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Water Impacts of CO_2 Emission Performance Standards for Fossil Fuel-fired Power Plants

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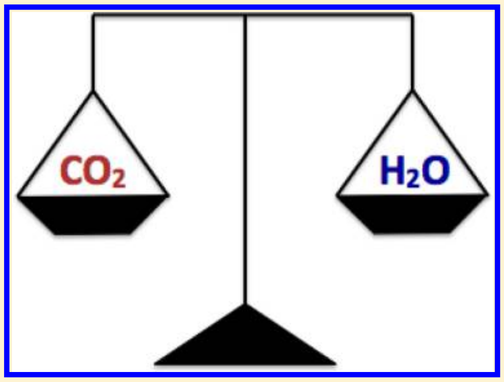
Supporting Information

ABSTRACT: We employ an integrated systems modeling tool to assess the water impacts of the new source performance standards recently proposed by the U.S. Environmental Protection Agency for limiting CO_2 emissions from coal- and gas-fired power plants. The implementation of amine-based carbon capture and storage (CCS) for 40% CO_2 capture to meet the current proposal will increase plant water use by roughly 30% in supercritical pulverized coal-fired power plants. The specific amount of added water use varies with power plant and CCS designs. More stringent emission standards than the current proposal would require CO_2 emission reductions for natural gas combined-cycle (NGCC) plants via CCS, which would also increase plant water use. When examined over a range of possible future emission standards from 1100 to 300 lb CO_2/MWh gross, new baseload NGCC plants consume roughly 60–70% less water than coal-fired plants. A series of adaptation approaches to secure low-carbon energy production and improve the electric power industry's water management in the face of future policy constraints are discussed both quantitatively and qualitatively.



■ INTRODUCTION AND RESEARCH OBJECTIVES

In September 2013 the U.S. Environmental Protection Agency (EPA) issued a proposal that sets separate emission performance standards (EPS) in pounds of carbon dioxide (CO_2) per *gross* megawatt-hour (lb CO_2 /MWh gross) to limit CO_2 emissions from new coal- and natural gas-fired electric generation units (EGUs).[1] This regulatory proposal is only applicable to new fossil fuel-fired EGUs. Depending on the chosen compliance period, the emission standard proposed for coal-fired EGUs is 1100 lb CO_2/MWh gross over 12 operating months or 1000 to 1050 lb CO_2/MWh gross over 84 operating months. For gas-fired EGUs, the proposed standards are 1000 lb CO_2/MWh gross for larger units (than 850 MMBtu/h) and 1100 lb CO_2/MWh gross for smaller units. In this proposal, carbon capture and storage (CCS) implemented for partial CO_2 capture is identified as the best system of emission reduction (BSER) for coal-fired EGUs to comply with the proposed standards, whereas modern, efficient natural gas combined cycle (NGCC) technology is considered as the BSER for gas-fired EGUs.[1] However, adding current commercial amine-based CCS to pulverized coal-fired (PC) power plants for 90% CO_2 capture would nearly double plant water use,[2,3] which could greatly intensify pressure on water resources, especially in arid regions. More stringent emission limits than the current proposal would also require CO_2 emission reductions for NGCC plants as well.[4] Thus, energy and climate polices for limiting CO_2 emissions from fossil fuel-fired EGUs will pose water challenges for the electric power sector and water resource management. However, the impacts on plant water use of adding CCS to comply with the newly proposed emission standards have not been investigated for new EGUs.

Water availability for thermoelectric power generation may be vulnerable to climate change. The summer capacity of U.S. power plants is predicted to decrease by 4.4–16% for 2031 to 2060 due to the collective impacts of lower summer river flows and higher river water temperatures, depending on cooling system type and climate scenario.[5] A recent assessment of water availability indicates that some U.S. regions, such as significant portions of the Florida, Great Plains, Southwest, and West, would have limited water availability for future development.[6] The U.S. Energy Information Administration (EIA)'s Annual Energy Outlook projects that total national electricity demand will increase by 29% from 2012 to 2040, though growth of U.S. electricity use has slowed; and coal and natural gas will still be a major fuel source of future U.S. electricity generation, accounting for nearly 70% of the national electricity grid in 2040.[7] Considering the potential change in regional water availability along with the energy production driven increasingly by the need to mitigate climate change, water will become critically important for future U.S. electricity generation in a carbon-constrained world.[3] The objectives of this paper are to (1) examine the water use impacts of the proposed performance standards for limiting CO_2 emissions from new fossil fuel-fired baseload power plants; (2) evaluate the effects on plant

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water use resulting from alternative power plant designs and regulatory compliance options for power plants under the CO_2 emission standard regulation; and (3) explore approaches for improving the electric power industry's water management in the face of possible future policy constraints. We conduct plant-level modeling and analysis for a range of regulatory scenarios starting from the U.S. EPA's current proposal to more stringent CO_2 emission standards. We use the term of *water use* to include both water withdrawal and water consumption. Water withdrawal is the total amount of water taken from a source. Water consumption is the amount of water needed to make up for evaporative losses in power plants. The results of this work inform the electric power industry's water management in the face of future low-carbon policy constraints and help water mangers and decision makers in planning water resources for energy production and water allocations among multiple sectors (e.g., agriculture and electric power sectors).

■ AN INTEGRATED SYSTEMS MODELING TOOL

To evaluate the technical and economic impacts of performance standards proposed for limiting CO_2 emissions from new fossil fuel-fired power plants, we apply the Integrated Environmental Control Model developed by Carnegie Mellon University to conduct plant-level modeling and analysis for coal- and natural gas-fired power plants under the CO_2 emission regulation. The IECM is a computer-modeling tool for preliminary design and analysis of an array of electric power generation systems including PC, integrated gasification combine cycle (IGCC), and NGCC plants that can employ a variety of cooling and environmental control systems.[8] Models for a variety of CCS systems are available for different types of power plants. The IECM can be run deterministically or as a stochastic simulation that propagates key uncertainties through the model. All technologies and systems are modeled consistently using a common technical and economic framework, in which process performance models and cost models are coupled, including uncertainty characterization.[8] The IECM has a detailed water system module that employs fundamental mass and energy balances to estimate water use for the steam cycle, the cooling system, and a variety of environmental control systems for different power plant designs.[3] Technical details of the water module are available elsewhere.[3,9]

As a basecase for our regulatory assessments we use IECM to configure a new baseload PC plant with a supercritical (SC) boiler and an NGCC plant with two GE 7FB gas turbines. When CO_2 capture is needed to comply with a proposed CO_2 emission standard, an amine-based CCS system is added to the plant.[10,11] The major performance metrics considered for assessments include CO_2 removal efficiency, net plant efficiency on the basis of high heating value (HHV), and water use on the basis of absolute mass and intensity. Costs are computed as total capital requirement (TCR) and annual levelized cost of electricity (LCOE). Given a specific EPS proposal, we first determine the CO_2 removal efficiency required for CCS to comply with the proposal and then estimate the water use. The difference in plant water use between the plants with and without CCS is the metric that we adopt to measure the water impacts of the proposed CO_2 emission standards. Considering that the bypass design is a cost-effective option for nonfull CO_2 control by amine-based CCS,[12] we adopt this design for all the partial carbon capture cases. In addition to the base case studies, we further conduct sensitivity and uncertainty analyses to examine the effects of major plant designs and factors on the plant water use for new fossil fuel-fired power plants under the CO_2 emission regulation.

■ BASE CASES RESULTS

We conducted basecase studies to evaluate the performance, water use, and costs of PC and NGCC plants subject to the U.S. EPA's proposed CO_2 emission standards. The 2012 release of IECM v8.0.2 was employed to establish the base supercritical PC plant fired by Illinois No. 6 coal and the base NGCC plant configured with two GE 7FB gas turbines and a heat recovery system generator. Environmental control systems including selective catalytic reduction (SCR), electrostatic precipitator (ESP), and wet flue-gas desulfurization (FGD) were installed to comply with the federal New Source Performance Standards for traditional air pollutants. As needed, the amine-based CCS system was assumed to be built at the same time as the new plant in order to control the CO_2 emissions to the proposed limit. Consistent with the Section 316(b) of the Clean Water Act's ruling on cooling water intakes, wet cooling towers were employed for the new plants to minimize adverse environmental impacts. The ambient air conditions were taken as the annual average conditions in the U.S. Southwest regions from 1981 to 2000. Table 1 summarizes the major technical and economic assumptions and parameters of the base power plants and environmental control systems. Information of fuel properties is available in Tables S-1 and S-2 of the Supporting Information (SI). To be consistent with the U.S. EPA's proposal, the CO_2 emission standards and emission rates are measured on the basis of gross power output and presented in the English units. All other variables are in the metric units.

To examine the effects of the CO_2 EPS on plant performance and costs, we first model a plant without carbon capture and then a plant with CCS employed for partial CO_2 capture as needed to meet the standard. For the coal-fired case, both the base plants are evaluated on the same basis of 500 MW (net) power output. Table 2 summarizes the major performance and cost results of the base plants with and without partial CO_2 capture. For the PC plant without any CO_2 control, the total plant water withdrawals and water consumption are $2.33 m^3/MWh$ and $1.63 m^3/MWh$, respectively. The cooling system accounts for 80% of the plant water withdrawals and 86% of the plant water consumption. Due to evaporative loss, the wet FGD system also accounts for 10% of the plant withdrawals and 14% of the plant water consumption. To comply with the U.S. EPA's proposed standard, the PC plant has to remove 40% of total CO_2 emissions from the emission rate of 1687 lb CO_2 /MWh gross to the 1100 lb CO_2/MWh-gross limit. To achieve the required CO_2 capture efficiency, about 56% of the total flue gas is bypassed in the PC plant and the rest enters the CCS system where 90% of the entering CO_2 is captured. The CCS system requires 92.8 tons of cooling water per ton of CO_2 captured for various operating units, such as flue gas and solvent coolers and interstage cooling for multistage CO_2 product compression, and extracts the steam in the amount of 3526 kJ/kg CO_2 from the plant steam cycle for solvent regeneration,[3] which lowers the plant efficiency. As a result of the CCS implementation, the net plant efficiency decreases from 38.2% to 32.8%, and both the plant water withdrawals and water consumption significantly increase by about 31% mainly because of the large amount of additional cooling water use, compared to the plant without CO_2 emission control. The total annual LCOE also increases by 30% for the overall plant and more than 50% for the cooling system.

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Table 1. Major Technical and Economic Assumptions and Parameters for Baseline Power Plants and Environmental Control Systems

variable	value
plant type	PC or NGCC power plant
fuel type[a]	Illinois No. 6 coal or natural gas
plant capacity factor (%)	75
Ambient Air Conditions	
temperature (°C)	13.3
relative humidity (%)	59
Traditional Air Pollution Controls	
nitrogen oxides	selective catalytic reduction
particulates	electrostatic precipitator
sulfur oxides	wet flue-gas desulfurization
partial CO_2 capture design (if applicable)	bypass design
Carbon Capture and Storage (If Applicable)	
capture system type	Econamine FG+
CO_2 removal efficiency (%)	90
Sorbent concentration (wt %)	30
CO_2 product pressure (MPa)	13.8
heat-to-electricity equivalent efficiency of extracted steam (%)	18.7
regeneration heat requirement (kJ/kg CO_2)	3526
makeup water for washing (% of flue gases)	0.8
process cooling duty (t H_2O/t CO_2)	92.8
Cooling System	
cooling technology	wet tower
water temperature drop across the tower (°C)	11.1
cycles of concentration (ratio)	4
auxiliary cooling duty (% of primary cooling)	1.4
Economic Parameters	
dollar type	2011 constant dollar
fixed charge factor	0.113
coal price ($/t)	42
gas price ($/GJ)	6.92

[a]Information of fuel properties is reported in the Supporting Information.

As Table 2 shows, the NGCC plant has a much higher plant efficiency (50%), compared to the PC plant. The cooling system only needs to serve the steam generation loop of the combined cycle. The CO_2 emission rate of the NGCC plant is less than the U.S. EPA's proposed emission standard and also less than 50% of the uncontrolled PC plant's emission rate. Thus, there is no CO_2 capture needed for the NGCC plant. As a result, the NGCC plant's water withdrawals and consumption are 71% and 69% lower than those of the PC plant under the EPS regulation, respectively. The cost advantage of the NGCC plant compared to the PC plant with CCS highly depends on the gas price, which could be diminished by gas prices above approximately $9.0/GJ for new baseload plants.[4]

■ SENSITIVITY ANALYSIS

Parametric analyses were conducted for the base PC plant under the CO_2 emission regulation to evaluate the effects on plant water use of power plant designs and regulatory compliance options, which are helpful to identify adaptation approaches to the potential water use growth under carbon constraints. The effects of plant designs on the added cost for CCS employed to comply with the emission standards are evaluated in a recent study by Zhai and Rubin.[4] The plant designs considered include different types of steam generator, coal, and cooling technology, which are key factors affecting power plant performance.[3,9,13] When a parameter was evaluated, all other parameters were held at their base case values given in Table 1 unless otherwise noted.

Table 2. Performance and Cost Results for Baseline Power Plants with and without Partial CO_2 Capture[a]

variable	performance and cost		
plant type	supercritical PC		NGCC
emission performance standard	no	yes	no/yes
gross electrical output (MW)	536	578	557
net electrical output (MW)	500	500	542
net plant efficiency (%)	38.2%	32.8%	50.1%
CO_2 removal efficiency (%)		40%	0%
CO_2 Emissions Rate			
(lb/MWh gross)	1687	1097	782
(lb/MWh net)	1809	1269	803
Water Consumption by Unit (t/h)	818.3	1065.0	361.1
wet cooling system	700.3	917.2	361.1
wet flue-gas desulfurization	117.9	137.4	
carbon capture and storage		10.9	
Water Withdrawal by Unit (t/h)	1166.6	1527.7	481.7
boiler	115.2	134.3	
wet cooling system	932.6	1222.0	481.7
selective catalytic reduction	1.2	1.4	
wet flue-gas desulfurization	117.9	137.4	
carbon capture and storage		32.2	
total water consumption (m^3/MWh)	1.63	2.13	0.67
total water withdrawals (m^3/MWh)	2.33	3.06	0.89
total capital requirement of cooling system ($/kW)	92.7	119.3	49.1
total capital requirement of power plant ($/kW)	2060	2354	812.3
cooling system levelized cost of electricity ($/MWh)	3.23	4.90	1.83
plant levelized cost of electricity ($/MWh)	63.5	82.6	66.8

[a]The CO_2 emission rates are reported on the gross power output basis unless otherwise noted, whereas the water use intensities and normalized cost measures are reported on the net power output basis.

Effects of Steam Cycle Design. The steam cycle design directly affects the plant performance. The supercritical boiler employed in the base case is more efficient than the subcritical steam generator that is widely used in power plants today, but less than the ultrasupercritical steam generator that would be installed increasingly for new coal-fired plants. Thus, to examine how much water use could be reduced by improving current plant efficiency, we evaluate three types of coal-fired plants subject to the emission standard of 1100 lb CO_2/MWh gross. Without CO_2 emission control, the plant emission rates of the three plants are 1786, 1687, and 1537 lb CO_2/MWh gross, respectively. As shown in Figure 1(a), the subcritical, supercritical, and ultrasupercritical plants have to remove 45%,

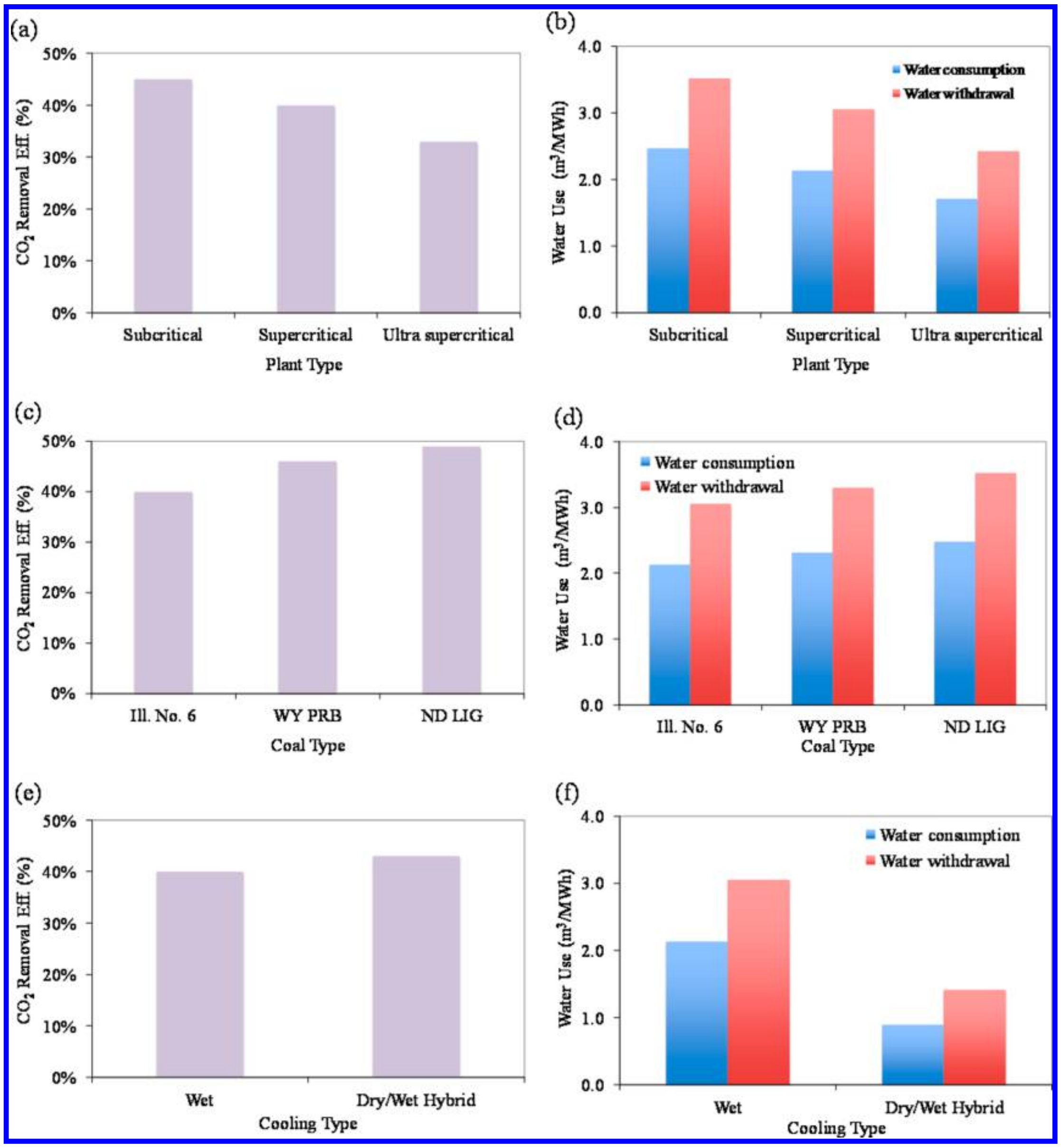

Figure 1. Effects of alternative plant designs on CO_2 removal efficiency and plant water consumption of coal-fired power plant under the 1100 CO_2/MWh standard regulation.

40%, and 33% of the plant CO_2 emissions to comply with the EPS, respectively. The resulting (net) plant efficiencies of the three plants with CCS are 29.7%, 32.8%, and 37.5%, respectively. Figure 1(b) shows the decreasing trends of plant water withdrawals and consumption with the increase of plant efficiency. The plant water use decreases by about 31% for the 7.8% increase (on the absolute basis) in the net plant efficiency varying from subcritical to ultrasupercritical plants under the EPS regulation, respectively. The added water use for partial CO_2 capture relative to the individual uncontrolled plants ranges from 25% to 37%. These results clearly indicate that improving the plant efficiency lowers the required CO_2 removal level to meet the U.S. EPA's emission proposal and then reduces the plant water use.

Effects of Coal Type. Coal quality is a major factor affecting power plant performance and costs.[13] Accordingly, we evaluate three types of widely used coals: Illinois No. 6 bituminous coal, Wyoming Power River Basin (WY PRB) sub-bituminous coal, and North Dakota lignite (ND LIG) coal. Coal properties are summarized in Table S-1 of the SI. Illinois No. 6 coal has the largest HHV and carbon content among the three coals. Without CO_2 emission control, the emission rates of the plant fired by the three coals are 1687, 1832, 1918 lb CO_2/MWh gross, respectively. Figure 1(c) shows that to comply with the EPS, the plant fired by the three coals has to remove CO_2 emissions by 40%, 46%, and 49%, respectively. Higher coal quality leads to a lower CO_2 removal requirement and in turn, improves the net plant efficiency and lowers the plant water use. As shown in Figure 1(d), the plant fired by ND LIG coal has the highest CO_2 removal requirement (nearly 50%), and has 15−16% more water withdrawals and consumption than the plant fired by Illinois No. 6 coal. In the context of regulating CO_2 emissions from new EGUs, the coal type appears to be a remarkable factor affecting the plant water use.

Effects of Cooling Technology. As the basecase results indicate, the wet cooling system is the largest source of plant water use. A dry cooling system in lieu of the wet cooling can significantly reduce plant water use. However, it often requires a higher capital cost and more electric power use for operating.[9] Thus, we examine the techno-economic impacts of wet versus dry cooling technologies in the context of regulating CO_2 emissions from new coal-fired EGUs. Air-cooled condensers (ACCs) for dry cooling are adopted as the plant's primary cooling system to condense the exhaust steam. ACCs are designed to have an initial temperature difference of 39 °C between the inlet exhaust steam and the ambient air, which is a key performance variable for ACCs;[9] Because the dry cooling system has no water available to cool down the CO_2 capture process, an auxiliary wet cooling system of the type described in the base case is used to support the carbon capture operations. Similar to a previous study, its total cost is treated as an added operating cost for the amine-based CCS system.[9]

Here, we make comparisons between the base PC plant illustrated in Table 1 (only using a wet cooling system) and the PC plant equipped with dry/wet hybrid cooling systems. For both the plants under the EPS regulation, the total capital requirement of ACCs used as the primary cooling system is 21% higher than that of the wet cooling system in the base PC plant illustrated in Tables 1 and 2; in contrast, the dry cooling system requires more electricity power use than the wet cooling system, resulting in a decrease in the net plant efficiency by 1.3% on the absolute basis. Thus, the PC plant using the dry/wet hybrid cooling requires a 3% higher CO_2 capture efficiency (absolute value) for CCS than the base PC plant to comply with the same emission standard. Figure 1(f) shows that the plant water withdrawal and consumption intensities are 54% and 58% less for the PC plant with the dry/wet hybrid cooling than the base PC plant (fully using a wet cooling system), respectively.

Effects of Regulatory Compliance Period and CCS Deployment Timing. The U.S. EPA's proposed rules provide new coal-fired EGUs with the flexibility of choosing a regulatory compliance period on a 12- or 84-month rolling average basis to meet the corresponding CO_2 EPS.[1] For either of the compliance period options, power plants can have different timetables for employing CCS to meet the emission standard: CCS may be employed constantly for partial CO_2 capture throughout the entire compliance period, or CCS with a high CO_2 removal efficiency may be launched some months later after the compliance period starts. Because the cost-effective CO_2 capture occurs at a removal efficiency of 90% for a typical amine-based system, there is a maximum waiting time allowable for initiating CCS deployment to ensure the compliance with the proposed standard. The PC plant unlikely meets the standard beyond that time threshold, which is estimated by averaging CO_2 emissions (weighted by gross power generation) over the operating months with and without 90% CO_2 capture to meet the standard. Here, we evaluate the effects of CCS deployment timing on plant water use for both the regulatory compliance period options.

Figure 2 shows two scenarios of CCS deployment timing for the 12-month operating compliance period option: CCS is employed for 40% CO_2 capture throughout the entire 12-month period to meet the 1100 lb CO_2/MWh-gross standard; no CO_2 capture is implemented in the first 7.7 months, but CCS is employed for 90% CO_2 capture for the rest of 12-month operating period. For the first CCS deployment scenario, the plant water consumption is 2.13 m^3/MWh for 12 months, whereas the plant water consumption of the second deployment scenario is 1.63 m^3/MWh for the first 7.7 months

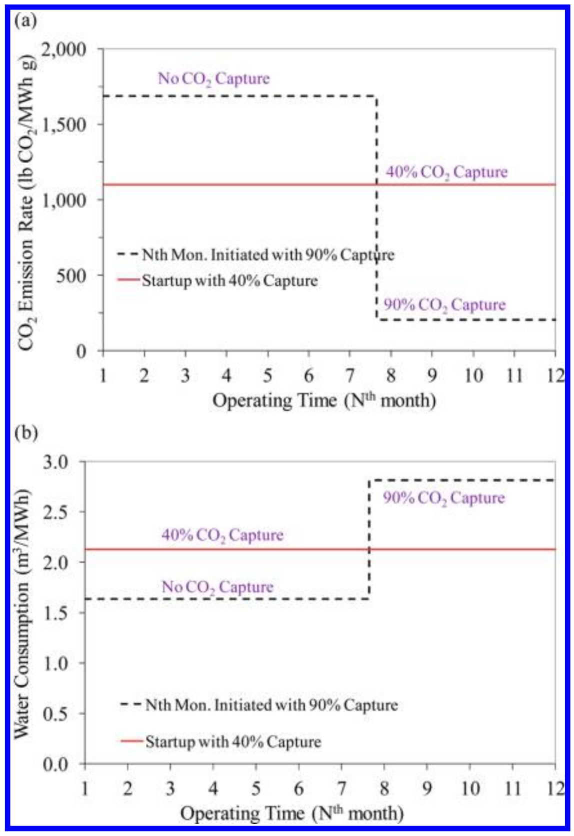

Figure 2. CO_2 emission rate and water consumption of regulated coal-fired power plant by CCS deployment timeline for a 12-month regulatory compliance scenario.

and 2.81 m^3/MWh for the rest months, resulting in 2.06 m^3/MWh on average for the 12 months. These results show no significant difference in plant water consumption on average between the two deployment scenarios. There are similar findings for the 84-month compliance period option, which are presented in Figure S-1 of the SI. In comparison between the two compliance period options, there are no significant differences in the average plant water withdrawals and consumption. Additional information is available in Tables S-3 and S-4 of the SI.

UNCERTAINTY ANALYSIS

To account for uncertainties and variability in the value of key parameters that affect plant water use, and provide likelihood information on a specific result (e.g., *plant water use* or *added water use*), we used the IECM's stochastic simulation capabilities to conduct uncertainty analysis for both the base PC plants illustrated in Tables 1 and 2. We first characterized the uncertainties of key input variables and then estimated the probabilistic distributions of plant water use for both the base PC plants and the added water use for partial implementation of CCS employed to comply with the CO_2 emission standard. The key uncertain variables considered include ambient air conditions and those that affect water use around the steam cycle, the wet FGD unit, and the amine-based CCS system (e.g., boiler blowdown, auxiliary plant cooling duty, and steam heat requirement and cooling duty of the CO_2 capture process). The distribution function assumptions of the uncertain variables are mainly based on the previous study by Zhai et al[3] and summarized in Table S-5 of the SI.

We conducted 500 samples Monte Carlo simulation to yield the cumulative distribution functions (CDFs) of plant water use. Figures 3(a) and 3(b) show the CDFs of plant water use for the PC plants with and without carbon capture. Given the assumed uncertainty distributions, the resulting probabilistic estimates for the plant without carbon capture have a 95-percentile confidence range from 1046 to 1260 t/h for plant water withdrawals and 786 to 849 t/h for plant water consumption, while the estimates for the plant subject to the CO_2 emission standard vary from 1356 to 1761 t/h for plant water withdrawals and 1001 to 1222 t/h for plant water consumption.

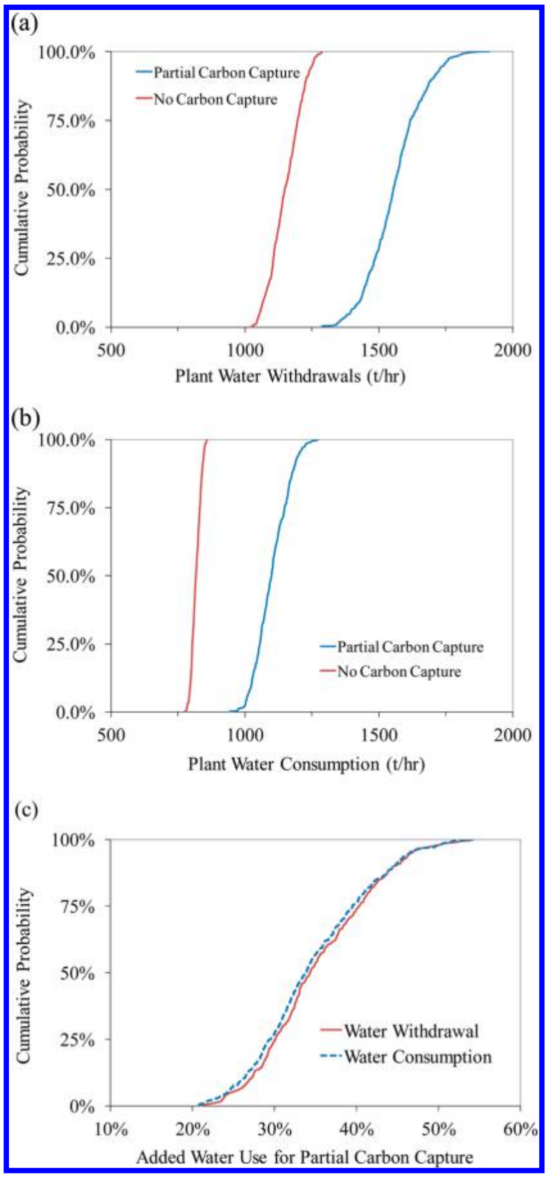

Figure 3. Probability distributions of plant water use obtained from IECM simulation for a 500 MWnet coal-fired plant and added water for partial CO_2 capture to comply with the 1100 lb CO_2/MWh emission standard.

Unlike the deterministic estimates, the added water use for partial CCS implementation cannot be estimated simply as the difference between the two plants under uncertainty. To estimate the added water use and the associated likelihood, we employed the comparative assessment procedure established for IECM applications to yield probability distributions of *added water use* for partial CO_2 capture between the two plants under uncertainty. In comparing two systems under uncertainty, correlated or common variables have the same sampling values assigned for both systems over the stochastic simulation, but uncorrelated variables are sampled randomly and independently.[14] Details of the assessment procedure are described elsewhere.[14,15] In this application, the identical set and sequence of random samples was assigned to the common uncertain variables, including the ambient air temperature and humidity and those of the steam cycle and the FGD unit; the uncertain variables of the CCS system were sampled randomly and independently. Figure 3(c) shows the resulting probability distributions of *added water use* for partial CO_2 capture to comply with the 1100 lb CO_2/MWh-gross emission standard. The 95-percentile confidence intervals of the added water use in relative percentage fall within the range from 23 to 50% for both the plant water withdrawals and consumption. Given the assumed distribution functions, the likelihood that the added water use will exceed the deterministic estimate is nearly 70%, mainly because of the assumed nonsymmetric distribution of the capture process cooling duty relative to the nominal deterministic value.

■ DISCUSSION

The enactment of the U.S. EPA's proposed standards for limiting CO_2 emissions from new fossil fuel-fired EGUs would greatly affect the performance and resource requirements of coal-fired power plants. The partial implementation of current amine-based CCS to meet the proposed standards over an either 12-month or 84-month compliance period will result in significant increases in plant water use due to the large amount of additional cooling water used for the capture process, varying with power plant and CCS system designs. This trend would further exacerbate water challenges for regions (e.g., southwest regions) where water supply for electric power generation already is under pressure or water availability for thermoelectric power plants is vulnerable to climate change. This outcome highlights the importance of the water use metrics in prioritizing R&D programs on advanced low-carbon technologies and associated waste-heat recovery or integration systems for the electric power industry and on planning for low-carbon energy production.

To mitigate climate change, future policy constraints for limiting CO_2 emissions may be more stringent than the U.S. EPA's current proposal. A consensus study of National Academies has recommended a mitigation "budget" that requires a significant reduction of national greenhouse gas emissions from 1990 levels by 50 to 80% to limit the magnitude of future climate change.[16] Meeting this would require some reductions of CO_2 emissions from NGCC plants. To reach this, more stringent emission standards than the U.S. EPA's current proposal would require partial implementation of CCS in NGCC plants as well. Figure 4 shows that over the increasingly stringent standards from 700 to 300 lb CO_2/MWh gross, the CO_2 removal requirement increases from 64% to 86% for the PC plant and 12% to 65% for the NGCC plant. As a result of the partial CO_2 capture via CCS, the plant water consumption increases by 13% from 2.43 to 2.75 m^3/MWh for the PC plant and by 19% from 0.85 to 1.01 m^3/MWh for the NGCC plant under the EPS regulation, shown in Figure 4(b). Compared to the PC plant without CO_2 emission control, complying with the emission standards from 1100 to 300 lb CO_2 /MWh gross

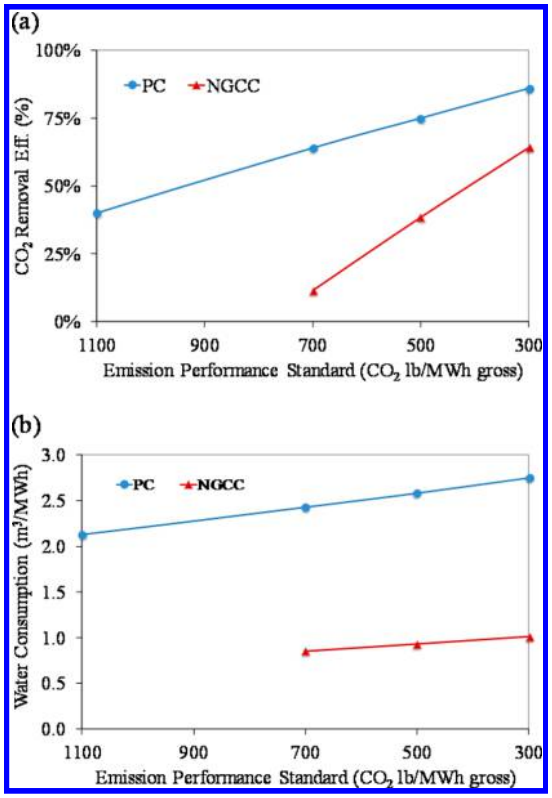

Figure 4. Effects of stringent CO_2 emission performance standards on CO_2 removal efficiency and plant water consumption.

would increase the coal-fired plant water consumption by 30 to 68%. In comparison between the two types of plants, the NGCC plant consumes about 64% less water than the PC plant on average over the increasingly stringent emission limits from 700 to 300 lb CO_2/MWh gross. More stringent CO_2 emission standards obviously increase plant water use. However, on a regional basis, a shift from coal to natural gas for low-carbon electricity generation would lower regional water demand for the electric power industry. Besides, high penetration of renewable energy (e.g., wind and solar power) into the electric power grid would further decrease water use for low-carbon electricity generation when their costs of electricity generation are widely affordable.

Different ruling bases on gross versus net power outputs were adopted by state and federal regulations. Gross power output is the total electric generation of fossil fuel-fired power plants, whereas net power output is the electricity available for delivery to the grid, which is the gross output minus the amount of power consumed for supporting the operations of power plants and associated environmental control systems plus CCS when applicable. The State of California has issued a standard of 1100 lb CO_2/MWh for baseload generation several years ago.[17] Unlike the U.S. EPA's ruling that is based on gross power output, the CO_2 emission rate to meet California's standard is based on net power generation. Such different choices in regulatory requirements affect power plant performance: for the 1100 CO_2/MWh emission limit, the CO_2 removal efficiency required for the base PC plant would increase from 40% to 50% if the rulemaking basis were changed from the gross to the net power generation. Subsequently, the plant water use intensity would increase by 5−6% accordingly. In contrast, the net basis actually requires a more stringent emission limit and then leads to a larger increase in consumptive plant water use.

To tackle added water use for CCS, adaptation approaches are needed for power plants, especially in regions facing water scarcity. As illustrated earlier, plant efficiency improvement and the use of high-quality coal not only lower the required CO_2 removal level, but also remarkably reduce plant water use for coal-fired EGUs under the CO_2 emission regulation. Dry cooling can be applied to effectively deal with the increasing water use driven by low-carbon electricity generation, though it requires a relatively high capital investment and results in a reduction in the overall plant efficiency. Along with advancing carbon capture technologies, innovative designs of waste heat recovery and integration within the capture plant or alternative refrigeration systems for CO_2 capture processes also hold potential for reducing plant water use.[18] These measures all carry their own costs,[4,9,14,18] but are able to reinforce the resilience of power plants to tackle growing water challenges for low-carbon electricity generation, especially in arid areas heavily dependent on fossil fuels.

Section 316(b) of the Clean Water Act promotes the shift from once-through cooling to wet tower cooling systems in thermoelectric power plants. This shift would significantly decrease plant water withdrawals, but increase plant water consumption. Along with these trends, the implementation of CCS to comply with future policy constraints would further intensify plant water consumption, especially in the face of more stringent emission limits. All these policy impacts should be considered explicitly in water supply demand management and planning for the electric power industry. In addition to the aforementioned adaptation approaches, alternative water resources also should be considered to meet potentially increased consumptive water use, especially for coal-fired electricity generation under carbon constraints. For CO_2 geologic sequestration, water will be extracted from the CO_2 storage sites because of brine displacement within geologic formations, with production rates up to 1.9 m^3 of water per megawatt hour.[19,20] Produced water can be reused to offset the increased water demand incurred by the CO_2 capture. But, appropriate treatments are often needed for produced water to make it acceptable for power plant use.[21] Besides, sufficient reclaimed water from municipal treatment plants is widely available for thermoelectric power plants within the distance of 40 km and also can be an alternative resource to make up water use in power plants,[22,23] especially when water availability for electric power generation is vulnerable to climate change.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Supporting Information for the paper includes text, tables, and a figure regarding coal and natural gas properties, additional results on different regulatory compliance scenarios, and assumed distribution functions for uncertainty analysis and the probabilistic range of plant water use for the NGCC plant. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

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