

> *Netherlands.* The 253-MW Willem Alexander Plant was commissioned in 1994. It served as a demonstration plant during its initial years of operation and has been used to test different operating conditions and fuels. Because it uses a dry-feed system, the plant consumes less water than slurry-based systems and has no water discharge (Wibberly et al. 2006). In 2001, the plant began operations as a commercial plant. Unlike the U.S. plants, the Willem Alexander plant includes full integration of the gas turbine and the air separation unit, meaning that the turbine supplies all of the air to the air separation unit, which helps increase efficiency. Capital costs for this plant were $1,750/kW and it is 41.4% efficient (Rosenberg et al. 2004).

Spain. Like the Netherlands IGCC plant, the 298-MW Puertollano IGCC plant in Spain has a fully integrated gas turbine and air separation unit, which enables it to operate at an efficiency of about 41.5%.

China. A demonstration program for IGCC plants in China is well underway. In China, IGCC plants are viewed as high-efficiency plants (50–60%) that use clean coal, conserve water, and can benefit from accumulated design and manufacturing experience (Qili 2007). At least 12 IGCC projects with capacities ranging from 250 to 800 MW are in the planning or feasibility stage (Qili 2007). In 2010, the Asian Development Bank approved a $135-million loan to facilitate construction of a 250-MW IGCC plant in the northern City of Tianjin China (Chada 2010). The $420 million (U.S. dollar) project, scheduled to be completed by 2012, will be the first IGCC plant in a developing country. The Chinese government is also considering rapid implementation of three other IGCC pilot plants—250 MW at Zhejiang, and 400 MW each at Langfang and Yanta, with the goal of demonstrating a critical mass of IGCC projects using different gasifier technologies and plant sizes, which will be used to identify a pathway for commercial IGCC deployment. The project is supported by Ministry of Science and Technology, and National Development and Reform Commission, and it is listed as one of the major projects for scientific development in the Eleventh Five-Year-Plan under the National High-Tech R&D Program (Asian Development Bank 2008).

3.2.3 Direct Firing of Gas Turbines with Coal

Ultra clean coal is a high-purity, chemically cleaned coal that can be fed directly into internal combustion engines such as gas turbines and diesel engines to generate electricity with high efficiency. The development of ultra clean coal as a substitute for fuel oil began in Australia in the 1980s. An important challenge to the concept of burning fine coal in gas turbines is that the ash that remains after the coal is burned can cause the erosion and abrasion damage to the turbine blades. Australian researchers have developed a process that produces coal with ash levels of about 0.5–1.0%. In the process, coal ground to 1 millimeter is treated with hot caustic soda that attacks the quartz and converts clay into an acid-soluble form. The coal is then washed in dilute acid, which removes more minerals, and a final washing removes more salts. After it is processed, the coal is milled to less than 10 microns in size and is then injected into a conventional gas turbine. Residual ash particles are less than 5 microns, which are small enough to not cause erosion or abrasion of the turbine blades (Power-Gen Worldwide 2001). A

$45-million (Australian dollars) pilot plant in New South Wales produces large batches of ultra clean coal from different coal feeds as required. Tests conducted on the ultra clean coal in Japan indicate that the ultra clean coal provides positive results in terms of efficient gas turbine combustion under continuous operating conditions. The ultra-clean-coal-fired turbine can be brought on- and taken offline quickly, can be located close to the end user, and can be used for small distributed power systems. While not a substitute for conventional coal, ultra clean coal provides opportunities for efficient use of coal as a substitute for gas and heavy fuel oil. Typically, internal combustion engines can convert 50–55% of the energy in the fuel to electricity, compared with about 33–35% for coal-fired power stations in Australia. Because it is more efficient than conventional coal generation, ultra clean coal consumes less water for cooling. Australia's national science agency, the Commonwealth Scientific and Industrial Research Organization, is supporting fundamental research into the ultra clean coal process and the fuel preparation and utilization aspects of ultra clean coal slurries (see http://www.uccenergy.com.au/home).

3.3 COOLING SYSTEMS

Coal-fired power plants use wet or dry cooling systems. Wet systems consume the most water, and dry systems consume the least. Of the wet systems, recirculating systems consume more water than once-through systems but withdraw less. Section 3.3.1 describes the relative advantages of once-through versus recirculating systems and offers some examples of how the use of the more water- (and energy-) efficient systems could continue to be used in light of U.S. Environmental Protection Agency (EPA) regulations that would otherwise tend to reduce their use—by using approaches being developed in Europe. Section 3.3.2 describes dry cooling technologies and provides examples of dry cooling use outside the United States.

3.3.1 Once-Through Cooling

Wet cooling systems are either once-through or recirculating. As explained in Section 3.1, plants that use once-through cooling remove water from a large source, such as an ocean, river, or lake; use that water to remove heat from the condenser; and then return the water to its source. Although some extra evaporation occurs offsite because of the warmer temperature of the discharge water, once-through cooling systems withdraw relatively high amounts of water, but consume relatively low amounts when compared with recirculating systems. In recirculating systems, warm cooling water is pumped from the condenser to a cooling tower where the heat is dissipated directly to ambient air by evaporation, and the water is recycled back to the condenser. Because of evaporative losses (about 85% of the water supplied to a power plant evaporates through the cooling towers) a portion of the cooling water is discharged to prevent the buildup of minerals and sediment that could adversely affect performance. In these systems, the only water that is withdrawn is the amount needed to replace the water that is consumed through evaporation and blowdown. Hence, when compared with once-through cooling systems, recirculating systems withdraw relatively low amounts, but consume relatively high amounts of water (Table 6).

TABLE 6. Average Withdrawal and Consumption Rates for Once-Through and Recirculating Cooling Systems

Cooling System	Withdrawal (gal/kWh)	Consumption (gal/kWh)	Consumption as a % of Withdrawal
Once-through	26	0.10	0.4%
Recirculating	0.54	0.45	83%

Source: based on data in NETL 2009d

To use once-through cooling systems, cost-effective technologies and other approaches that are consistent with best available technology—as required by the Clean Water Act's (CWA's) §316(b) regulations—are needed. Section 316(b) requires the EPA to ensure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement (being pinned against screens or other parts of a cooling water intake structure) or entrainment (being drawn into cooling water systems and subjected to thermal, physical, or chemical stresses). In 2001, EPA published final rules implementing §316(b) for new facilities, and in 2004, EPA published final rules for existing power plants that withdraw more than 50 million gallons per day. These "Phase II" rules required that the number of organisms pinned against parts of the intake structure be reduced by 80–95% from uncontrolled levels and that the number of aquatic organisms drawn into the cooling system be reduced by 60–90% from uncontrolled levels. In 2007, the EPA suspended the Phase II rules in response to a court case that remanded several of the provisions. In 2010, the EPA signed a settlement agreement with Riverkeeper in which it agreed to propose technology standards for cooling water intake structures for existing facilities by March 14, 2011, and to take final action by July 27, 2012.

Europe has not promulgated cooling water intake regulations comparable to those in the United States under CWA §316 that would limit the use of once-through cooling systems. Indeed, *The European Commission Reference Document on Application of Best Available Techniques to Industrial Cooling Systems* (BREF 2001) identifies direct cooling as best available technology for large power plant cooling systems:

> In an integrated approach to cooling an industrial process, both the direct and indirect use of energy are taken into account. In terms of the overall energy efficiency of an installation, the use of a once-through system is the best available technique, in particular for processes requiring large cooling capacities. In the case of rivers and/or estuaries once-through can be acceptable if also:
>
> - Extension of heat plume in the surface water leaves passage for fish migration;
> - Cooling water intake is aimed at reduced fish entrainment; and
> - Heat load does not interfere with other users of receiving surface water.

The World Bank Group's International Finance Corporation has established *Environmental, Health and Safety Guidelines for Thermal Power Plants*, which, along with other environmental, health, and safety guidelines, are to be applied when one or more World Bank members are involved in a project. The guidelines for thermal power plants (IFC 2008) address impingement and entrainment at water intake structures. They state that measures to prevent, minimize, and control environmental impacts associated with water withdrawal should be established based on the results of a project environmental assessment, considering the availability and use of water resources locally and the ecological characteristics of the project affected area. The guidelines, which also state that once-through cooling water systems may be acceptable if compatible with the hydrology and ecology of the water source and the receiving water, include several recommended measures to prevent or control impacts to aquatic habitats. These include the following:

- Reduce maximum through-screen design intake velocity to 0.5 feet per second.
- Reduce intake flow to the following levels:
  - For freshwater rivers or streams to a flow sufficient to maintain resource use (i.e., irrigation and fisheries), as well as biodiversity during annual mean low flow conditions.

  - For lakes or reservoirs, intake flow must not disrupt the thermal stratification or turnover pattern of the source water.
  - For estuaries or tidal rivers, reduction of intake flow to 1% of the tidal excursion volume.
- If threatened, endangered, or other protected species are within the hydraulic zone of influence of the intake, reduce impingement and entrainment of fish and shellfish by installing technologies such as barrier nets (seasonal or year-round), fish handling and return systems, fine mesh screens, wedge wire screens, and aquatic filter barrier systems. Operational measures to reduce impingement and entrainment include seasonal shutdowns, if necessary, or reductions in flow or continuous use of screens. Designing the location of the intake structure in a different direction or further out into the water body may also reduce impingement and entrainment.

Both the European Commission and International Finance Corporation guidelines embrace site-specific approaches that require consideration of the plant in its surroundings when developing measures to protect against impingement and entrainment. In 2010, the Environment Agency, the leading public body protecting and improving the environment in England and Wales, published a document on *Cooling Water Options for the New Generation of Nuclear Power Stations in the UK* (Turnpenny et al. 2010). Although this document does not address coal-fired power plants per se, many of its findings would presumably apply to all power plants. Of these findings, two are particularly relevant for this study:

- A distinct difference between the U.S. and UK approaches regarding entrapment has been the U.S. assumption of 100% mortality of any fish eggs, larvae or juveniles entrained in plant cooling systems and discharged back to sea. UK studies have shown that substantial proportions survive passage through cooling water systems, thereby potentially reducing the magnitude of entrainment impacts.
- The UK Environment Agency therefore concludes that direct cooling may be the best environmental option for large power stations sited on the coast or estuaries, subject to current best planning, design, and operational practice and mitigation methods being put in place, and meeting conservation objectives of the site in question.

Perhaps because they lack regulations comparable to the U.S. §316(b) regulations, which would dictate greater use of recirculating cooling systems, European and Asian countries have not demonstrated use of technologies that would limit fish impingement and entrainment to the extent required by U.S. regulations. Nonetheless, these countries recognize the issues and are conducting research into ways to reduce fish impingement and entrainment. According to Turnpenny et al. (2010), mitigation techniques to reduce losses to impingement have progressed considerably in the past decade. Combinations of techniques, including use of velocity caps (offshore intakes); acoustic fish deterrent (AFD) systems, which propagate underwater sounds to deflect fish from water intakes; fish recovery and return systems, which use band or drum screens modified for safe fish handling, including their return to the source water body; and other technologies (e.g., low-velocity side-entry intake designs, strobe light deterrents) that will be considered for the next generation of power plants, should further reduce losses to impingement. Examples of recent RD&D of technologies to reduce impingement and entrainment include the following:

Water Intake Protection Screens—France

Through-flow traveling band screens (a common fish-filtering method) suffer from "debris carry-over" and are not well suited to protecting water life. A new water intake protection system intended to mitigate these problems has been designed to retrofit most intake water systems with through-flow traveling band screens. With this system, water flows through the screening disk, and water life is arrested by a fish-friendly "no-cling" panel. The fish are then stored in deep radial compartments ahead of the "no-cling" mesh until they are backwashed to the fish returning flume. The backwash flow rate is created by an immerged fish-friendly pump connected to the suction scoop. The water intake protection system is installed in the thru-flow traveling band screen guides. Flow rates are 13,200–158,000 gallons per minute (Beaudrey 2010).

Nonphysical Acoustic Systems—the United Kingdom and Belgium

Nonphysical or behavioral systems provide alternatives to mechanical screening devices, because they eliminate or reduce blockage and reduce the likelihood of fish injury from mechanical contact. The difficulty with developing AFDs has been finding systems that are effective for a wide range of species that will last in a hostile marine or estuarine environment. However, problems ranging from handling necessary low-frequency components of the acoustic signal to corrosion, sediment accumulation, and overheating of amplifiers have been largely overcome, and today AFD systems can be run in hostile marine and estuarine environments for up to a year before maintenance is required. AFD systems can be installed on new units or retrofitted to existing plant intakes. As of 2003, about 60 AFD systems were operating at UK and

European freshwater locations (Turnpenny and Nedwell 2003). Specific examples include the following:

- Fish Guidance Systems Ltd. (UK) is developing several behavioral systems that include two types of AFDs: the SPA™ (Sound Projector Array) uses underwater low-frequency sound projections to produce a diffused field of sound. The BAFF™ (Bio-Acoustic Fish Fence) diverts fish by using sound sources coupled to a bubble curtain to produce a discreet wall of sound that can be used for more precise guidance of fish, for example into a bywash channel. SPA-based AFDs were initially developed in the early 1990s. Although they suffered from technical problems, they were sufficiently successful to encourage further development, and key problems were addressed. SPA AFD systems have been demonstrated or deployed at five UK estuarine power stations (nuclear) and one Belgium (nuclear) plant (see http://www.web4water.com/products/view_entry.asp?id=2940).

- ProFish Technology, a spinoff of the University of Liège (Laboratory of Fish Demography), Belgium, and the University of Oslo (Norway), have developed a new fish deflection system that is based on the emission of infrasounds. Infrasounds are acoustic signals, characterized by frequencies less than 20 Hz, that are too low for human hearing, but that serve as natural alarm signals for fish. The intensity of the infrasound fish fence literally shakes the fish, creating an uncomfortable area that they avoid. Testing of the cooling water intake of a nuclear power plant fitted with the new technology in Belgium showed an 85% reduction in fish entrainment. Operation of the system can be adapted to migration periods of target species (ScienceDaily 2007).

Low-Voltage Electric Fields—Poland

The Neptun electric-electronic barrier system (Poland) repels full-grown fish and fry by using a heterogeneous pulse low-voltage electric field, which reportedly affects the nervous and muscular system of fish, but does not threaten the organisms (see http://procomsystem.pl/index.php?page=neptun-electric-electronic-barrier). The field parameters are changed to prevent fish from adapting to the system, and it can be installed on new plants or can be retrofitted on existing plants. The Wroclaw University of Environmental and Life Sciences and the Inland Fisheries Institute in Olsztyn (Żabieniec Branch) are examining system efficiency. Neptun has been deployed on two hydro power plants in Poland, and according to the company, Fishways

Global, LLC, the Neptun system can be easily used at coal-fired power plants (Parasiewicz 2010).

3.3.2 Dry Cooling

Dry cooling systems can eliminate the need for cooling water. By using convective heat rather than evaporation as the cooling mechanism, dry cooling systems eliminate evaporative water losses and use about 15 times less water than conventional wet systems. There are two types of dry cooling: direct and indirect.

Direct Dry Cooling

In these systems, also known as air-cooled steam condensers (ACCs), the steam is condensed directly by air in a heat exchanger (the air-cooled condenser), and the condensate is returned to the steam cycle in a closed loop. The saturated steam from the turbine exhaust is discharged into a steam duct, which flows to a finned tube bundle. Conductive heat transfer, with large mechanical fans that force ambient air at a high rate across the outside surfaces of the tubes cools the steam in the bundle. The cooling air absorbs the heat of condensation from the steam.

Indirect Dry Cooling

In these systems, a conventional water-cooled surface condenser condenses the steam, but heat is transferred from the water to the ambient air via an air-cooled closed heat exchanger. The Heller system is an example of an indirect dry cooling system in which the steam is condensed by spraying water directly into the exhaust flow. This "direct contact jet condensing" creates a large volume of warm water, some of which is pumped back to the boiler, while the rest is pumped to bundles of tubes arrayed at the base of a natural-draft hyperbolic cooling tower. The warm water that circulates at the base of the tower and the cooler air at the top of the tower, combined with the tower's hyperbolic shape, create an updraft that draws ambient air over the tube bundles, thereby cooling the water convectively before it is returned to the condenser. Indirect dry cooling systems can use either natural or mechanical draft cooling towers. Natural draft towers eliminate fan power requirements, and reduce noise and maintenance.

Indirect systems generally have higher capital costs than direct systems, but they are mechanically simpler and have lower operating and maintenance costs and lower auxiliary power requirements (Jones et al. 2010). In general, indirect cooling systems are preferred for larger units, especially when natural draft can be used, and direct cooling systems are preferred for smaller units.

While they consume significantly less water than wet systems, dry cooling systems have several disadvantages. These include high costs and efficiency penalties.

- *High costs*. Because dry cooling involves the transfer of heat to the atmosphere by sensible heat transfer only (no evaporation), and because sensible heat transfer is less efficient than evaporative heat transfer, dry cooling systems have larger footprints and are taller than wet cooling systems, and therefore their capital costs are higher. It has been estimated that for the same amount of heat rejection, a direct dry cooling system will have a footprint about 2.2 times larger than a wet cooling tower and a height about 1.9 times higher (Wurtz and Nagel 2010). Dry cooling systems also have higher maintenance costs. This is because (1) they are mechanically more complex than wet cooling systems (they have larger heat transfer surface areas and more fans, motors, gearboxes, and drive shafts), and (2) there are more corrosive products in condensate water (because air cooled units have much larger cooling areas).

- *Efficiency penalties*. Dry cooling systems are generally less efficient than wet cooling systems, because the cooling fans consume considerable power and because the temperature differential in the dry systems is smaller than in the wet systems. Because dry cooling relies on the temperature of the ambient air (dry bulb temperature), which is typically higher than the temperature at which water evaporates (wet bulb temperature) in wet cooling, the output of a plant with dry cooling will be about 2% less than that of a similar plant with evaporative closed-loop cooling, depending on the local climate. In the hottest weather, when power demands are often highest, dry-cooled power-plant efficiency and plant output can decrease by 25% (Wurtz and Nagel 2010). This can limit generating loads in hot climates or on hot days.

Dry Cooling Use

Worldwide, about 90% of all dry-cooled power plants use air-cooled condensers (direct dry cooling) with mechanical draft towers; less than 10% use indirect dry cooling systems that have been retrofitted (Micheletti and Burns 2002).

In the United States, most dry-cooled systems are used for gas-fired, combined-cycle units. This is because these plants release much of their heat to the air in the turbine exhaust, and therefore require only about one-third as much cooling as normal thermal plants (Kidd 2008). Experience with dry cooling for baseload coal-fired power plants is generally limited to states where cooling water supplies are limited (e.g., California) and states where water costs are high (e.g., Nevada). Utilities in the United States have generally dismissed indirect dry cooling for new plants because of the poor thermal performance relative to direct dry cooling. Indirect dry cooling would be more technically suitable than direct dry cooling as a retrofit to an existing wet cooling system, but the poor thermal performance of indirect dry cooling system would likely reduce the generating efficiency too much to justify the retrofit (Micheletti and Burns 2002).

Other countries are more aggressively implementing dry cooling. In China, where many coal-rich regions are also water scarce, dry cooling is being adopted by many power plants. South Africa and Australia are also using dry cooling.

China

In China, coal-fired power plants are often sited near coal mines to minimize costs of coal transport. China has adopted dry cooling for many new plants. ACCs (direct dry cooling) had been installed on more than 35,000 MW of new plants as of 2008. Between 2006 and 2008, China purchased an average of one new ACC per month for new coal-fired power plants with capacities of 2 × 300 MW or 2 × 600 MW (Wurtz and Peltier 2008). Typically used in subcritical power plants located in areas where water is scarce, ACC technology is now being used in supercritical and ultra-supercritical units as well.

The Huaneng Qinling Power Plant provides an example of how dry cooling is being used in China. In Shanxi Province, water shortages are hindering the development of the central Shaanxi plain. The 1,300-MW Huaneng Qinling Power Plant, which is under construction in Shanxi Province, will use an indirect dry cooling system. The technology will use a traditional steam surface or jet condenser and a circulating water system to transfer waste heat to the natural draft concrete cooling towers using air-cooled heat exchanger bundles. The system also uses a two-level cooling arrangement designed to increase cooling efficiency. As the unit size of China's power plants continues to increase, larger cooling surfaces and tower sizes are required. A two-level cooling arrangement designed to provide higher cooling efficiency at a reasonable cost and a more economical system operation is being developed for the Huaneng Plant. The two-level arrangement will also be used at a similar plant (the 1,320-MW Huaneng Shanxi ZuoQuan Power Plant, which is expected to be operational in late 2011. The cost of the cooling system is estimated at $33 million U.S. (see http://spxcooling.com/en/news/spx-awarded-contract-to-install-indirect-dry-cooling-towers-at-power-plant-).

South Africa

Eskom, South Africa's state-owned electric utility, has implemented dry cooling technology on power stations wherever feasible, even though dry-cooled stations are less efficient than wet-cooled stations. As of 2004, South African coal-fired generating capacity using dry cooling was about 10,500 MW, which reportedly saves about 90 million m^3/of water per year (about 65 mgd) over what should have been consumed had these plants used wet cooling systems (Pather 2004).

Eskom operates both the largest indirect dry-cooled power plant (the 4,116-MW Kendal plant) and the largest direct dry-cooled power plant (the 3,600-MW Matimba Plant) in the world.

- The 4,116-MW Kendal Power Station near Witbank in the Mpumalanga Province uses an indirect dry cooling system. In this system, water from a standard condenser is circulated to the tower, where it enters a series of heat-exchange elements at the base. Air enters the bottom periphery of the tower, passing over the heat-exchange elements. Inside the tower, the heated air rises, pulling in more cooled air. Fans are not required (Wurtz and Peltier 2008). Water consumption at the Kendal Plant is about 0.08 liters per kWh of electricity sent out (Eskom 2007).

- The Matimba Power Plant near Lephalale in the Limpopo Province uses a direct closed-circuit cooling technology similar to the radiator and fan system used in motor vehicles. Water consumption is about of 0.1 liters per kWh of electricity sent out, compared with about 1.9 liters on average for wet-cooled stations (Eskom 2007). The choice of dry-cooled technology for Matimba was largely influenced by the scarcity of water in the area.

While Matimba currently has the largest direct dry cooling system in the world, a larger one, Medupi, is under construction near Lephalale. This supercritical coal-fired power plant will have six 790-MW units, with the first scheduled for commissioning in 2012, and the last scheduled for commissioning in 2015. Medupi will be the largest dry-cooled power station in the world. The footprint of the air-cooled condenser at the Medupi station is 108 m × 669 m, or the equivalent of ten football fields. The average ambient temperature at the Medupi site is 74.7°F (23.7°C). The air-cooled condenser will use the same A-tube design that is installed at the Matimba plant and in several other direct dry-cooled plants around the world. With the A-tube design, the ACC consists of finned tube bundles grouped together into modules and mounted in an A-frame configuration on a concrete or steel support structure. Each unit will have 64 fans, each 34 feet in diameter (du Preez 2008).

Australia

In Australia, dry cooling is used in two Queensland power stations (Millmerran and Kogan Creek). The 850-MW supercritical Millmerran plant in South West Queensland opened in 2003. One of the most energy-efficient plants in Australia, it uses air cooling to condense the steam from the turbine exhaust, and as a result, consumes 90% less water than conventional coal-fired power projects. Recycled wastewater from a nearby sewage treatment plant is treated on site and used as makeup water. All runoff water is contained on site and is reused. The 750-MW supercritical Kogan Creek power plant in Queensland began operations in 2007. It uses an air-cooled condenser that uses up to 90% less water than conventional plants, reducing the risk of reduced output during times of drought (see http://www.power-technology.com/projects/kogan).

3.4 COAL DRYING

Coal rank refers to the properties of coal that change as the coal matures from peat to anthracite. Outside North America, low-rank coal is known as brown coal and includes lignite, sub-bituminous, and some high-volatile bituminous coal. The IEA classifies sub-bituminous and bituminous coals as hard coal. In the United States, low-rank coals are generally considered to be lignite with a total with moisture higher than 35%. While the types of coal considered low rank and the levels of moisture in the definitions vary depending on country and organization, in general, low-rank coals contain high moisture and low carbon contents; high-rank coals contain more carbon, have lower moisture contents, and produce more energy. When the high-moisture-content, low-rank coals are burned, a significant amount of the heat generated during combustion is used to evaporate the moisture rather than to generate steam for the turbine. Because of the higher water content in low-rank coals, the maximum thermal efficiency achievable is about 1.5–2% lower than for high-rank coal (Couch 2002). According to Couch (2002), about 18% of the coal mined worldwide is lignite, 12% is sub-bituminous, and 69% is bituminous. Much of the low-rank coal is near the surface in thick seams, and more accessible relative to the deeper bituminous coals. If underground mining becomes less acceptable (due to safety concerns) or more expensive, the use of low-rank coals may increase. Because low-rank coals have relatively low concentrations of ash and sulfur, many coal plants use these coals to meet sulfur emissions limitations. By reducing the amount of water in the coal, the energy density can be increased and overall plant efficiency improved. Until recently, the energy requirements of drying coal prior to combustion were too high to make the process economically viable. Recent efforts, both in the United States and abroad, are showing some success.

3.4.1 United States

In the United States, 35 power generation units, with an installed capacity of 15,000 MW, burn lignite, and about 250 units, with an installed capacity of about 100,000 MW, burn Powder River Basin coal—a sub-bituminous coal with a high moisture content (Great River Energy 2010a). Great River Energy pioneered and recently deployed a lignite fuel enhancement system patented under the name “DryFining” at its Coal Creek Generating Station in Underwood, North Dakota. As reported by Great River Energy (2010a), the system uses waste heat from the power plant (which would otherwise be released to the atmosphere) in a fluidized bed dryer, which combines convection and conduction heat, to reduce the moisture level of low-rank coal from about 38.5% to about 29%. Reducing the moisture increases the heating value of the coal from 6,200 Btu/pound to 7,100 Btu/pound, and overall plant efficiency is increased by 2–4% (Great River Energy 2010b). In December 2009, a full-scale coal-drying system capable of processing 450 tons of raw lignite per hour was placed into commercial service at the North Dakota facility.

3.4.2 Other Countries

Significant RD&D efforts with respect to coal drying are underway in Germany and Australia. Examples of these are highlighted below.

Germany

Lignite with a natural moisture content of up to 60% provides 25% of the Germany's electricity needs. Because the inherent moisture in raw lignite impedes coal combustion, the coal must be dried upstream to remove as much moisture from the coal as possible. In conventional lignite-based power plants, this is accomplished by withdrawing some of the hot (900–1,000°C) flue gases that emerge during combustion and mixing them with moist raw lignite. The coal's moisture evaporates and is used in the boiler. In this process, a significant amount of the combustion energy is used to evaporate the moisture, rendering the steam cycle less efficient than in plants that use drier fuel and using energy that would otherwise be available for power generation. To address this problem, a new technology is being developed and used at the BoA "coal innovation center" plant at the Niederaussem power plant. (BoA stands for "lignite-fired power station with optimized plant engineering.") BoA 1, in Niederaussem, is the world's most modern lignite-fired coal-fired plant and has an efficiency of more than 43% (RWE Power 2008).

The new technology, WTA, which stands for "fluidized-bed drying with internal waste heat utilization," is a proprietary development of RWE power, Germany's largest power producer. The WTA process works as follows: the fluidized-bed drier keeps the pulverized raw lignite in a stream of gas of already evaporated coal water. In this state, the coal particles can be dried at 110°C. The heat required for this drying comes from the low-pressure steam of the BoA unit. Some of the thermal energy is recovered and is used to preheat the boiler feed water. The pre-dried lignite now has a moisture content of about 12%, compared with the raw lignite moisture content of 55%. Once it cools down, the lignite is placed in interim storage in silos and then co-combusted in the BoA unit (RWE Power 2008). The WTA process provides a net gain in cycle efficiency of about 4 percentage points, depending on the moisture content of the raw coal and the final moisture content of the dried lignite. It allows much better energetic use to be made of coal and, in future lignite-fired power plants, is expected to increase efficiency to about 48%.

In 2008, with 15 years of development experience at smaller facilities, a large WTA prototype plant was commissioned at the Niederaussem power station. The system—the largest lignite drying plant in the world—can process 210 tons of raw coal per hour and has an evaporation capacity of 100 tons of water power per hour. A key objective of the € 50 million (about $68 million U.S.) prototype plant is to pre-dry 20–30% of the raw lignite for the 1,000-MW power plant, and to demonstrate economic and technical benefits of fluidized-bed drying in continuous operations (RWE Power 2008).

Australia

In Australia, a number of drying technologies that use waste heat or heat pumps, or that attempt to remove moisture from coal as liquid water rather than as steam, to avoid latent heat losses are under development. According to Wibberly et al. (2006), different approaches are used depending on the power generation technology. For example, partial dewatering (from 65% to 50%) is used to improve the efficiency of current subcritical plants with minimal modification; moderate dewatering (from 65% to 25–30%) can be used for modified or new plants; and integrated flash drying (from 65% to 15%) for integrated drying gasification and combined cycle (IDGCC) plants. For new ultra supercritical plants or IGCC plants, heat pumps can be used to dry to moisture levels below 12%. However, for new ultra supercritical plants, the most promising drying option is the German WTA system, because it has the most pilot scale experience.

Wibberly et al. (2006) note that combining drying with power generation increases conversion efficiency, thereby requiring less water for cooling. Compared with standard supercritical plants, cooling water consumption would be reduced by about 10% for plants that use the WTA process. In addition, the liquid water produced in the process would be suitable for other purposes (e.g., agriculture). They note that the WTA process will be more appropriate for new plants than for retrofits. This is because current boilers are designed for high-moisture coals and the resulting higher gas flows. Because dry coal will significantly increase flame temperature and radiant heat transfer and reduced gas flow will decrease heat transfer in the convection sections, there will be an imbalance between steam raising and superheat, and only a small imbalance can be tolerated before boiler modifications are necessary. Without boiler modification, drying would be limited to about 25–30% water removal (CCSD 2006).

Two large coal drying projects are being developed in Australia.

- The Australian government has announced a $50-million grant, and the Victorian government a $30-million grant, toward a $369-million pilot project for a brown coal drying and post-combustion CO_2 capture project at International Power's Hazelwood power plant east of Melbourne. The intent is to use the WTA technology to reduce the moisture content of run-of-mine (raw) brown coal from more than 60% to about 12% in an initial 50% feed train at Hazelwood's 40-year-old Unit 1. The lignite drying process will entail fine grinding of the brown coal and use of a steam-heated fluidized bed to dry the coal. The heat for the drying process will be extracted from the steam turbine, with the heat transfer occurring in tube bundles located inside the fluidized drying bed. After passing through the fluidized bed, the condensate associated with this extraction steam will then be returned to the boiler feed system. The "Hazelwood 2030" retrofit project is intended to boost efficiency, reduce CO_2 intensity, and extend the life of the brown coal units. International and Australian private-sector companies are working with the government to build a commercial 800-MW, 100% dried, brown-coal-fired power plant that uses ultra supercritical technology and low-ranked coal sources, and to demonstrate that the technologies can be retrofitted to existing power plants worldwide (Victorian Government 2010).

- The Australian and Victorian governments are also supporting a coal drying project for gasification and combined cycle technologies. The Australian government is contributing $100 million, and the Victorian government is contributing $50 million to a $750-million project to develop a large-scale, brown-coal power generation demonstration project in the Latrobe Valley, which uses an IDGCC technology. The demonstration project will generate up to 550 MW of power with low-rank brown coals. The drying technology uses the hot syngas from the gasification plant to dry brown coal, which is then used as a feedstock for the gasifier. The drying of the coal cools the syngas and adds to the vapor content in the gas, thereby increasing the mass flow of gas through the combined cycle power plant. It is estimated that the use of this technology will result in a 70% reduction in water use (Victorian Government 2010).

3.5 DRY BOTTOM ASH HANDLING

Bottom ash consists of the noncombustible residues of combustion that do not escape through the flue as fly ash. Historically, bottom ash has been managed by wet handling systems that use water to cool and convey the ash from the plant. However, newer, dry handling systems are being implemented that use much less water.

3.5.1 Wet Handling Systems

Wet bottom ash handling systems include sluicing systems, recirculating systems, and submerged chain conveyor systems. Their characteristics are summarized below.

- A water-impounded hopper system is a sluicing system that receives, quenches, stores, crushes, and removes furnace bottom ash by using hydraulic means. Ash builds up in the hopper and is removed periodically (e.g., every 6–8 hours) by pumping the slurry via a sluice pipeline to a pond. Sometimes a dewatering bin is used to separate and remove the ash from the conveying water before it reaches the pond.

- A recirculating system is a variation of the sluicing system; it reuses the conveying water and requires a relatively small amount of makeup water. A recirculating system can replace the ash pond with dewatering bins that separate the water and ash. Ash can be unloaded from the dewatering bins into transport vehicles for disposal. Recirculating systems use less water than sluicing systems but more than submerged chain conveyor (see below) or dry systems. Because recirculating systems reuse the conveying water and require only a small amount of makeup water, they may be appropriate where some water supplies are available.

- The submerged chain conveyor (SCC) system is a heavy-duty chain conveyor submerged in a water trough below the furnace, which quenches hot ash as it falls from the combustion chamber and moves the wet ash continuously up a de-watering ramp. At the top of the ramp, the ash is discharged through a chute into mechanical conveyors or directly to storage silos. The SCC system uses less water than a recirculating (or sluicing) system because it uses no transport water.

Because slurry and circulation pumps are required, wet handling systems consume energy, can leak contaminated water, are costly to maintain (because of corrosion and clogging), and reduce boiler efficiency (because of maintenance and reliability issues).

3.5.2 Dry Handling Systems

Dry handling approaches do not require water for cooling and conveyance. They also increase the combustion of unburned carbon, thereby increasing efficiency. According to Yu (2009), the unburned carbon in bottom ash can be about 6–15% of the total carbon in the coal. All of this energy is lost in wet handling approaches, but in dry handling approaches, up to 90% can be combusted, with heat recovery contributing to increased boiler efficiency.

Several dry handling approaches have been developed, and some examples are summarized below.

- In one approach (developed by Magaldi), bottom ash is collected in refractory-lined hoppers placed under the boiler. Percolating air helps combust unburned carbon and cools the ash. Periodically, doors at the bottom of the hopper are opened to allow ash and clinker to pass into a crusher; they are then fed to a vacuum system for transport to a dry storage silo or an ash transfer truck.

- Another system (the DRYCON™ System) uses the negative pressure inside the boiler to induce air flow through a conveyor to cool the ash and allow the combustion process to continue on the conveyor. The conveyor runs continuously, carrying the hot bottom ash and discharging it into a crusher. This process also allows for a more complete burn of the residual carbon in the bottom ash, and yields a product that is similar to fly ash. The dry ash is removed from the crushers by vacuum pumps and stored in silos for further disposal or use.

- Yet another system (Vibratory Ash Extractor [VAX™]) incorporates fluidized bed vibratory technology to increase the combustion and cooling. With the conveyor belt approach, the air tends to flow over the ash pile, but with the fluidized bed approach, forced air is blown through openings to surround each particle and promote more efficient combustion. With the fluidized bed system, up to 90% of all the heat contained in the bottom ash is recovered and delivered to the boiler (UCC 2010).

3.5.3 Comparative Studies

Cianci (2007) reported the experiences of a multi-unit coal-fired baseload power plant that has both wet and dry bottom ash handling systems. The four-unit, 1,256-MW (total) plant has been gradually replacing its existing wet ash handling systems with dry ash systems. As a result, both technologies have been running side by side at the same site for several years. The bottom ash feed rate per unit is 1–2 tons per hour, with an unburned carbon content of around 6.5%. The plant's wet system is a hybrid water impounded hopper system (which traditionally uses a sluice system) and SCC system. Each of the two units using wet handling has a dedicated system for water circulation and treatment; the waste water from these units is sluiced into a centralized sludge treatment system. Because of this built-in redundancy, the system is particularly dependable. In 2004, dry bottom ash technology was introduced at the plant, and the resultant water savings was about 258,000 m^3 per year (about 0.19 mgd). The removal of the wet systems eliminated the need for the associated water circulation and treatment systems, reduced demands on the centralized sludge treatment system, lowered maintenance costs arising from corrosion and jamming along the sluicing lines, reduced power demand (due to the elimination of water circulation pumps), and increased boiler efficiency (due to the recovery of much of the heat leaving the boiler through the lower opening). Measurements show that the losses at the bottom of the boiler are 1,516 kW for a single wet system compared with 200 kW for a single dry system, meaning a net thermal power saving of 1,316 kW per dry system.

Another study (Bullock 2010) compared costs and operational characteristics of a dry bottom ash system with wet ash system using SSC technology for a typical European baseload 800-MW pulverized coal plant. The plant generates 8.5 tons per hour of bottom ash, the ash content in the feed material is 14.3%, and the plant operates 7,884 hours per year. The study found that the higher investment costs required for the dry system were offset by simpler transport and storage equipment and the lack of water treatment equipment such as pumps, filters, and heat exchangers (Table 7). The study also notes that the dry handling approach captures waste energy from the incomplete combustion of the bottom ash and introduces it into the boiler as pre-heated air at approximately 450°C, which results in an overall increase in boiler efficiency of roughly 0.15–0.5%.

Dry bottom ash handling systems are commonly used in Europe, Asia, and South Africa. One manufacturer, Magaldi, reports that between 2000 and 2006, it installed new dry bottom ash handling systems at power plants with capacities totaling more than 7,000 MW in six countries and retrofitted power plants totaling more than 4,400 MW of capacity in more than five countries (Table 8).

Table 7. Cost and Consumption Estimates for Wet and Dry Bottom Ash Handling Systems

Consumption Type and Cost	Wet Handling (SSC)	Dry Handling (DRYCON)
Investment Cost (Euros)		
Water Treatment Equipment	72,500	0
Crushing Equipment	30,000	30,000
Transport Equipment, Bins, etc.	150,000	120,000
Other Equipment	600,000	950,000
Total Investment Cost	852,500	1,100,000
Annual Operating Costs (Euros)		
Energy Consumption (€0.10/kWh	47,304	25,652
Cooling Water (€0.02/m^3)	3,469	0
Ash Handling and Disposal Cost	6,667	5,127
Spares, Service and Maintenance	42,625	16,500
Total Operating Costs	100,065	47,279
Consumption		
Energy Consumption (kWh/year)	473,040	256,520
Cooling Water Consumption (m^3/year)	173,448	0

Source: Bullock 2010

Table 8. Magaldi Dry Bottom Ash Installations, 2000–2006*

Location	Retrofits			New Units		
	Number of Units**	Capacity Range per unit (MW)	Total Capacity (MW)	Number of Units**	Capacity Range per unit (MW)	Total Capacity (MW)
Australia	6	350–660	3,020			
China	6	200–350	1,650	2	135	270
India				1	300	300
Italy	3	160–320	800	3	660	1,980
Japan				2	507–600	1,107
Philippines				1	105	105
Portugal	2	314	628			
South Korea				6	500–870	3,740
Spain	2	550–556	1,106			
Total	19		4,486	15		7,259

* Does not include small units at manufacturing facilities.

**Some plants have 2 or more units.

Source: Cianci et al. 2007

The following example illustrates the use of a dry handling system at a lignite-fueled power plant in Greece. Public Power Corp., the largest electric utility in Greece, uses lignite from Western Macedonia in several of its power plants, including the Ptolemais power station in northern Greece. In 1995, Public Power Corp. replaced the existing wet ash-removal system at its 300-MW Unit 4 with a dry bottom ash system that removes the unit's bottom ash without using water for ash cooling or conveying. The original SCC bottom ash system used more than 140 tons per hour (t/hr) of service water to cool the ash. Installing a dry bottom ash removal system at a Greek lignite-fired boiler was unique because until then, dry ash cooling systems had been used with boilers with no more than 3 t/hr of bottom ash. At the lignite-fired Ptolemais unit, much higher rates of bottom ash—6–8 t/hr—were expected. The system works as follows: Bottom ash from the boiler falls onto a slow-speed, continuously moving steel belt that is cooled by a flow of air. The amount of cooling air is controlled with variable inlet dampers that use the furnace's negative pressure. Ash cooling occurs in the sloped section of the dry cooling system's extractor, in the primary crusher, and in the post cooler. Depending upon the boiler's operating conditions, the bottom ash is discharged at a temperature ranging between 40 and 100° C into the intermediate bin. At this point, two options are available: (1) the ash can be recycled to the lignite silo, or (2) it can be conveyed to the ash silo. (The reason for the dual pathway is that when the system was originally proposed, the amount of unburned material remaining in the ash could not be forecast. After startup of the dry ash unit, it was found that unburned material in bottom ash was greater than expected. In addition, after 6 months of operation, it was found that the pulverizing efficiency of the bottom ash and the lignite were comparable, with no difference in the percentage of fly ash and bottom ash produced. It was also found that unburned material in fly ash was lower in the first 6 months of operation than when the unit was operated with the wet bottom ash system. As a consequence there was a saving in lignite and a subsequent increase in the boiler's efficiency. Because the bottom ash is 100 percent recycled to the boiler, the amount of bottom ash produced by Unit 4 has been reduced to zero. In addition, as a consequence of the improved boiler efficiency, total fly-ash production did not increase. With the dry ash system, the only water requirement is about 3 t/hr for the hydraulic seal, compared with the 140 t/hr of water required prior to the retrofit. Installation of the dry ash system increased the plant's output by 1.6% (with the fuel feed remaining the same) (Vlachos and Carrea 1996).

3.6 LOW-WATER-CONSUMING EMISSIONS CONTROL TECHNOLOGIES

The conventional approach for reducing sulfur dioxide (SO_2) emissions from the stacks of coal-fired power plants is to use either wet FGD or a dry spray dryer absorber (SDA). In wet scrubbing units, a water spray captures SO_2 and other pollutants, which are then removed by creating an alkaline slurry. Dry scrubbing units eliminate the need for water, because the alkaline particles are injected directly into the flue gas stream. However, without water, there is less contact among reactants and thus lower pollutant removal efficiencies. Although wet scrubbing units use only about 10% of the water used for cooling tower makeup, the amount is still significant (about 570 gallons per minute for a nominal 500-MW subcritical plant and about 500 gpm for a nominal 500-MW supercritical plant (NETL 2005). Technologies that reduce or recover evaporative losses from wet scrubbers or that increase removal efficiency of dry scrubbers could reduce water use. Two such options are regenerative activated coke technology (ReACT) and circulating fluidized bed (CFB) scrubbers. Each is described below.

3.6.1 Regenerative Activated Coke Technology

ReACT is an integrated multi-pollutant control approach that can remove sulfur oxides, nitrogen oxides, and mercury from the flue gas stream through adsorption with activated coke, while using only 1% of the water required by conventional wet FGD systems. Pollutant removal in the ReACT technology occurs in three stages. In the adsorption stage, flue gas contacts a slowly moving bed of activated coke that removes sulfur oxides, nitrogen oxides, mercury, and other species through adsorption, chemisorption, and catalytic reactions that are enhanced in the presence of ammonia. The adsorption process does not consume water. The activated coke is regenerated in the second stage, and a marketable sulfuric acid product is made in the by-product recovery stage. Power consumption in the ReACT process is about 60% of that in a typical wet FGD system.

ReACT Deployment

ReACT is fully commercialized as an advanced-generation, multi-pollutant control technology for coal-fired boilers up to 600 MW in Japan, and technology is used at Japan’s Electric Power Development Corp. coal-fired power plant in Iswogo. The plant was built in the early 1960s; after more than 30 years of operations, it underwent a major repowering project aimed at doubling generating capacity and reducing air emissions. Reducing water demand at the Isogo site was a key project requirement. To accomplish this, the plant’s two 265-MW conventional pulverized coal boilers and pollution control equipment (ESP and wet FGD) were replaced with two 600-MW ultra supercritical boilers fitted with ReACT controls. In the United States, the ReACT process was successfully demonstrated over a 5-month period as part of an Electric Power Research Institute project hosted by Sierra Pacific Power at its North Valmy Station. The high levels of SO_2, nitrogen oxide, and mercury removal were consistent with commercial results at the full-scale units in Japan (Peters 2010).

3.6.2 Circulating Fluid Bed Scrubbers

CFB scrubbers use dry treatment processes with high SO_2 removal rates and consume extremely small amounts of water. They are upflow reactors, in which the reactants are introduced at the bottom of the absorber vessel along with a large portion of particulate solids collected from the downstream particulate collection device. Dry hydrated lime is injected into the CFB absorber independently. Flue gas is introduced beneath the bed of sorbent and particulate solids through multiple vents and is distributed across the full diameter of the CFB absorber vessel. Water-injection nozzles spray an atomized cloud of water droplets into the bed of solids fluidized by the incoming flue gas. The CFB technology spreads the water over a large surface area of solids. Added residence time afforded by a tall and narrow CFB absorber vessel improves SO_2 removal efficiencies within a small system footprint (Moss 2010).

CFB Deployment

CFB scrubber technology is relatively new in the United States. The largest CFB scrubber in North America is under construction at Basin Electric Power Cooperative's Dry Fork Station near Gillette, Wyoming. The 420-MW plant is scheduled to enter commercial service in 2011 (Moss 2010). In Europe and China, however, CFB scrubber technologies are in commercial operation. In Europe, there are more than 60 CFB scrubbers in operation, with about 34 running on coal-fired units. Seventeen of these coal-fired units are 300 MW or higher. In China, CFB scrubbers have been installed on 14 projects totaling 6,000 MW since 2000 (Moss 2010).

3.7 REPLACEMENT/RETROFIT

Replacements or retrofits are often made to meet increasing power demand or emissions targets, extend plant lifetime, or enhance performance or efficiency. In some cases, entire power plants are replaced with larger, more efficient units. This is the case in China, where 54,000 MW of small, inefficient plant generating capacity was closed between 2007 and 2009 (see Section 2.2). In other cases, various components—particularly turbines—are replaced or retrofitted. While the primary objective of a replacement or retrofit may not necessarily be to reduce water use, any retrofit that improves efficiency can be expected to reduce water use as well.

The turbine is a key component of the overall thermal cycle, and therefore improvements in turbine design and operation can significantly improve overall plant efficiency. Options for modernizing and improving turbine efficiency can range from replacing seals with upgraded designs at scheduled maintenance outages to replacing major components. Replacing existing turbines with newer ones that incorporate technology improvements that have been made over the years can improve performance by 4–5% (Hansen 2007). Examples of turbine improvements include the following:

- *Blade replacement*. Existing operating turbine components, such as high-pressure and intermediate-pressure turbine sections, can be upgraded by replacing select blade rows with advanced blades. Longer blades mean that more heat can be extracted from the steam, resulting in increased efficiencies, thereby increasing output without increasing boiler steam production.
- *Improved material components.* These improvements help reduce casing distortion, which leads to excessive leakage and solid particle erosion, which in turn degrades blades and internal turbine parts. Newly developed, high-temperature materials make rotors and casings more durable and less susceptible to erosion. Turbine designs that incorporate stronger materials not only address mechanical problems, but also allow for the use of high-temperature, high-pressure coal-fired boiler technologies, which can provide substantial increases in efficiency.
- *Major component modernization*. With this option, the entire component is replaced, while as much existing equipment (e.g., bearings, bearing pedestals, outer casings, piping, and supports) as possible is reused.
- *Condenser optimization.* Condenser optimization can be implemented as a stand-alone project or incorporated with other turbine-modernization options. Modifications can range from reconfiguring the existing condenser tubes for better flow and reduced back pressure to replacing the entire condenser. New materials such as titanium and stainless steel used in replacement tube bundles provide maintenance, reliability, and availability benefits.

3.7.1 Challenges Associated with Retrofitting

Implementing retrofits and upgrades can be more difficult than developing new projects. Challenges include interfacing between the new equipment and old balance-of-plant systems, physical restrictions, and the outage time needed to conduct the retrofit (Schaarschmidt et al. 2005). In addition, installing new equipment can place the reliability and availability of a plant at risk if it does not perform as advertised; even with a proven technology, every plant is unique. NETL (2009c) identifies several other technical, regulatory, and institutional barriers that must be addressed to achieve higher efficiencies in existing coal-fired power plants. Nonetheless, efficiency improvements are being implemented at several existing power plants outside the United States. Some examples are highlighted below.

3.7.2 Replacement and Retrofit Outside the United States

Improved Efficiency through Modernization of Turbine and Condenser—Germany

The 350-MW Farge Power Plant in Bremen, commissioned in 1967, included a high-pressure, an intermediate-pressure, and two low-pressure turbines and a hydrogen-cooled generator. In 2002, after the plant had been operating for more than 30 years, efficiency improvements aimed at achieving an additional 22 MW of production were undertaken. These included new rotors and casings for the intermediate- and low-pressure turbines, a new condenser, maintenance of the high-pressure turbine, soot blower optimization, and other smaller improvements. These improvements increased power output by 27 MW and boosted efficiency to 42% (Bednorz and Henken-Millies 2006).

Modernization of Lignite Power Plant—Poland

The Belchatow plant in the Lodz Province, roughly 170 kilometers southwest of Warsaw, consists of 12 375-MW lignite-fired units. The plant began operations in the early 1980s and is currently undergoing modernization and expansion to improve efficiency, comply with environmental regulations, and meet growing power demands. Over the 2007–2013 time period, 10 of the 12 units will be upgraded (mostly through turbine improvements), and the two oldest units will be shut down permanently. A recent contract for an integrated retrofit of one unit (#6) is projected to increase the unit's efficiency to more than 41%. Included in the retrofit are reconstruction of the boiler and its auxiliary equipment, replacement of high-pressure and intermediate-pressure parts of the turbine, increasing power output of the generator, and installing new high-pressure heaters. In addition, a new 858-MW, lignite-fired supercritical plant is being built as an extension. Among other things, the new plant will reduce cooling water consumption by reusing cooling tower blowdown water and by reusing water from the nearby mine for ash slurry transport (Twardowski 2007). In 2010, the plant's owner/operator announced that it had signed a contract to evaluate and implement coal drying technology at the complex (Galtos 2010).

Increasing the Performance of Existing Power Plant—South Africa

The Arnot Plant in northeastern South Africa began operations in 1975 and was approaching the end of its nominal life in 2000. In 2007, construction was begun to retrofit steam turbines and boiler components of all six units and to increase plant output from 2,100 to 2,400 MW. The project includes replacing the high-pressure and intermediate-pressure turbines, modifying the low-pressure turbines, modifying the existing boilers, upgrading the water supply pumps, and overhauling the coal feeding mills. The project was scheduled for completion in 2010 at an estimated cost of R1,48 billion (about $200 million U.S. dollars) (http://www.engineeringnews.co.za/print-version/eskom-awards-r823m-contract-to-alstom-for-arnot-upgrade-2006-08-31).

Steam Turbine Modernization Project—England

The Drax power station in Selby is undergoing a turbine modernization project to replace the high- and low-pressure turbine modules for all six 660-MW units with modern steam turbines. The project is expected to increase the station's overall efficiency from 38% to nearly 40% (Power Technology 2010). The project is scheduled for completion in 2011 (Drax 2010).

Retrofit of 705-MW Lignite-Fired Power Plant—Germany

In 2003, after nearly 25 years of successful operations, the steam turbine at this conventional hard-coal-fired power plant in Mehrum was retrofitted to take advantage of the availability of new, more efficient technologies. The retrofit, which included replacing the rotors and inner casings of all partial turbines, including the blades, resulted in an increase in overall plant efficiency from 38.5% to 40.5% (Schaarschmidt et al. 2005).

3.8 MEASURING AND TRACKING WATER USE

Freshwater withdrawal and consumption at power plants can be reduced by finding and fixing leaks and by providing incentives to reduce water consumption. Both of these approaches are used in South Africa and are summarized below.

3.8.1 Water Metering and Monitoring

The South African Department of Water Affairs and Forestry measures the volume of water supplied to power plants at the boundary to a level of accuracy of 0.5% (previously the level of accuracy was 5%). Meters are continuously verified and upgraded, inspections are conducted during every shift at the power plants, and leaks are recorded and reported for repair according to formal operating reporting systems and maintenance procedures. Leaks from the raw water supply pipelines are indicated by the remote supervisory control system that senses any reduced water levels in the raw water reservoirs at the power plant.

3.8.2 Incentives

Eskom, South Africa's state-owned public utility, uses a sustainability index to ensure the long-term sustainability of its business with respect to technical, financial, social, and environmental issues—including access to water and water availability. The sustainability index is part of the performance contract of each employee—from executive level to the operational level—with targets for the various components allocated according to the responsibility and accountability exercised within the area. A specific water use indicator, liters per kilowatt-hour, which is calculated by dividing the amount of water consumed by the amount of energy sent out, is part of the sustainability index. The water use indicator is used to assess the performance of individual power plants and the company as a whole. Each power plant has a water-use target in liters per kilowatt-hour, which is benchmarked against historical and theoretical water consumption levels for each particular type of plant. These water targets are linked to the sustainability index contained in performance compacts, which in turn are linked to business-unit and individual performance bonuses. By using this indicator, Eskom monitors its water use, which allows for the identification of specific water management problems at individual power plants and the implementation of targeted corrective strategies.

3.9 CONTROL AND INSTRUMENTATION

High-performance monitoring and process control techniques and systems help ensure that initially designed efficiency performance can be maintained during long-term operations. These techniques and systems can improve operating efficiency by providing better control of excess air and steam pressure and temperature, and they can reduce boiler and turbine stresses by coordinating startup and load changing to reduce temperature and pressure variations. Wireless technologies, a relatively recent development in power plant control, can be implemented at various scales for a variety of applications, including monitoring pressure relief valves, monitoring the corrosion in pipelines and vessels, and monitoring temperatures at pre-heaters and pumps in order to improve thermal efficiencies. These systems provide an indirect means for reducing water consumption because as efficiency increases, water consumption decreases. Smart devices such as transmitters and actuators can measure and report multiple process variations and can provide data at higher resolutions than possible with conventional field devices. By constantly performing self-diagnostics and reporting, they can alert operators to emerging problems before they impact the process, enabling proactive responses to changing plant conditions (Power Technology 2008). During plant construction and start-up, high-speed communications networks, intelligent field devices, and asset management software help streamline device installation, communications, verification, and troubleshooting. Over the long term, the information made available by digital technologies and intelligent field devices can help optimize plant operations and maintenance activities and avoid unplanned outages.

3.9.1 Deployment

Several new plants in Europe and Asia are being equipped with advanced digital plant architectures and expert control systems to monitor and control boiler and other plant processes, thereby enabling operations at elevated steam and temperature levels and increasing efficiency.

Pingdingshan Luyang Plant—China

This plant, in China’s Henan Province, will ultimately include six 1,000-MW units, the first two of which will include an automation and control system to perform data acquisition and monitor and control all major plant components, including the boiler and turbine. The system will also manage the FGD system, sequence-control system, electrical-control system, and balance-of-plant processes, as well as water treatment, ash handling, transportation, and other auxiliary systems. The systems will be integrated by using multi-networking technology. A water treatment device manager will provide online access to instrument and valve process information, and to predictive diagnostic information (ProcessingTalk 2009). These expert controls are also being installed at existing plants, many of which are operating beyond their original life expectancy. Retrofitting older plants will improve control and efficiency, and several plants have performed cost benefit analyses that have determined that a retrofit with automatic controls is appropriate.

Ekibastuz Gres-1 Plant—Kazakhstan

Controls for the steam turbine and turbine drives of feedwater pumps at this 4,000-MW plant will be modernized. One process-control platform will control equipment supplied by different turbine manufacturers, thereby helping streamline operations and improve overall efficiency by reducing the need for training and spare parts. One unit is also being modernized by digital automation of all major equipment and processes to enhance unit-wide compatibility and contribute to improved thermal efficiencies (ProcessingTalk 2010).

3.10 ALTERNATIVE WATER SOURCES

The use of alternative water sources for cooling and boiler makeup water is being investigated in both the United States and abroad. NETL (2009b) describes research on alternative water sources that include treated municipal wastewaters/reclaimed waters, produced waters from oil and gas wells, mine pool waters, produced water from CO_2 storage in saline formations, and recovered ash pond waters. Researchers in China, South Africa, and the Netherlands are investigating and implementing other alternative water sources—within the plant and external to it. Examples include the following:

3.10.1 Recovery of Cooling Tower Water for Boiler Makeup Water—China

China's centrally located Shanxi Province has about one-third of China's total known coal deposits, but it also has an arid climate most of the year and a harsh monsoon season, meaning that 60% of the annual rainfall occurs between June and August. The Datong power plant, which supplies electricity to Beijing (10 miles to the east), has eight cooling towers that circulate about 39 mgd of water, one-seventh of which (5.6 mgd) is continually blown down to prevent the buildup of harmful solids. At the same time, high-pressure boilers for the steam turbines consume makeup water at a rate of 3.7 mgd. Until recently, this makeup water was purchased from the municipal water utility, which also had to meet the needs of other industrial, residential, and agricultural customers. Datong plant engineers found that by purifying the cooling tower blow-down water with reverse osmosis technology that had been pretreated with ultrafiltration, the treated blow down could replace the municipal water as a source for the boiler makeup water. The ultrafiltration pretreatment system, which was needed because of the high concentration of silicate in the cooling tower blow-down water, reduces the cleaning frequency of the reverse osmosis system and extends membrane life, and was commissioned in July 2005. The ultrafiltration membranes take the 5.6 mgd feed from cooling tower blow down and produce a permeate of 4.9 mgd. The reverse osmosis system recovers 75% of the flow, producing 3.7 mgd of high-quality water—completely replacing municipal water as the source for boiler makeup water. The concentrate from the ultrafiltration and reverse osmosis processes is used for coal washing (Koch Membrane Systems 2010).

3.10.2 Water Recycling—South Africa

South Africa's coal plants use low-grade coal, which produces a large amount of ash when combusted. The ash is disposed of in ash dumps by either wet or dry ash handling. In 1987, South Africa's state-owned electric utility adopted a zero liquid effluent discharge policy, which requires the taking of all reasonable measures to prevent water pollution through the establishment of a hierarchy of water uses based on quality. Cascading the water used from higher to lower quality enables extensive reuse. South Africa's wet-cooled power plants cascade water from good to poor quality until all pollutants are finally captured in the ash dumps, so that wastewater rather than freshwater is used for dust suppression. The objective is to dispose of the maximum mass of salts with the smallest possible volume of water without compromising the ability of the ash to encapsulate the salt load imposed.

3.10.3 Reclaiming Water from FGD Systems—the Netherlands

Researchers in the Netherlands are investigating the recovery of water vapor from flue gases. De Vos et al. (2008) report that an average 400-MW coal-fired power plant in the Netherlands uses 30 m^3/h of demineralized water for steam production and that the same 400-MW plant with an FGD unit will emit 150 m^3/h of water through the stack. They note that if 20% of this water could be recovered, the plant would become self-supporting with respect to water. Condensing the flue gas to recover the water would require an enormous cooling capacity, and the acidic flue gas compounds would make the water highly corrosive. The Netherlands University of Twente has developed a polymer-based membrane material that is highly selective for water vapor at flue gas temperatures. The concept is to place the membranes behind the FGD unit, where the flue gas is saturated with water. The water recovered by the membranes is transported to the condenser, where it is added to the water steam cycle as additional water to compensate for the steam/water loses. Experimentation with these membranes over the course of a year showed that the principle works, the water flux is good, and the quality of the recovered water is high. The next step is to determine whether the price of water recovered from the flue gas would be competitive with that from a conventional demineralization plant. A pilot plant aimed at recovering 1 m^3/h is in the planning stages (de Vos et al. 2008).

3.10.4 Use of Saltwater in Cooling Towers

Saltwater can be used in cooling towers as a means for reducing freshwater consumption and for avoiding impacts associated with fish impingement and entrainment (see Section 3.3.1), but saltwater can affect cooling tower performance (Jones et al. 2010). For example, saltwater evaporates more slowly than pure water and has a lower heat-absorbing capacity than pure water, both of which effectively reduce the tower's thermal performance. Because more heat exchange area is needed to compensate for the salt-related performance losses, saltwater towers are larger than freshwater towers for a given heat load. Larger cooling towers require more fan horsepower to move the required air volume and therefore require additional energy. Seawater also causes more scaling than freshwater, and high salinity levels reduce the effectiveness of scale inhibitors. (A scale of calcium carbonate as little as 0.1 inch thick can reduce heat transfer by up to 40% [Jones et al. 2010].) Finally, bacteria and algae can form slimes and films that impede heat transfer. Nonetheless, these problems can be controlled. Higher towers can compensate for reduced efficiency, proper acidic additions can help reduce requirements for scale inhibitors, and biocides can control biological fouling.

3.10.5 Desalination

Desalination is the process of removing salt and other minerals from seawater to convert it to water that is suitable for industrial processes, consumption, or irrigation. Two main desalination techniques are (1) distillation, in which seawater is boiled to produce steam that is collected, cooled, and condensed back into freshwater; and (2) filtering. Filtering can occur through reverse osmosis, in which pressure forces the seawater through a membrane with the desalinated water collected on the other side. Filtering can also occur through elecrodialysis, in which an electric current induces a charge on the salt molecules. Electrodes with the opposite charge placed on the other side of the membrane pull the salt across, leaving purified water behind. Desalination plants located near the ocean pretreat the water to remove particulate matter, kill pathogens, and adjust the pH. A byproduct of the desalination process is a concentrated brine, which must be disposed of. Desalination is energy intensive and costly. Costs can be reduced by treating brackish water or groundwater with lower salt levels instead of seawater (because there is less salt to remove from brackish water). By collocating desalination plants and thermoelectric power plants, waste heat from the power plant can be used to preheat the seawater, thereby saving energy that would otherwise be used to heat the seawater prior to treatment. Technology improvements made over the past decade in reverse osmosis processes also contribute to significant energy reductions. Examples of how desalination is being used to reduce freshwater needs at coal-fired power plants in Asia and Europe are highlighted below.

3.10.6 Desalination for Cogeneration of Water and Power—China

China is developing large desalination plants to produce process water for coal-fired power plants. Examples include the following:

- The desalination facility in China's Zheijang Province, built in 2006 by Beijing CNC Technology, Inc., was designed to supply process water to a new 1,800-MW electrical power station built for the 2008 Olympics. The technology uses a patented PX Pressure Exchanger® Technology for the 36,000-m^3/day capacity desalination plant. Compared to conventional waste-heat recovery technologies, the PX system reduces the amount of energy required to desalinate seawater for power plants by up to 68% (Energy Recovery, Inc. 2008).

- The Huarun Power Plant south of Guangzhou City, Guangdong Province, entered commercial service in 2007 with two 360-MW pulverized coal boilers. Makeup water comes from the Xiao Hu Li River, but because of its proximity to the South Sea, it has high levels of total dissolved solids, chloride, and conductivity during the dry season. A reverse osmosis system is used to produce the necessary boiler makeup water for the two power generation units from the available sub-sea water supply (Zhao et al. 2010).

- The 4,000-MW Tianjin Power Plant (about 200 kilometers northeast of Beijing) has deployed four units, and plans to add four more, to provide desalinated seawater for the plant's steam boilers. The units use the "multi-effect distillation" process in which seawater is vaporized and then runs through multiple iterations of evaporation and condensation. The distillation plants use waste heat from the power plant to reduce total desalination costs and minimize the plant's discharge of heat into the atmosphere. Each unit has a production capacity of 25,000 m^3/day (6.6 mgd) of distilled water. Thus, the additional four units, when combined with the existing units, will provide a daily total capacity of 200,000 m^3/day (about 53 mgd) (IDE 2010).

3.10.7 Desalination for Boiler Makeup—India

A seawater desalination plant at Mundra in coastal Gujarat is being built to supply water for the 4,000-MW supercritical coal-fired Ultra Mega Power Project. The seawater reverse osmosis plant will have a production capacity of 25,200 m^3/day (about 6.7 mgd) of desalinated water, which will be used in various applications. A portion of the desalinated water will be treated through a brackish water reverse osmosis system and ion exchange to produce high-purity water for boiler makeup.

3.10.8 Desalination and Reuse of Heated Water—Italy

In Civitavecchia, Ener—Italy's major electricity producer—is converting a massive oil-fired power plant to an efficient coal-fired power plant. The plant will use an on-site desalination plant to generate cooling water, and the discharged water will be used to heat one of Italy's largest fish farms (Rosenthal 2008).

3.10.9 Desalination for Cooling Water and Ash Conditioning—South Africa

The Tutuka Power Plant, near Standerton in Mpumalanga, uses a dry ash handling system, in which overland conveyers move moistened ash to the ash pond, where it is conditioned with blowdown water from the wet cooling water tower. When the power plant operates at a low load factor, the amount of ash generated is not sufficient to contain all the blowdown water. In 1985, a desalination plant was built to treat the blowdown water to reduce the volume of water disposed of at the ash pond, and to counteract the effect of the poor water quality of the Vaal River. The desalination plant produces a permeate, which is fed into the cooling water system, and a brine, which is used for ash conditioning. Initially, the plant was intended to treat only the blowdown water, but in 1998, South Africa passed the National Water Act, which prohibits the discharge of wastewater into water resources without proper authorization and treatment to acceptable standards. The mines that provide the coal to Eskom's Tutuka and nearby Lethabo power plants produce significant volumes of wastewater and Eskom uses desalination plants to treat this wastewater, which it then uses for cooling. The desalination units, which use spiral-wound reverse osmosis membranes to treat the contaminated mine water, provide a permeate water recovery rate of 87% (for Tutuka) and 80% (for Lethabo). The reduced water intake at the two plants saves about 5.16 million m^3 per year (about 3.7 mgd). The total capital cost for both the treatment plants was about $7 million U.S. (Pather 2004).

3.11 WATER-EFFICIENT PLANTS

Many of the water-savings approaches described above are targeted toward specific areas or processes within a power plant, such as cooling towers or ash handling. Some newer plants, particularly in Asia, are combining several direct and indirect approaches to develop water-efficient plants. China, for example, is building power plants specifically designed to save water by implementing multiple water-savings approaches. Two examples follow:

- The SP Power Datong No. 2 Power Plant Phase II uses direct air cooling for its two 600-MW units. Also at this plant, treated municipal waste water is used as service water. By using the treated municipal waste water, the plant managers calculated that the project saves 5 million m^3 of water per year (about 3.6 mgd) (http://www.ncpe.com.cn/ncpey/business/experience.htm).

- Huaneng Xinjiang Energy Development Co. plans to invest $825 million U.S. in the construction of a water-saving coal-fired power plant in Hami City (Xinjiang autonomous region). Water-saving technologies and approaches to be incorporated include large (1,320-MW) supercritical coal-fired units, the advanced "active coke"–based dry process for capturing SO_2 emissions, an air-cooling system for both main and auxiliary equipment, the wide use of intermediate water from an urban sewage processing plant, and a storage pool for collecting rainwater. Water consumption is expected to be about one-third of that consumed in conventional power plants. Construction is expected to start in July 2011, and operations are expected to start in December 2013 (http://energybusiness.in/china-develop-water-saving-power-plant).

A new plant in India is avoiding the use of freshwater. The 1,500-MW conventional thermal power plant in Vallur is being constructed in two phases: Phase 1 will have two 500-MW units starting production in October 2011; Phase II will have one 500-MW unit starting production in

December 2012. The plant will have six induced draft cooling towers with a capacity of 30,000 m^3/hr. Seawater will be used in the towers, and freshwater will be produced from a desalination plant (http://www.power-technology.com/projects/vallurconventional).

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4 CONCLUSIONS

In many countries, including the United States, coal provides—and is expected to continue to provide—a major share of electricity production. In addition, many countries (e.g., Germany, Australia, the United States) have large coal resources, which provide relatively inexpensive and secure fuel sources. However, regarding water consumption for coal-fired power plants, there are some important differences between the United States and other countries. First, while the water supply situation in the United States is a growing concern in some regions, at the national level, the U.S. water situation is much less dire than in China, Australia, South Africa, and other countries where huge portions of the country lack water. In these countries, water-savings approaches (such as dry cooling, desalination, in-plant water recycling, and high-efficiency plants) are essential for power generation, and have been in place for several years. These and other approaches (such as coal drying, direct firing of gas turbines with coal, and low-water-consuming emissions control equipment) are being developed and deployed as knowledge and experience with them grows. Few of these approaches have been deployed aggressively in the United States.

Second, the demand for power in countries with large and growing populations, such as China and India, is growing faster than in the United States. As a result, these countries need and will continue to need plants with large generating capacities to meet their growing demands. Because of its relative abundance and lower cost (relative to other fuels that could produce the quantities of power needed), coal is a dominant fuel, and large supercritical and ultra supercritical coal-fired power plants are being built to meet the demand. Because they are more efficient than traditional subcritical plants (which are the norm in the United States), these plant consume less water. While coal is projected to continue to provide a significant portion of electrical generating capacity in the United States, the projected increase in coal-fired capacity (6,300 MW between 2009 and 2035) is a fraction of that projected for China (about 648,000 MW over the same period). Because the U.S. coal-fired generating capacity will be less than that in China and other large developing countries, the efficiencies and attendant water savings provided by new large plants will also be proportionately less.

Further impetus for building more efficient plants in other countries comes from policies requiring reduced CO_2 emissions, because more efficient plants emit less CO_2. Although the United States is moving in this direction, other countries, for example those that have ratified the

Kyoto Protocol and especially those in the European Union, are building more efficient plants than the United States.

Third, besides building large, efficient plants, many countries are increasing efficiencies at existing power plants by retrofitting them and by replacing components (such as turbines) or entire plants. In the United States, plant owners and operators may be reluctant to implement such retrofits because they may trigger regulatory requirements, for which compliance is costly. For example, new source review standards that could be triggered by replacing a turbine can require a pre-construction permit review, which can in turn require the installation of additional emission controls technology, the costs of which may outweigh the benefits gained by improving the efficiency.

This report has identified 20 direct and indirect approaches for reducing water consumption at coal-fired power plants being used, or investigated for use, in countries outside the United States. All of these approaches may warrant additional investigation for application to U.S. power plants. NETL can play an important role in applying the work done in other countries to U.S. coal-fired power plants. For example, it can do the following:

- Support investigations to identify potential issues that hinder implementation of these approaches at U.S. power plants and determine how to broaden implementation of the approaches within the United States.
- Support collaborative research efforts with other countries that are investigating specific technologies to hasten deployment worldwide.
- Support U.S. organizations in obtaining information to move promising approaches that are in the R&D stage toward deployment.
- Support value-added research into freshwater-savings approaches conducted by U.S. trade organizations, power plants, and equipment manufacturers by offering these entities information on approaches used outside the United States.
- Investigate the role of policy and regulatory decisions on water-reducing efforts at power plants, and work with policy makers and regulatory agencies (1) to leverage benefits (e.g., by disseminating information regarding potential benefits regarding certain approaches, as the European Union has done with cogeneration) and (2) to mitigate negative consequences. For example, the UK's Environmental Agency supports site-specific approaches that require consideration of the plant in its surroundings when developing measures to protect against fish impingement and entrainment in cooling

tower intakes, whereas the U.S. EPA takes a prescriptive approach that essentially requires recirculating systems in all cases.

- Work directly with power plants and country organizations to share information (e.g., on potential costs and benefits of various approaches, implementation requirements) needed to set research priorities.

In setting priorities for supporting these R&D efforts, factors to consider include the following:

- Potential costs and benefits of various approaches;
- Number of plants or capacity for which a given approach could apply;
- Requirements for implementation (e.g., changes to plant design that might be required, regulatory implications);
- Ongoing or projected research supported by NETL on individual approaches that could benefit from work done in other countries, or that could be used to collaborate with research activities outside the United States; and
- Role of government policies (e.g., how changes to government policies such as new source review or §316(b) requirements could encourage deployment of water-savings approaches).

By identifying various water-savings approaches and providing information on how and where they are used, their status with respect to RD&D, and the drivers that have led to their deployment, this study provides an important first step toward applying water-savings approaches used in other countries to U.S. coal-fired power plants. Further action by NETL, industry, and the government to facilitate deployment of successful water savings approaches will help ensure that the water needs of coal-fired power plants *and* those of other energy and nonenergy uses in the United States can be met with a minimum potential for disruption to energy production or water use.

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APPENDIX A. APPROACHES FOR REDUCING FRESHWATER CONSUMPTION AT COAL-FIRED POWER PLANTS OUTSIDE THE UNITED STATES

Approach	Description	Development/ Implementation Status	Reported Benefits	Challenges
Increase power plant efficiency, primarily by increasing the steam parameters (temperature and pressure)	More efficient plants require less power, and therefore less water. Supercritical and ultra supercritical boilers have higher thermal efficiencies than conventional coal-fired boilers.	Supercritical and ultra supercritical plants are in commercial operation in Australia, China, South Korea, Japan, Taiwan. Research on increasing steam parameters beyond ultra supercritical is underway in Germany.	Efficiencies of up to 45%. Increased efficiency lowers water consumption.	New materials are required to withstand the impacts of high temperatures and pressures.
Cogeneration/CHP	The use of waste heat to produce power increases overall plant efficiency.	Widely used in Europe (Germany, Denmark, Sweden).	Increased efficiency lowers water consumption.	Need assured demand for heat.
Integrated gas combined cycle (IGCC)	Combined cycle, which uses waste heat to produce more electricity, is more efficient than conventional coal-fired generation.	Commercially deployed in the Netherlands, Spain. Demonstration program underway in China.	Cooling requirements for IGCC plants are roughly 35–40% less than those of pulverized coal plants.	Costs.
Direct firing of gas turbines with coal	More efficient than conventional generation.	Fuel being produced in Australia, testing underway in Japan.		
Once-through cooling	Does not rely on water consuming evaporation.	Behavioral fish protection systems are being developed in the UK, Belgium, and Poland.	Lower water consumption than recirculating and dry cooling.	Systems to reduce entrainment.
Dry cooling	Uses convection heat rather than evaporation to reduce water consumption.	Deployed in China, South Africa, Australia.	90% less water consumption than with conventional recirculating systems.	High costs, efficiency penalties.

Reducing Freshwater Consumption at Coal-Fired Power Plants:
Approaches Used Outside the United States

Approach	Description	Development/ Implementation Status	Reported Benefits	Challenges
Coal drying	Reduces the moisture content of low-rank coals prior to combustion; increases overall plant efficiency.	Prototype plant uses fluidized bed drying in Germany. Drying techniques being developed in Australia.	Can increase thermal efficiency by 5 percentage points. Water produced from coal drying can be used for other purposes.	Boiler modification needed for retrofitting some drying technologies.
Dry bottom ash handling	Does not require water for cooling and conveyance and increases combustion of carbon.	Commonly used in Europe, Asia, and South Africa.	Can be used for new plants and retrofits.	
Low-water-consuming emissions control technologies	Efficient dry scrubbers.	Commercially deployed in Japan.	ReACT uses 1% of the water used by conventional wet FGD systems; CFB scrubbers have smaller footprint than conventional FGD systems.	
Plant replacement	Old, low-efficiency plants replaced with new, more efficient plants.	China has active program to replace old, small, inefficient plants with larger, more efficient ones.	Increased efficiency.	
Retrofit/ component replacement	Improve thermal efficiency of aged steam turbines and plants.	Retrofits have been implemented in Germany, Poland, South Africa, and England.	Increased efficiency.	Physical restrictions, outage time, linking new equipment with balance of plant.
Water metering and monitoring	Measures and tracks water use.	Deployed in South African plants.	Facilitates identification and fixing of leaks.	
Incentives	Build incentives for reducing water consumption into employee and plant performance measures.	Deployed in South African plants.	Reduced freshwater consumption.	

Approach	Description	Development/ Implementation Status	Reported Benefits	Challenges
Control and instrumentation	High-performance monitoring and process control helps ensure operational efficiency.	Being deployed in new plants in China and retrofitted at plant in Kazakhstan.	Increased efficiency.	
Recovery of cooling tower water for boiler makeup water	Reverse osmosis to purify cooling tower blowdown water.	Deployed in China.	Replaces freshwater for boiler makeup.	
Water recycling	Cascade water use from higher to lower quality.	Deployed in South African plants.	Minimizes water consumption.	
Reclaiming water from FGD systems	Membranes used to recover water from FGD systems.	Pilot plant planned in the Netherlands.	Reduced freshwater consumption.	Costs.
Saltwater use in once-through cooling	Enhances cooling efficiency, particularly where seawater is cold.	Deployed in Northern Europe	Reduced freshwater consumption.	Requires accommodations to address performance and other impacts of saltwater.
Desalination	Treat seawater or brackish water by distillation or filtering.	Deployed at power plants in China and South Africa; under construction at plant in India.	Reduced freshwater consumption.	Energy intensive, costs.
Water-efficient plants	Combines multiple water-savings approaches in a single plant.	Deployed and under development in China; under development in India.	Reduced freshwater consumption.	

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