AUTHOR QUERY FORM

ELSEVIER	**Journal: JEPO** **Article Number: 4266**	**Please e-mail or fax your responses and any corrections to:** **E-mail: corrections.esil@elsevier.macipd.com** **Fax: +44 1392 285878**

Dear Author,

Any queries or remarks that have arisen during the processing of your manuscript are listed below and highlighted by flags in the proof. Please check your proof carefully and mark all corrections at the appropriate place in the proof (e.g., by using on-screen annotation in the PDF file) or compile them in a separate list.

For correction or revision of any artwork, please consult http://www.elsevier.com/artworkinstructions.

Articles in Special Issues: Please ensure that the words 'this issue' are added (in the list and text) to any references to other articles in this Special Issue

Uncited references: Referen hat occur in the reference list but not in the text – please position each reference in the text or delete it from the list.	
Missing references: References listed below were noted in the text but are missing from the reference list – please make the list complete or remove the references from the text.	
Location in article	**Query/remark** **Please insert your reply or correction at the corresponding line in the proof**
Q1	Rao et al. (2002) changed to Rao and Rubin (2002) as per the reference list. Please confirm.

Electronic file usage

Sometimes we are unable to process the electronic file of your article and/or artwork. If this is the case, we have proceeded by:

☐ Scanning (parts of) your article ☐ Rekeying (parts of) your article ☐ Scanning the artwork

Thank you for your assistance.

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage

Haibo Zhai, Edward S. Rubin*

Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA 15213, USA

A R T I C L E I N F O

Article history:
Received 10 February 2010
Accepted 6 May 2010

Keywords:
Cooling system
Pulverized coal power plant
Carbon capture system

A B S T R A C T

Thermoelectric power plants require significant quantities of water, primarily for the purpose of cooling. Water also is becoming critically important for low-carbon power generation. To reduce greenhouse gas emissions from pulverized coal (PC) power plants, post-combustion carbon capture and storage (CCS) systems are receiving considerable attention. However, current CO_2 capture systems require a significant amount of cooling. This paper evaluates and quantifies the plant-level performance and cost of different cooling technologies for PC power plants with and without CO_2 capture. Included are recirculating systems with wet cooling towers and air-cooled condensers (ACCs) for dry cooling. We examine a range of key factors affecting cooling system performance, cost and plant water use, including the plant steam cycle design, coal type, carbon capture system design, and local ambient conditions. Options for reducing power plant water consumption also are presented.

1. Introduction and objectives

Water is an integral element of electricity generation at thermoelectric power plants, primarily for the purpose of cooling. Thermoelectric power plants account for approximately 39% of freshwater withdrawals in the United States, ranking slightly behind agricultural irrigation as the largest source of freshwater use (Feeley et al., 2008). Future water demands for electricity generation will increase as thermoelectric generating capacity is projected to grow by approximately 18% by 2030 relative to 2005 (NETL, 2009). To minimize adverse environmental impacts, the Clean Water Act (CWA) requires the use of best available control technologies for new power plants, which has promoted the widespread use of closed-loop evaporative cooling systems employing wet cooling towers in place of once-through cooling systems (EPA, 2008).

If evaporative cooling towers continue to be utilized in new power plants, consumptive water use for electricity production in the U.S. could more than double by 2030 (DOE, 2006). In the meanwhile, to address growing concerns about greenhouse gas emissions from pulverized coal (PC) power plants, post-combustion carbon capture and storage (CCS) is receiving considerable attention. However, as will be seen in this paper, significant quantities of water are required to cool the post-combustion capture processes that are now commercially available for removing carbon dioxide (CO_2). This puts further pressure on the demand for water resources (IPCC, 2005; NETL, 2007a). Population and electricity demand growth, along with an increasing possibility of droughts in some areas, could induce water shortages that would further exacerbate this problem (Sovacool and Sovacool, 2009). In some regions of the U.S., limited water supplies already have led to deployment of alternative cooling technologies such as dry cooling systems in order to reduce power plants water use, albeit at a higher cost than conventional systems (EPRI, 2004). Given the growing importance of power plant water use, it is important to have a more complete picture of the performance and cost implications of alternative cooling technologies, particularly in the context of low-carbon power generation with CO_2 capture.

The major objectives of this paper, therefore, are to: (1) evaluate the plant-level performance and cost of current wet and dry cooling technologies for PC power plants, including systems with post-combustion CO_2 capture; (2) identify and display the effects of key factors affecting cooling system performance and cost for different plant designs; (3) compare the impacts of wet and dry systems on overall power plant water consumption, efficiency and cost for cases with and without CCS; and (4) draw out policy implications for integrating energy production and water resource management, especially in the context of climate change. The cooling technologies considered include recirculating evaporative towers for wet cooling and air-cooled condensers (ACC) for dry cooling. The performance evaluation emphasizes makeup water usage for wet systems and ACC sizing for dry systems. The cost assessment focuses on total capital cost and total levelized cost of electricity (COE) generation.

* Corresponding author. Tel.: +1 412 268 5897; +1 412 268 1089.
E-mail addresses: rubin@cmu.edu, haibo_zhai@yahoo.com (E.S. Rubin).

0301-4215/$ - see front matter © 2010 Published by Elsevier Ltd.
doi:10.1016/j.enpol.2010.05.013

2. Analytical approach

In a wet tower design, the water used to cool the steam turbine exhaust is in turn cooled by contact with ambient air, then recirculated to the main condenser (Fig. 1). The wet tower relies mainly on the latent heat of water evaporation for cooling (Threlkeld, 1970). Makeup water is then needed to replace the losses due to evaporation, as well as the smaller losses from drift and blowdown. In contrast, dry systems employing ACCs utilize the sensible heating of atmospheric air passed across finned-tube heat exchangers to reject the heat from condensing steam (Fig. 2) (Kroger, 2004; EPRI, 2005).

To evaluate each process, a complete cooling system performance model was developed using detailed mass and energy balances for a PC power plant. The performance models are linked to engineering-economic models that calculate the capital cost, annual operating and maintenance costs and total annual levelized cost of the specified system and plant. The water systems modules are embedded in the Integrated Environmental Control Model (IECM) developed by Carnegie Mellon University for the U.S. Department of Energy's National Energy Technology Laboratory (USDOE/NETL). The IECM is a well-documented publicly available model that provides systematic estimates of performance, emissions, cost and uncertainties for preliminary design of fossil-fueled power plants with or without CO_2 capture and storage (IECM, 2009; Rubin et al., 2007a). Detailed technical documentation for each of the IECM cooling options and power plant systems discussed in this paper are available elsewhere (Zhai et al., 2009a, 2009b; Versteeg et al., 2009; Rubin et al., 2007a; Rao and Rubin, 2002).

The main factor affecting the size and cost of a cooling system is the heat load rejected at the primary condenser. This, in turn, depends mainly on the plant's gross size and thermal efficiency, including the influence of environmental control systems such as a CO_2 capture process. To account for the many factors that directly or indirectly affect the water requirements of a PC power plant, the IECM Version 6.2 was employed for this paper. A series of sensitivity analyses was conducted to investigate the effects on plant performance and cost of key factors including the plant design, fuel type, cooling system type, ambient conditions, carbon capture option, and steam turbine design (for dry cooling systems). The results of this analysis are summarized below.

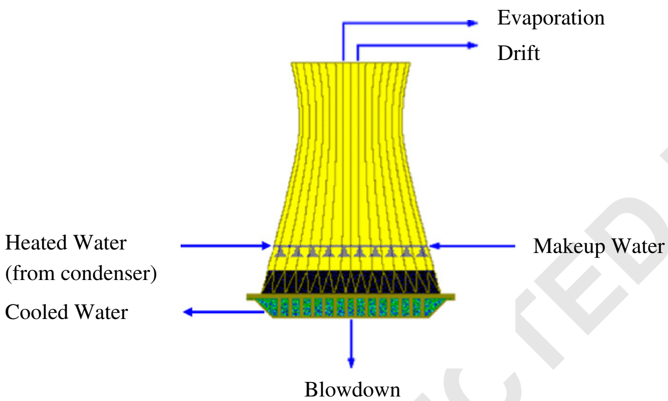

Fig. 1. Schematic of a wet recirculating cooling tower system.

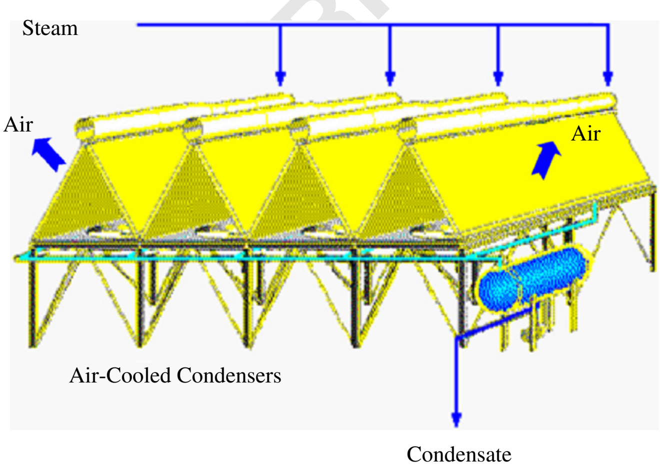

Fig. 2. Schematic of a dry cooling system.

3. Base case studies

Base case studies were conducted to characterize the performance and cost of wet and dry cooling system options for subcritical PC power plants without carbon capture (typical of most current plants). Major environmental control systems included selective catalytic reduction (SCR), an electrostatic precipitator (ESP) and flue gas desulfurization (FGD). Key technical and economic design assumptions for the base case plants are given in Table 1. The resulting performance and costs of the base plant with wet and dry and cooling systems are given in Table 2. To compare cases with different design parameters and configurations, all plants in this paper are evaluated on a basis of 550 MW power net output.

Table 2 shows that the plant with a conventional wet tower has a smaller gross size and higher efficiency than the plant with

Table 1
Key assumptions for the baseline cases.

Parameters	Value
Technical parameters	
Net plant output (MW)	550.0
Boiler type	Subcritical
Environmental controls	SCR+ESP+FGD
Coal type	Illinois #6
Ambient air pressure (kPa)	101.4
Ambient air temperature (°C)	25
Ambient relative humidity (%)	50
Cooling water temperature drop across the wet tower (°C)	11
Cycle of concentration in the wet cooling system[a]	4
Turbine backpressure for the dry cooling system (in.Hg)	4
Air-cooled condenser (ACC) plot area per cell (m^2)[b]	110
Configuration of air-cooled heat exchanger	Multiple-row
Initial temperature difference for ACCs (°C)	27
Economic/financial parameters	
Cost year	2007
Plant capacity factor (%)	75
Fixed charge factor	0.148
Plant life time (years)	30
Water cost ($/$m^3$)	0.26
Coal cost ($/tonne)	46.3
General facilities capital (% of PFC[c])	10
Engineering and home office fees (% of PFC)	10
Project contingency cost (% of PFC)	15
Process contingency cost (% of PFC)	0

[a] The cycle of concentration is defined as the concentration ratio of the pollutant dissolved in cooling water versus makeup water.
[b] A condenser cell consists of multiple heat exchanger bundles arranged in the form of "A" frame and is serviced by a large fan.
[c] PFC represents process facilities capital cost.

Please cite this article as: Zhai, H., Rubin, E.S., Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage. Energy Policy (2010), doi:10.1016/j.enpol.2010.05.013

Table 2
Results for the baseline cases using the IECM.

Performance and cost measures	PC plant with a wet cooling system	PC plant with a dry cooling system
Gross power output (MW)	593.3	600.7
Net plant efficiency, HHV (%)	36.1	34.6
Tower evaporation loss (tonnes/h)	1012	0
Tower blowdown (tonnes/h)[a]	337	0
Tower drift loss (tonnes/h)[b]	0.6	0
Total cooling system makeup water (tonnes/MWh)	2.46	0
Number of air cooled condenser cells		63
Cooling system total capital requirement[c] ($/kW)	90.4	224.4
Cooling system levelized annual cost[c] ($/MWh)	3.9	7.2
Plant total capital requirement ($/kW) [c]	1788	1940
Plant revenue requirement (COE) [c] ($/MWh)	69.1	73.1

[a] Salts or other impurities accumulate in the cooling water due to water evaporation. To avoid scaling of the surface within the tower, it is necessary to blow down a portion of the water and replace it with the fresh water (Li and Priddy, 1985).

[b] The drift loss is a relatively small amount of entrained water lost as fine droplets in the air discharge from a tower (Li and Priddy, 1985). It is estimated as 0.001% of the cooling water (NETL, 2007a).

[c] All costs are in constant 2007 US dollars.

dry cooling because less auxiliary power is required to run the wet cooling system. Total makeup water for the wet system is 2.5 l/kWh (net), which is about 2.3% of the total recirculating cooling water volume. Tower evaporation accounts for 75% of water losses, while blowdown accounts for approximately 25%. Tower drift and other losses are small, less than 1% of the total. The tower blowdown rate is affected both by evaporation losses and by the cycles of concentration, a design parameter related to cooling water quality. Tower operation at higher cycles of concentration reduces the cooling tower blowdown loss, but results in greater buildup of impurities in the cooling water. This may increase system costs for additional water treatment processes needed to maintain water quality. For the dry cooling system there is no makeup water required.

The total capital requirement (TCR) for each power plant subsystem is calculated using the procedure and cost categories established by the Electric Power Research Institute (EPRI, 1993). Cost elements include the process facilities capital (PFC), general facilities cost, engineering and home office fees, contingency costs and several categories of owner's costs (including interest during construction). All costs in IECM v.6.2 were updated to 2007 U.S. dollars based on recent studies by the USDOE (NETL, 2007a). The resulting TCR for the base plant design is $90/kW for the wet cooling system and $224/kW for the dry cooling system. The wet system accounts for approximately 5% of the total plant capital cost, whereas the dry system represents about 12% of the total plant capital cost. As a result of its higher capital cost and lower efficiency, the total cost of electricity (COE) for the plant with dry cooling is $4.0/MWh more than for the base case plant with the wet cooling.

4. Sensitivity analysis for wet cooling systems

Sensitivity analyses were conducted to investigate the impacts of the several factors noted earlier. In each case, other parameters were kept at their base case values, unless otherwise noted.

4.1. Effects of plant type

The effects on the cooling system cost and water requirements were evaluated for three types of PC power plants with increasing efficiency: subcritical, supercritical and ultra-supercritical units. The steam cycle heat rates for three plant types are 8220, 7760 and 7070 kJ/kWh, respectively, corresponding to HHV efficiencies of 43.8%, 46.4% and 50.9%. For a given net power output, the supercritical and ultra-supercritical plants have smaller cooling duties than the subcritical plant due to their higher thermal efficiencies. Fig. 3 shows that this has pronounced effects on the performance and cost of the cooling system. Compared to the subcritical PC plant, the supercritical and ultra-supercritical plants require 10% and 26% less cooling water makeup, respectively. The TCRs for the supercritical and ultra-supercritical plant cooling systems are approximately 90% and 75% that of the subcritical plant. There are similar reductions in the total levelized cost of the cooling system, reflecting the benefits of higher thermal efficiencies.

4.2. Effects of fuel type

Coal quality is another important factor affecting the performance and cost of a PC power plant (Rubin et al., 2007b). However, few studies have evaluated coal quality impacts on the plant cooling system. Here, we evaluate three coal types that are widely used in studies of U.S. power plants (Table 3). Fig. 3(a)

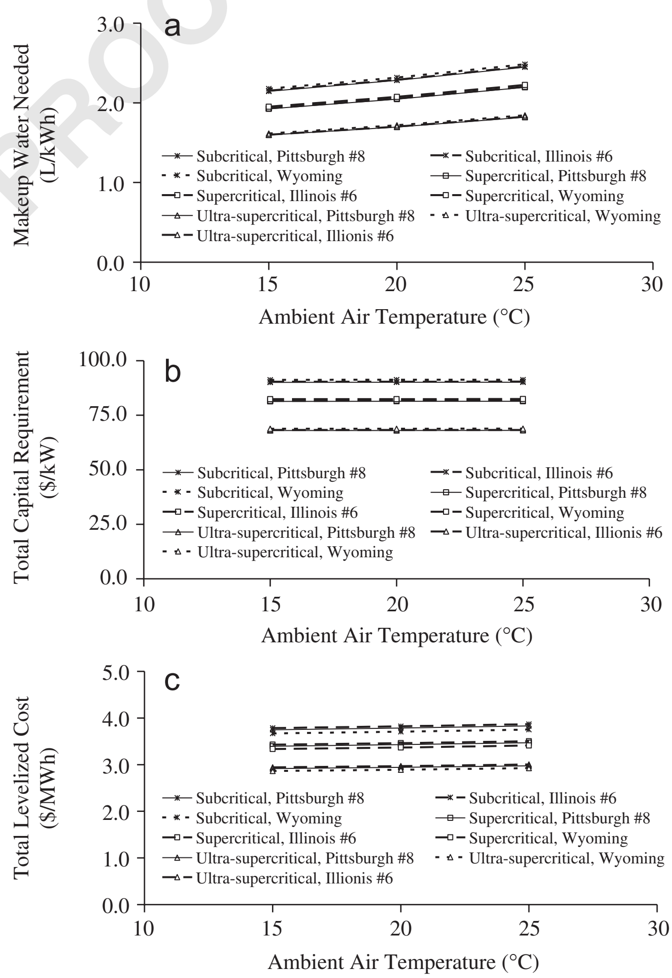

Fig. 3. Effects of plant design, fuel type and air temperature on wet cooling system.

Please cite this article as: Zhai, H., Rubin, E.S., Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage. Energy Policy (2010), doi:10.1016/j.enpol.2010.05.013

Table 3
As-fired properties of three US coals.

Coal type	Pittsburgh #8	Illinois #6	Wyoming PRB
Coal rank	Bituminous	Bituminous	Sub-bituminous
Heating value (kJ/kg)	30,840	27,140	19,400
Carbon (%)	73.81	63.75	48.18
Hydrogen (%)	4.88	4.50	3.31
Oxygen (%)	5.41	6.88	11.87
Chlorine (%)	0.06	0.29	0.01
Sulfur (%)	2.13	2.51	0.37
Nitrogen (%)	1.42	1.25	0.70
Ash (%)	7.24	9.70	5.32
Moisture (%)	5.05	11.12	30.24
Cost ($/tonne)	49.9	46.3	9.6

shows that coal quality does not significantly affect the makeup water requirement for cooling. Thus, from the perspective of water savings coal quality is not a significant factor for a wet system. Similarly, Figs. 3(b) and (c) show that difference in coal quality had only a slight effect on both the capital cost and total levelized cost of the wet cooling system. As exemplified by Fig. 3(c), changes in coal quality produced no more than a $0.1/MWh difference in total cooling system cost for a given plant type.

4.3. Effects of ambient air temperature

Ambient air temperature affects the performance of a wet cooling system via the evaporative process. We evaluated three levels of ambient air temperature and assumed that the relative humidity is 50% for all cases. Fig. 3(a) shows that makeup water usage increases by 14% when the average ambient temperature increases from 15 to 25 °C. Thus, more water is required for plants with wet cooling systems operating in areas with higher average air temperatures. Nevertheless, Fig. 3(b) shows that ambient air temperature does not significantly affect the cooling system capital cost, while Fig. 3(c) shows a small effect on the total levelized cost because of the variable operating expense for makeup water. For the base case plant design, the levelized cost of the wet cooling system increases by about 2% when the ambient air temperature increases from 15 to 25 °C. As illustrated later, however, higher costs for water could have more significant impacts on overall cost.

4.4. Effects of carbon capture system

An amine-based post-combustion CO_2 capture system is used to evaluate effects on plant water requirements. Fig. 4 presents a schematic of the amine-based capture system. Major performance parameters of the capture system are given in Table 4 based on recent studies by USDOE (NETL, 2007a). The addition of a carbon capture system affects PC plant performance in two major areas: the steam cycle and the cooling system. To separate captured CO_2 from the rich amine solvent, heat is applied using low-quality steam extracted from the steam turbine. With a regeneration heat requirement of approximately 3500 kJ/kg CO_2 product, the steam cycle heat rate increases by about 25% and the net plant efficiency decrease by roughly 11–12% across the three plant types.

Additional cooling water also is required to support the operations of the direct contact cooler (needed to lower the flue gas temperature), the CO_2 absorption and stripping processes and CO_2 product compression (which is considered to be part of the capture system; Rao and Rubin, 2002; Fluor and Statoil, 2005a, 2005b). As a result, the total cooling duty for the carbon capture system requires 91.2 tonnes of cooling water per tonne of CO_2 product for the base case design, which could be reduced through

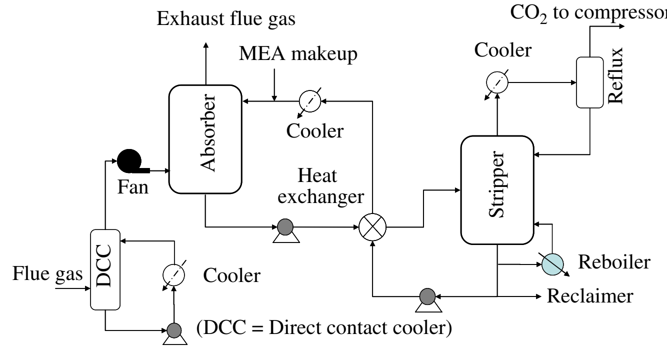

Fig. 4. Schematic of an amine-based capture system.

Table 4
Major performance parameters of the amine-based carbon capture system.

Parameters	Values
Process sorbent	Econamine FG+
CO_2 removal efficiency (%)	90
Sorbent concentration (wt%)	30
Temperature exiting direct contact cooler (°F)	113
Maximum CO_2 train capacity (tonnes/h)	209
CO_2 compressor capacity (tonnes/h)	299
Lean CO_2 loading (mol CO_2/mol sorbent)	0.19
Nominal sorbent loss (kg/tonne CO_2)	0.3
Liquid-to-gas ratio (mol MEA liquid/mol flue gas)	3.015
Gas phase pressure drop (psia)	1
Solvent pumping head (psia)	30
Pump efficiency (%)	75
Regeneration heat requirement (kJ/kg CO_2)	3500
Capture system cooling duty (tonnes H_2O/tonne CO_2)	91.2

improved heat integration, dependent on the specific design. This cooling water is provided by the plant cooling system. The total makeup water required for the plant cooling thus increases in proportion to the added demand of the CO_2 capture system.

As shown in Fig. 5(a), the net result of lower thermal efficiency (steam cycle effect) and increased cooling demands for CO_2 capture (cooling system effect) is a substantial increase in the size and makeup water requirement of the plant's cooling system. With CO_2 capture, consumptive water use for cooling increases by 83–91% across the three plant types. Thus, the availability of cooling water is critically important for low-carbon power generation using CCS. In addition, the amount of wastewater due to tower blowdown (plus other low-volume waste streams modeled in the IECM) also increases significantly. In turn, Figs. 5(b) and (c) show that the wet cooling system capital cost increases by 63–74% relative to a plant without CO_2 capture, while the total levelized cost of cooling increases by more than 90%. The latter increase includes higher operating costs for energy and other items.

5. Sensitivity analysis for dry cooling systems

Here we present results of sensitivity analyses for the dry cooling system using ACCs. In addition to the factors above, we investigate the effects of steam turbine backpressure on dry system operation.

5.1. Effects of plant type

As illustrated in Fig. 6, the performance and cost of the dry cooling system are strongly affected by the boiler type. The

Please cite this article as: Zhai, H., Rubin, E.S., Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage. Energy Policy (2010), doi:10.1016/j.enpol.2010.05.013

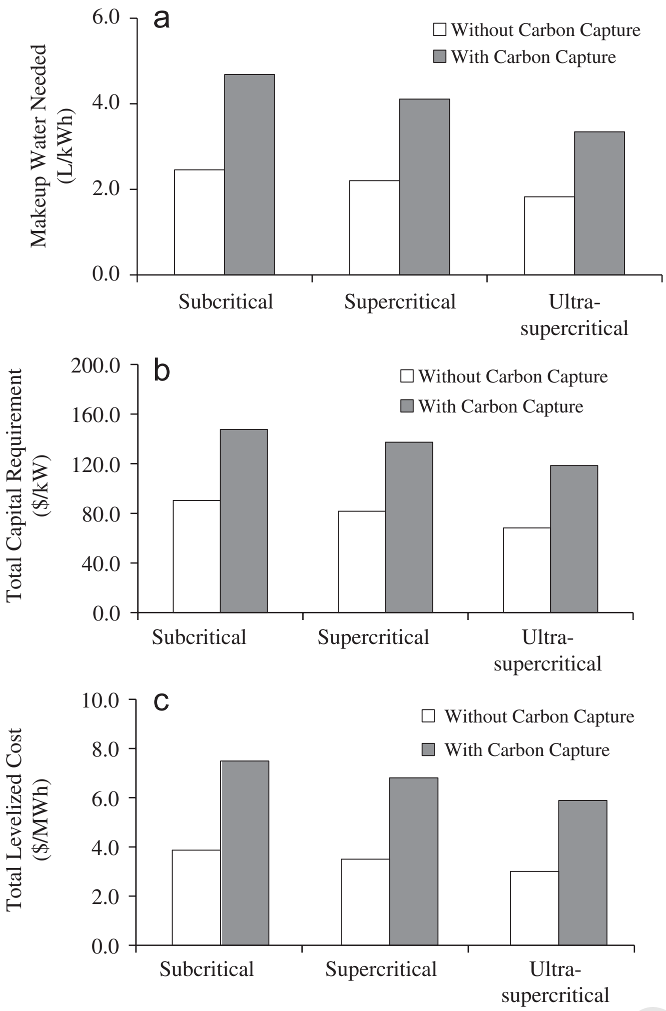

Fig. 5. Effects of carbon capture on wet cooling system.

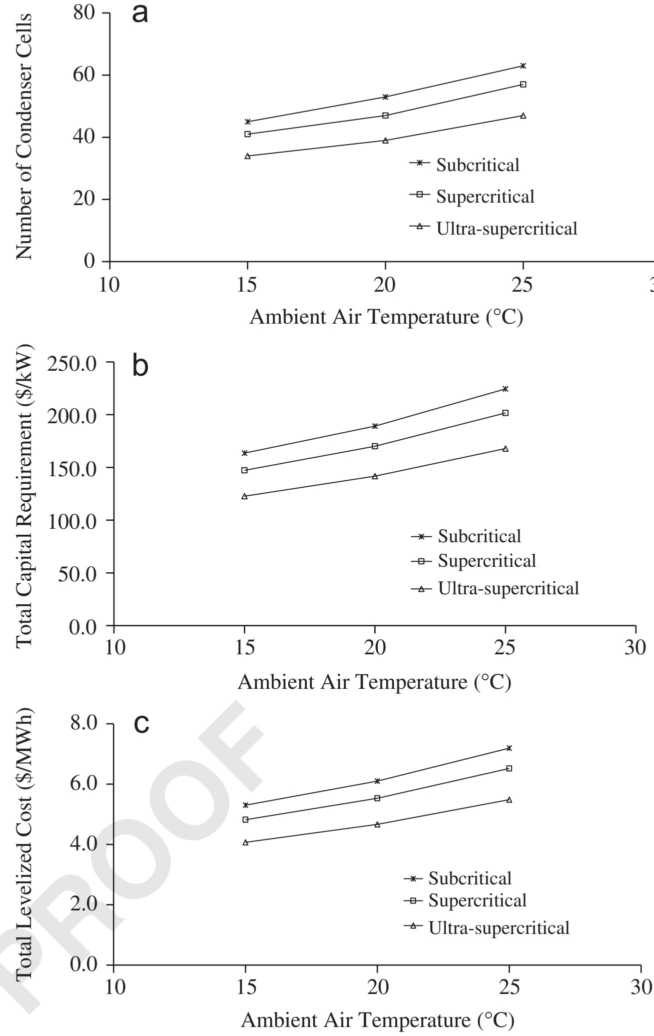

Fig. 6. Effects of plant design and ambient air temperature on dry cooling system.

number of ACC cells required to handle the cooling load for the base case ambient air temperature (25 °C) is 63, 57 and 47 cells for the subcritical, supercritical and ultra-supercritical units, respectively. The corresponding steam cycle efficiency for each unit with an ACC is 42.5%, 45.0% and 49.4% (HHV), respectively. Both the capital cost and total levelized cost of the dry cooling system shown in Fig. 6 are approximately 10% lower for the supercritical plant compared to the subcritical plant and 25% less for the ultra-supercritical plant. Higher plant efficiency thus reduces the size and cost of a dry cooling system, just as with the wet system.

5.2. Effects of fuel type

The effects of coal type also were evaluated for the three coals shown in Table 3. Similar to the findings for wet cooling systems, coal type did not have a significant effect on the performance or cost of the dry cooling system.

5.3. Effects of ambient air temperature

As seen in Fig. 6, the ambient air temperature also has a significant impact on dry cooling system performance and cost. For the base case steam turbine backpressure, the size of the dry cooling system for each type of plant increases by approximately 40% when the average ambient air temperature changes from 15 to 25 °C. As a result, the capital cost and levelized cost of the dry system increase by more than 35% over this temperature range. These results show that the use of a dry cooling system in high-temperature areas will significantly increase costs.

5.4. Effects of turbine backpressure

The steam turbine backpressure affects both the steam cycle efficiency and the dry cooling system design. In general, the temperature of steam exiting the steam turbine (and entering the primary condenser) increases with higher turbine backpressure (EPRI, 2005). This is usually not desirable since it decreases the steam cycle efficiency. However, for dry cooling systems, a higher inlet temperature for the condensing steam reduces the size of the ACC system for a given ambient air temperature. Thus, when ACCs are used, the steam turbine generally is designed for a higher backpressure (up to 8 in.Hg) compared to designs with a wet cooling system (EPRI, 2004).

A sensitivity analysis for the base case power plant (Table 1) illustrates this effect. To cover a broad range of ACC operating conditions, the turbine backpressure design was varied from 2 to 8 in.Hg (6.8–27.1 kPa). The temperature of condensing steam was empirically estimated as a polynomial function of the back-pressure with an R^2 value near unity over the range modeling (EPRI, 2005). Fig. 7(a) shows how the size and capital cost of the

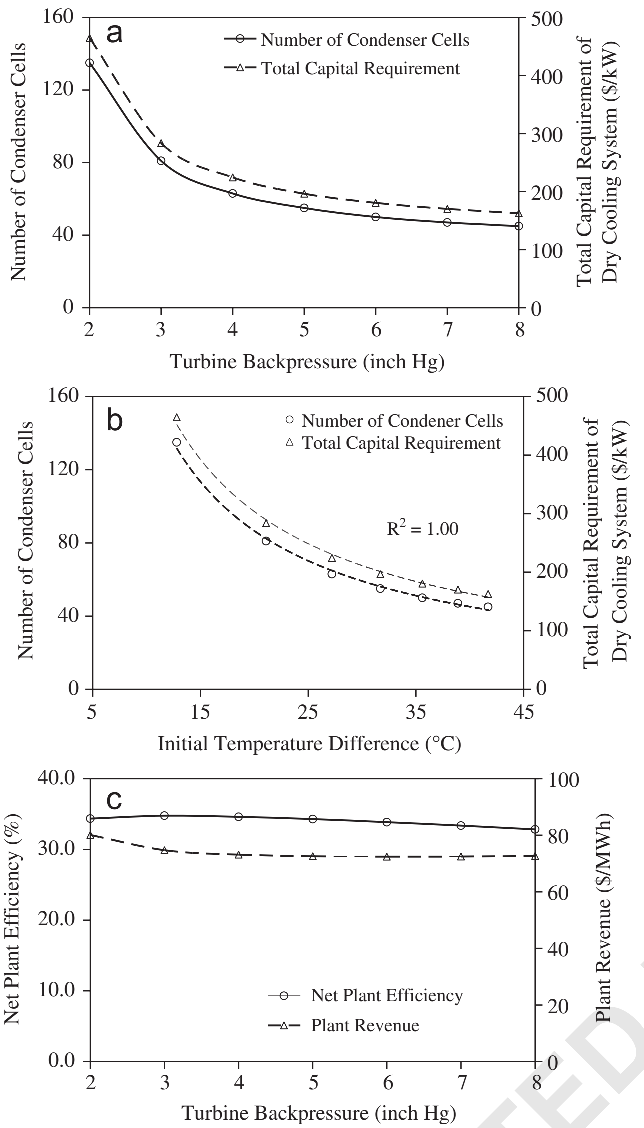

Fig. 7. Effects of turbine backpressure on dry cooling system design and power plant efficiency without carbon capture.

dry cooling system are affected. Increasing the backpressure from 2 to 8 in.Hg reduces the number of ACC cells from 135 to 45. The cooling system capital cost thus decreases dramatically.

A key parameter in ACC design is the initial temperature differential (ITD), defined as the difference between the inlet condensing steam temperature and the inlet ambient air temperature (EPRI, 2005), The ITD reflects the joint impact of the turbine backpressure and the ambient air temperature. Fig. 7(b) shows its effects on performance and cost based on the results in Fig. 6(a), where ITD varied from 13 to 42 °C. Both the ACC size and capital cost fall significantly with increasing ITD (up to a factor of three for the range shown).

As noted above, an increase in the turbine backpressure has an adverse impact on steam cycle performance. The thermal efficiency of the base case (subcritical) steam cycle decreases from 43.4% to 40.1% when the turbine backpressure increases from 2 to 8 in.Hg. On the other hand, the auxiliary power required to operate the dry cooling system decreases because of the smaller cooling system size. As a result, the net effect on overall plant efficiency is small, as seen in Fig. 7(c). That figure also shows that the overall cost of electricity generation (COE) decreases slightly as the backpressure increases from 2 to 3 in.Hg, and does not change significantly beyond 4 in.Hg (13.5 kPa) backpressure. Thus, the adverse impacts of a high turbine backpressure on steam cycle efficiency are offset by favorable impacts on the dry cooling system.

5.5. *Effects of carbon capture system*

The addition of a post-combustion CO_2 capture system poses a design challenge for a PC plant with dry cooling since there is no cooling water readily available to meet the cooling demands of the capture unit. Therefore, an auxiliary cooling system is required for the capture process. A variety of hybrid (wet–dry) cooling system designs are conceivable. For the purposes of this study, we assume the auxiliary system is a wet recirculating system of the type described earlier. Its total cost is treated as an added operating cost for the capture system, estimated to be $0.035 per tonne of cooling water required. The size of the power plant dry cooling system and the makeup water required for the carbon capture unit are given in Fig. 8 for the three PC plant types.

For these cases, the steam extracted from the steam cycle for use in CO_2 sorbent regeneration reduces the cooling duty of the primary dry cooling system. For example, with CO_2 capture, the number of condenser cells for the subcritical plant drops by three relative to the base plant without capture. However, Fig. 8 also shows that for a given plant type, the makeup water required for auxiliary cooling of the CO_2 capture system is comparable to that of the wet cooling system at a plant without carbon capture (see Fig. 3). Thus, a large amount of water is still needed if an amine-based CO_2 capture system with conventional water cooling is added to a plant with primary dry cooling. Alternatively, other types of cooling or refrigeration systems that do not require water would have to be designed for CCS applications.

6. Comparisons of wet and dry cooling systems

Here we compare the performance and cost of PC plants with dry and wet cooling systems, with and without CO_2 capture, for the baseline assumptions given in Table 1 that are applicable to all boiler types. Fig. 9 first shows that the ratio of capital cost for dry versus wet cooling systems is approximately 2.5 for all three plant types without CCS. Note that this cost ratio is sensitive to the ITD because it strongly affects the capital cost of a dry cooling system, as demonstrated in Fig. 7(b).

Fig. 9 further shows that the ratio of the total levelized cost for the dry versus wet cooling technology is close to a factor of two

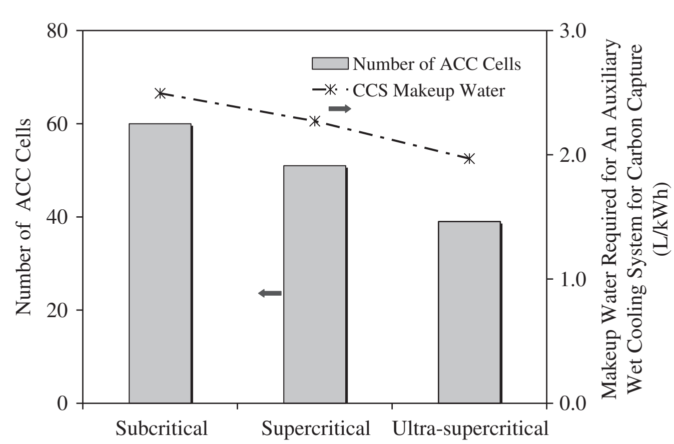

Fig. 8. Potential effects of carbon capture at power plants with primary cooling by air-cooled condensers.

Please cite this article as: Zhai, H., Rubin, E.S., Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage. Energy Policy (2010), doi:10.1016/j.enpol.2010.05.013

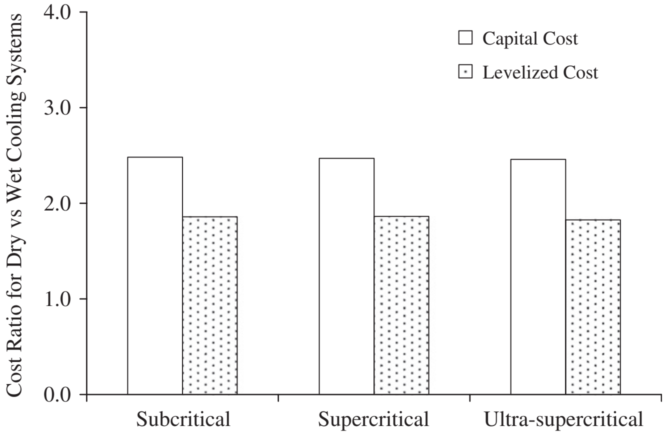

Fig. 9. Cost comparisons of dry versus wet cooling systems without carbon capture.

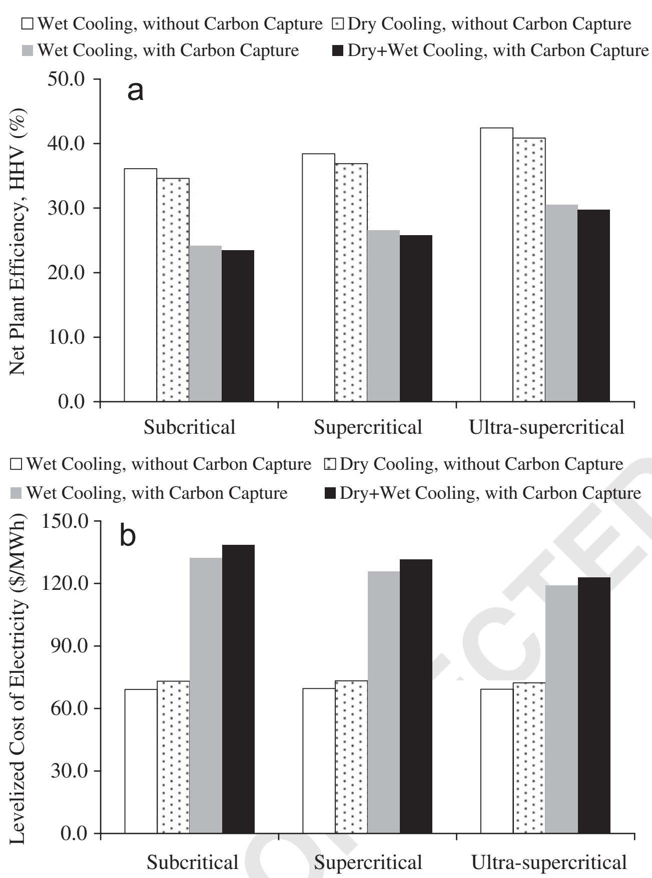

Fig. 10. Comparisons of effects of cooling systems on power plants with and without carbon capture.

for all plant types. However, further analysis shows that this ratio falls from 1.9 to 1.6 if the cost of water at the base case plant doubles from 0.26 per cubic meter ($1.0/kgal) to $0.53 per cubic meter ($2.0/kgal). If water cost escalates to $1.61 per cubic meter the levelized costs of wet and dry systems are equal (ratio of 1.0). This result implies that in addition to water resource availability, future increase in water cost can be another factor motivating the use of dry cooling technology in some areas, since the cost of water can vary significantly with location (Czetwertynski, 2002).

Fig. 10 compares the impacts of cooling technology on overall plant performance and cost for cases with and without carbon capture. Across all cases the net plant efficiency is approximately one to two percentage points higher for the plants with primary wet cooling systems than for plants with dry cooling (including the hybrid of dry plus wet system with CCS). The levelized COE is $3–$6/MWh lower for plants with wet cooling systems. Thus, while the cost of cooling systems alone may differ significantly, at the overall plant level cooling system designs with ACCs rather than wet towers yields only a modest decrease in efficiency and increase in the cost of electricity generation for the new PC plants modeled here. As seen in Fig. 10, it is the addition of CO_2 capture and storage that has the most pronounced impacts on overall plant performance, cost and water use.

7. Policy implications

Energy production at PC plants is tightly linked to water. In the face of growing demands for electricity, water resources must therefore be carefully planned to avoid potential shortages. As seen in this paper and another recent study (e.g. NETL, 2007b), technologies to control greenhouse gas emissions can significantly exacerbate future power plant water needs.

Technological options to reduce water use at PC power plants include improving water use efficiency, improving plant energy efficiency and using dry cooling systems where feasible (Smart and Aspinall, 2009). Water use efficiency can be improved via measures such as improving water quality and reusing or recycling plant wastewater. For example, the use of water treatment systems to improve cooling water quality can increase the cycles of concentration for wet towers; thus, decreasing tower blowdown and makeup water requirement. The tower blowdown can also be recycled or reused as ash sluicing water (already common practice) or makeup water after appropriate treatment. Some non-traditional water sources such as coal mine water and produced water from oil and gas extraction have been studied as alternative cooling water supplies to replace fresh water (EPRI, 2003; Veil et al., 2003; NETL, 2009). All of these approaches tend to increase overall plant costs, which must be considered in energy and environmental policy analyses involving future power generation.

Perhaps the strongest policy implication underscored by the results presented here is the need for close coordination of energy, climate change, and water resource policies to ensure that the potentially large new water demands for reducing power plant CO_2 emissions are taken into account in water resource management and planning for the electric power industry. Avoiding water supply–demand conflicts must be an integral part of planning to secure low-carbon energy production. In addition, lowering consumptive water use should be a more prominent metric in R&D programs focused on developing new low-carbon technologies and carbon capture systems for power plants and other industrial facilities.

8. Conclusions

This paper has systematically evaluated the performance, cost, and water requirements of wet and dry cooling systems for PC power plants with and without carbon capture systems. Cooling water systems are the dominant source of water consumption for power generation. Comparisons between wet and dry cooling technologies also were presented for a range of illustrative power plant configurations. The study also identified and quantified the effects of key factors influencing the choice of wet vs. dry cooling systems for PC plants. Increasing the plant efficiency can decrease cooling system size and cost as well as consumptive water use.

Please cite this article as: Zhai, H., Rubin, E.S., Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage. Energy Policy (2010), doi:10.1016/j.enpol.2010.05.013

Average ambient air temperature also affects makeup water requirements for a wet cooling system, but does not significantly affect its overall cost unless the price of water more than doubles. In contrast, both the performance and cost of a dry cooling system are extremely sensitive to local air temperature as well as the steam turbine backpressure. This requires careful attention to the design of the power plant steam turbine, as well as the cooling system, in order to minimize overall plant costs with dry cooling. In general the design of a dry cooling system is more sensitive to site-specific conditions and plant characteristics compared to wet cooling systems.

Current post-combustion carbon capture and storage (CCS) systems have additional cooling demands that nearly double the consumptive water use at a PC plant with conventional wet cooling towers. For a plant with dry cooling, a large-scale auxiliary cooling system would be required to support the CO_2 capture process. If a recirculating wet tower system is employed, the water consumption of the auxiliary system would be comparable to that of a water-cooled plant without CCS.

Finally, although dry cooling systems were found to be much more capital-intensive than wet cooling systems, the plant-level impacts for the cases modeled in this paper were generally more modest, i.e., a 1–2% point reduction in overall plant efficiency and a $3–$6/MWh increases in the levelized cost of electricity compared to a similar plant with wet cooling (with or without CCS). Future limitations on water availability and increases in water cost would lead to greater increases, however. The modeling tool employed in this study (IECM, 2009) allows a wide range of alternative plant configurations and design assumptions to be evaluated.

Acknowledgements

This work was supported by the U.S. Department of Energy under Contract No. DE-AC26-04NT4187 from the National Energy Technology Laboratory (DOE/NETL). Michael B. Berkenpas and Karen Kietzke provided invaluable assistance with the IECM computer code. Any opinions, findings, conclusions or recommendations expressed in this paper are those of the authors alone and do not reflect the views of DOE or any other government agency.

References

Czetwertynski, M., 2002. The sale and leasing of water rights in western states: an overview for the period 1990–2001. Water Policy Working Paper #2002-002, Andrew Young School of Policy Studies of Georgia State University, March.

Electric Power Research Institute (EPRI), 1993. TAG™ technical assessment guide: electricity supply—1993, vol. 1, Rev. 7. Report No. TR-102276-VIR7, Electric Power Research Institute, Palo Alto, CA, June.

Electric Power Research Institute (EPRI), 2003. Use of degraded water sources as cooling water in power plant. Report No. 1005359, Prepared for California Energy Commission Public Interest Energy Research Program, Electric Power Research Institute, Palo Alto, CA, October.

Electric Power Research Institute (EPRI), 2004. Comparison of alternate cooling technologies for U.S. power plants: economic, environmental, and other tradeoffs. Report No. 1005358. Electric Power Research Institute, Palo Alto, CA, August.

Electric Power Research Institute (EPRI), 2005. Air-cooled condenser design, specification, and operation guidelines. Report No. 1007688. Electric Power Research Institute, Palo Alto, CA, December 2005.

Feeley III, T.J., Skone, T.J., Stiegel Jr., G.J., McNemar, A., Nemeth, M., Schimmoller, B., Murphy, James T., Manfredo, L., 2008. Water: a critical resource in the thermoelectric power industry. Energy 33 (1), 1–11.

FluorStatoil, 2005a. Study and estimate for CO_2 capture facilities for the proposed 800 MW combined cycle power plant—Tjeldbergodden, Norway. Final Report CB2005-0022, April.

Fluor and Statoil, 2005b. CO_2 capture study at Mongstad. Final Report CB2005-0079, June.

Integrated Environmental Control Model (IECM), 2009. Integrated Environmental Control Model computer code and documentation, 〈http://www.iecm-online.com〉.

Intergovernmental Panel on Climate Change (IPCC), 2005. IPCC special report on carbon dioxide capture and storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Kroger, D.G., 2004. Air-Cooled Heat Exchangers and Cooling Towers. Pennwell Corporation, Tulsa, OK.

Li, K.W., Priddy, A.P., 1985. Power Plant System Design. John Wiley & Sons, Inc..

National Energy Technology Laboratory (NETL), 2007a. Cost and performance baseline for fossil energy plants. Report DOE/NETL-2007/1281, U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA, August.

National Energy Technology Laboratory (NETL), 2007b. Estimating freshwater needs to meet future thermoelectric generation requirements. Report DOE/NETL-400/2007/1304, U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA, September.

National Energy Technology Laboratory (NETL), 2009. Existing plant program: energy-water R&D technology roadmap & program plan. U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA, November.

Rao, A.B., Rubin, E.S., 2002. A technical, economic, and environmental assessment of amine-based CO_2 capture technology for power plant greenhouse gas control. Environmental Science and Technology 36 (20), 4467–4475.

Rubin, E.S., Berkenpas, M.B., Zaremsky, C.J., 2007a. Integrated Environmental Control Model (IECM) with carbon capture and storage. Final Report of Contract No. DE-AC21-92MC29094, Prepared by Carnegie Mellon University for U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA, May.

Rubin, E.S., Chao, C., Rao, A.B., 2007b. Cost and performance of fossil fuel power plants with CO_2 capture and storage. Energy Policy 35 (9), 4444–4454.

Smart, A., Aspinall, A., 2009. Water and the electricity generation industry. Waterlines Report Series No. 18, National Water Commission, Canberra, August.

Sovacool, B.K., Sovacool, K.E., 2009. Identifying future electricity–water tradeoffs in the United States. Energy Policy 37 (7), 2763–2773.

Threlkeld, J.L., 1970. Thermal Environmental Engineering 2nd ed. Prentice-Hall, Inc., Englewood Cliffs, NJ.

U.S. Department of Energy (DOE), 2006. Energy demands on water resources: report to congress on the independency of energy and water. U.S. Department of Energy, December. Available at 〈http://www.sandia.gov/energy-water/docs/121-RptToCongress-EWwEIAcomments-FINAL.pdf〉. Accessed on August 10, 2009.

U.S. Environmental Protection Agency (EPA), 2008. Cooling water intake structures—Clean Water Act §316(b). 〈http://www.epa.gov/waterscience/316b/〉. Accessed on July 7, 2008..

Veil, J.A., Kupar, J.M., Puder, M.G., 2003. Use of mine pool water for power plant cooling. Prepared for Department of Energy's National Energy Technology Laboratory, Argonne National Laboratory, Argonne, IL, September.

Versteeg, P.L., Mantripragada, H., Zhai, H., Kietzke, K., Rubin, E.S., 2009. Integrated Environmental Control Model (IECM) technical documentation updates final report Volume (IV). Final Report of Contract No. DE-AC26-04NT41917, Prepared by Carnegie Mellon University for U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA, November.

Zhai, H., Berkenpas,M., Rubin, E.S. 2009a. Integrated Environmental Control Model (IECM) technical documentation updates final report volume (I). Final Report of Contract No. DE-AC26-04NT41917, Prepared by Carnegie Mellon University for U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA, November.

Zhai, H., Berkenpas,M., Rubin, E.S. 2009b. Integrated Environmental Control Model (IECM) technical documentation updates final report volume (II). Final Report of Contract No. DE-AC26-04NT41917, Prepared by Carnegie Mellon University for U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA, November.

Please cite this article as: Zhai, H., Rubin, E.S., Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage. Energy Policy (2010), doi:10.1016/j.enpol.2010.05.013