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A Techno-Economic Assessment of Hybrid Cooling Systems for Coal- and Natural-Gas-Fired Power Plants with and without Carbon Capture and Storage

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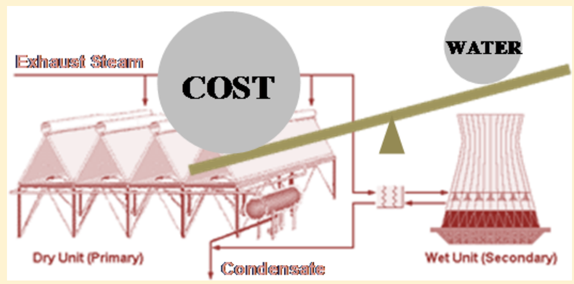
Supporting Information

ABSTRACT: Advanced cooling systems can be deployed to enhance the resilience of thermoelectric power generation systems. This study developed and applied a new power plant modeling option for a hybrid cooling system at coal- or natural-gas-fired power plants with and without amine-based carbon capture and storage (CCS) systems. The results of the plant-level analyses show that the performance and cost of hybrid cooling systems are affected by a range of environmental, technical, and economic parameters. In general, when hot periods last the entire summer, the wet unit of a hybrid cooling system needs to share about 30% of the total plant cooling load in order to minimize the overall system cost. CCS deployment can lead to a significant increase in the water use of hybrid cooling systems, depending on the level of CO_2 capture. Compared to wet cooling systems, widespread applications of hybrid cooling systems can substantially reduce water use in the electric power sector with only a moderate increase in the plant-level cost of electricity generation.



INTRODUCTION AND RESEARCH OBJECTIVES

Energy production highly depends on water. Thermoelectric power plants account for approximately 40% of U.S. freshwater withdrawals,[1] principally for cooling. Thus, thermoelectric power generation is vulnerable to water availability, which has already been affected by climate change.[2] To mitigate climate change, future electricity generation will be increasingly under the pressure of controlling carbon emissions. Carbon capture and storage (CCS) is a key option for deeply cutting carbon dioxide (CO_2) emissions from existing and new fossil-fuel-fired power plants.[3,4] However, current amine-based CCS requires a large amount of cooling water for the CO_2 capture process.[5] To limit CO_2 emissions, the U.S. Environmental Protection Agency (EPA) has established emission performance standards for new, modified, and reconstructed power plants.[6] The addition of amine-based CCS to comply with the current standard of 1400 pounds of CO_2 per megawatt-hour (lb CO_2/MWh-gross) would increase plant water use by about 17% at pulverized-coal-fired plants using wet cooling towers.[7] More stringent emission standards would remarkably elevate water use due to the increased CO_2 removal requirements.[8] Advanced cooling systems can be deployed to enhance the resilience of thermoelectric power generation systems.[9]

The U.S. EPA has issued regulations on cooling intake structures under Section 316(b) of the Clean Water Act,[10] promoting a shift from once-through cooling to wet closed-loop cooling systems. This shift would significantly decrease national water withdrawals but increase national water consumption in the future, especially when CCS is deployed.[9] In regions suffering from severe drought, limited water availability can constrain the plant operations.[2] Dry cooling systems can be employed to significantly reduce water use. However, compared to wet cooling systems, dry cooling systems are much more cost-intensive, and their cooling efficiency can pronouncedly drop in hot periods.[11] Thus, deployment of a hybrid cooling system that provides a compromise between the cooling efficiency and the water conservation appears attractive.[12] Currently, however, there are only five hybrid cooling systems installed in the United States.[13] From recent review of water use at U.S. thermoelectric power plants, Badr et al. found that water usage information for hybrid cooling systems is inadequate.[12] Rare engineering−economic studies on hybrid cooling are available.[12,14−16] The effects of hybrid cooling deployment on the overall plant efficiency and cost of electricity generation have not been investigated thoroughly. Furthermore, bare studies have been conducted to examine hybrid cooling systems for fossil-fuel-fired power plants under carbon constraints. Thus, a recent review study emphasized that efforts are needed to investigate performance and cost penalties of hybrid cooling systems for fossil-fuel-fired power plants using CCS.[15] Although some studies made comparisons of water use and cost among wet, dry, and hybrid cooling systems, they did not address the discrepancy among collected data because of the differences in ambient air conditions and power plant and cooling system designs as

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well as economic assumptions.[12,14−16] Such comparisons should be made under a common framework.

The major objectives of this paper, therefore, are (1) to evaluate the plant-level performance and cost of hybrid cooling systems for water conservation at pulverized coal (PC) or natural gas combined cycle (NGCC) power plants with and without CCS, (2) to examine the effects of key parameters on hybrid cooling systems, and (3) to compare performance and cost among different cooling technologies under a common platform. The key performance metric considered is the annual average makeup water use for hybrid cooling systems, while the major cost metrics considered are the total annualized cost and total levelized cost of electricity. Commercially available amine-based CCS is deployed for CO_2 capture when applicable.

■ MATERIALS AND METHODS

In this study, performance and cost models of hybrid cooling systems are developed and incorporated in a power plant modeling tool. Then, the newly enhanced power plant tool is employed for plant-level case studies.

Integrated Environmental Control Model for Power Plant Assessments. The Integrated Environmental Control Model (IECM) is a computer tool developed by Carnegie Mellon University to perform systematic estimates of the performance, resource use, emissions, and costs for fossil-fuel-fired power plants with and without CCS.[17] The IECM encompasses an array of major cooling technologies, including once-through cooling, wet towers, and dry cooling.[5,11] The performance and cost models outlined below for hybrid cooling systems are incorporated in the IECM. The costing method and nomenclature employed in this study are based on the Electric Power Research Institute's Technical Assessment Guide.[18] This study employed the 2015 release of IECM version 9.1 for assessments.[17]

Performance and Cost Models of Hybrid Cooling System. This study investigates a hybrid cooling system that uses both closed-loop dry and wet units. Dry and wet cooling units are arranged in parallel, splitting the steam flow between air-cooled condensers (ACC) and a surface condenser coupled with a wet tower unit. The dry cooling unit employs ACC and is primarily used to serve the steam cycle. When the ambient air temperature reaches higher levels than the design and the dry cooling unit cannot maintain a low turbine exhaust pressure, part of the exhaust steam is routed to the supplemental wet unit. Thus, this design allows ACC to reject less exhaust heat and operate at a smaller initial temperature difference (ITD) between condensing steam temperature and inlet air temperature.[19,20]

Wet Cooling Unit. The required amount of cooling water is determined in terms of the plant size, steam cycle heat rate, and cooling water temperature drop across the tower.[5] Given that only part of the exhaust steam is routed to the wet unit in the summer, the total amount of cooling water in the wet unit for a PC power plant without CCS is then estimated as[5]

$$\dot{m}_c = \frac{\alpha\{(\mathrm{Hr} - 3600) \times \mathrm{MWg} \times 1000(1 + \eta_{aux})\}}{C_p \Delta T_w \times 1000} \tag{1a}$$

where α is the fraction of the total cooling duty assigned for the wet cooling unit in the summer (fraction), Hr is the steam cycle heat rate (kJ/kWh) (3600 = units conversion factor), $\dot{m}_c$ is the total recirculation cooling water (tonnes/h), MWg is the plant gross size (MW_e), ΔT_w is the cooling water temperature drop range (°C), η_{aux} is the auxiliary cooling load (%), and C_p is the water specific heat capacity (kJ/kg·°C).

When the CO_2 is captured by CCS, an amount of cooling water is needed for the capture process. So, the wet cooling unit has to serve in both summer and nonsummer seasons. However, the heat rejected around the primary condenser excludes the thermal energy of the steam extracted for solvent regeneration. The larger cooling duty in summer relative to other seasons is adopted to size the wet cooling unit. The total amount of cooling water is then estimated for a PC plant with CCS as[5]

$$\dot{m}_c = \frac{\alpha\{(\mathrm{Hr} - 3600) \times \mathrm{MWg} \times 1000(1 + \eta_{aux}) - q_r^{CCS}\}}{C_p \Delta T_w \times 1000} + \dot{m}_c^{CCS} \tag{1b}$$

where $\dot{m}_c^{CCS}$ is the amount of cooling water required for the capture system (tonnes/h), MWg is the plant gross size (MW_e), and q_r^{CCS} is the extracted steam heat for solvent regeneration (kJ/h).

In the wet unit, the cooling water is cooled by contact with ambient air and then recirculated back to the condenser to cool the exhaust steam. The wet cooling unit relies mainly on the latent heat of water evaporation for transferring exhaust heat to the atmosphere. Water is used to make up evaporation, drift, and blowdown losses. A mass and energy balance model developed in the previous study is adopted to estimate various water losses around the tower.[5,21]

The engineering−economic model of a wet cooling system in the IECM is adopted to estimate the capital and operating and maintenance (O&M) costs for the wet cooling unit.[5,17,21] The total capital requirement includes the direct costs plus indirect costs, such as the general facilities cost, engineering and home office fees, contingency costs, and owner's costs. The indirect costs, such as general facilities cost, engineering and home office fees, and process contingency cost, are empirically estimated as a percent of process facilities capital cost (PFC), whereas the project contingency cost is estimated as a percent of the sum of PFC, engineering and home office fees, and process contingency cost.[18] The major direct cost components include the cooling tower structure, circulation pumps, auxiliary systems, piping, makeup water system, component cooling water system, foundation and structures, and tower structure. The variable O&M costs are considered only when the wet cooling unit is in operation. The capital and O&M cost components are detailed in Tables S-1 and S-2 of the Supporting Information (SI), respectively.

Dry Cooling Unit. The dry cooling unit utilizes the sensible heating of atmospheric air passed across finned-tube heat exchangers to reject exhaust heat. There is no water used in the cooling process. In the nonsummer seasons, the amount (kJ/h) of exhaust heat rejected by the dry cooling unit is estimated as

$$Q = (\mathrm{Hr} - 3600) \times \mathrm{MWg} \times 1000(1 + \eta_{aux}) \tag{2a}$$

In the summer, a large portion of the exhaust steam is routed to the dry unit, while the rest is delivered to the wet unit. The corresponding amount (kJ/h) of exhaust heat rejected by the dry cooling unit is estimated as

$$Q' = (1 - \alpha)\{(\mathrm{Hr} - 3600) \times \mathrm{MWg} \times 1000(1 + \eta_{aux})\} \tag{2b}$$

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When the CO_2 is captured by amine-based CCS, the heat rejected around the dry cooling unit does not include the thermal energy of the steam extracted for solvent regeneration. The wet cooling unit provides the cooling water required for the CO_2 capture process.

The performance of the dry cooling unit highly depends on the ITD between the condensing steam temperature and inlet air temperature.[11] The ACC plot area and fan shaft power normalized by the rejected heat are estimated using a reduced-order model[5]

$$\bar{a} = 462.346\left(\frac{9}{5}\text{ITD}\right)^{-1.0344}\left(\frac{P_{\text{ambient}}}{101.3}\right)^{-0.7401} \quad (3)$$

$$\bar{e} = 848.024\left(\frac{9}{5}\text{ITD}\right)^{-1.0227}\left(\frac{P_{\text{ambient}}}{101.3}\right)^{0.2709} \quad (4)$$

where $\bar{a}$ is the ACC plot area normalized by rejected heat (m^2/MW_t), $\bar{e}$ is the required fan shaft power normalized by rejected heat (kW/MW_t), ITD is the initial temperature difference (°C), and P_{ambient} is the ambient pressure (kPa). ITD is a key parameter affecting the dry unit size and power use and varies with season. The ACC plot area and power use on an absolute basis are estimated as the product of the normalized performance parameter ($\bar{a}$ or $\bar{e}$) and the cooling duty, respectively. Equation 2 shows that the dry unit's cooling duties are different in summer versus nonsummer seasons. To determine the dry unit size, the plot area is first estimated on the basis of the cooling duty and air temperature in summer and fall or spring, respectively. Then, the larger plot area is chosen to size the dry cooling unit. A similar analysis is conducted to estimate the power use of the dry unit in summer and nonsummer seasons.

The engineering−economic model of a dry cooling system in the IECM is adopted to estimate the capital and O&M costs for the dry cooling unit.[5,17,22] The ACC equipment cost is estimated as a function of cooling duty and ITD[5]

$$C_{\text{equip}} = 663.4\left(\frac{9}{5}\text{ITD}\right)^{-1.0055}\left(\frac{Q}{Q_o}\right) \quad (5)$$

where C_{equip} is the ACC equipment capital cost (2003 US dollars), Q is the actual cooling duty (MW_t), and Q_o is the reference cooling duty (288 MW_t). In addition to the equipment cost, the equipment erection cost is approximately 30% of the sum of the equipment and erection costs.[5] The major direct cost components include the condenser structure, steam duct support, electrical and control equipment, auxiliary cooling, and cleaning system, which are summarized in Table S-3 of the SI . Except for water use, the dry cooling unit has O&M cost components similar to those summarized in Table S-2 of the SI for the wet cooling unit. However, the variable O&M costs are always considered for the dry cooling unit, since it provides the primary cooling service.

Overall Cooling System Water Use and Costs. The water use intensity of a hybrid cooling system is estimated as the total annual water use divided by the annual net electricity generation of a power plant, whereas the cooling system's capital, O&M, and levelized cost of electricity generation are estimated as the sum of those outlined above for both wet and dry cooling units. The LCOE is calculated as[23]

$$\text{LCOE} = \frac{\text{TCR} \times \text{FCF} + \text{FOM}}{(\text{CF} \times \text{Hrs})\text{MW}} + \text{VOM} + \text{HR} \times \text{FC} \quad (6)$$

where LCOE is the levelized cost of electricity generation ($/MWh), TCR is the total capital requirement ($), CF is the capacity factor (%), FCF is the fixed charge factor (fraction/yr), FOM is the fixed O&M costs ($/yr), VOM is the variable nonfuel O&M costs ($/yr), HR is the net plant heat rate (GJ/MWh), FC is the unit fuel cost ($/GJ), MW is the net power output (MW), and Hrs is the total annual hours (h/yr).

■ BASE CASE RESULTS

The enhanced IECM was applied to evaluate hybrid cooling systems at baseload supercritical pulverized coal and NGCC plants. The base plants were configured using the IECM to comply with the new source performance standards for traditional air pollution controls, in which hybrid cooling systems were assumed to be installed. Major parameters and assumptions for the base plants and cooling systems are summarized in Table 1. Coal and natural gas properties are summarized in Table S-4 of the SI. Otherwise, the IECM default values are adopted. In this study, all costs are reported in 2012 constant dollars, all PC plants are evaluated on a basis of 550 MW net power output, and the gross power output of NGCC plants is determined by the gas turbine type and the number of gas turbines. Thus, the plant fuel requirement is 4246 GJ/h for both the base NGCC plants with and without CCS. It was assumed that the thermal energy for solvent regeneration is extracted from the steam cycle, which results in a larger fuel requirement for the PC plant with CCS and an amount of losses in gross generating capacity for the NGCC plant with CCS, compared to the corresponding noncapture cases.

Equations 1a, 1b, and 2b indicate that the allocation of the plant cooling duty between the dry and wet units in summer is a key factor that affects the size and performance of individual cooling units. In one previous study on geothermal power plants, the wet unit was sized to handle about 30% of the overall cooling duty.[18] Besides, the total annual water use of a wet cooling unit also depends on its duration of service within a year. In the base cases, the wet cooling unit is designed to share 30% of the overall cooling duty during the summer period from June to August.

The performance of wet and dry cooling units is affected by ambient air conditions.[11] This study refers to the monthly meteorological data in Texas from 1981 to 2010 for designing and evaluating hybrid cooling systems.[24] Table 2 summarizes the ambient air conditions adopted for assessments. The monthly average air temperature and relative humidity (RH) in summer fall within ranges from 26.6 to 28.1 °C (in July) and 45.2% to 47.8%, respectively. The average air temperature and RH in the summer were used to evaluate the cooling system performance during that period. In nonsummer seasons, the corresponding average air temperature was used to evaluate the dry unit performance as well as the wet unit performance when CCS is implemented. However, the highest seasonal air temperature was referred to in sizing the dry cooling unit.

The major performance parameters of CCS systems are summarized in Table S-5 of the SI.[25,26] As eq 1b indicates, the implementation of CCS affects power plant performance in two major areas: the steam cycle and the cooling system. For 90% CO_2 capture, the thermal energy extracted from the steam cycle

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Table 1. Major Technical and Economic Parameters and Assumptions for Base Plants

parameter	value
Technical Parameters	
plant type	supercritical pulverized coal or GE-7FB NGCC
plant capacity factor (%)	75%
ambient pressure (MPa)	0.10
environmental control systems (if applicable)	
nitrogen oxide	selective catalytic reduction
particulates	electrostatic precipitator
sulfur dioxide	flue gas desulfurization
carbon dioxide	CCS
hybrid cooling: dry unit	
air-cooled condenser plot area per cell (m^2)	110
configuration of air-cooled heat exchanger	multiple-row
turbine backpressure (bar)	0.14
fan efficiency (%)	80
auxiliary cooling load (%)	5
hybrid cooling: wet unit	
cooling duty in summer (fraction of the total)	0.3
duration of service in summer (months)	3
cooling water temperature drop range (°C)	11.1
cycle of concentration (ratio)	4
auxiliary cooling load (%)	5
Economic Parameters	
dollar type	2012 constant
fixed charge factor	0.113
plant book lifetime (years)	30
water cost ($/$m^3$)	0.3
coal price ($/tonne)	42
natural gas price ($/GJ)	6.9
electricity price ($/MWh)	50
hybrid cooling system (dry/wet unit if noted)	
general facilities capital (% of PFC)	10
engineering and office fees (*E*) (% of PFC)	10
process contingency cost (% of PFC)	5/0
project contingency cost (% of PFC + *E* + process contingency)	20/10
number of operating jobs	2
number of operating shifts	4.75
labor rate ($/h)	34.65
total maintenance cost (% of total plant cost)	1.5

Table 2. Ambient Air Reference Conditions

time scale	average temp (°C)	average RH (%)
annual	18.7	44.6
summer	27.6	46.7
nonsummer	15.7	43.9
fall	19.3	45.7
spring	18.7	40.8
winter	9.2	45.2

for solvent regeneration is approximately 3500 kJ/kg CO_2 captured for the PC plant and 3950 kJ/kg CO_2 captured for the NGCC plant, and the total cooling duty for the CO_2 absorption and stripping processes and CO_2 product compression is 91 ton of H_2O/ton of CO_2 for the PC plant and 123 ton of H_2O/ton of CO_2 for the NGCC plant. Thus, the overall cooling duty of the wet cooling unit includes the additional cooling requirement for CCS but excludes the extracted thermal energy from the steam cycle.

Table 3 summarizes the major results of the base power plants and hybrid cooling systems. For the two base cases without CCS, the makeup water use of the hybrid cooling system, equivalent to the water withdrawal, is 0.19 L/kWh for the PC case and 0.09 L/kWh for the NGCC case. This mainly offsets evaporation and blowdown losses in the wet unit. For the given cycle of concentration of the wet cooling unit, the evaporation loss accounts for 75% of the total makeup water use. This means that the cooling system's water consumption is 0.14 L/kWh for the PC case and 0.07 L/kWh for the NGCC case. Given the large amounts of power and thermal energy required for CCS operation, the implementation of amine-based CCS for 90% CO_2 capture would decrease the net plant efficiency by about 10% for the PC case and about 7% for the NGCC case. When CCS is added to power plants, the resulting makeup water use increases by a factor of 8−9 at both the base PC and NGCC plants, compared to the noncapture cases, because the wet cooling unit primarily provides the CO_2 capture process with cooling service throughout the year. In comparison between PC and NGCC plants, the makeup water use of hybrid cooling systems at NGCC plants with and without CCS is just about half that of PC plants, mainly because a NGCC plant has a much higher plant efficiency than a PC plant, and its cooling system only needs to serve the steam generation loop of the combined power cycle.[8]

For the given economic assumptions in Table 1, for plants without CCS, the wet cooling unit accounts for only 14% of the total capital requirement of the cooling system for the PC case and 15% for the NGCC case. However, with CCS, the wet cooling unit's capital cost share increases to 42% and 35% for the PC and NGCC cases, respectively. As shown in Table 3, the annualized capital costs of hybrid cooling systems account for roughly 60−70% of the total annualized cost of the cooling systems for the four base plants. However, the addition of CCS to the PC plant increases the plant and cooling system LCOE by roughly 70% and 40%, respectively. In contrast, the addition of CCS to the NGCC power plant increases the plant and cooling system LCOE by roughly 40% and more than 60%, respectively. These results clearly indicate that CCS deployment will have a big effect on hybrid cooling system cost. In addition, the cooling system levelized cost accounts for only 7−9% of the total plant LCOE for the PC plants with and without CCS and only 4−5% for the NGCC plants with and without CCS. These results indicate that a hybrid cooling system is not a major contributor to overall plant cost and suggest that retrofitting a hybrid cooling system to existing plants using wet cooling towers may not lead to substantial increases in the overall plant LCOE.

SENSITIVITY ANALYSIS

The cooling duty assigned to the wet unit and the CO_2 capture are the key factors affecting hybrid cooling systems. Besides, as eq 6 shows, capacity factor and fixed charge factor also are the key parameters affecting the LCOE.[3,27,28] Thus, a sensitivity analysis was conducted for these key parameters. In each parametric analysis, other parameters were kept at the base case values given in Table 1, unless otherwise noted.

Effects of Wet Unit Cooling Duty Assignment. The fraction of total plant cooling duty assigned to the wet unit and

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Table 3. Performance and Costs of Hybrid Cooling Systems for Coal- and Natural-Gas-Fired Power Plants with and without CCS

parameter	SC PC		NGCC	
CCS (yes or no)	no	yes	no	yes
gross power output (MWg)	595	686	600	544
net power output (MWnet)	550	550	581	502
net plant efficiency (HHV, %)	36.9	26.4	49.3	42.5
plant CO_2 emission rate (kg/kW-net)	0.85	0.12	0.37	0.04
hybrid cooling system				
annual average makeup water use (L/kWh)	0.19	1.73	0.09	0.86
parasitic load (% of MWg)	2	3	1	1
number of ACC cells	46	39	23	24
annual fixed cost (M$/yr)	3.0	3.4	2.0	2.4
annual variable cost (M$/yr)	3.4	7.9	1.7	2.8
annualized capital cost (M$/yr)	14.2	17.3	7.1	9.8
total annualized cost (M$/yr)	20.5	28.6	10.7	14.9
cooling system LCOE ($/MWh)	5.6	7.8	2.8	4.5
power plant LCOE ($/MWh)	65.3	110	67.8	93.7

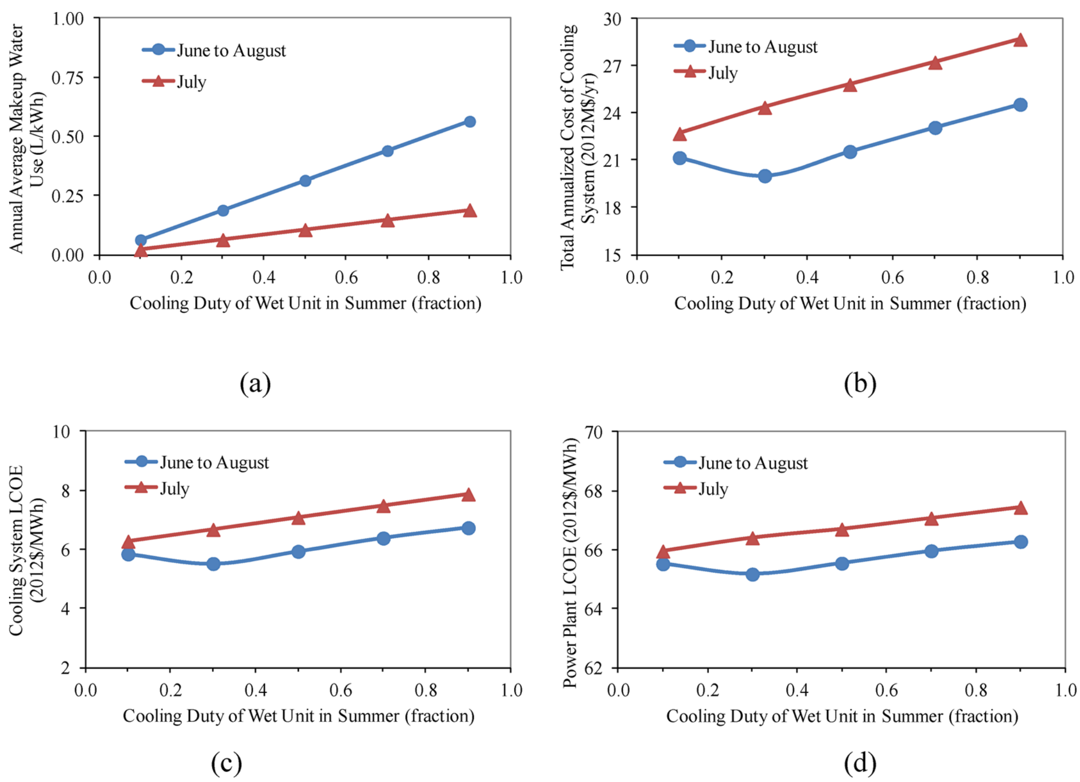

Figure 1. Effects of wet unit cooling duty at a coal-fired power plant without CCS: (a) annual average makeup water use, (b) total annualized cost of cooling system, (c) cooling system LCOE, and (d) power plant LCOE.

its duration of service in summer directly affect the makeup water use and size of the wet cooling unit, which in turn affect the overall plant and cooling system. The cooling duty fraction for the wet cooling unit was varied from 0.1 to 0.9, while the duration of summer service was varied from 3 months to 1 month. For the ambient air conditions given in Table 2, the monthly air temperature reaches the highest level in July. For the 1-month service case (on wet cooling unit), the dry cooling unit size was determined by first estimating the required plot area based on the cooling duty and air temperature in July and then comparing it to the plot area based on the cooling duty and average air temperatures in June and August, respectively. The difference between the design temperatures is less than 2 °C, whereas the dry unit cooling duty is larger in June and August than in July. The resulting larger plot area was chosen to size the dry cooling unit.

Using the PC plant without CCS as an illustrative example, Figure 1 shows how these two parameters affect the cooling system's makeup water use, capital cost, and levelized cost of electricity generation, as well as the plant-level LCOE. For either service duration design, the makeup water use monotonically increases with the cooling duty fraction of the wet cooling unit. However, the costs show a different trend. When the wet cooling unit is designed for 3-month cooling service, the lowest costs occur when the wet cooling unit duty fraction is 0.3. In contrast, when the wet cooling unit is

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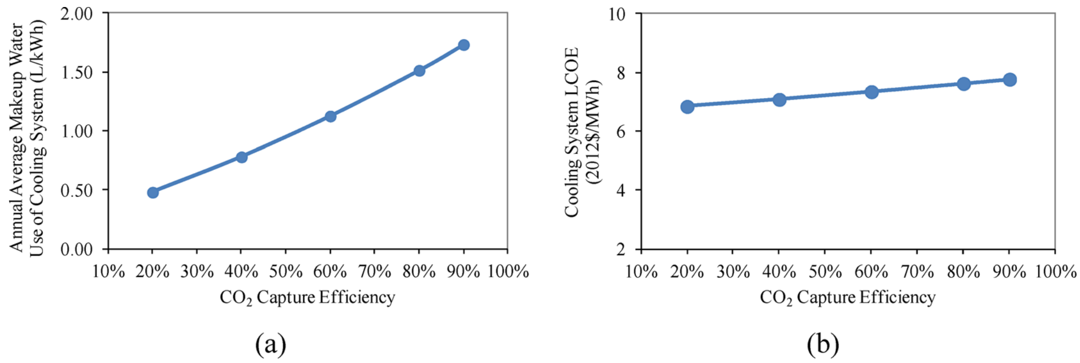

Figure 2. Effects of CO_2 capture efficiency at coal-fired power plant: (a) annual average makeup water use and (b) cooling system LCOE.

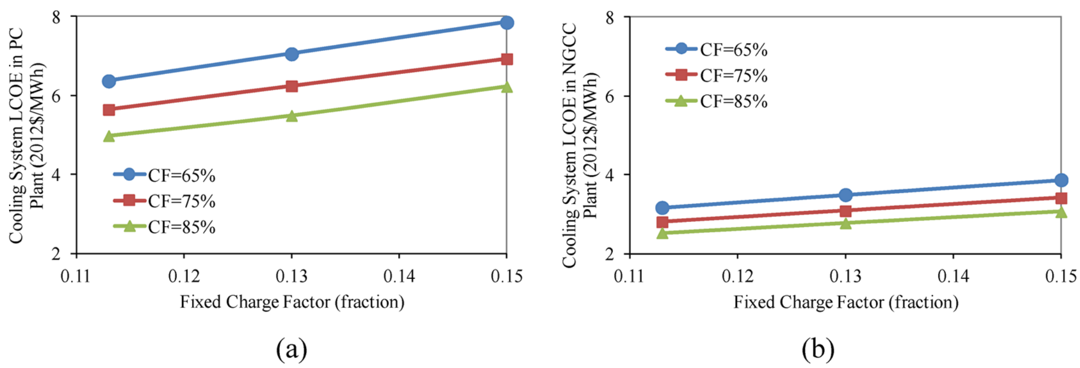

Figure 3. Effects of capacity factor and fixed charge factor on cooling system LCOE at power plants without CCS: (a) PC and (b) NGCC.

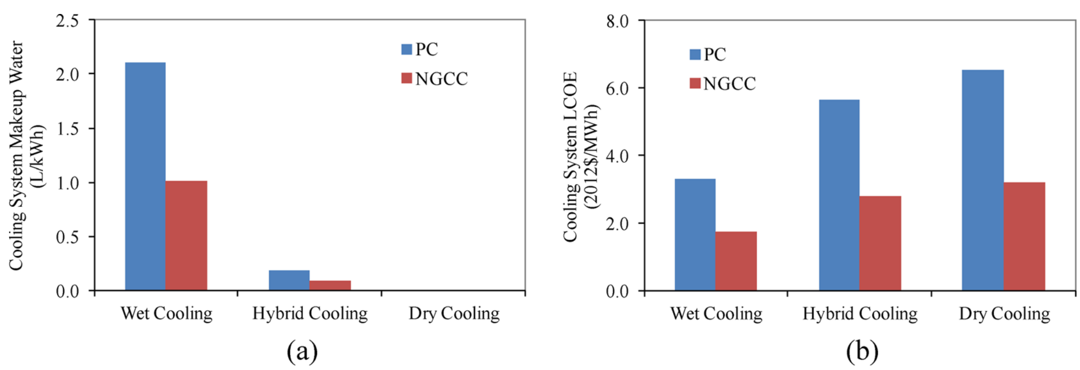

Figure 4. Comparisons of different cooling technologies: (a) makeup water use and (b) cooling system LCOE.

designed for 1-month service, all costs increase monotonically with the cooling duty fraction. This is because, although the shorter duration of service results in a smaller makeup water requirement, it also requires a larger dry cooling unit, which leads to larger costs for both the overall cooling system and the overall plant. For example, when the wet unit cooling duty fraction is designed to be 0.3, the number of air-cooled condenser cells is 46 for the 3-month summer service case and 62 for the 1-month service case. This finding implies that designing the wet cooling unit for 3 months of summer service, rather than 1 month, would reduce both the total capital cost and total levelized cost of a hybrid cooling system if high air temperatures occurred throughout the entire summer.

Effects of CO_2 Capture Efficiency. To comply with the U.S. EPA's current emission standards, a supercritical coal-fired plant needs to remove about 20% of its carbon pollution.[7] However, there is no CO_2 capture needed for modern NGCC plants. Thus, we examined the effects on the hybrid cooling system of CO_2 capture efficiency starting from 20% at PC plants. The bypass design was adopted for amine-based CCS because it is a cost-effective option for partial CO_2 capture.[29] Figure 2 shows that the makeup water use of hybrid cooling system increases by a factor of nearly 3 due to the increased cooling water use for CCS when the CO_2 capture efficiency is elevated from 20% to 90%. Meanwhile, the overall system LCOE increases by about \$1/MWh, though the addition of CCS significantly increases the overall plant LCOE.

Effects of Capacity Factor and Fixed Charge Factor. Further parametric analysis was conducted to evaluate the impacts of capacity factor (CF) and FCF assumptions. Figure 3 shows the resulting effects on the cooling system LCOE at the base PC and NGCC plants without CCS. The ranges of parameter values shown in Figure 3 cover the values that were often adopted in the literature.[3,28] For a given CF, the cooling system LCOE increases by 21−22% when the FCF is increased from the base value (given in Table 1) to 0.15. For a given

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FCF, the cooling system LCOE decreases by about 20% when the plant CF is increased from 65% to 85%. These two parameters have pronounced effects on the levelized costs of cooling systems.

COMPARISONS OF DIFFERENT COOLING TECHNOLOGIES

A switch from once-through cooling to advanced cooling systems has been considered widely as a major strategy to reduce plant water use.[9] To examine the implications, we quantify the trade-offs in water use and cost among different cooling technologies. For the illustrative purposes, the IECM was applied to evaluate and compare the performance and costs of wet, dry, and hybrid cooling systems at the base PC and NGCC plants without CCS. The annual average ambient air conditions in Table 2 were used for assessing the wet tower systems, while the average summer conditions were used to size the dry cooling systems. Other major parameters of wet and dry cooling systems were assumed to be the same as those given in Table 1.

The PC plant using a wet tower system was found to have a net plant efficiency of 38.3%, compared to 36.9% for the PC plants using dry or hybrid cooling systems (which have similar parasitic loads). Similarly, the net plant efficiency of the NGCC plant using a wet tower system is 0.7% higher (on the absolute basis) than that of the NGCC plants using hybrid or dry cooling systems. Figure 4 compares the makeup water use and LCOE of the three cooling technologies. Compared to the wet cooling system, the hybrid cooling system has much lower water use but 70% higher LCOE for the PC case and 60% higher LCOE for the NGCC case. This results in a \$2–4/MWh increase in the plant LCOE for the given assumptions in Table 1. Although dry cooling has no water requirement, it has the highest LCOE among the three cooling systems. However, as shown in Figure 4b, the difference in the LCOE between dry and hybrid cooling systems is small, which is about \$1/MWh for the PC case and \$0.4/MWh for the NGCC case.

A further comparison shows that the makeup water use of wet tower cooling at the PC plant without CCS is similar to that of hybrid cooling for the PC plant with 90% CO_2 capture. However, as shown in Figure 2a, hybrid cooling for cases with partial CO_2 capture requires less makeup water. This result implies that for PC plants subject to the U.S. EPA's current CO_2 emission standards, a switch from wet cooling to hybrid cooling can significantly decrease plant water use. Given the trade-offs and factors discussed above, therefore, the choice of an appropriate cooling system should be made on the basis of a full consideration of performance, costs, regulations, and resource availability.

DISCUSSION

This study provides systematic estimates of the performance and cost of hybrid cooling systems at PC and NGCC plants. Their cost and performance depend on a range of environmental, technical, and economic parameters. In general, however, hybrid cooling systems were found to significantly reduce water use, compared to prevailing wet cooling systems (e.g., reductions of roughly 91% for PC and NGCC cases without CCS). These reductions in water use, however, come with some increase in overall plant LCOE (e.g., increases of 3–5% for PC and NGCC plants without CCS). Furthermore, hybrid systems still require some makeup water in the summer, and their operational control is generally more complex.

In order to minimize overall system cost in regions where hot periods last the entire summer, the wet unit of a hybrid cooling system needs to handle about 30% of the overall plant cooling load during the summer months. To lower capital investments on hybrid systems, more research and development (R&D) efforts are needed to improve the dry cooling unit performance, so as to decrease the size, footprint, and cost of the required air-cooled condenser.

The addition of CCS systems to comply with current and future CO_2 emission regulations can lead to a significant increase in power plant water use. A previous analysis for plants employing a wet cooling system showed that 90% CO_2 capture using amine-based CCS increases water use by more than 80%, relative to a plant without CCS producing the same net power.[5] With hybrid cooling systems, the annual makeup water requirement with CCS would still be greater than without CCS. But, compared to systems with wet cooling,[5] the hybrid system water use would be substantially smaller with or without CCS (e.g., 90% less without CCS and 52% less with CCS).

Because limitations on water availability due to drought, population growth, and other factors may become increasingly common in the future, water use metrics also need to be considered in R&D programs for advancing carbon capture technologies and planning water resources for energy production, especially under carbon constraints. This paper has shown that hybrid cooling technology can be an adaptive option to improve the resilience of fossil-fuel-based electricity generation, especially in the face of CO_2 emission regulations. For both coal- and gas-fired power plants, hybrid cooling systems can substantially reduce water use in the electric power sector with only moderate impacts on the overall plant-level cost of electricity generation. Hybrid cooling, as an alternative to the conventional wet cooling technology, thus offers a promising option for future power plant designs.

ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.6b00008.

Tables S-1–S-5 (PDF)

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Notes

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