The Future of Low Carbon Electric Power Generation: An Assessment of Economic Viability & Water Impacts under Climate Change and Mitigation Policies

Submitted in partial fulfillment of the requirements for

the degree of

Doctor in Philosophy

in

Engineering and Public Policy

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May 2016

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ACKNOWLEDGEMENTS

I would like to deeply thank my research advisors and committee members for their invaluable help and guidance throughout this degree. I am incredibly grateful for the input, support, and advice of Haibo Zhai and the many hours he spent helping me improve and progress my research. I would also like to thank Granger Morgan for his help and guidance. Additionally, I would like to thank Page Kyle and the Joint Global Change Research Institute for their contributions and collaboration. I am also grateful to Iris Grossmann for her advice and participation in my committee. In addition, I am indebted to the EPP staff for all their help and support.

Finally, I would like to thank my fellow students, friends, and boyfriend for their advice, encouragement, and ability to listen to me complain. Their support has been instrumental. I'd especially like to thank my parents, Shraddha and Kirit Talati, and my sister, Achala Talati for all they do for me, the list of which is far too long to describe here.

This work was supported in part by the Center for Climate and energy Decision Making (CEDM) through a cooperative agreement between the National Science Foundation and Carnegie Mellon University (SES-0949710). This work was also supported in part by the the Bertucci Graduate Fellowship from the Carnegie Mellon College of Engineering as well as the Pugh Fellowship. I would also like to thank the Tom Johnson Fellowship for its support of my summer internship with White House Office of Science and Technology Policy during the course of my PhD.

ABSTRACT

As the electric power generation sector transitions towards low-carbon technologies under climate change and mitigation policies, technology choices and water use will shift alongside it. With the implementation of climate regulations, the viability of different technologies will begin to change as decreased emissions begin to be incentivized. This thesis addresses how proposed climate regulations necessitating use of carbon capture and storage (CCS) will affect water use from new fossil-fuel fired power generation as well as how climate changes and policies could affect water use from the electricity generation sector on the whole in the long term. This thesis also addresses the economic viability of existing coal-fired power plants using carbon capture and storage (CCS) retrofits under the impending market structure of the finalized Clean Power Plan.

Chapter 1 examines the water use impacts of the proposed New Source Performance Standards for CO_2 emissions new fossil fuel-fired electricity generation units proposed by the U.S. Environmental Protection Agency in September 2013. To meet the emissions requirements of this regulation, coal-fired units will require use of CCS at 40% capture, increasing water use by approximately 30%, though added water use varies with plant and CCS designs. More stringent standards could require CCS at natural gas combined cycle (NGCC) plants as well. When examined over a range of emission standards, new NGCC plants consume roughly 60 to 70% less water than coal-fired plants.

Chapter 2 quantifies plant and regional shifts in water consumption from the energy generation sector in light of ambient climate changes and potential regulation shifts from climate mitigation policies on a 100-year planning horizon in the Southwest. Employing an integrated modeling framework, feedbacks between climate change, air temperature and humidity, and

consequent power plant water requirements are assessed. These direct impacts of climate change on water consumption by 2095 range from a 3%-7% increase over scenarios that do not incorporate ambient air impacts. Adaptation strategies to lower water use include the use of advanced cooling technologies and greater dependence on solar and wind. Water consumption may be reduced by 50% in 2095 from the reference from an increase in dry cooling shares to 35-40%. This reduction could also be achieved through solar and wind power generation constituting 60% of the grid, necessitating a 250% in technology learning rates.

Chapter 3 analyzes the economic feasibility of retrofitting carbon capture and storage (CCS) to existing coal-fired electricity generating units (EGUs) in Texas for compliance with the Clean Power Plan's rate-based emission standards under an emission trading scheme. Using a database of 18 technologically capable EGUs in Texas, CCS retrofits are modeled under a range of scenarios. Through an emission rate credit (ERC) marketplace, units enlisting the use of 90% capture of CO_2 would prove to be more profitable than existing units at average prices of $27.8 per MWh under the final state standard. The combination of ERC trading and CO_2 utilization can greatly reinforce economic incentives and market demands for CCS to accelerate large-scale deployment, even under scenarios with high retrofit costs. This chapter additionally compares the costs of electricity generation between CCS retrofits and renewable technology under the trading scheme, finding that EGUs retrofitted with CCS may not only be competitive with wind and solar, but more profitable under certain market conditions.

TABLE OF CONTENTS

List of Tables and Figures

Chapter 2

Chapter 3

CHAPTER 4

APPENDIX A

APPENDIX B

APPENDIX C

CHAPTER 1: INTRODUCTION

Climate change poses a severe threat to global welfare.[1] Growing anthropogenic greenhouse gas emissions stem from electricity generation, land use change, transportation, agriculture, and industrial processes.[2] In the United States, currently the second largest emitter of greenhouse gases, electricity generation contributes 31% to total emissions.[3] For the first time in U.S. history, regulatory measures for new and existing power plants limiting carbon dioxide emissions have recently been proposed and finalized by the U.S. Environmental Protection Agency (EPA).[4,5] Under these regulations, emissions within the sector can be lowered through a vast range of technological options, from use of renewable technologies to more efficient fossil-fuel fired generation and the use of carbon capture and storage (CCS).

As the electric power generation sector undergoes a vast transformation under mitigation policies, it must also grow to meet increasing demand. The U.S. Energy Information Administration (EIA)'s *Annual Energy Outlook* projects that total national electricity demand will increase by 30% by 2040.[6] In 2015, almost 90% of electricity in the United States was produced by thermoelectric power plants, almost all of which require large quantities of consumptive and withdrawal water for cooling.[7,8] Electricity production is one of the largest consumers of freshwater in the country, accounting for 49% of total water use.[9] As demand for electricity grows, the future profile of the grid will dictate how water use will shift in a climate of higher temperatures and drought frequency.[1] This future profile is highly dependent on technological and regulatory changes.

Proposed regulation for new coal-fired power plants dictated CCS as the best method for reducing CO_2 emissions.[10] The finalized regulation for existing coal-fired plants, known as the

Clean Power Plan, excludes CCS as a suggested method, though it may provide an environment to allow more economical adoption of the technology through a market scheme.[5] CCS is a technology that effectively reduces emissions, but with high water tradeoffs.[11] On a regional scale, choices between water intensive and water neutral low-carbon power generation technologies will deeply impact long-term water use.

The work and analyses in this thesis quantify the changing water demand from the plant level to a regional scale in coming years in the context of carbon regulation policies as well climactic changes. Further, it delves into understanding the economic viability of CCS retrofits within the market structure of the Clean Power Plan, a technology that has high water use, but the ability to vastly reduce emissions from coal-fired power generation. Different chapters of this thesis include rigorous policy analysis to help inform industry in addition to research of future scenarios to assist decision makers on policy choices.

Chapter 2 analyzes the effect that proposed regulatory standards for CO_2 emissions from fossil-fuel fired power generation could have on water use for new power plants. Emission standards for coal-fired power plants under the proposed rule necessitate use of CCS as the best system for emissions reduction. With this added component, water use changes dramatically, which is quantified with additional analysis on sensitivity to changing technological and policy parameters. This study evaluates the tradeoff that emissions reductions can have with water use at both coal- and natural-gas fired power plants for a range of more stringent standards, and further investigates measures to improve water management. Investigation into the economic viability of CCS retrofits for existing coal-fire units under finalized regulation is discussed in Chapter 4.

Chapter 3 projects long-term consumptive water use from the entire power generation sector under different climate, technological, and policy scenarios. Low-carbon generation technologies may increase water consumption intensity through use of nuclear power or CCS for fossil-fuels. Use of renewables, however, would have the opposite impact through use of technologies with zero water consumption, such as solar photovoltaic and wind power generation. Direct impacts of climate can also affect cooling water requirements, especially under changing temperatures and humidity. This study focuses specifically on how changing water consumption from this sector will affect the Southwest United States, a region with high projected future temperatures, a growing population, and increasing concern over water scarcity.[1] Through use of an integrated modeling system, water consumption is projected to 2095 for a range of scenarios under different climate futures.

Chapter 4 assesses the viability of CCS retrofits for existing coal-fired power plants under the market structure of the Clean Power Plan. While I analyze how water use may change under carbon capture and storage for new plants in Chapter 2, understanding the viability of CCS technology on the whole under the market structure of the Clean Power Plan for existing plants has not yet been quantified. Coal currently accounts for 33% of electricity generation in the United States.[12] While many of these units are not feasible for CCS retrofits, some may find it not only possible, but economical. Under the emissions rate-based market, certain price conditions may prove to be favorable for CCS as compared to existing units. The study conducts a range of simulations to understand what these conditions may be, including assessing utilization of CO_2 and high CCS retrofit cost scenarios. The cost of renewables within the market is also examined in comparison to both existing and retrofitted EGUs. Finally, to understand the environmental impacts from existing EGUs, the water impacts are also assessed for a range of rate standards.

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Chapter 2: Water Impacts of Carbon Dioxide Emission Performance Standards for Fossil Fuel-Fired Power Plants

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 1,100 to 300 lbs CO_2/MWh gross, new baseload NGCC plants consume roughly 60 to 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.

2.1 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 (lbs 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 1,100 lbs CO_2/MWh gross over 12 operating months or 1,000 to 1,050 lbs CO_2/MWh gross over 84 operating months. For gas-fired EGUs, the proposed standards are 1,000 lbs CO_2/MWh gross for larger units (than 850 MMBtu/hr) and 1,100 lbs 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 to 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 chapter 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 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).

2.2 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 combined 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 base case 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 non-full 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.

2.3 Base Cases Results

We conducted base case 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 #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. 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.

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 (^oC)	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	.113

Coal price ($/t)	42
Gas price ($/GJ)	6.92

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

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 2.33m^3/MWh and 1.63m^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 lbs CO_2 /MWh gross to the 1,100 lbs 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 inter-stage cooling for multi-stage 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.

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/hr)	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/hr)	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	.67
Total water withdrawals (m^3/MWh)	2.33	3.06	.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.

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]

2.4 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.

2.4.1 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 ultra-supercritical 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 1,100 lbs CO_2/MWh gross. Without CO_2 emission control, the plant emission rates of the three plants are 1786, 1687 and 1537 lbs CO_2/MWh gross, respectively. As shown in Figure 1(a), the subcritical, supercritical, and ultra-supercritical plants have to remove 45%, 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 ultra-supercritical 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.

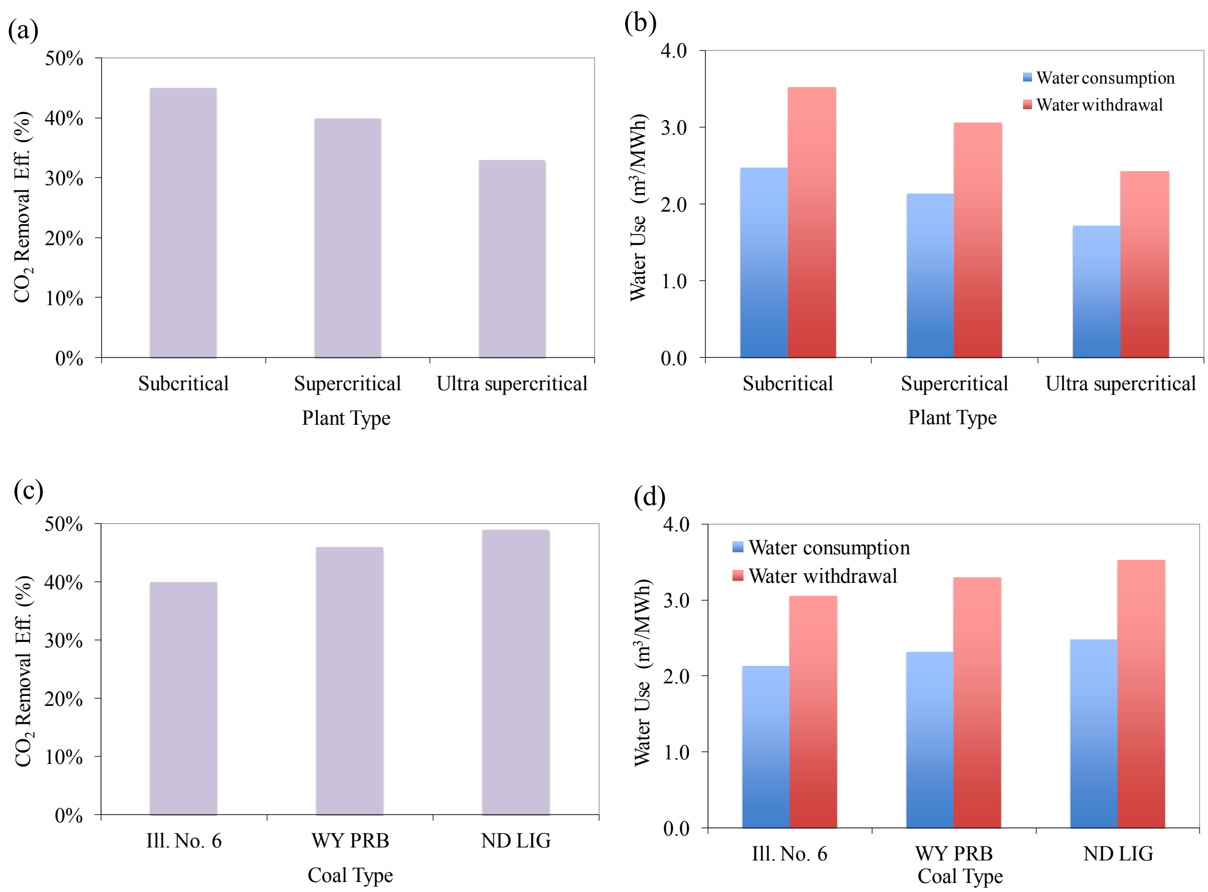
2.4.2 Effects of Coal Type

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 Supporting Information. 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 lbs 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 to 16% more water withdrawals and consumption than the plant fired by Illinois #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.

2.4.3 Effects of Cooling Technology

As the base case 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 ^{o}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.



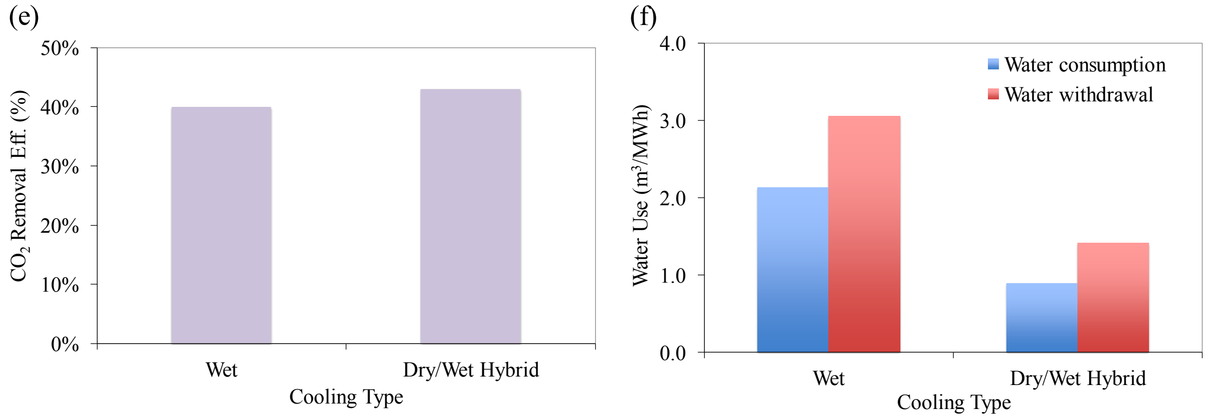


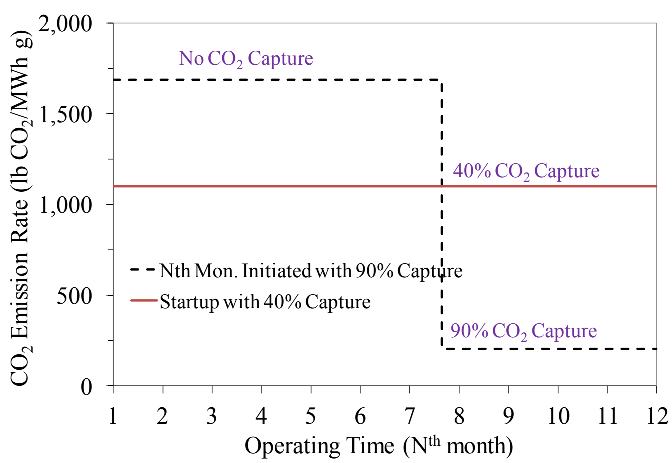
Figure 1. Effects of alternative plant designs on CO_2 removal efficiency and plant water consumption of coal-fired power plant under the 1,100 CO_2/MWh standard regulation (a, b) plant type; (c,d) coal type; (e,f) cooling type as estimated with a deterministic use of IECM.

2.4.4 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 1,100 lbs 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 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 Supporting Information. 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 Supporting Information.

(a)



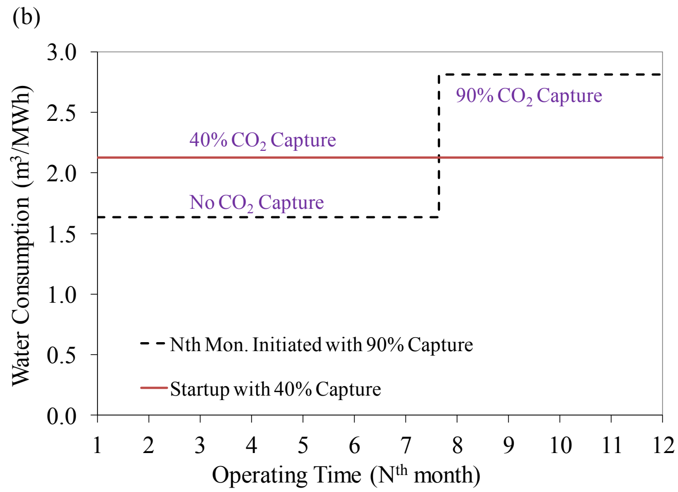


Figure 2. CO_2 emission rate and water consumption of regulated coal-fired power plant by CCS deployment timeline for a 12-month regulatory compliance scenario (a) CO_2 removal efficiency; (b) plant water consumption. Similar results for an 84-month compliance scenario are shown in Figure S-1.

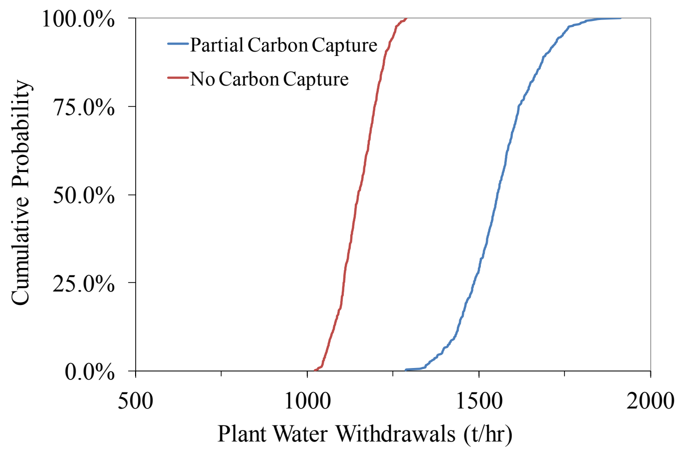
2.5 Uncertainty Analysis

To account for uncertainties and variability in the value of key parameters that affect plant water use, and provide likelihood information of 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 Supporting Information.

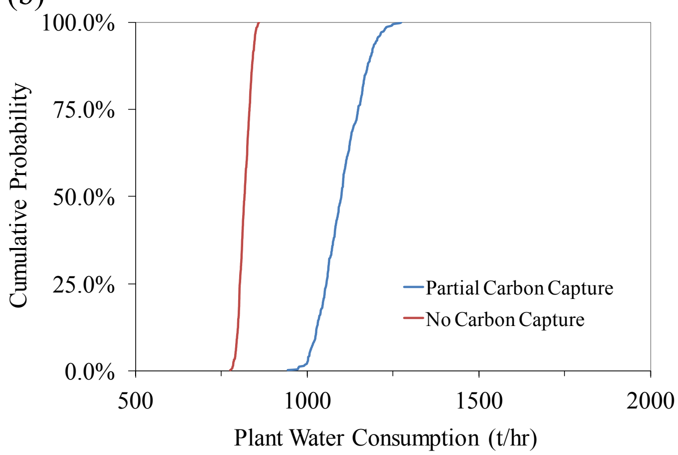
We conducted 500 samples Monte Carlo simulation to yield the cumulative distribution functions (CDFs) of plant water use. Figures 3(a) and 3(b) show the CDFs of plant water use for the PC plants with and without carbon capture. Given the assumed uncertainty distributions, the resulting probabilistic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

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 1,100 lbs 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 non-symmetric distribution of the capture process cooling duty relative to the nominal deterministic value.

(a)



(b)



(c)

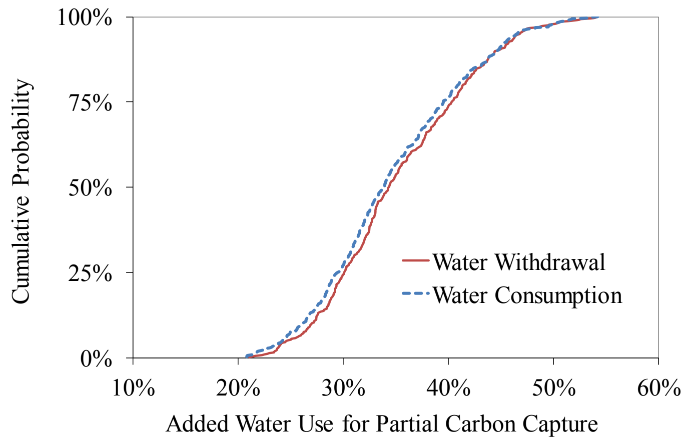


Figure 3. Probability distributions of plant water use obtained from IECM simulation for a 500MWnet coal-fired plant and added water for partial CO_2 capture to comply with the 1,100 lbs CO_2/MWh emission standard (a) plant water withdrawals; (b) plant water consumption; (c) added water use

2.6 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.[14] 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 lbs 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 1,100 to 300 lbs CO_2 /MWh gross 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 lbs 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.

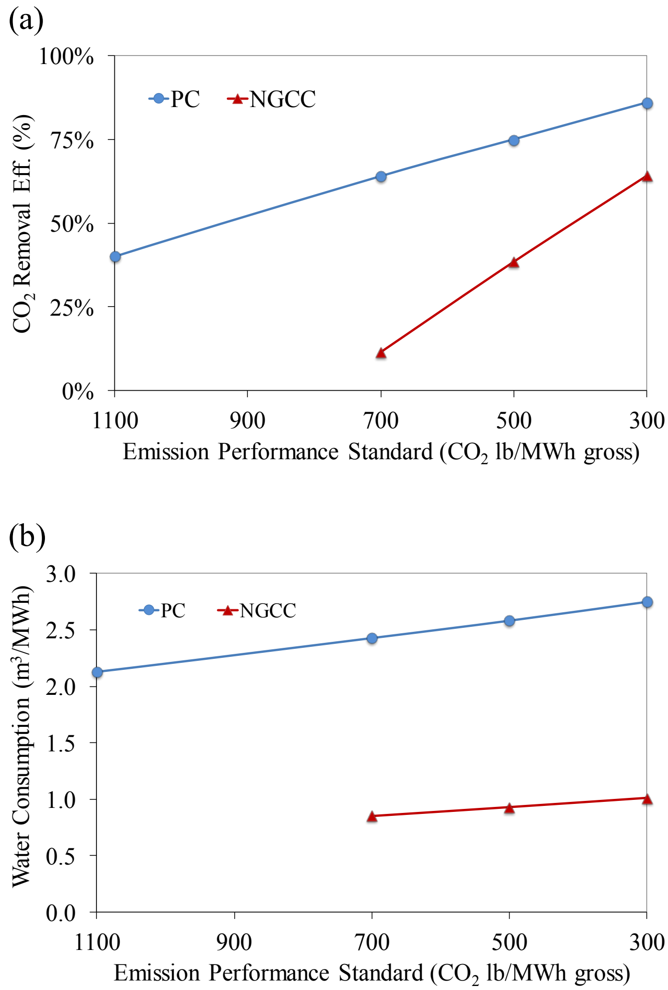


Figure 4. Effects of stringent CO_2 emission performance standards on CO_2 removal efficiency and plant water consumption

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 1,100 lbs 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 1,100 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 to 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 cubic meters 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 kilometers 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.

2.7 Acknowledgements

This work is supported by the Center for Climate and Energy Decision Making (SES- 0949710) through a cooperative agreement between the National Science Foundation and Carnegie Mellon University. All opinions, findings, conclusions and recommendations expressed in this chapter are those of the authors alone and do not reflect the views of any U.S. Government agencies.

Supporting information for the chapter 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 in Appendix A.

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CHAPTER 3: CONSUMPTIVE WATER USE FROM ELECTRICITY GENERATION IN THE SOUTHWEST UNDER ALTERNATIVE CLIMATE, TECHNOLOGY AND POLICY FUTURES

Abstract

This research assesses climate, technological, and policy impacts on consumptive water use from electricity generation in the Southwest over a planning horizon of nearly a century. We employed an integrated modeling framework taking into account feedbacks between climate change, air temperature and humidity, and consequent power plant water requirements. These direct impacts of climate change on water consumption by 2095 differ with technology improvements, cooling systems, and policy constraints, ranging from a 3%-7% increase over scenarios that do not incorporate ambient air impacts. Upon changing additional factors that alter electricity generation, water consumption increases by up to 8% over the reference scenario by 2095. With high penetration of wet-recirculating cooling, consumptive water required for low-carbon electricity generation via fossil fuels will likely exacerbate regional water pressure as droughts become more common and population increases. Adaptation strategies to lower water use include the use of advanced cooling technologies and greater dependence on solar and wind. Water consumption may be reduced by 50% in 2095 from the reference, requiring an increase in dry cooling shares to 35-40%. Alternatively, the same reduction could be achieved through photovoltaic and wind power generation constituting 60% of the grid, consistent with an increase of over 250% in technology learning rates.

3.1 Introduction And Objectives

Water is integral to power generation. In 2010, roughly 90% of electricity in the United States was produced by thermoelectric power plants, which accounted for 44% of national freshwater withdrawals and 6% of consumptive use. [1,2] Consumptive water use for power generation has been increasing due to capacity expansion and a shift from once-through to wet recirculating cooling systems. In the future, changes in power generation technologies for low-carbon energy may increase water consumption intensity, including such efforts that may favor nuclear power and power generation technologies with carbon capture and storage (CCS). [3] For example, Chandel et al. (2011) evaluated the water impacts of climate policies and found a 24−42% increase in national water consumption by 2030 under different climate mitigation scenarios.[4] Similarly, Cameron et al. (2014) found changes in water consumption within a range from -4% to +42% by 2055, depending on emission reduction targets.[5] Macknick et al (2012) demonstrated that substantial deployment of nuclear facilities and coal plants with CCS will increase consumptive water use in the Mid-Atlantic, Great Lakes, Central, Southeastern, and Southwestern regions.[6] In addition to these short- or medium-term projections, a recent study applied a US-specific version of the Global Change Assessment Model (GCAM-USA) to project state-level water use over the century under alternative energy demand and policy scenarios, and found that low-carbon policies promoting CCS installation and nuclear generation have higher effects on water consumption than renewable-focused strategies.[7] While water withdrawals in these scenarios were estimated to decrease by 91%, water consumption would increase over the next century by 40 to 80%. However, these studies did not incorporate direct impacts of climate change on power plant water use, which are potentially significant due to the influence of ambient air temperature and humidity on cooling water requirements.[8]

To limit carbon dioxide (CO_2) emissions, the U.S. Environmental Protection Agency (EPA) proposed emission performance standards for new fossil fuel-fired power plants in 2013 and finalized the proposal in 2015.[9] The implementation of CCS to comply with the proposed emission standards of 1100 lbs/MWh would increase plant water use by roughly 20 to 50% at coal-fired power plants.[10] The EPA's Clean Power Plan proposes to reduce nationwide carbon pollution from existing power plants by 32% in 2030. This is to be achieved through the use of various mitigation measures, such as increased utilization of natural gas and renewable energy for electricity generation.[11] In addition, the EPA has also issued regulations on cooling intake structures under Section 316(b) of the Clean Water Act (CWA), promoting a switch from once-through cooling to wet cooling systems.[12] This shift will potentially double national water consumption from power generation by 2030.[2]

While different regions will face different issues, this study focuses on the Southwest, where population is projected to continue to rise and water scarcity is an increasing concern. Water demand will soon exceed supply, and as the climate warms, water supply will likely shrink.[13] For example, the yield of the already over-allocated Colorado River could drop by 10-20% by mid-century from climate change alone.[13,14,15] Many Southwest states are using groundwater to compensate for the supply-demand difference. However, total annual availability from this source is dropping.[12] In addition, all sectors are projected to increase water use as average temperatures rise, further depleting sources that are already stressed.[15] This study aims to deepen the understanding of the long-term water demands of the power sector in this region.

This study projects consumptive water use for electricity generation in the Southwestern United States over a planning horizon of nearly one century and to examine how changes in climate, technological, and policy dimensions shaping energy systems would influence regional water consumption. It does not, however, look at water scarcity, or how water availability will impact decisions in the power sector. The states considered include Arizona (AZ), New Mexico (NM), Utah (UT), Nevada (NV), Oklahoma (OK) and Texas (TX). We explore the implications for the electric power industry's technology choices and water management in the face of future policy constraints and varying regional conditions.

3.2 ASSESSMENT METHODS AND TOOLS

Representative Concentration Pathways (RCP) from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) are used to drive three widely-used general circulation models (GCMs) and project regional climate scenarios through 2095. To test the hypothesis that climate-related changes in ambient air temperature and humidity will have an effect on consumptive water use for electricity generation over the century, region-specific climate projections from the GCMs are used as inputs for a power plant model to estimate water consumption intensities of cooling system and power generation technologies under different climate scenarios. These plant-level water consumption intensities are used to calculate climate correction factors that account for the impacts of climate change on regional water use. Driven by RCP scenarios, we use GCAM-USA updated with recent water use and cost information in order to model regional energy systems and then estimates regional water consumption under different climate scenarios. 2005 was chosen as the base year, while 2050 and 2090 were selected as benchmark years for future scenarios.

3.2.1 Climate Pathways

Two RCP scenarios from IPCC AR5 that describe possible radiative forcing values in the year 2100 were employed. RCP 8.5 is a high emissions pathway with increasing greenhouse gas emissions throughout the 21st century. RCP 4.5 is a scenario with strategies or technologies deployed to stabilize radiative forcing.[16,17] Global carbon emitted per year by the end of the century under RCP 8.5 is almost six times that of RCP 4.5. Subsequently, the corresponding global surface temperature change leads to twice the warming compared to RCP 4.5.[18]

Ambient air temperature and relative humidity are the variables that affect evaporative losses in wet towers.[19,20] Given that once-through cooling will rarely be used in the future, we do not consider effects on the intake cooling water temperature. Region-specific estimates of these variables were determined based on the climate outputs from GCMs. Enough GCM ensemble runs were used to mitigate internal variability within each model.[21] Further information on the GCMs is available in the Supporting Information (SI) Section S-1. For each RCP scenario, average near surface air temperature and relative humidity specific to locations of representative power plants in the Southwest were from each ensemble run of the three GCMs.

3.2.2 Integrated Environmental Control Model for Power Plant Assessments

The Integrated Environmental Control Model (IECM) is a model developed by Carnegie Mellon University to perform systematic estimates of the performance, resource use, emissions, and costs for pulverized coal (PC), integrated gasification combined cycle (IGCC), and natural gas combined cycle (NGCC) power plants with and without CCS.[22] IECM also includes a set of major cooling technologies including once-through cooling, wet towers, and air-cooled condensers for dry cooling. The water models in the IECM are developed based upon the mass and energy balances to estimate water use, energy penalties, and costs of cooling systems.[19,20] Additional information on IECM is provided in the SI. IECM was applied to model representative power plants in each state in terms of major plant designs and attributes and then estimate water consumption intensities (m^3/MWh) for wet cooling systems under different climate conditions, which are used to derive the correction factors that quantify the water use impacts of climate change.

We used the Union of Concern Scientists' Energy-Water Database and the EPA's National Electric Energy Data System (NEEDS) to characterize existing southwest fossil fuel-fired plants in terms of plant location, size, efficiency, capacity factor, and cooling type, and fuel type.[23,24] For both PC and NGCC plants, a representative power plant was created for each state in terms of the estimates on average for these major plant attributes. Temperature and humidity inputs were based on current power plant locations.

Future energy systems will include low-carbon and advanced generation technologies. Thus, climate-related correction factors were also determined for PC plants with CCS, IGCC plants, IGCC plants with CCS, and NGCC plants with CCS. Since there are currently no plants with CCS or IGCC plants in the region, the default designs within IECM were used for these plants. When CO_2 emission standards are considered for new PC plants, amine-based CCS is employed for partial CO_2 capture to comply with the standards.[10] As some states still utilize cooling ponds that are not an option available within IECM, it was assumed that the effects of ambient air conditions on cooling ponds' water use intensities are similar to those of wet cooling towers. Thus, water consumption intensities were estimated as a function of power plant designs, climate conditions, and low-carbon regulations.

3.2.3 Global Change Assessment Model for Regional Assessments

GCAM is an integrated assessment model developed by the Pacific Northwest National Laboratory to project global changes in energy, agriculture, emissions, and climate over the next century.[25,26] GCAM is a well-established integrated assessment model that has been widely used for various applications, such as evaluating climate impacts from increased natural gas usage, mitigation impacts on land use and energy systems, and comparative mitigation impacts on water stress in the United States.[27,28,29] This study employs a modified version of the model: GCAM-USA, a US, state-specific model nested within the global model.[7] This model includes coal (PC, IGCC), natural gas (steam turbine (NGST) and NGCC), nuclear, photovoltaic (PV) and concentrated solar power (CSP)), wind, hydro-, bio- (conventional and Bio-IGCC), and oil-based energy generation systems. For each type of fossil fuel-fired generation systems, there are three technology options available in GCAM-USA: conventional technology, an advanced technology, and that same advanced technology with CCS (e.g. PC, coal-fired IGCC and IGCC plants with CCS). In this analysis, we added PC with CCS as another option to the model. CCS technologies are only incorporated into RCP 4.5, whereas they are not included in the RCP 8.5 scenario since that assumes no climate policies. CCS is not employed until 2020, competing directly with the same type of generation systems without CCS. While the RCP 8.5 trajectory has no mitigation policies in place, the RCP 4.5 trajectory is sufficiently aggressive to drive large changes to the generation mix in the electric power sector.[7] This scenario enables analysis of impacts from large-scale shifts in the electric power sector. GCAM uses a carbon tax initiated in 2020, increasing at 5% per year until the stabilization target of 4.5 W/m^2 radiative forcing is reached.[7]

All sectors in the model, including the power sector, are influenced by the equilibrium effects of the carbon price. Inter-state trading of electricity is included in the model.

In GCAM-USA, regional water consumption is estimated as the product of plant-level water consumption intensities and regional power generation by each modeled power plant type. For each fuel and technology, water use is estimated for each five-year period for each state. The baseline water consumption intensities in GCAM are from a review study by Macknick et al (2012).[30] Because these estimates are not provided for a range of ambient air conditions, average water consumption intensities were adjusted by a climate correction factor for each generation technology under each RCP. The correction factor is estimated as the ratio of plant-level consumption intensities from the IECM simulations based on base year and future climate conditions. The climate correction factor was calculated for 2050 and 2090, after which 5-year interpolations were calculated starting with the base year of 2005. When a scenario with no climate change is considered, the same water intensity factors as those used in the base year are adopted for the future periods. See SI Table S-3 for more details. Electricity demand within GCAM can take ambient air impacts into account using degree days, though not included in this study.

3.2.4 Alternative Future Scenarios

In addition to the climate scenarios specified by two RCPs, the nature of this study, which focuses on long-term projections, necessitates sensitivity to other potential important changes in technology and policy that would significantly affect the electric power sector. Table 1 describes these alternative scenarios analyzed.

Table 1. Alternative Climate, Technology and Policy Scenarios

Technology or Policy Scenario	Climate Scenario	Scenario Code	Scenario Feature Description
Reference Scenarios	8.5, 4.5	RCP8.5 Ref RCP4.5 Ref	Default settings in GCAM except for the changes noted
Alternative Scenarios			
High natural gas prices	4.5	RCP4.5-NG 50 or 100	Increase in natural gas prices by 50% or 100% throughout the century relative to the default values under the RCP4.5
CO_2 emissions performance standards	4.5	RCP4.5-EPS 20 or 40	Compliance with both the finalized and proposed U.S. EPA's CO_2 emission performance standards for new coal-fired power plants
Renewable energy	4.5	RCP4.5-RE	High penetration of PV and wind power in the electric power sector
Dry cooling	4.5	RCP4.5-DC	High penetration of dry cooling shares in thermoelectric power plants

3.3 Results and Analyses

3.3.1 Regional Features

Electricity demand in GCAM-USA is driven by the activities of end-use consumption sectors, whose activity levels respond to population and GDP and whose fuel substitution capacities are exogenous and sector-specific.[26] Electricity generation values in each state are calculated endogenously.[7] These socio demographic projections are based on the U.S. Census as well as growth functions made by the builders of GCAM-USA.[31] The growth of these variables is summarized in Table 2 by state through 2095. Emissions in the study region under RCP8.5 reach 237 million tonnes of carbon (MtC) in 2095, growing by 99% from 2005, while regional emissions under RCP 4.5 reach 41 MtC across, a decrease of 65% from 2005.

The future climate scenarios corresponding to RCP 8.5 and 4.5 are characterized in terms of ambient near surface air temperature and relative humidity.[20] Table 2 summarizes the multi-model projected average changes in the two parameters by the end of this century relative to 1990 under each RCP scenario. The temperature increases are estimated to be 5−6 °C and 2−3 °C for RCP 8.5 and 4.5, respectively (See SI Section S-1 for more information). Relative humidity is estimated to drop by 4% on average for RCP 8.5 and 2% for RCP 4.5. The stabilization of radiative forcing via mitigation strategies or technologies under RCP 4.5 would generally result in smaller air temperature and humidity changes.

Table 2. Average Changes in State-Level Parameters by 2095 relative to 2005[a]

State	Annual Population Growth	Annual GDP MER Growth	Absolute Changes in Ambient Air Conditions under RCP8.5		Absolute Changes in Ambient Air Conditions under RCP4.5	
			Temperature	Relative Humidity	Temperature	Relative Humidity
	(%)	(%)	(°C)	(%)	(°C)	(%)
AZ	5.86	19.21	5.94	-2.62	3.12	-2.05
NM	-0.28 [b]	1.32	5.85	-5.95	2.98	-3.63
NV	4.50	15.25	6.30	-6.41	3.31	-3.03
OK	0.21	2.74	5.84	-2.64	3.08	-1.54
TX	2.32	8.89	4.95	-0.83	2.71	-1.61
UT	2.36	9.02	5.03	-3.77	2.65	-2.73

[a] Data in this table is from output of GCMs as well as GCAM-USA model input.
[b] Following U.S. census projections until 2030, New Mexico is projected to have an increasing population until mid century, after which it decreases, leading to an overall negative average growth. Dominant states are Texas and Arizona, with the highest projected population growth in the region.

3.3.2 Plant-Level Water Consumption

Region-specific near surface air temperature and relative humidity from GCMs are used as inputs for IECM to estimate water consumption intensities of fossil fuel-fired power plants and their relative changes over time. As nuclear, concentrated solar power (CSP) plants, and natural gas steam turbine (NGST) use the same type of wet recirculating cooling systems, the relative changes derived from fossil fuel-fired power plants are used to account for climate impacts on their water use intensities. Figure 1a depicts average percent changes in water consumption intensities over time under both climate scenarios. For plants using wet recirculating cooling, there is an 8−10% increase in water consumption intensity by the end of the century under RCP 8.5 and a 4−5% increase under RCP 4.5. This is expected, as RCP 4.5 is a stabilization scenario resulting in less temperature changes after 2050. More specific results are available in SI Table S-2. As described earlier, water consumption intensities in GCAM are adjusted by the climate correction factors derived from these IECM modeling results.

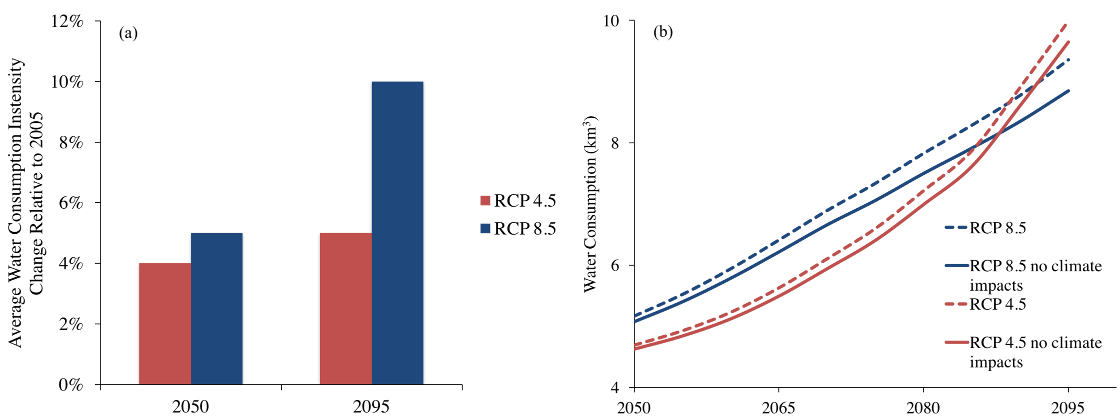


Figure 1. Impacts of changes in ambient air conditions (a) changes in regional water consumption intensity of thermoelectric plants relative to 2005 in the Southwest; (b) total projected regional water consumption from energy generation over time from 2050 to 2095 under RCP 4.5 and RCP 8.5, with and without direct ambient impacts from climate change

3.3.3 Reference Scenarios

The reference scenarios are based on current cost, technological and socioeconomic values and projections, representative of a likely outcome under both RCP 8.5 and RCP 4.5.

Electricity Generation

The generation profile of a future grid is dependent on the capital and O&M costs of power generation technologies. The baseline year costs used in GCAM are updated with the National Energy Technology Laboratory's baseline report for PC and IGCC plants and the U.S. Energy Information Administration (EIA)'s recent power plant cost estimates for other technology types.[32,33] Future cost changes over time are inherited from the GCAM assumptions with minor changes to adjust for input cost changes.

Regional electric power generation over time is estimated under RCP 8.5 and 4.5, respectively. Under RCP 4.5, the carbon price is projected to be about \$100/tC (2012\$) by 2050 – a comparable value based on the social cost of carbon analysis conducted by the U.S. Government.[36] (See SI Section S-3 for further expansion.) The price then rapidly increases in the latter half of the century to more than \$700/tC by 2095 due to the radiative forcing constraint to motivate shifts to low-carbon technologies. While climate mitigation policies lead to high electricity prices, they also led to slightly higher demand – approximately 2.2% in the reference scenario – due to electricity replacing direct combustion of fossil fuels in the building, transportation and industrial sectors.[7] The phenomena that the substitution effect can cause electricity demand to increase in emissions mitigation scenarios also has been demonstrated with other models, such as the Research Triangle Institute's Applied Dynamic Analysis of the Global Economy model and MIT's Integrated Global System Model. [34,35]

As shown in Figure 2, the projected regional energy generation increases by approximately 177% from 2005 by 2095 under RCP 8.5 and by 184% under RCP 4.5. In 2095, nuclear and renewables account for 25% of regional power generation under RCP 8.5 and 44% under RCP 4.5, which indicates that the electric sector shifts to these low carbon technologies under climate policies. Compared to RCP 8.5, total fossil fuel-based electricity generation under RCP 4.5 is 6% lower in 2050 and 20% lower in 2095. PC, IGCC and NGCC plants are almost exclusively installed with CCS under RCP 4.5. Coal-based generation encompasses IGCC plants, which are not part of the 2005 mix, but account for about 50% and 72% of total coal generation in 2095 under RCP 8.5 and 4.5, respectively.

Water Consumption

Regional water consumption is significantly affected by energy demands, electricity generation technology shares, cooling technology shares, and ambient air conditions. Future cooling systems installed at thermoelectric power plants in each state are estimated as described below. In the base year, almost all coal and NGCC plants in AZ, NM, NV, OK and UT use wet cooling towers or ponds, whereas 15−20% of coal and natural gas power plants use once-through cooling in Texas. Nuclear, CSP, and geothermal plants in the study region also exclusively use wet recirculating cooling. Among NGCC plants, 90% of plants use wet recirculating cooling, with 10% using dry cooling. It was assumed that future cooling shares up to 2095 for each electricity generation technology are equal to the average of new investment in 2000-2008 for relevant GCAM-USA grid regions; in the study region, the shares are as follows: 83% for wet towers, 2% for cooling ponds, 15% for dry cooling, and 0% for once-through cooling. Under the regulation of CWA Section 316(b), existing once-through cooling will be phased out and wet recirculating or dry cooling systems will be installed in all new thermoelectric power plants. The performance of wet cooling systems is assumed not to change over time because it is a mature technology.

For each reference scenario, water consumption from power generation over the century was projected for both cases with and without incorporating the effects of climate change on ambient air conditions. Under RCP 8.5 Ref without incorporating climate change impacts, absolute consumptive use in the Southwest would increase by 210% from 2005 to 2095 and reach approximately 8.8 km^3. With ambient air impacts incorporated, water consumption rises by about 7% in 2095 to 9.4 km^3, shown in Figure 1b. While not a large percent change, this absolute difference is equivalent to almost 20% of the baseline (2005) water consumption in the Southwest. Under RCP 4.5 Ref without incorporating ambient climactic impacts, absolute consumptive use is approximately 9.6 km^3 – a 250% increase from 2005. With ambient air impacts incorporated, water consumption rises to 10 km^3. Under this scenario, these changes lead to a lower increase of almost 4% in water consumption, illustrated in Figure 1b – almost 14% of the baseline value. These results imply that the growth in energy demand driven by population and GDP increases. This factor and the wide deployment of wet cooling towers are the major factors elevating future water consumption for electricity generation.

Figures 2(c) & 2(d) show water consumption by generation technology over the century, under RCP 4.5 Ref and RCP 8.5 Ref, respectively. In comparing the two reference scenarios, there is 6% higher water consumption in 2095 under RCP 4.5 Ref. The difference in water consumption is due to the higher total energy generation under RCP 4.5 Ref, as well as the different grid generation mix. In this scenario, fossil fuel generation almost entirely utilizes CCS, and nuclear power significantly rises.

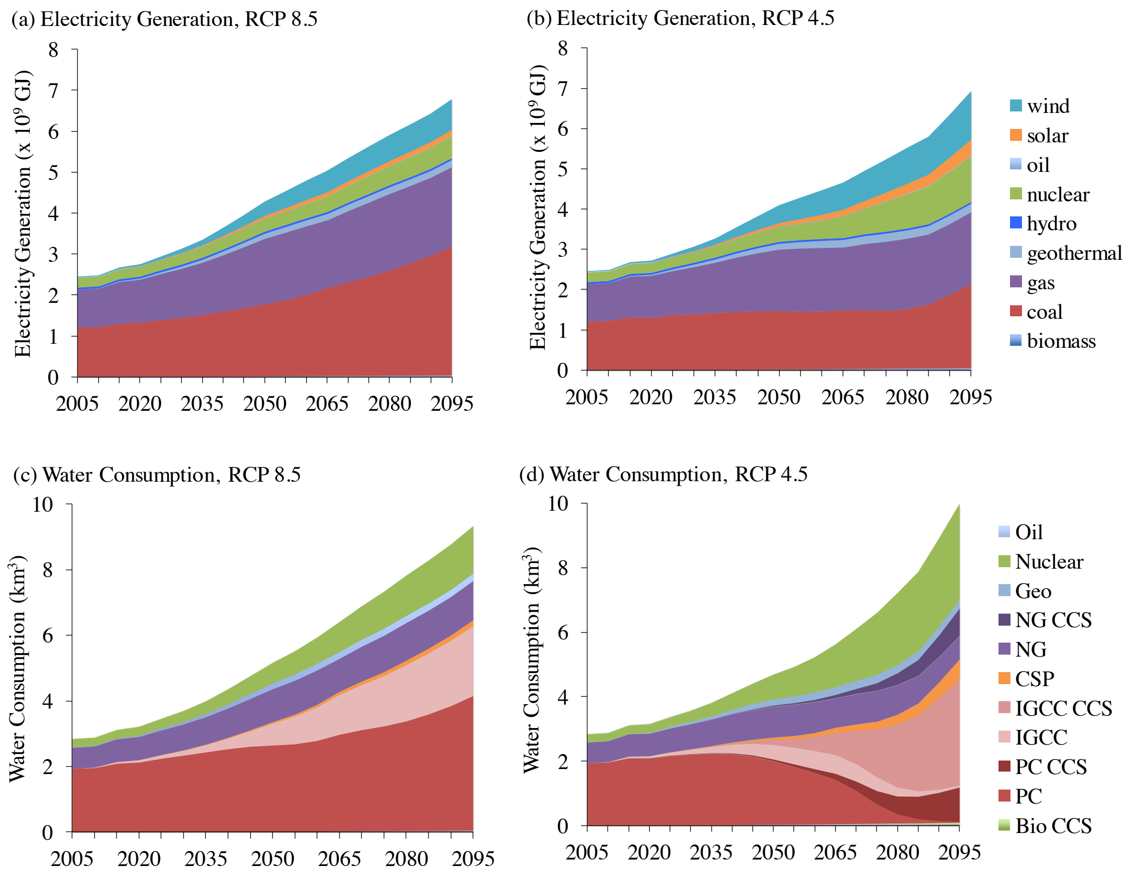


Figure 2. Projected distribution profiles of electricity generation and water consumption over the next century* (a) electricity generation under the RCP 8.5 Ref (b) electricity generation under the RCP 4.5 Ref; (c) water consumption under the RCP 8.5 Ref (d) water consumption under the RCP 4.5 Ref

* In comparing GCAM's electricity generation to recent projections from the EPA accordance with the Clean Power Plan (CPP), the total regional generation for 2050 is very similar. However, the generation mix projections differ, likely due to differing model formulations and assumptions about the future characteristics of power generation technologies. Additional detail is provided in the SI.

3.3.4 Alternative Scenarios

RCP 4.5 simulates a future grid that facilitates the use of low-carbon technologies. The future grid mix also will be highly affected by natural gas price, solar and wind power costs, carbon policies, and potential shifts from the current projections on population and GDP growth. Thus, alternative scenarios given in Table 1 were evaluated to demonstrate the potential effects on water use and explore adaptation strategies for low-carbon electricity generation under RCP

4.5. These alternative scenarios were chosen based on the parameters that would have potentially high impact on the generation mix and in turn, the water consumption projection.

Socio-demographic Changes

To account for possible lower population and wealth growth in the region, a more conservative projection was assessed for both RCP 4.5 and 8.5 based on 1990 U.S census state projections. This led to absolute population and GDP values of approximately 25% less than the reference, a percentage chosen as compared to our current population trends based on the 2000 state-level census projections. When incorporating slower population and GDP growth, energy generation drops accordingly. The resulting water consumption would drop approximately 20% under RCP 4.5 and 22% under RCP 8.5 by 2095 in comparison with the reference cases.

High Natural Gas Prices

In RCP4.5 Ref, the assumed natural gas prices are relatively low, reaching $6.7/MMBtu ($2012) by the end of the century. In contrast, the EIA's AEO projects that gas prices will be approximately $7.0/MMBtu by 2035, roughly 50% higher than GCAM's reference case in that same year.[37] Thus, alternative gas price scenarios were simulated to examine the effects of higher gas prices on electric power grid and water consumption. The first alternative scenario (RCP4.5-NG 50) closely follows the EIA/AEO projections and has 50% higher gas prices than those of RCP4.5 Ref throughout the century, ending with a natural gas price of $10/MMBtu. The second alternative scenario (RCP4.5-NG100) was assumed to have 100% higher gas prices than those of RCP4.5 Ref, resulting in a price of $13/MMBtu in 2095.

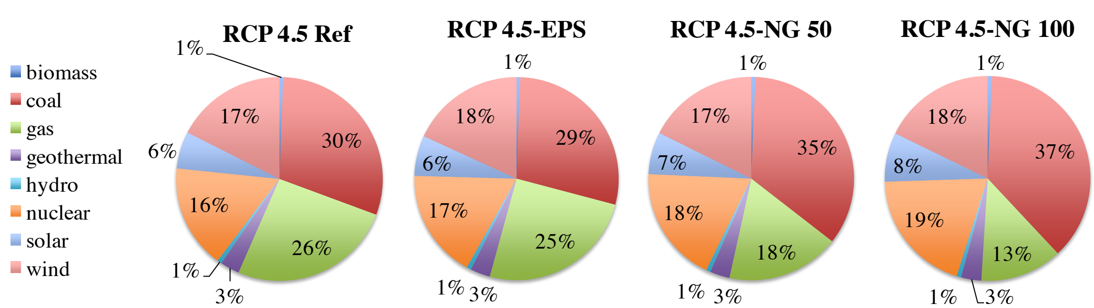
In the RCP4.5-NG50 scenario, there is a remarkable shift in the electricity generation profile, while overall generation remains the same as the reference. Figure 3a shows that while there is an 8% drop in electricity generation from natural gas as compared to the reference, electricity generation increases by 5% from coal, 2% from nuclear, and 1% from solar and wind. The shift moves towards coal and nuclear plants, which have 50 to 100% higher water consumption intensities than NGCC plants. Thus, overall water consumption increases by approximately 5% over the reference scenario seen in figure 3b. In the RCP4.5-NG100 scenario, the shift in the generation profile follows the trend of RCP4.5-NG50. However, the changes in the generation profile are not linear – there is a smaller shift in the grid mix between the 50% price increase scenario and the 100% increase scenario. Electricity generation from natural gas in the RCP4.5-NG100 scenario decreases by approximately 13%, compared to the reference scenario. The resulting shift in the grid mix would elevate the overall water consumption by 8%.

Carbon Dioxide Emission Performance Standards

CCS can be employed to comply with the U.S. EPA's CO_2 emission performance standards for new PC plants. Compliance with the proposed emission limit of 1100 lbs CO_2/MWh requires roughly 40% CO_2 capture at PC plants.[10] However, the finalized standard of 1400 lbs CO_2/MWh-gross requires approximately 20% carbon capture. Over the century, to significantly reduce CO_2 emissions for stabilizing climate change, more stringent emission limits may be needed. To assess both the regulation proposal and finalized rules, we evaluate additional scenarios: RCP4.5-EPS40 – CCS is employed for 40% CO_2 capture at new PC plants to meet the emission limit before 2050, but 90% CO_2 capture is considered after 2050; and RCP4.5-EPS20 – CCS is employed for 20% CO_2 capture at new PC plants to meet the emission limit before 2050, but 90% CO_2 capture is considered after 2050. Since PC plants with CCS for partial CO_2 capture have a higher plant efficiency but less water use and costs than plants with CCS for 90% CO_2 capture, a set of performance and cost adjustment factors were derived from the plant-level simulations in IECM and then applied to GCAM-USA.

The modeling results of the RCP4.5-EPS40 and EPS20 scenarios show that the overall generation profile remains relatively similar to the reference scenario, illustrated in figure 3b. However, within the coal fleet, there is a higher penetration in electricity generation from IGCC plants with CCS for 90% CO_2 capture, which increases from 72% in the reference scenario to 88% in 2095. This shift is driven by the need for meeting the radiative forcing target. Because IGCC plants have lower water consumption intensities than PC plants for both cases with and without CCS, this shift leads to a small drop (about 3%) in the overall water consumption in 2095, compared to the reference.[30]

(a)



(b)

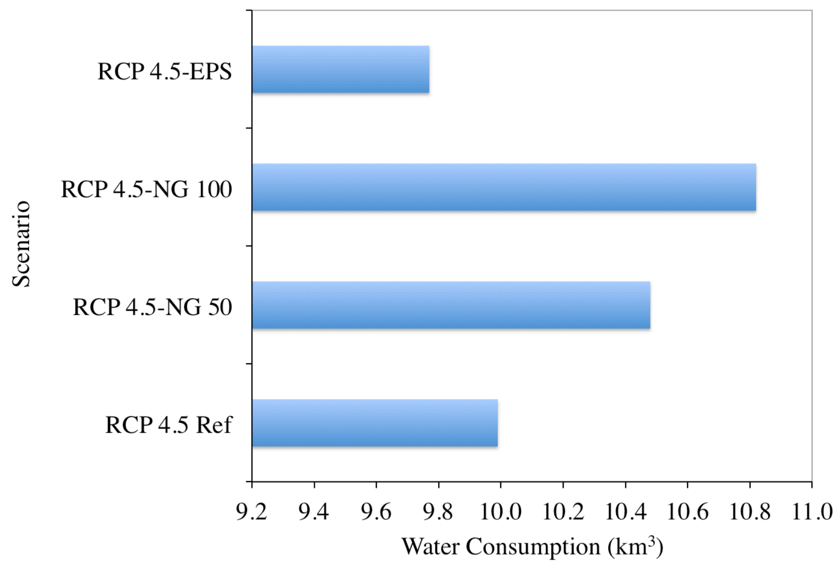


Figure 3. Projected generation profile and water consumption under alternative policy and gas market futures (a) Electricity generation profile by scenario; (b) Comparative absolute increase in water consumption by scenario

High Renewable Energy Penetration

PV and wind are key options to decarbonize the electric power sector and significantly reduce water consumption.[30] Driven by technology advances and low-carbon policies, more renewables will likely be integrated into the future grid. Projecting the cost trajectories of electricity generation technologies is important to the understanding of the evolution of energy systems and the implications of policy measures.[38] Thus, alternative scenarios of renewable energy (RCP4.5-RE) are examined to quantify the relation of water consumption reduction with PV and wind technology learning.

GCAM-USA contains inherent learning curves to project technology cost trajectories. Technology learning used in GCAM-USA is a time-based rather than capacity-based learning function. Average learning rates of capital cost for PV and wind power are .5%/year and .25%/year in the reference scenario, respectively. While lower than learning rates in other major modeling systems, the ratio of learning rates of PV versus wind power is similar, such as the National Energy Modeling System (NEMS) that has learning rates of 3.1% and 1.6% per year, respectively.[39] It is this ratio that determines what proportion of each technology will be built in any given year. As shown in SI Table S-3, the results for mid-century electricity generation by technology yielded from NEMS for the 2015 AEO are very similar to that of GCAM-USA. The specific learning rate functions used in GCAM-USA are given in SI Table S-6. To evaluate the impacts of technology learning, GCAM-USA was updated with a range of higher learning rates for PV and wind power and then run to project the future generation grid mix. Figure 4 shows regional water consumption in 2050 and 2095 as a function of the total share of PV and wind generation. To reduce water consumption by 50% in 2095, PV and wind generation must account for 60% of the generation grid. To reach this generation share, the learning rates of PV and wind power systems are 260% higher than those of the RCP4.5 Ref scenario, which lowers their capital costs by .92% and .63% per year, respectively. When learning rates reach 500% higher than those of the reference scenario, PV and wind generation account for 82% of total fleet generation. As a result, regional water consumption drops to 2.35 km^3 in 2095, 23% of the reference case.

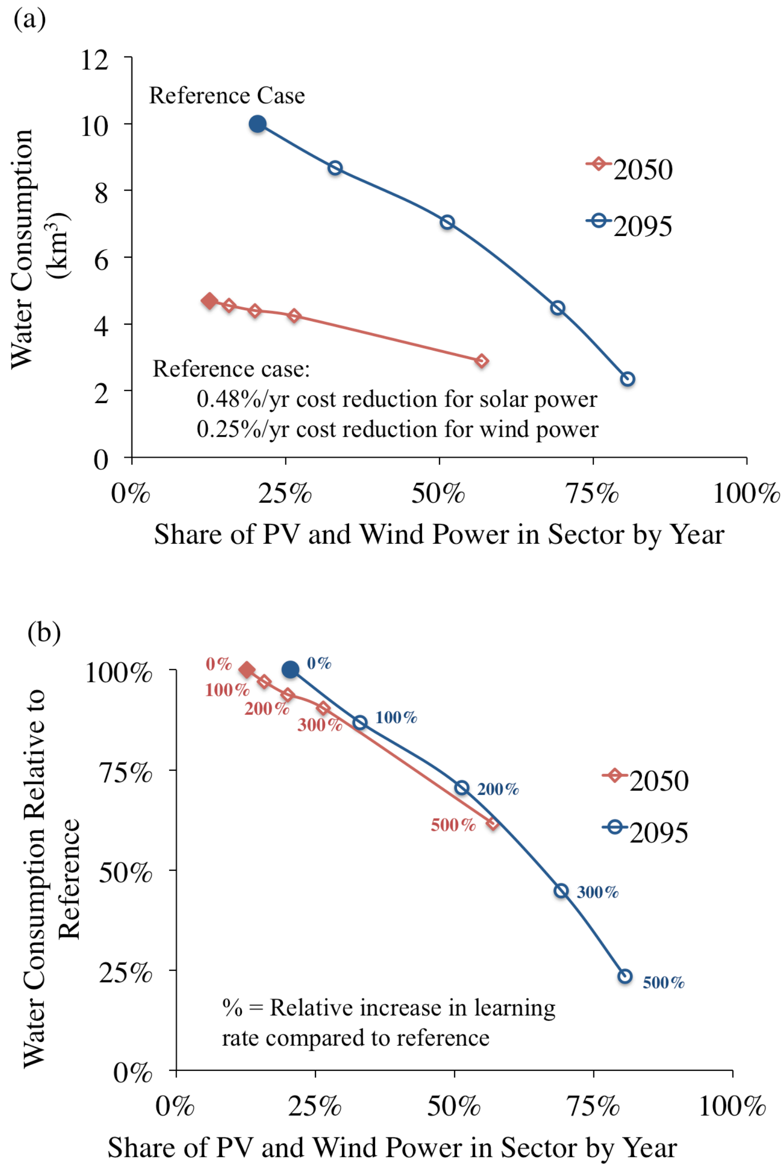


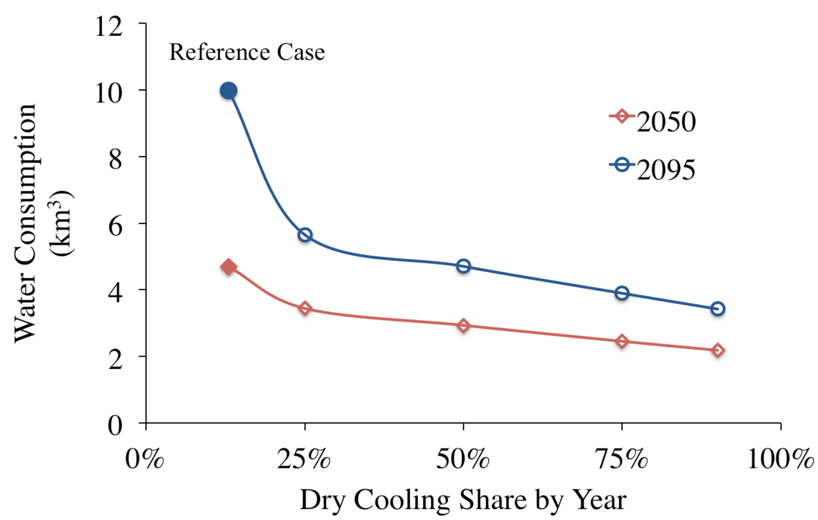
Figure 4. Water consumption in 2050 and 2095 as a function of the total share of PV and wind power in the electric power sector under the RCP 4.5-RE (a) Absolute water consumption (b) Relative water consumption

High Dry Cooling Penetration

A shift from wet to dry cooling in thermoelectric power plants can reduce water consumption significantly and secure low-carbon energy production. Thus, alternative scenarios (RCP4.5-DC) for dry cooling in thermoelectric plants are examined to quantify the relation of water consumption reduction with dry cooling penetration. When amine-based CCS is needed, a dry/wet hybrid system is employed for PC and NGCC power plants, as cooling water is needed for the carbon capture process.[10,20] IGCC plants use different CCS systems, thus a hybrid system was not employed.

Figure 5 shows regional water consumption for electricity generation in 2050 and 2095 as a function of the dry cooling share on both absolute and relative bases. The regional water consumption falls significantly with the dry cooling share over a range from 13% (RCP4.5 Ref) to 25%, but appears to be a relatively flat reduction trend beyond the 25% cooling share, mainly due to the increased generation from low-carbon renewable resources without water use over time. It would be hard to eliminate regional water consumption since amine-based CCS systems still need water for cooling. If the dry cooling share were increased to 90%, the regional water consumption would decrease by approximately 50% by 2050. If that ambitious penetration target were achieved, the regional water consumption would fall by approximately 65% in 2095. A 35-40% dry cooling share would lead to a 50% decrease in the regional water consumption in 2095.

(a)



(b)

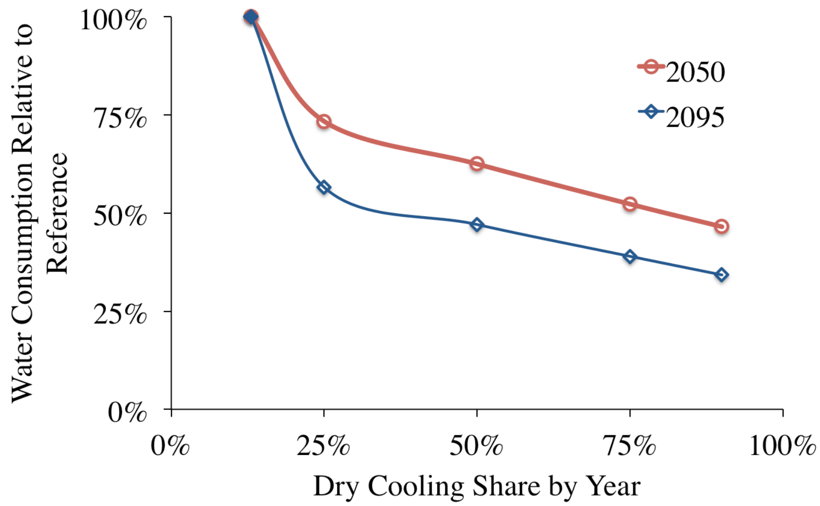


Figure 5. Water consumption in 2050 and 2095 as a function of dry cooling share in the electric power sector under the RCP 4.5 pathway* (a) Absolute water consumption (b) Relative water consumption.

*Because there are no entries to specify parasitic loads and costs of cooling systems in GCAM-USA, the effects of dry cooling systems on the demand and cost of electricity generation are not considered in the GCAM modeling, though the application of dry cooling to a PC power plant may lead to a 1–2% reduction in overall plant efficiency and $3–$6/MWh increases in the cost of electricity generation compared to a similar plant with wet cooling.[18] This scenario assumed that wet/dry hybrid cooling is used for PC and NGCC with amine-based CCS, whereas dry cooling is used for all IGCC plants.

3.4 Discussion

The Southwest will have high growth expected in upcoming decades despite historical and present-day water shortages. Projections for increased water consumption by the power sector fall in the range of 200−250% for the Southwest in 2095, far more than the national projections for the same sector (55−110%). Regional population and GDP growth are the major driving forces for energy demand growth and in turn, regional water consumption for electricity generation. In both reference scenarios (RCP 8.5 and 4.5), future energy will be highly dependent on thermoelectric generation throughout the century. If these trends take place, the existing stressed water supply will struggle to maintain the growing water demand for electricity generation.[14] Note however that these scenarios do not consider water scarcity, or feedbacks between water availability and technology choice in the power sector. While water limitations are becoming a more prevalent concern, they have historically not been a limiting factor power plant construction. This is evident as the Southwest already accounts for a disproportionate share of U.S. water consumption, and could foreseeably continue to do so. This study is meant to illustrate the potentially growing demand of water consumption in the region, even as they are already starting to face constraints.

Direct changes in ambient air temperature and humidity from climate change alone have a relatively modest impact on regional water consumption for energy production. Among the scenarios analyzed, the reference scenario under RCP 8.5 will face the relatively largest water impacts from such changes. However, it is important to note that the increases in water consumption incurred from climate change along with the growing energy demand by the end of the century are equivalent to 20–25% of current water consumption in the Southwest, which may sizably exacerbate regional water pressure in the future. In addition, it is important to note that considering water availability limitations would likely increase the importance of any climate-driven changes in the water demands of power plants, further increasing the stresses on the remainder of the system. These changes in water demand and availability will increase competition between sectors and change the allocation frameworks that currently exist.

Climate mitigation policies would facilitate deployment of low-carbon generation systems in the future fleet. Although the deployment of CCS would significantly increase water use, the shift from fossil fuels to renewables for low-carbon electricity generation could offset the added water use. High natural gas prices would shift electricity generation to technologies with larger consumption intensities, namely coal and nuclear power, and in turn, increase water consumption. Implementation of CO_2 emission performance standards under RCP 4.5 would have little extra effect on regional water consumption by the end of the century, as the radiative forcing target does not change, but electricity generation shifts slightly towards IGCC and NGCC plants.

From a regional perspective, electricity generation is not a large proportion of regional water consumption. However, significant increases in consumptive water use over the century would affect the allocation of water to different sectors. Our GCAM modeling results show that the amount of water consumed by the regional electric power sector from 2005 to 2095 relative to national consumption increases from 15% to 25%, which might be an unacceptable increase given the already present water constraints in the Southwest.[14] Growing investment in renewables and dry cooling can significantly decrease water consumption by the end of the century. These decreases, however, would necessitate long-term supporting policies in place.

3.5 Acknowledgements

This work is supported by the Center for Climate and Energy Decision Making (SES-0949710) through a cooperative agreement between the National Science Foundation and Carnegie Mellon University. Additional support was provided by the Bertucci Fellowship. We acknowledge the World Climate Research Programme's Working Group on Coupled Modeling, responsible for CMIP, and the climate modeling groups for producing and making available their model output. All opinions, findings, conclusions and recommendations expressed in this chapter are those of the authors alone and do not reflect the views of any U.S. Government agencies.

Supporting Information for the chapter includes text, tables, and figures regarding climate analysis, additional information on models, and assumptions. This material is available in Appendix B.

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Chapter 4: Viability of Carbon Capture and Storage Retrofits for Existing Coal-fired Power Plants in Texas under the Clean Power Plan: Role of Emissions Rate Trading

Abstract

This paper assesses the economic feasibility of retrofitting existing coal-fired electricity generating units (EGUs) in Texas with carbon capture and sequestration (CCS) technology in order to achieve compliance with the Clean Power Plan's rate-based emission standards under an emission trading scheme. Trading emission rate credits (ERCs) via an administratively created compliance instrument, the retrofit of CCS for 90% carbon dioxide (CO_2) capture is shown to be more economically viable for a range of suitable coal-fired EGUs than purchasing ERCs from the trading market at average ERC prices above ~$28 per MWh under the final state standard and ~$35 per MWh under the final national standard. The breakeven ERC trading prices would decrease significantly if the captured CO_2 was used (e.g. for EOR), making CCS retrofits viable at lower trading prices. The combination of ERC trading and CO_2 use can greatly reinforce economic incentives and market demands for CCS and hence accelerate large-scale deployment, even under scenarios with high retrofit costs. Comparing the levelized costs of electricity generation between CCS retrofits with that of new renewable plants under the ERC trading scheme, coal-fired EGUs retrofitted with CCS not only become competitive with new wind and solar plants, and may be significantly cheaper than new renewables under some market conditions.

4.1 INTRODUCTION AND RESEARCH OBJECTIVES

In December 2015, an historic agreement to take action against climate change was reached by 195 nations in Paris with the objective of keeping the average increase in global temperature at or below 2 degrees Celsius this century.[1] Given that a reliance on fossil fuels will likely continue in the future, carbon capture and sequestration (CCS) will be essential if deep reductions in carbon dioxide (CO_2) emissions are to be achieved. The Intergovernmental Panel on Climate Change's Fifth Assessment Report emphasized that while stabilizing the greenhouse gas concentrations below 450 ppm CO_2-equivalent is necessary to meet this goal, the cost of mitigation could increase by roughly 140% in the absence of CCS.[2]

To combat anthropogenic climate change domestically, the U.S. Environmental Protection Agency (EPA) established the Clean Power Plan (CPP) in August 2015, which would reduce national CO_2 emissions from *existing* electric generating units (EGUs) by 32% from 2005 levels by 2030.[3] The CPP established uniform national emission performance standards for existing fossil fuel-fired EGUs. Reflecting each state's energy mix, the final rule also presented state-specific rate- and mass-based emission standards. The CPP established three "building blocks" to achieve compliance: heat rate improvements; increased electricity generation from existing natural gas combined cycle (NGCC) plants; and, increased electricity generation from new renewable plants.[3] CCS was not included in the building blocks due to space, cost and integration concerns, if applied broadly to the overall source fleet.[3] However, retrofit of CCS can be a viable option for some existing coal-fired EGUs depending on the unit attributes.[3,4] The CPP provides states with the flexibility to decide whether to implement a rate- or mass-based standard and to choose the compliance measures, including market-based mechanisms.

Emission trading programs have been increasingly used for cost-effective management of emissions in national and global environmental and climate policy. They have encouraged innovation, incentivized further pollutant reduction, and lowered compliance costs when compared with strategies based on command-and-control.[5,6,7] For example, under the acid rain trading program sulfur dioxide (SO_2) emission reductions were achieved faster than expected due the flexibility afforded by the trading scheme.[7] Innovation in and diffusion of SO_2 reduction technology has grown while costs have declined.[7] Estimates for compliance ranged from \$2.7 −\$8.7 billion/year, with real costs eventually proving to be much lower at \$1.9 billion/year.[8]

Regarding carbon trading, domestic trading programs, such as the Regional Greenhouse Gas Initiative and the California Cap-and-Trade Program, have demonstrated the viability of carbon trading at the state and multi-state level.[9] Multi-State auctions for carbon allowances have been run since 2008 and state-level auctions have been run since 2012 respectively.[9,10,11] In addition, under the European Union Emission Trading System, multiple survey studies found innovation and investment from industry related to CO_2 abatement motivated by the policy.[12]

Under a rate-based emission standard, a state or multiple states can develop an emission trading program or participate in a federal program. This would allow EGUs operating below the standard to generate and sell emission rate credits (ERCs). Retrofits of CCS at suitable coal-fired EGUs have the potential to not only meet the emission standards, but also to generate ERCs to trade with other affected EGUs, thus providing income to offset some of the cost of retrofits.

The major objectives of this study are: 1) to investigate the viability of retrofitting CCS to existing coal-fired EGUs as a measure to comply with the CPP under a rate-based emission standard; 2) to examine how emission reduction trading would affect the viability of CCS retrofits; and 3) to compare the costs of electricity generation between CCS and renewable technology as compliance measures under the emission trading scheme. The resulting quantitative results should help states and utilities to design informed mitigation and policy strategies.

4.2 Retrofitting CCS for Rate-based Standard Compliance under Emission Trading Scheme

The CPP established uniform national interim and final CO_2 emission standards for existing fossil-fuel-fired steam EGUs over the compliance period from 2022 to 2030, which are 1534 and 1305 lbs CO_2/MWh, respectively.[3] The CPP also presented state-specific interim and final emission standards, which are 1188 and 1042 lbs CO_2/MWh for Texas, respectively. States using a rate-based standard may implement a market-based emission trading program that employs an administratively created tradable compliance instrument called an emission rate credit (ERC), defined as one MWh of electric generation with zero-associated CO_2 emissions. ERCs can be generated by numerous sources, including new renewable plants (e.g. wind and solar), demand-side energy efficiency programs, or existing EGUs with an emission rate less than the rate-based standard. The amount of ERCs that an EGU must buy or can sell is estimated as the product of the annual electricity generation and the normalized difference between the emission rate standard and the actual emission rate.[3] ERCs can be traded between EGUs that are under the same compliance pathway. Further details about the CPP are available in the Federal Register.[3]

A recent study found that the implementation of CO_2 capture appears feasible for some existing coal-fired EGUs that already have environmental systems for controlling major traditional air pollutants, are fully or substantially amortized, relatively efficient, have net capacities of more than 300 MW with high utilization, and can operate for 20 years or more.[4] Capture becomes more cost effective when the captured CO_2 can be used for enhanced oil recovery (EOR),[4] as elaborated upon below, since EOR results in a net increase in emissions it is not a sustainable long term strategy.

Texas has18 such EGUs, resulting in a total summer capacity of about 10 GW.[4] For illustrative purposes, Texas is chosen for a case study as its feasible capacity exceeds that of other states. Texas also has substantial potential for CO_2 sequestration via oil and natural gas reservoirs within an estimated range from 134 to 142 billion metric tons.[13] The key attributes of the identified EGUs are summarized in Table 1. For the suitable EGUs, there are at least three options available to comply with a rate-based standard: purchasing the required amount of ERCs from a trading market; retrofitting partial CCS to exactly meet the emission standard; and retrofitting CCS for 90% CO_2 capture (or called full-CCS) and selling the generated ERCs to a trading market. This study focuses closely on the final state rate-based standard for Texas.

Table 1. Summary of relevant characteristics of feasible EGUs, with and without retrofits

Characteristic	Statistic	Existing EGUs	Retrofit of Partial CCS		Retrofit of Full CCS
			National Standard	State Standard	
Average Gross Power Output[a] (MW)	Min	374	374	374	374
	Mean	529	529	529	529
	Max	711	711	711	711
Net Power Output (MW)	Min	359	317	310	295
	Mean	505	448	440	418
	Max	655	588	576	547
Efficiency(HHV, %)	Min	29.9	24.4	23.2	20.3
	Mean	32.6	25.8	24.7	21.6
	Max	34.4	27.5	26.4	22.9
Annual Operation Hours	Min	7276	7276	7276	7276
	Mean	8186	8186	8186	8186
	Max	8678	8678	8678	8678
CO_2 Emission Rate (lb/MWh)	Min	2103	1304	1040	316
	Mean	2220	1305	1042	336
	Max	2424	1305	1042	356
Annual Net Electricity Generation (Billion kWh)	Min	3.05	2.69	2.64	2.51
	Mean	4.13	3.67	3.60	3.41
	Max	5.62	5.05	4.95	4.70

Unit Levelized Cost of	Min	12.0	39.8	44.8	59.9
Electricity (2009 constant	Mean	15.3	43.4	49.4	65.5
$/MWh)	Max	22.0	48.3	53.9	70.9

[a] The corresponding summer capacity ranges from 436 MW to 760 MW with an average of 576 MW.

4.3 RESULTS

The Integrated Environmental Control Model (IECM), a power plant modeling tool, was applied to evaluate the performance and cost of each feasible EGU with and without CCS under a variety of design and marketing conditions.[14] As explained in the section on material and methods, the evaluation was done using sub-bituminous Wyoming Powder River Basin coal, which in the IECM's fuel database has a price of $8.75/ton. The average gross power output and annual operating hours were fixed for each CCS retrofit case. All costs are reported in 2009 constant dollars.

4.3.1 Effects of CCS retrofits on existing EGUs

Amine-based CCS, a commercially available technology, was assumed to be installed for CO_2 capture. The major technical and economic assumptions and parameters of amine-based CCS are summarized in Table S-1 of the Supporting Information (SI). Low-quality steam extracted from the unit's steam cycle provides the required thermal energy for solvent regeneration. We find that a CO_2 removal efficiency of 50−56% would be required for CCS to meet the final national standard and 62 −67% for the final state standard. The implementation of partial CCS to meet the final national standard would decrease the net power output and unit efficiency by 56 MW and 6.7% and increase the annual levelized cost of electricity generation (LCOE) by $28/MWh on average. To comply with the final state standard, it would decrease the net power output and net unit efficiency by 65 MW and 8.0%, respectively, and increase the unit LCOE by \$34/MWh, on average. However, the average unit LCOE of the existing EGUs retrofitted with partial CCS is similar to or less than that of new supercritical pulverized coal-fired or NGCC plants without CCS.[15] Table 1 also shows that the deployment of full CCS (90% CO_2 capture) would lead to more significant effects on the unit performance and cost. Figure S-1 in the SI depicts the LCOE of EGUs retrofitted with CCS in meeting both the interim and final standards over the compliance period.

4.3.2 Economics of CCS retrofits under ERC trading scheme

We first estimated the amount of required or sellable ERCs for each of the three mitigation options available to each suitable EGU to comply with the rate-based emission standards. Figure 1(a) shows the amount of ERCs for an example EGU under the final national and state standards, while Figure 1(b) shows the unit LCOE of the example as a function of the ERC price for each option adopted to meet both the final state and national standards. Without CCS, the example unit has to buy 4.3×10^6 MWh of ERCs annually from the market to comply with the final state standard. However, retrofitting full CCS generates 2×10^6 MWh of ERCs annually for sale. There are no ERCs generated or available using partial CCS. Figure 1(b) illustrates how the ERC price would affect the unit LCOE for each option. For the credit purchase option, the unit LCOE increases linearly with the ERC price. It decreases linearly for the full-CCS option due to the revenue from the ERC market. The unit LCOE, however, stays constant for the partial-CCS option. Using the credit purchase option as the benchmark across this study unless otherwise noted, the breakeven ERC price is \$29 per MWh for the partial-CCS option and \$27 per MWh for the full-CCS option under the final state rate. Under the final national rate, the breakeven ERC values are higher, occurring at $38 and $34 per MWh, respectively. As shown in Figure 1(b), for ERC prices less than these values, purchasing credits from the ERC market is the cheapest compliance strategy for the example EGU. When ERC prices are more than the breakeven prices, retrofitting CCS, in particular for 90% CO_2 capture, becomes economically viable. Although the addition of CCS would significantly increase the levelized cost of electricity generation even under the emission trading scheme with a breakeven ERC price, the unit LCOE of the retrofitted EGU is similar or less than that of a new fossil fuel-fired plant without CCS.[15]

We conduct the same analysis for all suitable EGUs retrofitted with partial and full CCS. The box plots in Figure 1(c) show the distributions of the resulting breakeven ERC prices under the final state and national rate-based standards. Under either the state or the national standard, there is considerable overlap in the breakeven ERC prices between the full and partial CCS retrofit options. However, for a given retrofit option, the breakeven ERC prices in meeting the state standard are lower than those in meeting the national standard, indicating that under more stringent standards, the CCS retrofit options become viable at lower ERC prices. When complying with the state standard, the breakeven ERC prices fall within the range of $22 to $35 per MWh for the partial-CCS option and $23 to $31 per MWh for the full-CCS option. As a result, the unit costs of electricity generation at the breakeven point fall within the range of $45 MWh to $54/MWh for the partial-CCS option and $44/MWh to $53/MWh for the full-CCS option. To understand which of the key attributes of the existing EGUs is most closely associated with breakeven ERC price, a Spearman rank correlation analysis for multiple parameters finds that unit LCOE of existing units as well as *added* LCOE for CCS retrofits have the highest statistically significant correlation. For more details of this analysis, see SI section S-4.

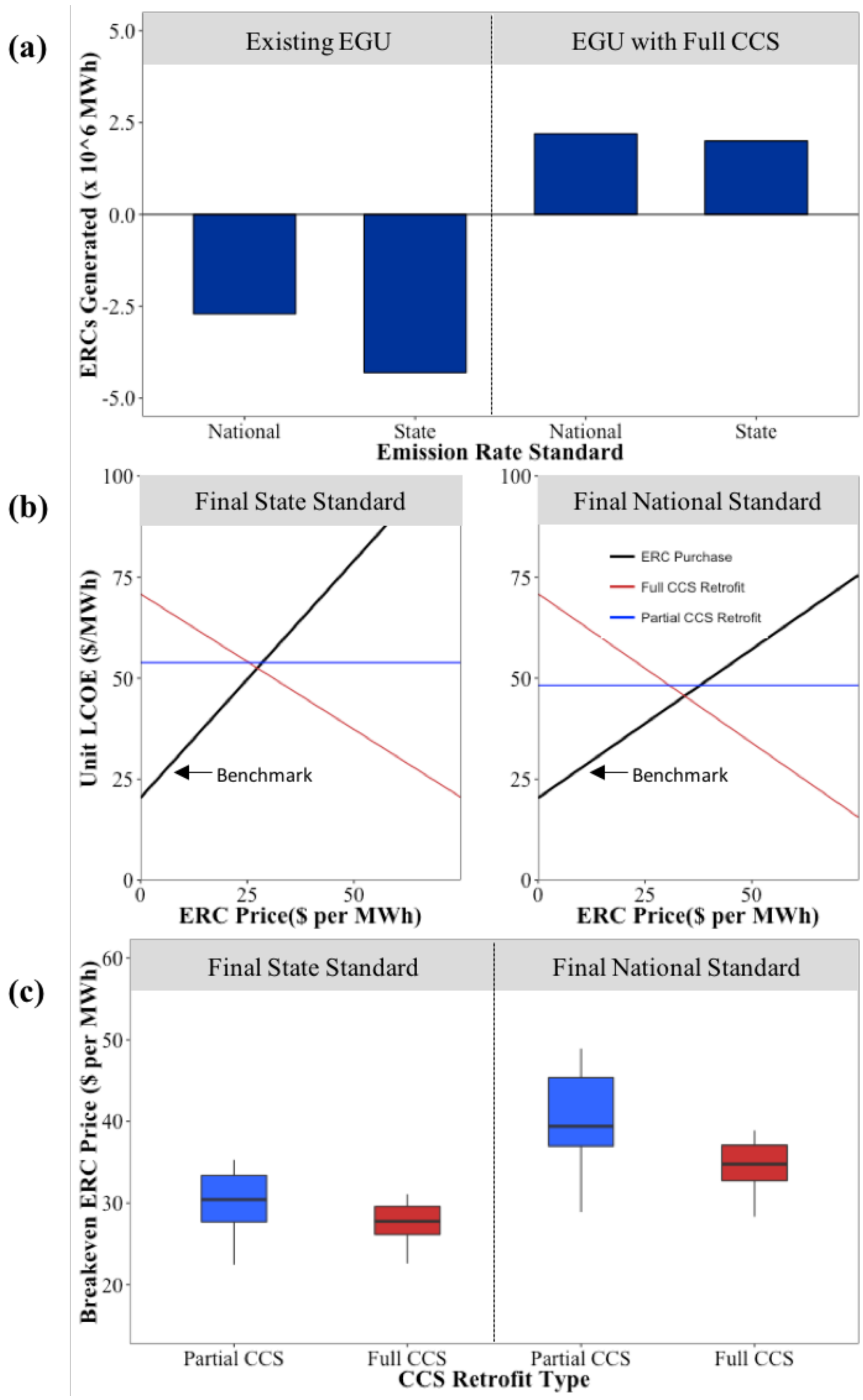

Figure 1. Economics of EGUs under an ERC trading scheme: (a) ERCs generated for an illustrative EGU with and without CCS retrofits under the rate-based standards. (b) Unit LCOE of the example EGU as a function of ERC price for three compliance options. (c) Boxplot of breakeven ERC prices for partial and full CCS options

In addition to the unit cost of electricity generation, the cost of CO_2 avoided is an important economic metric for CCS. Figure 2(a) shows the cost of CO_2 avoided by retrofitting partial or full CCS to the example EGU as a function of the ERC price in complying with the final state standard. For the partial-CCS option, the avoidance cost remains constant at $55/ton, as no ERCs are generated or required. However, for the full-CCS option, it decreases from $53/ton to zero as the ERC price increases from zero to $75 per MWh, beyond which the avoidance cost becomes negative. Figure 2(b) employs box plots to demonstrate the distributions of the cost of CO_2 avoided by full CCS for all suitable EGUs at four ERC prices. As shown in Figure 2(b), all the avoidance costs decrease when the ERC price increases. Emission trading does improve the economic viability of retrofitting CCS for 90% CO_2 capture. However, at a low ERC price of $10 per MWh or less, the avoidance cost has an average value of $46/ton or more, which is still high. This result indicates the need of additional economic incentives for enhancing the viability of CCS retrofits when the trading price is low.

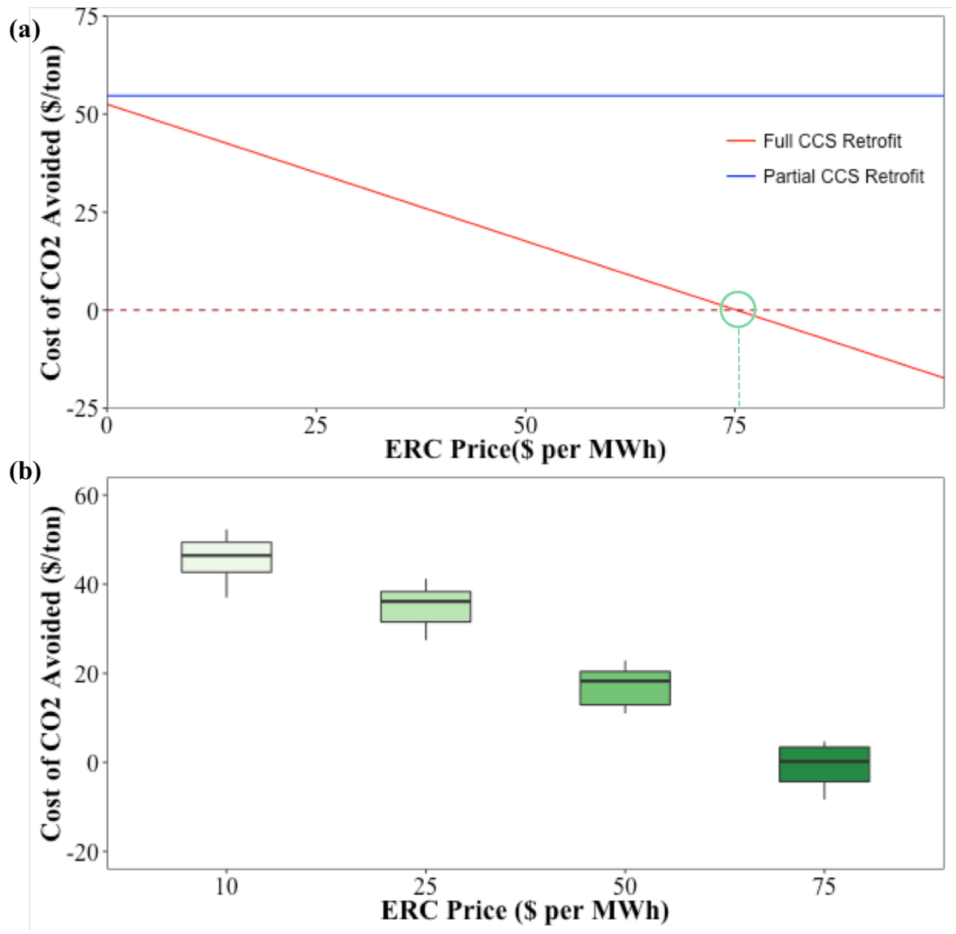

Figure 2 Cost of CO_2 avoided by CCS as a function of ERC price: (a) Cost of CO_2 avoided by retrofitting CCS for an illustrative EGU under an ERC trading market. (b) Boxplot of costs of CO_2 avoided by full CCS at EGUs under different ERC trading prices

Coal price has a large effect on the unit LCOE of both existing and retrofitted EGUs. In the EPA's Integrated Planning Model (IPM) for the CPP, the coal price in Texas was projected to fall within the range from \$8.1−\$27 in 2016 and \$9.4−\$31 in 2030 (in 2009 dollars).[16] It is thus necessary to examine the impacts of higher coal prices. As the coal price increases from the base case value to \$18/ton and \$26/ton (two and three times the base price), the levelized costs of electricity generation increase by 1.4 to 1.8 times on average for existing EGUs and 1.1 to 1.3 for EGUs retrofitted with full CCS. As a result, the average breakeven ERC prices increase just by

$1.5 per MWh and $3.1 per MWh, respectively (See figure S-2 in the SI). The fuel cost thus has a moderate effect on the breakeven ERC price.

Enhanced oil recovery (EOR) can lower the retrofit cost by providing income in lieu of a CO_2 sequestration cost, although the CO_2 transportation cost is still needed.[4] In conventional EOR much of the injected CO_2 is retrieved and reused. If we assume that EOR can be operated in a way that provides permanent sequestration, we can then examine the effects of CO_2-EOR operations on the EGUs that deploy full CCS to meet the final state standard. With an assumed sale price of $10/ton CO_2, using the captured CO_2 for EOR operations would substantially lower the average LCOE of EGUs retrofitted with full CCS from $65/MWh to $40/MWh. As a result, the breakeven ERC prices drop dramatically from an average of $28 per MWh (shown in Figure 1c) to $14 per MWh (See Figure S-3 in the SI); This result indicates that a low sale price of the captured CO_2 can have a big impact on the ERC trading market, thus enhancing the viability of deployment of full CCS as a compliance measure for suitable EGUs.

4.3.3 Potential High Costs of CCS Retrofits

While amine-based capture is an available technology, it has yet to be deployed at large scale for capture at power plants. When estimating the capital cost of a technology, the process contingency accounts for additional capital costs that may arise as a system matures into a commercial-scale technology, whereas the project contingency accounts for additional equipment or other costs that may be identified in a more detailed project design.[17] EPRI estimates process contingency to vary from 5% to 20% for a technology whose full-scale modules have been operated, and the project contingency to vary from 15% to 30% for a preliminary project.[18] To account for potential difficulty of access to different areas of the plant and integration of a new system with existing facilities, a recent study suggests an average retrofit factor of 1.25 for post-combustion CCS, representing the cost ratio of new equipment for a retrofitted plant versus a new plant.[19,20] When estimating the total annual levelized cost, the fixed charge factor (FCF) converts the total capital requirement to the constant annualized amount, depending on the interest or discount rate and the economic lifetime of a project. In the base case, the FCF values range from 0.113 to 0.127. To examine the economic impact of potential high financing conditions, a high fixed charge factor of 0.15 is often adopted for CCS assessments.[15,21,22] Considering all these factors in implementing full CCS retrofits to comply with the final state standard, Figure 3 shows the cumulative economic effects of elevating the total contingency from 30% to 50%, retrofit factor from 1.00 to 1.25, and FCF from the base values to 0.15.

Without ERC trading, Figure 3a shows the cumulative effects of elevated parametric values on the unit LCOE of EGUs retrofitted with full CCS. With the elevated values for the three cost parameters, the unit LCOE would cumulatively increase by 29% on average for the 18 EGUs, compared to the base case. Figure 3b shows that under the ERC trading market, the breakeven ERC prices associated with CCS retrofits would cumulatively increase by 38% on average, due to the combined effect of the three elevated parametric values, compared to the base case. Figure 3c shows the unit LCOE of retrofitted EGUs with income measured at the corresponding breakeven prices shown in Figure 3b. In comparison between Figure 3a and Figure 3c, we can see that trading ERCs from full-CCS deployment would decrease the unit LCOE by 29−31% on average for the three high retrofit cost scenarios.

Figure 3 also shows the economic effects of CO_2-EOR operations with different CO_2 sale prices for the cases with the highest retrofit costs. As shown in Figure 3, the viability of full-

CCS deployment improves with an increase in CO_2 sale price. Figure 3c shows that with a CO_2 sale price of \$30/ton, the LCOE values of retrofitted EGUs are similar to those given in Table 1 for existing EGUs without CCS. This result implies that even under the highest retrofit cost scenario, the combination of ERC trading and CO_2 product utilization would substantially facilitate deployment of full CCS at existing coal-fired EGUs.

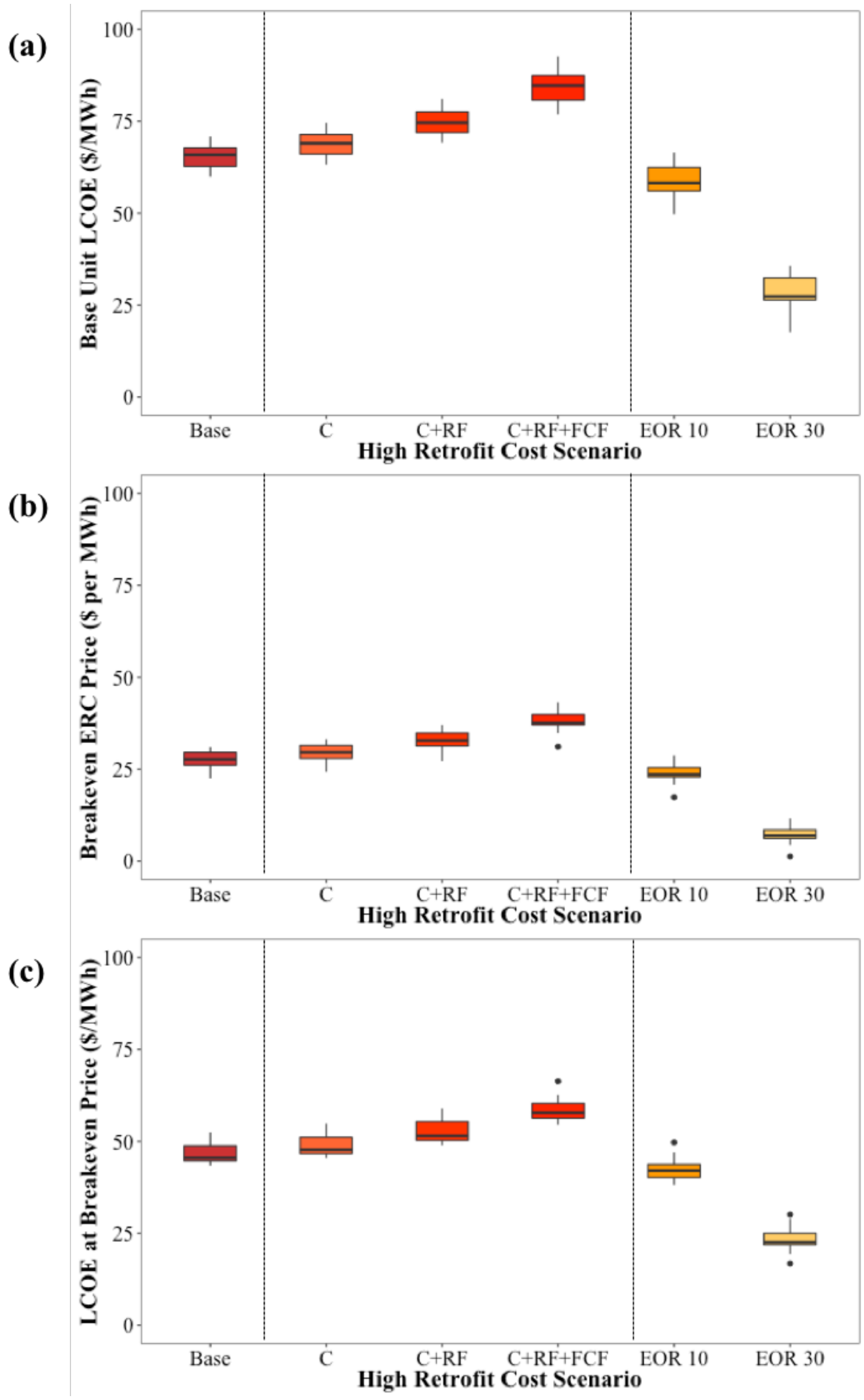

Figure 3 Economics of EGUs with high CCS retrofit costs: (a) Base unit LCOE of EGUs retrofitted with full CCS under different retrofit cost scenarios prior to emission trading. C = high contingencies (process = 20%; project = 30%), C+RF = high contingencies and retrofit factor, C+RF+FCF = high contingencies, retrofit factor, and fixed charge factor, EOR10/30 = all factors and EOR at different prices CO_2 sale prices. (b) Breakeven ERC prices for the full-CCS option under high retrofit cost scenarios. (c) Unit LCOE for EGUs under high retrofit cost scenarios at the breakeven price.

4.4 DISCUSSION

Although retrofits of CCS are not a viable option for meeting emission standards across the entire existing fleet, it is feasible for such coal-fired EGUs as those evaluated in this study. At the state level, the losses in net electricity generation from retrofitting CCS can be offset by the increased use of existing NGCC plants in meeting the CPP standards, which would also lower costs of electricity generation for those gas-fired plants. ERC trading programs are able to improve the economic viability of CCS retrofits, especially for the implementation of CCS for 90% CO_2 capture. However, if actual ERC market prices were less than the breakeven values, additional economic incentives, such as direct financial support, subsides or revenue from CO_2 sales, would be needed in order to promote investments in CCS deployment. Along with ERC-based trading mechanisms, using the captured CO_2 for CO_2-EOR can help further promote the viability of CCS retrofits, depending on the CO_2 sale price. Even if the ERC trading price were to remain as low as \$10 per MWh, the income stream from selling the captured CO_2 at a price of \$10/ton CO_2 would substantially lower the average avoidance cost from \$46 to \$19/ton. Current sale prices for CO_2 are estimated to be approximately \$35−40/ton based on oil prices of \$85/bbl.[23] This price level is higher than those adopted in our analysis. We use this lower value because of uncertainty about reservoir capacity and oil market fluctuation and the fact that if sequestration is to be successful EOR operations will need to forgo strategies that now focus on maximizing CO_2 recovery for reuse.

Because the life cycle CO_2 emissions associated with sequestration via CO_2-EOR will be net positive when the produced oil is combusted, [24] EOR sequestration should be regarded as an interim bridging solution that can improve the viability of CCS as technological learning continues. In the future it is possible that other forms of CO_2 utilization may be developed, but given the enormous volumes that are involved, to date viable alterative uses have yet to be found.[25] With respect to the total mass-based emission reduction, just retrofitting partial CCS at those suitable coal-fired EGUs with removal efficiencies slightly higher than to meet the state rate-based standard would result in a total amount of emission reductions similar to that necessary for achieving the state mass-based emission goal for the entire existing fleet (see Section S-7 of the SI).

Another important consideration for CCS is water use due to the large amount of cooling water required for the capture process.[26] Retrofitting CCS for 90% CO_2 capture at existing coal-fired EGUs with wet cooling towers would approximately double water use (See Figure S-6 in the SI). Hence water availability must be considered in evaluating CCS retrofits, especially in regions such as Texas, that have experienced increased frequencies of drought and high temperatures.[27] See Section S-5 in the SI for additional water information and analysis.

The decision for existing units to employ CCS in meeting the rate-based standards will be in competition with new wind and solar power plants outlined in the CPP as the best system of emission reductions. For the same amount of electricity generation, new zero emission renewable plants would generate more ERC credits than full CCS. Thus, the ERC market could greatly affect the choice of mitigation options between CCS and new renewable plants. Using a 30-year economic lifetime and a 7% discount rate, the LCOE values of new wind and solar plants were estimated to be $74.5/MWh and $83.3/MWh based on the IPM's capital and fixed O&M cost estimates for 2016, respectively.[16,28] As shown in Figure 4a, they decrease linearly when the ERC price increases. For the illustrative case, the resulting breakeven ERC price for wind is slightly less than that of full CCS at about $25 per MWh, and for PV is more than that for retrofitting full CCS to the example coal-fired unit at $28.9 per MWh. On average for these

EGUs, however, the breakeven ERC prices for wind and solar are \$27.8 and \$32.0 per MWh, equal to, or higher than, that of EGUs retrofitted with full CCS.

At ERC prices less than \$28 per MWh coal-fired EGUs retrofitted with full CCS have a lower levelized cost of electricity generation than that of new wind. This equivalent ERC price at which this occurs for new PV plants is \$56 per MWh. Figure 4b compares the distributions of the breakeven ERC price for the 18 EGUs between partial and full CCS retrofits and new renewable plants employed for meeting the final state standard. The lowest breakeven ERC prices occurs under the mitigation option of retrofitting full CCS to suitable coal-fired EGUs. However, IPM projects that by 2030, new PV plant costs would drop dramatically by 38.5%.[16] With such low costs, the lowest breakeven ERC prices occur from using new PV plants. See Section S-6 of the SI for additional analyses.

Coal-fired power plants will continue to provide a significant share of the electricity demand in the United States and other countries like China and India, though renewable plants are expected to make growing contributions to future energy demand.[29] However, deep emission reductions by over 80−90%, a much more challenging target than the 32% outlined by the CPP, will be needed to stabilize the climate.[30,31] CCS retrofits are a defensible step in the effort to reach this ambitious abatement aim.

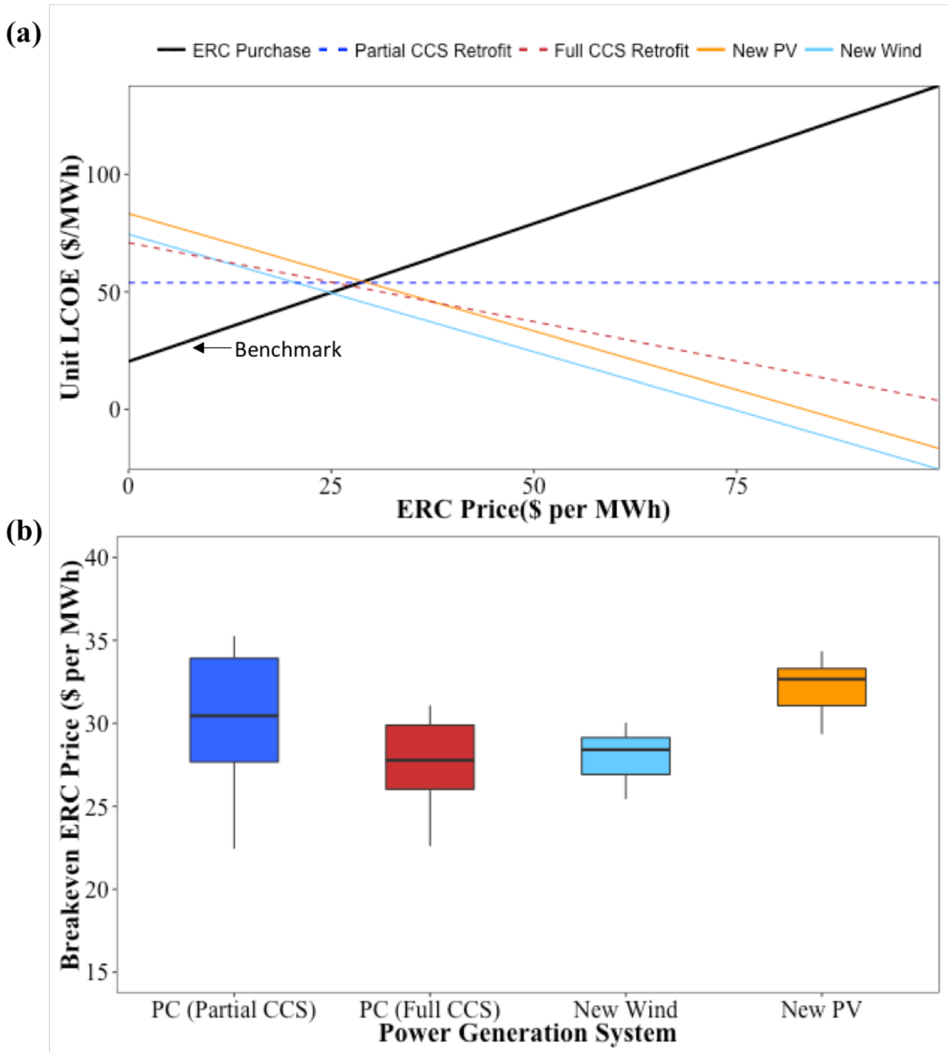

Figure 4. Cost comparisons between CCS retrofits and new renewable plants under an ERC trading scheme: (a) Unit LCOE of example EGU and new renewable plants under an emission trading market. (b) Breakeven trading prices for different compliance options

4.5 CONCLUSION

Currently, the CCS cost is a major barrier to large-scale deployment. Supportive regulations and policies are strongly needed to provide economic incentives for CO_2 capture technologies and help establish market demands for CO_2 capture, utilization and storage. This study evaluates and demonstrates the viability of CCS retrofits as a mitigation strategy for some existing coal-fired units to comply with rate-based emission standards under the trading scheme.

Depending on market price signals, the combination of emission trading and CO_2 utilization can greatly reinforce economic incentives and market demands to accelerate large-scale deployment of CCS. Some retrofits of commercial-scale CCS would foster "learning by doing" to lower CCS costs and promote technology innovation, which in turn will amplify its diffusion around the world as a key technology for mitigating climate change.

4.6 MATERIALS AND METHODS

The Integrated Environmental Control Model (IECM v9.1), a power plant modeling tool developed by Carnegie Mellon University, was employed to simulate and evaluate feasible existing coal-fired EGUs.[14] These EGUs are based on the unit-specific attributes information from an integrated emissions and power generation database that combines the U.S. EPA's National Electric Energy Data System and Emissions and Generation Resource Integrated Database.[4] The key attributes adopted for characterizing individual EGUs include the unit location, unit age, boiler type, coal type, heat rate, capacity, annual electricity generation, operating hours, and environmental control systems. Details on the IECM simulations are in Zhai *et al* (2015).[4] The key performance metrics considered include the CO_2 removal efficiency, CO_2 emission rate, total annual CO_2 emissions, net power output, annual electricity generation, water use, and net unit efficiency. Key cost metrics are the total LCOE of an EGU with or without CCS and the cost of CO_2 avoided by CCS.

For a given CO_2 emission performance standard, the IECM was used to assess each EGU under the rate-based emission standard regulation via three compliance options: purchasing ERCs from a trading market; implementation of CCS for partial CO_2 capture; and implementation of CCS for 90% capture with an income stream from an ERC trading market.

The cost-effective bypass design is adopted for partial CO_2 capture.[28] In each CCS retrofit case, the IECM is applied to first determine the CO_2 removal efficiency required for an EGU in meeting the given emission rate limit. The amount of sellable ERCs from full-CCS deployment is then determined to estimate the unit performance and the unit LCOE as a function of the ERC price. Details on the IECM and the ERC, LCOE, and CO_2 avoidance cost calculations are in Sections S-1 and S-3.

To make cost comparisons between CCS and renewable generation systems under the ERC trading market, the plant LCOE was calculated for new wind and solar power plants using capital and operating cost data from the Integrated Planning Model, which was applied by the U.S. EPA to assess the CPP.[16] The detailed LCOE calculations for new renewable power plants are in Section S-5 of the SI.

4.7 References

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CHAPTER 5: CONCLUSION

5.1 SUMMARY OF RESULTS AND RECOMMENDATIONS FOR FUTURE RESEARCH

Climate change and mitigation policies will have profound impacts on the low carbon power sector. Emissions regulations and ambient changes will not only deeply affect water use but also change economically-based technological decisions in electricity generation. The work in this thesis helps clarify these potential changes and provides insight into these issues for both industry and policymakers.

Chapter 2 shows that the proposed CO2 emissions regulations for new coal fuel-fired EGUs would drastically change both performance and water use. Maintaining a 40% removal efficiency under partial CCS to meet the 1100 lbs/MWh-gross standard would lead to water increases of 30% due to additional cooling water needed for the capture process. In comparison to the PC plant without CO_2 emissions control, complying with more stringent emission standards ranging from 1,100 to 300 lbs CO_2/MWh-gross would increase water consumption by 30% to 68%. In looking at how natural gas-fired power plants would perform under more stringent limits, an NGCC plant consumes an average of 64% less water than a PC plant over emission limits from 700 to 300 lbs CO_2/MWh gross. On a regional basis, a shift from coal to natural gas could lower regional water demand for the electric power industry. This study also finds that water use varies by coal type, plant type, and cooling system. Higher plant efficiency and use of high-quality coal can lower the required CO_2 removal level and reduce overall water use. Dry cooling can very effectively address increasing water use, but comes at a high cost and can lower plant efficiency.

It should be noted here, however, that the proposed rule was more stringent than the ultimate finalized rule for new EGUs, indicating that growth in water use may actually be limited until the standards are tightened.[1] In looking towards future analysis, further work on alternative water resources for use in EGUs is merited. This includes water from CO_2 geologic sequestration and produced water from municipal treatment plants.

Chapter 3 finds that water consumption from electricity generation in the Southwest U.S will potentially increase by 200-250% by 2095, outpacing national growth. Regional population and GDP growth are major driving forces for energy demand growth and in turn, regional water consumption for electricity generation. Direct changes in ambient air temperature and humidity from climate change alone have a relatively modest impact on regional water consumption for energy production. The reference scenario under RCP 8.5 will face the relatively largest water impacts from such changes, an increase equivalent to 20–25% of current water consumption in the Southwest. These changes in water demand and availability will increase competition between sectors and change the allocation frameworks that currently exist. Further, the study finds that mitigation policies would facilitate deployment of low-carbon generation. While CCS would significantly increase water use, a shift from fossil fuels to renewables could offset this increase. High natural gas prices, however could shift electricity generation to technologies with larger consumption intensities. Growing investment in renewables and dry cooling can significantly decrease water consumption by the end of the century. Water consumption would drop by 50% in 2095 from PV and wind generation must account for 60% of the generation grid or from a 35-40% dry cooling share These decreases, however, would necessitate long-term supporting policies in place.

This analysis however, did not consider water scarcity, which will also experience changes under climate change. Further research is merited on the feedback between water availability and technology choices within the sector. In addition, future work can encompass additional regions of the United States, looking at climate impacts of each, as well as additional scenarios incorporating climate impacts on electricity demand.

Chapter 4 illustrates the viability of employing CCS retrofits under a rate-based program in the Clean Power Plan. We find that within an ERC market, the profitability of CCS retrofits over existing units is greater and occurs sooner under more stringent rates. In addition, for relatively low ERC prices, full CCS quickly becomes more economical than partial CCS, especially under the state rate. Under these rate-based market conditions, PC plants with CCS retrofits could also foreseeably be competitive with the projected 2016 costs of solar and wind, potentially even more so than our numbers indicate as we did not incorporate transmission costs for renewables. With utilization of CO2 through EOR, full CCS is even more profitable over the lowest price projections of PV. Though the increased LCOE from CCS is much greater under the high retrofit cost scenarios, higher EOR sale prices could bring the highest risk scenario prices low enough to still being profitable over renewables under certain market conditions. Conversely, EOR is a short term solution and a volatile market. It should be used to promote technological development, but will likely be less available once the technology is mature. In addition, consideration of CCS retrofits should be made with close evaluation of environmental impacts. Water use increases dramatically with CCS, and could serve as major limiting factor for retrofitting units, especially for those in drier climates.

This study was focused on rate-based compliance. The analysis for mass-based compliance for EGUs using CCS should be expanded upon to understand the viability and costs as compared to a rate-based strategy. Finally, as this study was specific to units in Texas a broader national analysis may be helpful to better understand how CCS would perform on a larger scale, and how different parameters of different states would affect prices.

5.2 Future Implications & Applications

The results from the analyses conducted in this thesis provide insights that should be helpful in addressing a range of future and ongoing environmental and policy issues. Section 5.2.1 offers a few recommendations for reducing water use from electricity generation in the Southwest. Section 5.2.2 discusses implications of and recommendations for CCS under the Clean Power Plan.

5.2.1 Electric Power Water Use in the Southwest

The numerous agreements, laws, contracts, and guidelines governing the Colorado River came into place in 1922.[2,3] Otherwise known as the Law of the River, the allocation provisions in these laws for the states in the Southwest have not changed significantly over the last century, even as electricity generation, population, and climate in the region most certainly have.[2,3] Chapter 3 of this thesis projects future water consumption from electricity generation for the region under a range of scenarios, all of which project large growth. The changing water needs and supply in the region require a change in the river's allocation framework, and perhaps a reassessing of the volume distributed. More rights are currently allocated than there is water, a growing problem for California as their dependence on the waning river surplus is a major threat to all sectors in the state.[2] These laws, however, have been notoriously difficult to amend, indicating that a future crisis may be imminent. Under such a potential future crisis, in looking specifically at the electric power sector, there are multiple pathways to reducing water use, as discussed in this thesis. Prevention of a dire situation for the electric power sector requires incentives for installment and technology improvement for dry cooling, increased used of electricity generation with low water use intensity, and greater use of reclaimed water. Different entities, such as state governments, federal agencies, and utilities can put in place a range of measures to prevent a crisis based on the results presented.

One major policy option Southwest states or the federal government could consider would be to implement water intensity standards at thermoelectric power plants for both water consumption and withdrawal, similar to that of CO_2 emissions performance standards. These standards could be imposed incrementally or through a market framework, providing credits for over-compliance or requiring them for underperformance. Market frameworks have proven to be successful for a range of environmental policies, as described in Chapter 4. Such standards would not only provide an incentive for dry cooling installation, but use of reclaimed water and increased use of power generation technologies with little to no water use. In looking at increasing deployment of low water intensity power generation technologies, many states already have incentives or policies in place to encourage use of low carbon technologies, many of which also have low water use. However, some of these may also have high water use, such as nuclear generation or use of CCS. Water intensity standards would apply to these technologies as well, economically encouraging use of dry or hybrid water systems to dramatically lower water use. More broadly speaking, a water credit (or allocation right) trading system could potentially be spread to agriculture and manufacturing, encouraging lower water use across all sectors. This idea is immensely complex and has been discussed a great deal in the literature, meriting further reseach.[4] Both state and federal governments should begin looking more carefully at creating such a framework.

As a water intensity standard may be politically challenging to introduce, state governments in the Southwest should also begin to assemble policies and regulations that provide power plants with incentives to install dry cooling systems over wet cooling in both new and existing thermoelectric power plants. As these systems are more expensive, financial incentives would be necessary, and could be in the form of either tax credits or penalties. From a federal perspective, agencies like the Department of Energy could begin to invest more heavily in research projects aimed at improving the efficiency and cost of dry cooling systems. Such investment could lower the short-term financial incentives needed for power plants to install the systems.

In addition to these long-term policy options, water utilities, entities that are a mix of public and private, could develop and implement water pricing frameworks that do not exist today. These utilities set water pricing rates – rates that have been consistently low for decades.[5] While rates are indeed currently increasing, it is not at a level that effectively discourages wet cooling at thermoelectric plants. Though politically variable and difficult, utilities must begin to put in effort towards long term strategies that increasingly lead to economically based choices for use of dry cooling, renewables, and municipal water for cooling. One such measure could be to move from a variable (volumetric) rate, the current norm, to variable + fixed rate, a better measure of the real water cost.[5] This cost structure is similar to that of the power sector, and would lead to a more reasonable price estimate. One relevant entity that can test such a system is the Salt River Project (SRP) in Arizona, a large multipurpose public utility that provides both power and water to over a million consumers. This utility is in a unique position to move both sectors towards a more sustainable balance and assess the success of these different incentive structures.[6,7] SRP, a user of major tributaries of the Colorado River, has the ability to see both sides of the energy-water nexus to well understand the best pathway towards low water use for growing electricity demand.[7]

Reducing water use for the electric power sector in the midst of a water supply crisis would be much more difficult. Research from this thesis suggests that only with long term strategies can the water shortage issues in the Southwest be effectively addressed. State and federal governments must quickly act upon the issues presented in order for the electric power sector to continue to reliably meet consumer demand. Given the likelihood of a water crisis from the allocation challenges described above, analyses must quickly start thinking about the comprehensive changes that are needed. Only with ideas in place will decision makers be ready when a "policy window" opens.[8]

5.2.2 CCS under Emission Performance Standards

This thesis provides insight for upcoming compliance strategies and short-term choices as state governments form their implementation plans to comply with the CPP. These choices will in turn deeply affect the future direction of coal- and gas-fired power generation. Though large scale deployment has not yet taken hold, the next generation of CCS technology could lead to a different landscape for low-carbon electricity generation.

The Clean Power Plan and New Source Performance Standards are likely only the first steps in emissions regulation that will be put forth to limit carbon dioxide and other greenhouse gas emissions. As presented in Chapter 4, more stringent rate standards would lead to lower breakeven ERC prices between existing EGUs and EGUs with CCS – rates that would also lead to lower emissions from fossil fuel-fired units. The U.S EPA should expand the emission performance standards for new and existing EGUs beyond the CPP, increasing the stringency of rate standards past 2030 to help incentivize installation of carbon capture technologies for viable units in the shorter term within a market. Such an expansion would not only encourage longer term planning and investment strategies for electric utilities, but would also ensure a continuing commitment to emission reductions. That said, the results presented in this thesis are specific to rate-based standards at a unit level. In addition, the viability investigated is economically specific, and does not discuss other environmental concerns. There are energy and emissions costs associated with mining, extraction, and leakages. While CCS will allow some continued use of base-load coal a life cycle emission and cost analyses should be conducted should be done within a market framework to understand how emissions and costs between technologies interact as rate standards and ERC prices change – as well under changing mass caps and allowance costs.

As discussed in Chapter 4, CCS retrofits without a market framework or at low ERC prices will require additional economic incentives to be viable, such as EOR. However, acknowledging that EOR is a short term solution that has limited geographical availability, further federal policy mechanisms would be necessary to increase the economic viability of CCS. One such mechanism is an investment tax credit, similar to credits currently in place for renewables. An investment tax credit for CCS might be implemented on a national level as a different bridging solution over EOR if ERC prices were to remain low. Such tax credits could improve the rate at which CCS retrofits are deployed even without a market structure, improving technological learning and lowering costs. But tax credits come at a cost and the short and long-term economic and environmental consequences of promoting different mixes technologies described in Chapter 4 require thorough investigation to prove its long term benefits.

Affordable CCS retrofits would significantly change the future of the coal industry. This industry is currently facing a significant decline in its share of electricity generation, and faces only steeper losses in the face of an emission standard.[9] If, within a market, the affordability of CCS becomes realistic, coal-dependent states would not only find financial relief, but could potentially become more amenable to future climate regulations. Changing the political will of the coal industry towards mitigating climate change would be nothing short of remarkable. However, given today's gas prices, EPA projects that all new fossil generation by 2030 may be in the form of NGCC without CCS.[10] If no new fossil generation utilizes CCS, retrofits for existing units will be the only way to ensure technological learning. Looking beyond 2030, to achieve long term climate goals, emission standards will likely eventually be low enough that NGCC plants will also require CCS – an option that will only be available if we begin to invest in retrofits in the short term.

Finally, the results from all chapters imply that CCS retrofits should only be encouraged as a viable option in regions with stable water resources, rather than the Southwest. Without alternative cooling systems, state governments facing dwindling water resources should look to other solutions to comply with the CPP, such as those listed as building blocks under the best system of emissions reduction, while forming state implementation plans. However, switching to and building new natural gas capacity, one of the three building blocks, will lead to similar issues, as they will likely one day require CCS to comply with future regulations. Installing both low-carbon and low-water use electricity generation systems must be simultaneous priorities to ensure consistent base load power. Entities in the Southwest should begin to invest heavily in increasing PV and wind power generation, while federal agencies should supply more economic incentives for these technologies. This region could additionally begin to invest heavily in using reclaimed water for thermoelectric plants. A cost assessment comparing the financial burden of moving to such a water source over building new renewables should be investigated more thoroughly. In this vein, federal labs and agencies should begin to focus some of the CCS research and development on reducing water use. If the cooling duty from CCS were able to be lowered, such as through use heat integration within a plant, it may become more viable in the region.

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APPENDIX A – SUPPORTING INFORMATION FOR CHAPTER 2

The following supporting information provides text, tables, and a figure pertaining to 1) coal and natural gas properties; 2) additional results of plant water use for different regulatory compliance scenarios; and 3) distribution functions assigned to uncertain parameters for uncertainty analysis.

S-1 Coal and natural gas properties

The properties of Illinois No. 6 coal, North Dakota Lignite coal, and Wyoming Powder River Basin coal are presented in Table S-1, including the composition and higher heating value. The properties of natural gas are presented in Table S-2.

Table S-1. Coal Properties

Coal type	Ill No. 6	ND Lignite	WRB
Coal rank	Bituminous	Lignite	Sub-bituminous
Higher heating value (kJ/kg)	2.71E+04	1.4E+04	1.94E+04
Coal composition			
Carbon (wt %)	63.75	35.04	48.18
Hydrogen (wt %)	4.5	2.680	3.310
Oxygen (wt %)	6.88	11.31	11.87
Chlorine (wt %)	0.29	9.000e-2	1.000e-2
Sulfur (wt %)	2.51	1.160	0.3700
Nitrogen (wt %)	1.25	0.7700	0.7000
Ash (wt %)	9.7	15.92	5.320
Moisture (wt %)	11.12	33.03	30.24

Table S-2. Natural Gas Properties

Higher heating value (kJ/kg)		5.229E+04
Gas composition		
	Methane (vol %)	93.1
	Ethane (vol %)	3.2

Propane (vol %)	1.1
Carbon Dioxide (vol %)	1
Oxygen (vol %)	0
Nitrogen (vol %)	1.6
Hydrogen Sulfide (vol %)	0
Natural Gas Density (kg/m^3)	.7308

S-2 Additional results of plant water use for different regulatory compliance scenarios

The amount of time for 90% carbon capture was estimated for each regulatory compliance scenario in terms of the average emissions over a compliance period with and without carbon capture and storage (CCS) for 90% CO_2 capture to comply with the CO_2 emission standard. Based on the amounts of time with and without 90% CO_2 capture, the water use for each regulatory compliance scenario was estimated on average for those of the base coal-fired plant without CCS and the plant with 90% CO_2 capture. The results regarding the time spent for 90% CO_2 capture and the average water use are summarized in Tables S-3 and S-4, respectively.

Table S-3. Time Spent for 90% Carbon Capture per Regulatory Compliance Scenario

Regulatory Compliance Scenario	Months of 90% Capture	Percent of Total Time for 90% Carbon Capture
1100 lbs/MWh-g over 12 months	4.35	36.3%
1050 lbs/MWh-g over 84 months	33.1	39.4%

Table S-4. Results of Average Water Intensity per Regulatory Compliance Scenario

Regulatory Compliance Scenario	Water Consumption (m^3/MWh)	Withdrawal Intensity (m^3/MWh)
1100 lbs/MWh-g over 12 months	2.06	2.94
1050 lbs/MWh-g over 84 months	2.10	2.99

The consumptive plant water use over time for the 12-month compliance scenario is depicted in the main body, and the plant water consumption for the 84-month compliance scenario is shown in Figure S-1.

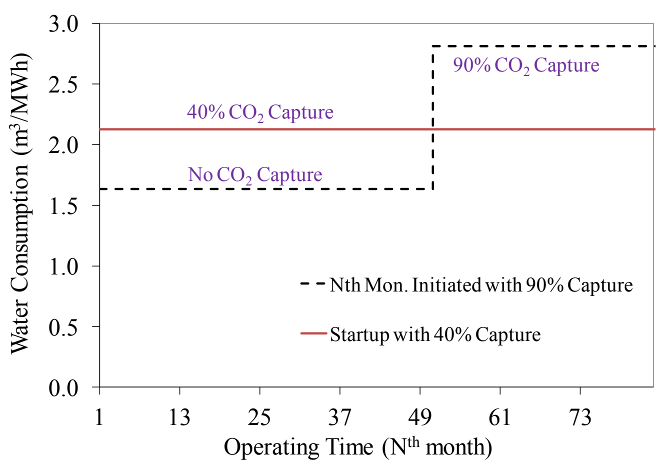

Figure S-1. Water consumption of regulated coal-fired power plant as a function of operating time for 84-month compliance scenario

S-3 Uncertainty analysis of water use for the supercritical PC plant with CCS

The key uncertain variables, as discussed in the main body, include ambient air conditions and those that affect water use around the steam cycle, the wet flue-gas desulfurization (FGD) unit, and the amine-based CCS system. The assumptions about the distributions for the uncertain variables are based primarily on a previous study [1] and are summarized in Table S-5.

Table S-5. Distribution Functions Assigned to Uncertain Parameters for Supercritical PC Plants with and without CCS

Category	Parameter	Units	Nominal Value	Distribution Function
Ambient Air	Ambient air temp	^oC	13.3	Uniform (10,16.7)
	Relative Humidity	%	59	Uniform (50,68)
Base plant (steam cycle)	Boiler blowdown	%	6	Uniform (0,10)
	Miscellaneous steam losses	%	.4	Uniform (0,1.0)
	Demineralizer underflow	%	8.5	Uniform (0,17)
	Auxiliary cooling duty	%	1.4	Uniform (0,2.8)
FGD	Total pressure drop across FGD	cm H_2O gauge	25.4	Uniform (0,50.8)
	Temperature rise across ID fan	^oC	7.78	Uniform (0,13.89)
CCS	Makeup water for wash section	%	.8	Uniform (0,1.6)
	Capture system cooling duty	t H_20/t CO_2	92.8	Triangular (67,92.8,162)
	Regeneration heat requirement	kJ/kg CO_2	3526	Triangular (2645,3526,4408)
	Heat-to-electricity efficiency	%	18.7	Triangular (14,22)

S-4 Uncertainty analysis of water use for the NGCC plant

The key uncertain variables for NGCC plants include ambient air conditions and those that affect water use. The assumptions about the distributions for the uncertain variables are based primarily on a previous study [1] and are summarized in Table S-6. The resulting probabilistic estimates for the plant have a 95-percentile confidence range from 462 to 503 t/hr for plant water withdrawals and 347 to 377 t/hr for plant water consumption.

Table S-6. Distribution Functions Assigned to Uncertain Parameters for NGCC plants

Category	Parameter	Units	Nominal Value	Distribution Function
Ambient Air	Ambient air temp Relative Humidity	^oC %	13.3 59	Uniform (10,16.7) Uniform (50,68)
Base plant (steam cycle)	Auxiliary cooling duty	%	1.4	Uniform (0,2.8)

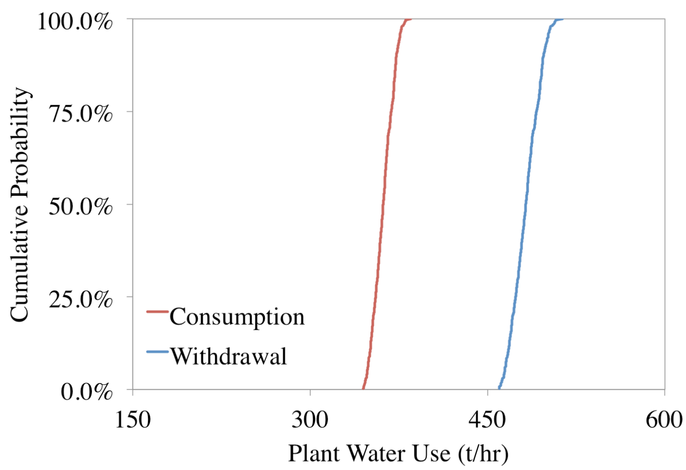

Figure S-2. Probability distributions of plant water consumption and withdrawal obtained using IECM simulation for a 542MWnet NGCC power plant

Reference

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APPENDIX B – SUPPORTING INFORMATION FOR CHAPTER 3

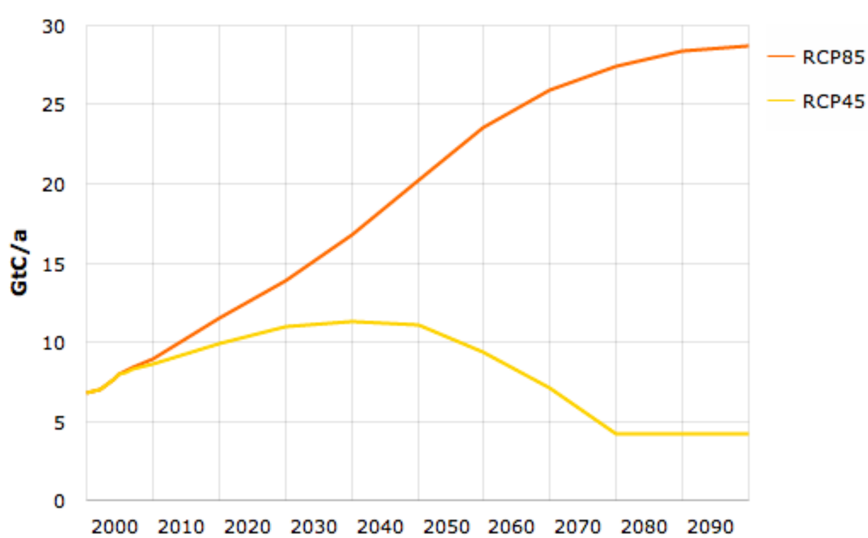
The following supporting information provides text, tables, and figures pertaining to 1) climate analysis; 2) IECM; and 3) GCAM-USA and assumptions made in the model.

S-1 Climate Analysis

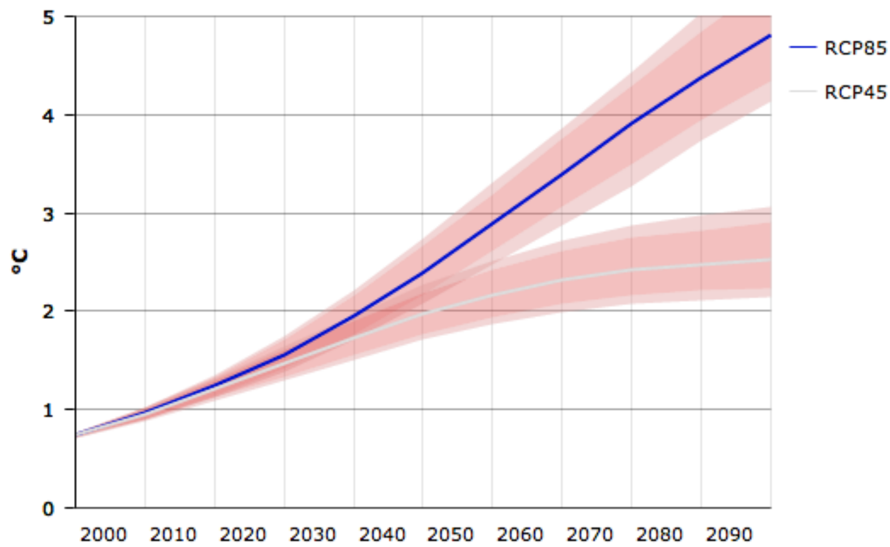
The following section provides further background information on the climate analysis conducted in this study, including RCP information, data collection, and calculations.

RCP Background

There are four available RCPs: 2.0, 4.5, 6, 8.5 Watts/m^2. Each RCP value is representative of literature when the values were selected to enable comprehensive projections.[1] Figure S-1 comparatively depicts carbon emitted per year and the corresponding average global surface temperature change over the next century for RCP 8.5 and 4.5 scenarios.



(a)



(b)

Figure S-1 Projections of annual emissions and corresponding global surface temperature change over the next century under RCP 4.5 and 8.5 (a) annual emissions, (b) global surface temperature change. From: Model for the Assessment of Greenhouse Gas Induced Climate Change (MAGICC).[2]

Climate Data

The climate data were extracted from the most recent GCM outputs from the fifth phase of the coupled model intercomparison project (CMIP5). CMIP5 is the fifth phase of the coupled model intercomparison project- an effort to gather GCM output data from many major modeling groups. In order to attain more reliable outputs, multiple models were adopted to better integrate uncertainty in temperature and humidity projections. The outputs of three GCM models from different groups were analyzed, listed in Table S-1. For each GCM, there are at least three to four ensemble runs that mitigate internal variability within each model; ensemble runs with differing realizations (or output) have the same boundary conditions but different initial or observed conditions.[3,4] All the differing realization ensemble runs from the GCMs were integrated to quantify future climate conditions.

Table S-1 GCMs used and their respective characteristics[5]

Model	Group	Resolution (Lat. x Lon.)	Data Type	Ensemble Runs	Scenarios Analyzed
CCSM4	National Center for Atmospheric Research	.9 x 1.25	Average monthly near surface temp & relative humidity	4	RCP 4.5, RCP 8.5, Historical
HadGEM2-ES	Met Office Hadley Centre	1.25 x 1.875	Average monthly near surface temp & relative humidity	4	RCP 4.5, RCP 8.5, Historical
GISS-E2-R	NASA Goddard Institute for Space Studies	2 x 2.5	Average monthly near surface temp & relative humidity	3	RCP 4.5, RCP 8.5, Historical

Climate Analysis

The outputs of climate models are categorized into numerous data sets in terms of variable time and ensemble run for each scenario. Figure S-2 illustrates the organizational scheme of a GCM and the data that were used for this study.

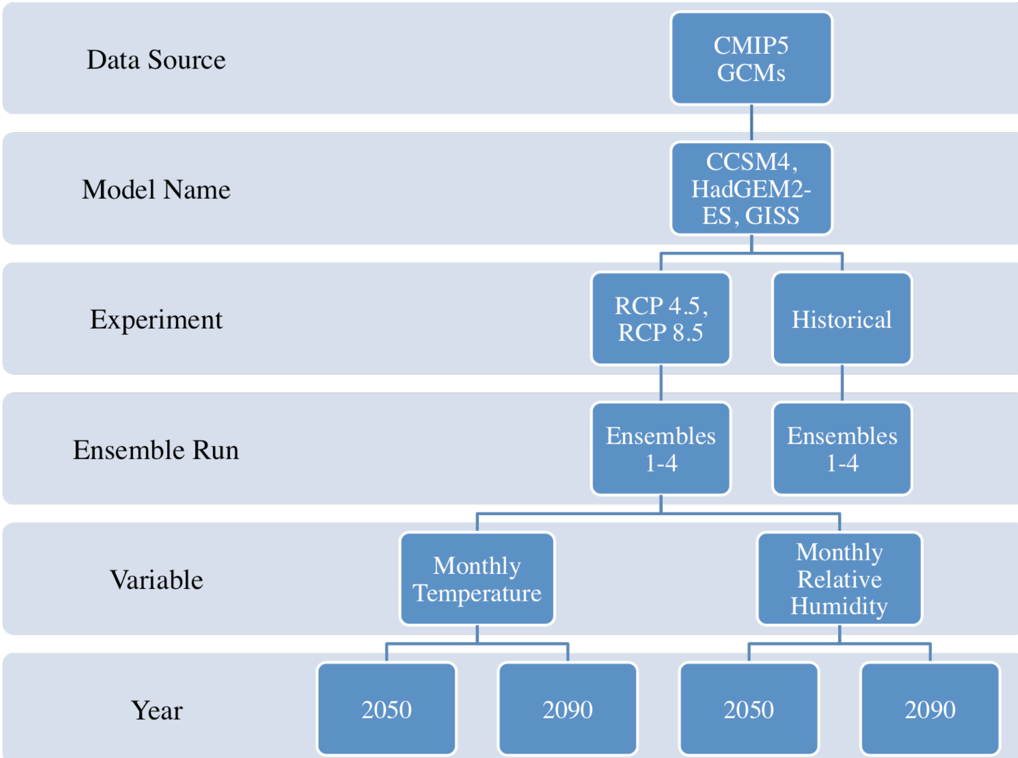


Figure S-2 Procedure of data analysis with each GCM

Each model has a different resolution, requiring normalization of different power plant locations each one's specific resolution. Conventional practice is to look at multiple years surrounding the year under analysis to filter out any short-term anomalies. For each scenario, a 20-year average for temperature and humidity was determined for each year: 2040-2060 for 2050 and 2080-2100 for 2090, separated by season. This process was repeated for each ensemble run of each model, and a multi-model average of temperature and humidity was estimated for each location per year. Additionally, to quantify uncertainty on the average, a 95% confidence interval was determined for each state. Multi-model average temperature T (or relative humidity) for a particular location, experiment and year X were determined as follows:

$$\frac{T_{June} + T_{July} + T_{August}}{3} = T_{Summer} \ in \ year \ X$$

$$\frac{\sum_{year\ X-10}^{year\ X+10} T_{Summer}}{20} = T_{ensemble\ 1,model\ 1}\ in\ summer, year\ X$$

$$\frac{\sum_{i=1}^{m} \frac{\sum_{i=1}^{n} T_{ensemble\ i}}{n}, Model\ i}{m} = T_{multimodel\ ensemble\ average}\ in\ summer, year\ X$$

Where n is the number of ensemble runs per model, and m is the number of models.

In order to quantify future estimates of water consumption, a baseline value of past water consumption intensity in 1990 was also necessary. Initially, historical monthly temperature datasets from the National Climactic Data Center (NCDC) were used to determine these values. These datasets hold monthly average temperature values starting in January 1860 for climate stations in the United States in Celsius, scaled by .1.[6] This dataset was matched to their location datasets (latitude and longitude datasets per station), and subsequently determined which station was closest to each representative power plant. The relevant temperature values were extracted and averaged for each month. However, these final values proved to be incomparable to the model data. The stations that were closest often didn't have data, or were missing data for particular years and months, altering the averages. The second, third, and sometimes fourth closest stations were also analyzed; however, at distances this far, the locations are no longer comparable. In addition, there is no similarly comprehensive historical dataset for relative humidity. Thus, historical model runs were used for each of the chosen GCMs, and perform the same set of calculations done for future years to attain average summer 1990 temperature and humidity. While not ideal, it was the best option.

The stabilization of radiative forcing via mitigation strategies or technologies under RCP 4.5 would generally result in smaller air temperature and humidity changes on average, though there is large uncertainty with which GCMs project humidity. In general however, these are reasonable values- warmer air requires more water vapor to be at the same saturation level as cooler air, and thus leads to lower relative humidity values over land. This is especially true of dry areas like the Southwest.

S-2. Introduction to Integrated Environmental Control Model (IECM)

IECM uses fundamental mass and energy balances along with empirical data to develop engineering and cost models that estimate performance, cost, and environmental control options as well as power generation systems.[7] The water module of IECM has three major cooling technologies used for thermoelectric power plants: once-through, wet cooling tower, and air-cooled condenser for drying, all of which have different water consumption and withdrawals. All cooling technology models are incorporated in the common framework that accounts for the many correlated or uncorrelated factors affecting the cooling system performance and costs. Once-through cooling is an open-loop system that has large withdrawals, and returns the bulk to the environment. It has low consumption, but may cause ecological impacts by increasing stream temperatures. Recirculating cooling is a closed-loop system that has lower water withdrawals, but higher water consumption. For recirculating cooling systems, the cooling water is cooled through exposure to ambient air and then recycled to the condenser. During the cooling process, water is lost to evaporation, blow-down, and drift, for which make up is needed, with the bulk lost to evaporation: the tower relies largely on the latent heat of water evaporation to lower the temperature of the cooling water.[8] Thus, the amount of evaporation is affected not only by the temperature the cooling water comes into contact with, but also by ambient air temperature and humidity- variables that will vary with climate change. Dry cooling, which is not yet widely utilized, uses a minimal amount of water, but is expensive- both in terms of capital cost and energy penalty. In addition, warmer air temperatures adversely affect dry cooling efficiency. It is possible that in some cases, with current technology, efficiency loss could negate the benefits.[9] For this study, IECM was utilized to analyze water consumption rates with changing ambient temperature and humidity. Representative power plants for each state were modeled in IECM for plant design: plant type, plant efficiency, plant size, fuel type, and cooling system. When carbon capture is needed (when a policy measure is put in place), the current amine-based CCS available in IECM is employed for PC and NGCC plants and the selexol CCS is employed for IGCC plants. By re-creating representative power plants within IECM and then feeding in changing ambient conditions, water consumption rates were attained for each location (tons per hour). By then using the generation of each representative power plant, water consumption intensity factors (m^3/MWh) were found for each state. Table S-2 below describes changes in water consumption intensity by plant type based on changes in each respective climate scenario. Figure S-3 further describes changes in total absolute water consumption in the southwest under each climate scenario, both with and without the consumption intensity changes caused by ambient condition shifts under climate change.

Table S-2. Average annual relative changes in water consumption intensity for different plant types under different scenarios of temperature and humidity change

Plant Type	RCP Scenario	Average Ambient Changes (Temp, Humidity)	Consumption Intensity Change
PC	4.5	3.0, -2.4%	4%
	8.5	5.7, -3.7%	8%
NGCC	4.5	2.9, -2.0%	5%
	8.5	5.5, -3.0%	10%
IGCC	4.5	3.0, -2.4%	5%
	8.5	5.7, -3.7%	10%
NGCC_CCS	4.5	2.9, -2.0%	5%
	8.5	5.5, -3.0%	10%
IGCC_CCS	4.5	3.0, -2.4%	5%
	8.5	5.7 -3.7%	10%

S-3 GCAM-USA

The following section provides more information on the model, validation, and assumptions for the major variables within GCAM-USA, including demographic assumptions, water intensity factors, technology costs, technology learning curves, and the costs of carbon.

GCAM Background [10,11,12]

GCAM is a dynamic-recursive model used to project regional supply and demand for both energy and agricultural needs within a partial economic-equilibrium framework.[8] The model runs in 5-year time steps to 2100. GCAM-USA represents the energy system of each state in terms of electricity generation, other energy transformation, and end-use demands, including industrial, residential and transportation sectors. Electricity is traded freely within regional markets based on NERC regions. For each modeled activity—whether energy transformation or end-use demand—a logit choice formulation is used to allocate market shares between different technologies. Costs at a given time are based on the non energy costs (all fixed/variable costs for the lifetime of the equipment per output unit), efficiency of energy transformation (which determines the amount of fuel needed per output unit), and the price of fuel consumed (calculated endogenously from supply, demand and resource depletion). Electricity in GCAM is produced from 9 different fuel types, and multiple generation technology types within each fuel type. Generation in any time period includes output from the "existing" stock of power plants built in prior time periods and whose output is largely determined by exogenous survival curves, and output from "new" installations, built in the prior 5-year timestep. New installations are required to replace retired plants as well as to meet increasing demand. This market share is allocated by a two-level nested logit choice mechanism, where generation technologies compete within fuels. Improving efficiencies are incorporated into GCAM for new builds of each technology for each time step. Please see Figure S-3 for a flowchart illustrating the model framework.

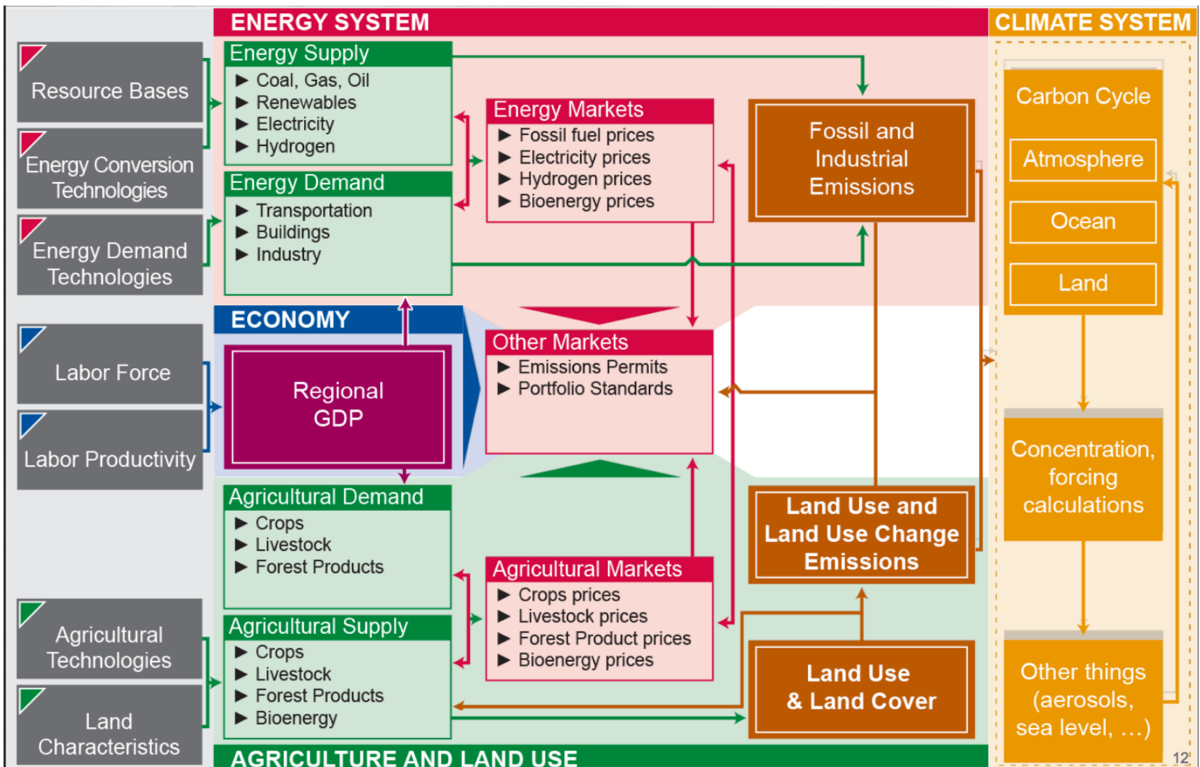


Figure S-3: An overview flow chart of GCAM[12]

GCAM runs with five-year time steps, where each modeled period represents one year. All of the reported commodity flows are per year, and the given year should be understood to be between January 1 and December 31 of the reported year. The annual averages take sub-annual dynamics into account, and the next generation of the model will explicitly consider sub-annual dynamics.

Model Validation

Table S-3 shows the projections of regional generation profiles in 2050 from GCAM-USA and the NEMS model under the EIA's 2015 Annual Energy Outlook. The regions assessed (AZNM, ERCT, and SPSO) were those relevant based on the AEO electricity market module regions versus states used in GCAM-USA. (NWPP was excluded due the grouping with the pacific northwest region.) These results are quite similar, validating projections made by GCAM-USA in comparison to other models.

Table S-3. Comparison of mid-century regional generation and generation profile of different technologies under NEMS/AEO and GCAM-USA using Relevant Electricity Market Module Regions

Technology	Generation Share	
	AEO	GCAM
Coal	33%	35%
NGCC	40%	39%
O/G Steam	1%	0%
Renewables (with Hydro)	17%	16%
Nuclear	9%	9%
Total Generation (EJ)	2.9	3.2

Demographic Assumptions

Figure S-4 shows the region under analysis. Figure S-5 shows absolute population projections numbers by state over the century. These values were used as exogenous inputs in GCAM-USA. Dominant states are Texas and Arizona, with the highest projected population growth in the region.

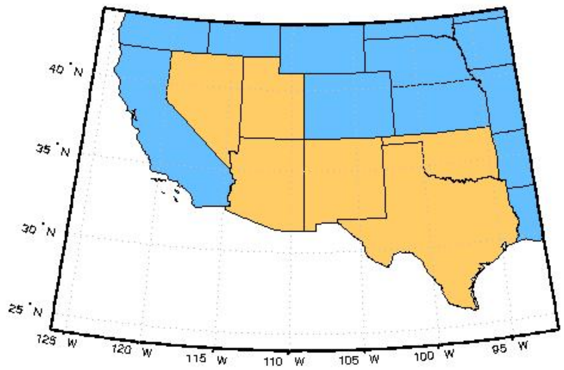


Figure S-4: States in the Southwest United States under analysis in yellow

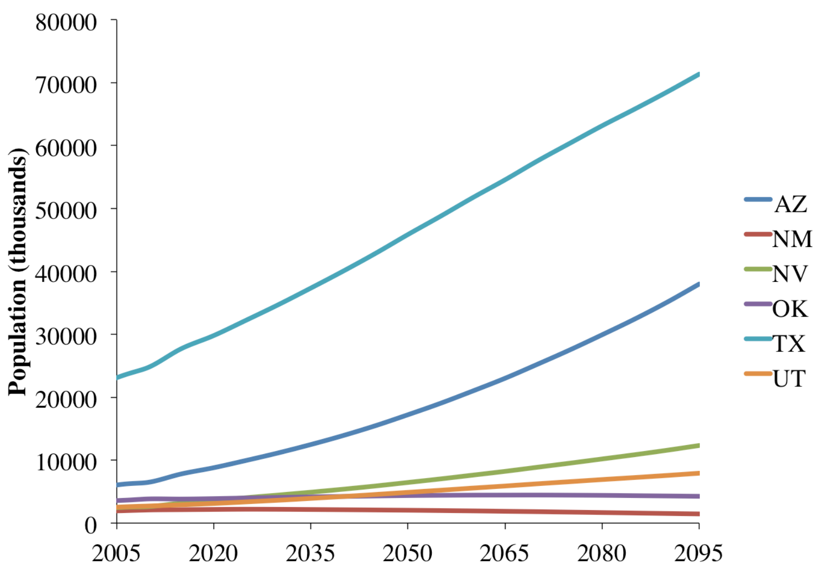


Figure S-5 Total projected population over time by state

Baseline Water Consumption Intensity Factors

Table S-4 summarizes the water consumption factors used in GCAM-USA for wet cooling systems by different technology types. These values are based on a review study by Macknick et al. (2012).[13] These water consumption factors from the literature were further adjusted by climate-related correction factors that explain the effect of climate change on plant water use over time, discussed in the assessment methods and tools of the main chapter.

Table S-4 Baseline water intensity factors in GCAM by technology

Fuel	Cooling	Technology	Base Water Consumption Factors (m^3/MWh)
Coal	RC	PC	2.6
	OT	PC	.95
	RC	IGCC	1.41
	RC	PC_CCS	3.49
	Dry (Hybrid)	PC_CCS	1.46
	RC	IGCC_CCS	2.08
Natural Gas	RC	NGCC	0.78
	RC	Steam	3.13
	RC	NGCC_CCS	1.49
	Dry (Hybrid)	NGCC_CCS	0.94
Nuclear	RC	Generic	2.54
CSP	RC	Trough	3.43
Biopower	RC	Generic	2.09
	RC	CC	1.41
	RC	CC_CCS	2.08
Geothermal	RC	Flash	.02
	RC	Binary	1.02
	RC	EGS	1.91

The climate correction factor used in GCAM is estimated as the ratio of plant-level consumption intensities from the IECM simulations based on the current and future climate conditions.

$$WC_{GCAM-USA,t} = WC_{GCAM-USA,base} * \frac{WC_{IECM,t}}{WC_{ICEM,base}}$$

where *WC* denotes water consumption intensity, and *t* represents a future time.

Technology Costs

The input values for overnight capital costs, fixed O&M, and variable O&M costs for the majority of technologies were based on the *Annual Energy Outlook* (AEO) Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.[14] The two exceptions were for pulverized coal (with and without CCS) and IGCC (with and without CCS), as we found the

AEO values to be unreasonably high and not in line with other literature estimates. The AEO values for PC and IGCC plants (both with and without CCS) are not consistent with other sources such as the National Energy Technology Lab's *Cost and Performance Baseline for Fossil Energy Plants* report published in 2013. The AEO places the overnight capital cost (in 2012 dollars) of PC plants at $3426/kW and IGCC plants at $4400/kW, compared to $2024/kW and $3568/kW from NETL, respectively. It is unclear how the AEO arrived at these estimates, but from comparison to IECM and other sources, costs for these technologies were taken from the NETL 2013 estimates.[12] The renewable costs were comparable to from reports of the Lawrence Berkeley National Lab and the U.S. Department of Energy. [16,17]

Table S-5 Base-year costs by technology type and the source of information.

Technology	Overnight Capital Cost ($2012/kW)	Fixed O&M ($2012/kW)	Variable O&M ($2012/kW)	Source
PC	2024	59.33	5.04	NETL
PC_CCS (90% Capture)	3750	96.73	8.73	NETL
PC_CCS (40% Capture)	2592	77.57	6.75	NETL/IECM
PC_CCS (20% Capture)	2424.49	74.14	6.17	NETL/IECM
IGCC	2505	11.5	7.43	NETL
IGCC_CCS	3568	15.67	9.67	NETL
NGCC	917	13.17	3.60	AEO
NGCC_CCS	2095	31.79	6.78	AEO
Nuclear	5530	93.28	2.14	AEO
CSP	5067	67.26	0	AEO
PV	4183	27.75	0	AEO
Wind	2213	39.55	0	AEO
Geothermal	4362	100	0	AEO
Bio Conventional	7065	253.63	27.51	AEO
Bio IGCC	8180	356.07	17.49	Ratio*
Bio IGCC_CCS	10549	399.84	29.77	Ratio*
Oil IGCC	2426	11.15	7.20	Ratio*
Oil IGCC_CCS	3757	14.26	7.35	Ratio*
Hydropower	2936	14.13	0	AEO

* "Ratio" under source implies that updated capital costs were not available and ratios from the older values in GCAM between these technology types were used to update costs.

Projection Comparison between GCAM and Integrated Planning Model

GCAM is a representative concentration pathway (RCP)-class model driven by a radiative forcing target and explores consequences and responses to global change[18] whereas the Integrated Planning Model (IPM) is an expansion and dispatch linear programming model for the U.S. electric power sector[16] Although we could not directly model the Clean Power Plan in the GCAM framework, we compared regional generation profiles in 2050 to see how they differ from the IPM's projections. To make a comparison between the two models, GCAM is first updated with the IPM's technology costs (capital cost, fixed O&M cost, and variable O&M cost) and then run under RCP 4.5. Table S-6 illustrates a comparison of electricity generation between the two models. Overall generation remains similar, while there are differences in projections from fossil-fuel based generation.

Table S-6 Comparison of regional generation and generation profile of different technologies under IPM and GCAM (using EPA cost estimates) in 2050.

Technology	Generation Share	
	IPM Base	GCAM
Coal	24.5%	30.2%
NGCC	42.9%	29.1%
O/G	0.5%	0.2%
Non-hydro Renewables	28.1%	31.2%
Hydro	2.8%	1.1%
Nuclear	1.1%	8.3%
Total Generation (*10^6 GWh)	.97	1.1

Technology Learning Curves

Learning for technological changes in GCAM is exogenous and time-based. These baseline exogenous learning curve equations used in GCAM-USA are based on a 15-year time step and are given in Table S-7.

Table S-7 Technology learning curves in GCAM-USA

Technology	Period	Function	Equation
PC (with and without CCS)	All	Linear	$(\text{cost of previous period})*(1-.4\%)^{15}$
IGCC	2095	Sin-based	(1-30%)* (base year cost)
	2050		base year cost-80%* (base year cost-2095 cost)
	2035-2080		$(\text{2095 cost-2020 cost})*\left(\sin\frac{\text{year-2020}}{\text{2095-2020}}*\frac{\pi}{2}\right)^{.93}$ +2020 cost
NGCC	2095	Sin-based	(1-30%)* (base year cost)
	2050		base year cost-80%* (base year cost-2095 cost)
	2035-2080		$(\text{2095 cost-2020 cost})*\left(\sin\frac{\text{year-2020}}{\text{2095-2020}}*\frac{\pi}{2}\right)^{.72}$ +2020 cost
Nuclear	All	Linear	.1%/year
Wind	All	Linear	$(\text{cost of previous period})*(1-.25\%)^{15}$
PV	All	Linear	$(\text{cost of previous period})*(1-.5\%)^{15}$
CSP	All	Linear	$(\text{cost of previous period})*(1-.5\%)^{15}$
Geothermal	2020-2050	Linear	$(\text{cost of previous period})*(1-X\%)^{15}$ $X=\left(1+\frac{\text{Past period multiplier-Current multiplier}}{\text{Past multuplier}}\right)^{1/15}-1$ Improvement multipliers for capital costs from input to MARKAL model
	2065-2095		$(\text{cost of previous period})*(1-.25\%)^{15}$
CCS component (for NGCC/IGCC)	2050-2095		(1-30%)* (base year cost)
	2020-2050	Linear	$\text{2005 cost}*\frac{\text{2050 cost}}{\text{2005 cost}}^{\left(\frac{\text{year}-2005}{2050-2005}\right)}$

Cost of Carbon

Figure S-6 shows the value of the cost of carbon within GCAM-USA over time. This value can be compared with the Social Cost of Carbon (SCC), generated by the Interagency Working Group on Social Cost of Carbon, released in 2013.[20] Also shown are the average SCC values at the 2% discount rate values as well as the 95th percentile SCC values at a 3% discount rate, enabling us to look at a wide range of projections to 2050. In comparing these values to GCAM-

USA, the average values at 2% discount rate meet the GCAM-USA projections in 2050. The 95th percentile values are much higher than that of GCAM-USA. Thus, the values within GCAM-USA are a reasonable estimate over the course of the century.

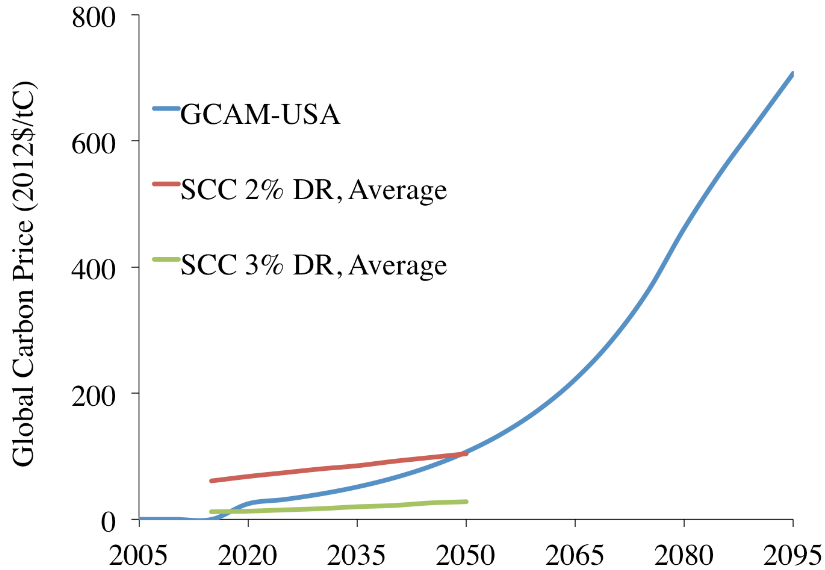


Figure S-6 Projected cost of carbon from GCAM-USA and SCC analysis

Future Modeling

As for the value of integrating these results into future modeling, the key question will be whether these impacts will change the modeled outcomes in a detectable way, and identify where the magnitudes of these changes are significant when compared to the surrounding and un-modeled sources of uncertainty. Unlike the present study which was focused on this issue, this may not be the case for a lot of models, scenarios, and regions, particularly given the magnitude of the uncertainty of future climate impacts on humidity in most cases. Nevertheless, the issue is likely to be more important for the modeling community going forward, and more significant in magnitude than the results of this study would indicate, as the places that will have the greatest climate-related increases in water consumption intensities will also likely have the most severely diminished river flows from climate change, and thus the least amount of water available for this purpose. For the next generation of combined energy-water-climate modeling, which will compare supplies and demands and balance the flows in the hydrologic systems, this climate-intensity feedback may actually be important for determining the basic outcomes for the power sector.

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Appendix C – Supporting Information for Chapter 4

The following supporting information provides text, tables, and figures on the model used, technical aspects of the modeled CCS system, cost assessment methods, additional results, analysis on water use, and a short assessment on mass-based compliance.

S-1. Introduction to the Integrated Environmental Control Model

The Integrated Environmental Control Model (IECM) is a publicly available computer model developed by Carnegie Mellon University (http://www.cmu.edu/epp/iecm/) to provide systematic estimates of the performance, resource use, emissions, costs, and uncertainties for fossil fuel-fired power plants including pulverized coal (PC), integrated gasification combined cycle (IGCC), and natural gas combined cycle (NGCC) systems.[1,2] The IECM has an array of power plant configurations that can employ a variety of environmental control and cooling systems as well as a fuel database including representative U.S. coals and typical natural gas compositions. The IECM has been greatly expanded to incorporate various CCS technologies applicable to various power generation systems. The IECM applies basic mass and energy balances along with empirical data to develop process performance models and further link them to engineering−economic models that estimate the capital cost, annual operating and maintenance (O&M) costs, and total annual levelized cost of electricity (LCOE) of an overall power plant and environmental control systems. The costing method and nomenclature employed in the IECM are based on the Electric Power Research Institute's Technical Assessment Guide.[3] Further information and documentation on the model can be found in several sources.[4-12]

The newly enhanced IECM (v9.1) was employed in conjunction with the integrated power plant database to evaluate the viability of retrofitting carbon capture and storage (CCS) to individual feasible coal-fired electric generating units (EGUs) for compliance with the CO_2 emission targets.[1] This database was based on the National Electric Energy Data System and the Emissions & Generation Resource Integrated Database.[13] The major attributes of feasible EGUs that were identified by Zhai *et al* (2015) based on this database were used to specify units for retrofit modeling in this study. Table S-1 lists the fuel properties of the coal used in the study. Table S-2 provides details on the components of capital and O&M costs of EGUs. Further information on the capital and O&M costs of EGUs are summarized in Tables S-3 and S-4, including CCS retrofit applications for 90% CO_2 capture. Table S-3 provide the detailed capital and O&M cost components for the illustrative EGU with and without CCS for 90% CO_2 capture. Table S-4 presents a statistical summary of the cost component values for the 18 feasible EGUs. Table S-5 provides details on the financing assumptions used for estimating the fixed charge factor in the IECM.

Table S-1. Coal properties

Property	Value
Coal Rank	Sub-bituminous
Coal Name	Wyoming Power River Basin
HHV (Btu/lb)	8340
Carbon (wt %)	48.2
Hydrogen (wt %)	3.31
Oxygen (wt %)	11.9
Chlorine (wt %)	.001
Sulfur (wt %)	.37
Nitrogen (wt %)	.70
Ash (wt %)	5.32
Moisture (wt %)	30.2
Default Cost ($/ton)	8.75

Table S-2. Cost components for base unit and environmental controls*

	Capital Cost	Variable O&M	Fixed O&M
Base Unit	Process Facilities Capital	Fuel	Operating Labor
	General Facilities Capital	Water	Maintenance Labor
	Engineering & Home Office Fees	Disposal	Maintenance Material
	Process Contingency Cost		Administrative & Support Labor
	Project Contingency Cost		
	Interest Charges (AFUDC)		
	Royalty Fees		
	Preproduction (Startup) Cost		
	Inventory (Working) Capital		
CO_2 Capture	SO_2 Polisher/Direct Contact Cooler	Sorbent	Operating Labor
	Flue Gas Blower	Auxiliary Gas	Maintenance Labor
	CO_2 Absorber Vessel	Corrosion Inhibitor	Maintenance Material
	Heat Exchangers	Activated Carbon	Administrative & Support Labor
	Circulation Pumps	Caustic (NaOH)	
	Sorbent Regenerator	Reclaimer Waste Disposal	
	Reboiler	Electricity	
	Steam Extractor	Auxiliary Power Credit	
	Sorbent Reclaimer	Water	
	Sorbent Processing	CO_2 Transport	
	Drying and Compression Unit	CO_2 Storage	
SO_2 Control	Reagent Feed System	Reagent	Operating Labor
	SO_2 Removal System	Solid Waste Disposal	Maintenance Labor
	Flue Gas System	Electricity	Maintenance Material
	Solids Handling System	Water	Administrative & Support Labor
	General Support Area		
	Miscellaneous Equipment		
NO_x Control	Combustion NOx Capital Requirement	Catalyst	Combustion NOx Costs
	SNCR Capital Requirement	Ammonia	SNCR Boiler Costs
	Reactor Housing	Water	
	Ammonia Injection		Operating Labor
	Ducts		Maintenance Labor
	Air Preheater Modifications		Maintenance Material
	ID Fan Differential		Administrative & Support Labor
	Structural Support		
	Miscellaneous Equipment		
	Initial Catalyst		
TSP Control	Particulate Collector	Water	Operating Labor
	Ductwork	Solid Waste Disposal	Maintenance Labor

	Fly Ash Handling	Electricity	Maintenance Material
	Differential ID Fan		Administrative & Support Labor

*capital cost components for environmental control processes are process area costs. Fixed variable cost components listed under the base plant are common for all environmental control processes.

Table S-3. Capital cost & O&M cost by technology for illustrative EGU

Technology	Cost (M$/yr)					
	Existing EGU			EGU retrofitted with Full CCS		
	Fixed O&M	Variable O&M	Annualized Capital	Fixed O&M	Variable O&M	Annualized Capital
Combustion NOx Control	0.101	0	0.511	0.101	0	0.511
Post-Combustion NOx Control	0	0	0	0.809	1.63	3.39
Mercury Control	0	0	0	7.85E-02	2.47	0.193
TSP Control	0.955	1.42	0.666	1.03	1.78	0.786
SO2 Control	8.13	1.84	2.37	9.11	3.66	2.79
Combined SOx/NOx Control	0	0	0	0	0	0
CO2 Control	0	0	0	13.4	56.8	55.6
Cooling Tower	1.52	3.35	1.17	1.98	6.09	1.70
Wastewater Control	0	0	0	0	0	0
Base Plant	18.9	19.0	14.2	20.7	13.9	16.3
Emission Taxes	0	0	0	0	0	0
Total	29.6	25.6	19.9	47.2	86.2	81.3

Table S-4. Statistical summary of annualized costs

Cost Type	Annual Cost (M$/yr)					
	Existing EGUs			EGUs with Full CCS*		
	Min	Mean	Max	Min	Mean	Max
Annualized Capital	0.357	8.74	37.3	54.9	79.4	101
Variable O&M + Fuel	18.5	25.5	36.6	38.8	48.0	59.1
Fixed O&M	19.9	28.6	44.0	68.6	95.5	139

* When applicable, EGUs are first upgraded by installing the missing air pollution control devices to limit emissions of traditional air pollutants and further reduce the impurities in flpg gas streams entering CO_2 capture systems.

Table S-5. Financing parameters[5]

Parameter (%)	Value
Real Bond Interest Rate	5.83
Real Preferred Stock Return	5.32
Real Common Stock Return	8.74
Percent Debt	45.0
Percent Equity (Preferred Stock)	10.0
Percent Equity (Common Stock)	45.0
Federal Tax Rate	34.0
State Tax Rate	4.15
Property Tax Rate	2.00
Investment Tax Rate	0.0

* Book lifetime is assumed to be a maximum of 30 years. Existing EGUs older than 30 years are treated as fully amortized units.

S-2. Technical Details of Amine-based CCS

Table S-6 presents the major performance and cost parameters and assumptions of the amine-based CO_2 capture and storage in the IECM. A bypass design is used for all CCS retrofits due to its effectiveness with the avoidance cost.[14]

Table S-6. Cost and performance assumptions of amine-based CCS in IECM

Performance	
Partial CO_2 capture design	Bypass
Capture system type	Econamine FG+
CO_2 removal efficiency (%)	90
Sorbent concentration (wt%)	30
CO_2 product pressure (psia)	2000
Heat-to-electricity equivalent efficiency of extracted steam (%)	19.7
Regeneration heat requirement (Btu/lb CO_2)	1514
lean CO_2 loading	0.19 mol CO_2/mol sorbent
Liquid to gas ratio	3.05
Maximum train CO2 capacity (tons/hr)	230
Cost	
Construction time	3 years

General facilities capital (% of process facilities capital)	10
Engineering and home office fees (% of process facilities capital)	7
Process contingency cost (% of process facilities capital)	10
Project contingency cost (% of engineering/home office fees+ process facilities capital +process contingency)	20
Royalty fees (% of process facilities capital)	0.5
Monoethanolamine cost ($/ton)	2128
Operating labor rate ($/hr)	34.7
Total maintenance cost (% of total plant cost)	2.5
Transportation cost[15] ($/ton)	3.0
Storage cost[15] ($/ton)	7.0

S-3. Cost Assessment Metrics

The two major cost metrics used in this analysis are the annual levelized cost of electricity (LCOE) of an EGU with or without CCS and the cost of CO_2 avoided by CCS. The LCOE of each EGU is calculated using equation (1).[16]

$$\mathrm{LCOE} = \frac{\mathrm{TCR} * \mathrm{FCF} + \mathrm{FOM}}{\mathrm{CF} * \mathrm{Annual\ Hours} * \mathrm{MW}} + \mathrm{VOM} + \mathrm{HR} * \mathrm{FC} \qquad (1)$$

Where:
TCR = total capital requirement ($)
FCF = fixed charge factor (fraction)
FOM = fixed O&M costs ($/year)
CF = capacity factor (%)
MW = net power output (MW)
VOM = variable nonfuel O&M costs ($/year)
HR = net heat rate (MBtu/MWh)
FC = unit fuel cost ($/MBtu)

TCR, FOM, VOM CF, MW, and HR for each of the existing EGUs are based on existing unit attributes.[13] Unit fuel cost is based on the IECM default value for the selected sub-bituminous coal. When CCS is deployed, the heat rate of retrofitted EGUs was calculated using an adjustment factor through IECM. The adjustment factor was determined through calculating the difference in heat rate for each EGU with and without CCS using the HHV values of a new steam generator, keeping all other values consistent with the existing EGUs. This was done for each specific goal emission rate standard. This difference was then applied to the HHV of existing EGUs for CCS retrofits plants to update the HHV value. Figure S-1(a) shows the changing LCOEs under changing emission rates for one EGU, a relatively linear relationship, decreasing as emission rate limits are relaxed. Figure S-1(b) subsequently shows these results for all 18 EGUs analyzed though employment of CCS retrofits.

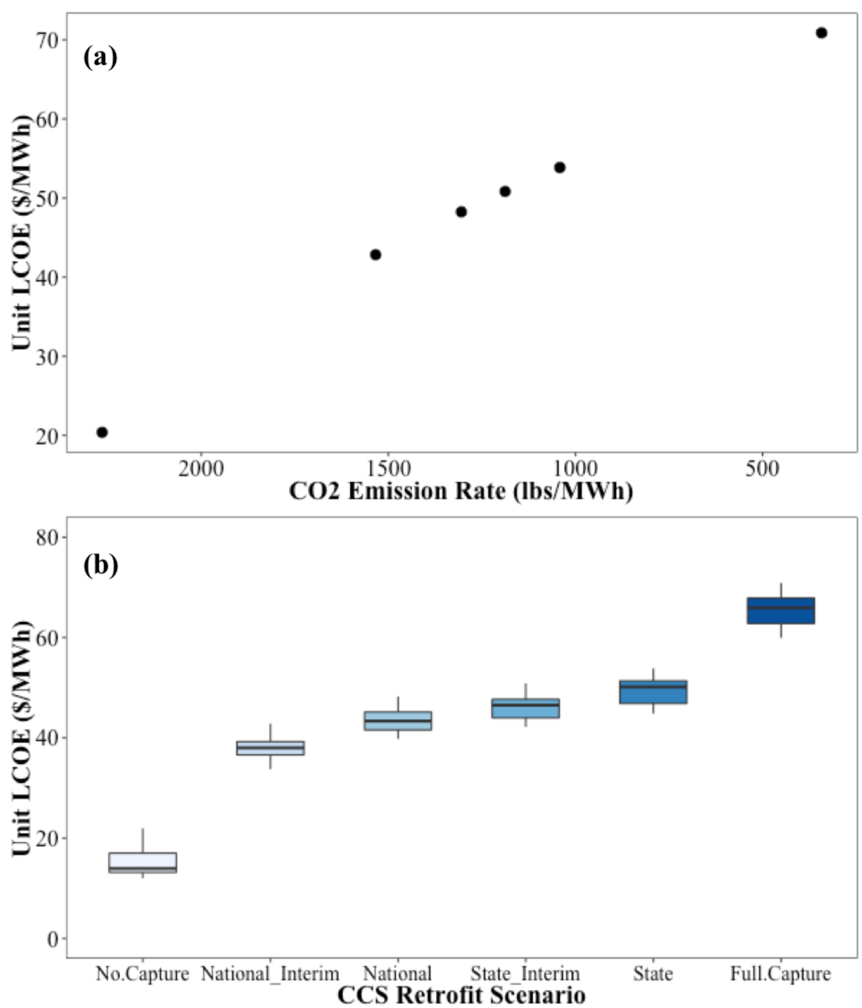


Figure S-1(a): LCOE Unit-specific example assessment of multiple compliance options. Figure 1(b): LCOE Assessment of all units for all emission rate standards (compliance via CCS retrofits)

The unit LCOE under the rate-based market trading scheme is dependent on Emission Rate Credits (ERCs). ERCs are defined as one MWh of electric generation with zero associated emissions. They can be generated by units operating below the performance standards, zero-carbon electricity generation, and demand side efficiency.[17] These are tradable units with a market-based price in dollars per MWh. In a rate calculation for an EGU, total emissions are in the numerator. Once ERCs are attained, they are added to the denominator, lowering the emissions rate of the unit. For a particular EGU, the total ERCs generated or needed in a given year is calculated by equation (2).[17]

$$\text{Total ERCs Needed} = \frac{\text{Emission rate standard} - \text{EGU operating emission rate}}{\text{Emission rate standard}} * \text{Net generation} \quad (2)$$

To understand how ERCs would affect the cost of electricity generation, we determine how they would affect the LCOE for each viable EGU. To calculate this resulting LCOE, we look at ERCs needed or generated per MWh for each EGU (or how many ERCs are equivalent to one MWh for that particular unit). This value remains constant for a particular rate standard. While more than one ERC may be needed per MWh based on the goal rate, a unit can at most generate one ERC per MWh. We then look at a range of potential prices for ERCs per MWh, as trading prices in an open market are difficult to foresee. We focus on a range from 0 to 100 dollars. Based on whether the EGU needs to buy or sell credits, these prices are added or subtracted from the unit's original LCOE, illustrated in equation (3).

$$\text{LCOE}_{\text{Utilizing Trade}} = \text{LCOE}_{\text{Existing/Retrofit}} + \frac{\text{ERCs Needed }(+)/\text{Generated}(-)}{\text{MWh}} * \ \text{Price}_{\frac{1\text{ ERC}}{\text{MWh}}} \quad (3)$$

Where the subscript "existing/retrofit" indicates the LCOE value for either the existing EGU or the LCOE once the EGU has been retrofitted. The subscript "utilizing trade" is the updated

LCOE value incorporating the cost of ERCs, which changes with the market price. If ERCs are needed, the value will be positive, while if they are generated, the value will be negative. Under this ERC market, the value of the LCOE of different retrofit options will vary and intersect at breakeven ERC price points, discussed and illustrated in the manuscript. Equation (4) describes the cost of CO2 avoided as a function of ERCs using the LCOE values once trading was incorporated as an added measure of CCS cost, listed below:

$$\text{Cost of CO2 Avoided}\left(\frac{\$}{\text{ton CO2}}\right) = \frac{\text{LCOE}_{\text{Utilizing Trade}} - \text{LCOE}_{\text{Existing}}}{\text{EGU operating rate} - \text{Emission rate standard}} * \frac{2000\text{ lbs}}{\text{ton}} \quad (4)$$

S-4. Additional Results for the Base Case

Table S-7 lists the statistical details on the breakeven ERC prices between the different CCS retrofit options and existing units under both the state and national rates, shown in Figure 1c of the main paper.

Table S-7: Statistical summary of breakeven ERC prices

Between	State Rate (1042 lbs/MWh)			National Rate (1305 lbs/MWh)		
	Min	**Mean**	**Max**	**Min**	**Mean**	**Man**
Existing/Partial CCS	22.5	30.2	35.3	28.9	40.4	48.9
Full CCS/Partial CCS	21.7	23.8	25.3	27.6	29.6	32.3
Existing/Full CCS	22.6	27.8	31.1	28.3	34.8	38.9

In looking at the key parameters listed in Table 1 of the manuscript (gross power output, net power output, plant efficiency, annual operation hours, CO_2 emission rate, annual net electricity generation, and unit LCOE) as well as FCF and the CO_2 removal requirement, further analysis is merited to determine if they are correlated with the breakeven ERC prices for EGUs with full and partial CCS. A Spearman rank correlation is used to test the correlation between the breakeven ERC price and each of the parameters, with the results shown in Table S-8. This table shows that the P-values of all the parameters, excluding unit LCOE for EGUs for full CCS, are quite high, indicating that the correlations are not significant. The rho value for the correlation between LCOE for EGUs with full CCS and breakeven price value is .445, indicating that there is a slight positive correlation between the ranks of breakeven price and unit LCOE.

Table S-8. Spearman rank correlation coefficients with breakeven ERC price

Parameter	EGU with Full CCS		EGU with Partial CCS	
	Rho	P-Value	Rho	P-Value
Average Gross Power Output	-.162	.521	-.226	.367
Net Power Output	-.187	.458	-.257	.303
Efficiency	-.049	.848	.038	.880
Annual Operation Hours	-.269	.281	-.234	.349
CO_2 Emission Rate	.049	.848	.258	.302
Annual Net Electricity Generation	-.187	.458	-.218	.386
Unit LCOE	.445	.064	.346	.16
Fixed Charge Factor	.055	.827	.076	.763
CO_2 Removal Requirement	n/a	n/a	-.050	.846

Figures S-2 through S-5 represent graphical illustrations of the results presented in the manuscript concerning the impacts of coal prices and enhanced oil recovery (EOR). Figure S-2 shows the impact on breakeven prices of all EGUs retrofitted with full CCS under the final state rate using the base case coal prices ($8.75/ton), two times that value ($17.50/ton), and three times that value ($26.25/ton). At these medium and high price increases, the unit LCOE increases by an average of 1.13 and 1.25 times over the base case, respectively. The resulting average breakeven ERC prices increase by $1.5/MWh and $3.1/MWh, respectively. As stated in the manuscript, coal prices clearly have an impact, but remains modest. Figure S-3 subsequently shows the effects of EOR at a price of $10/short ton on all 18 EGUs retrofitted with full CCS, discussed in detail in the manuscript. The average LCOE drops from $65.5/MWh to $39.8/MWh, resulting in the breakeven ERC prices shifting down from an average of \$27.8 per MWh to \$13.5 per MWh.

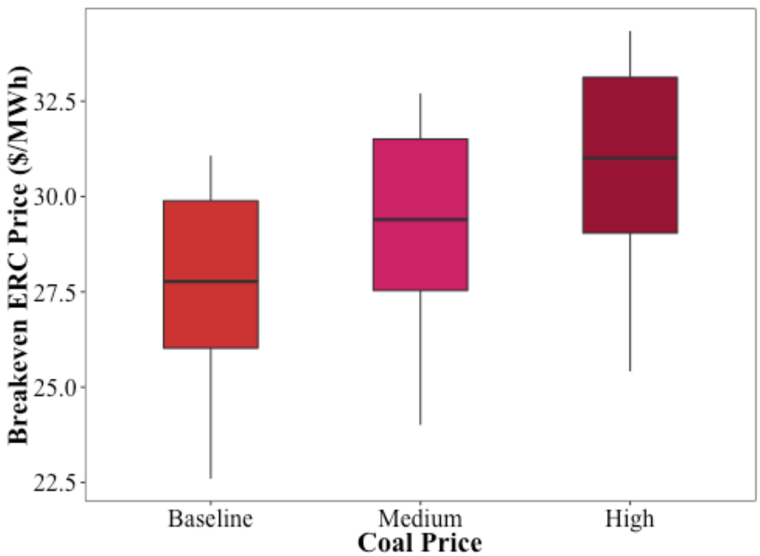


Figure S-2. Effect of changing coal prices on breakeven ERC prices for EGUs with full CCS under the state rate-based standard

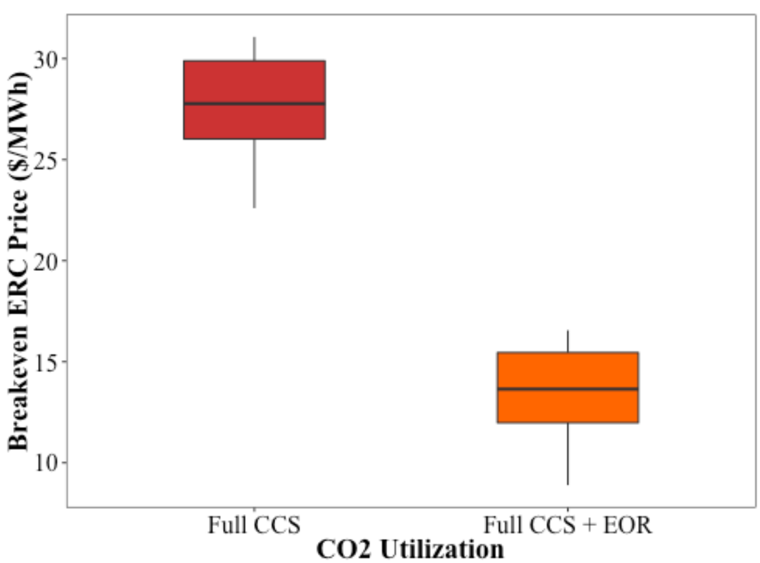
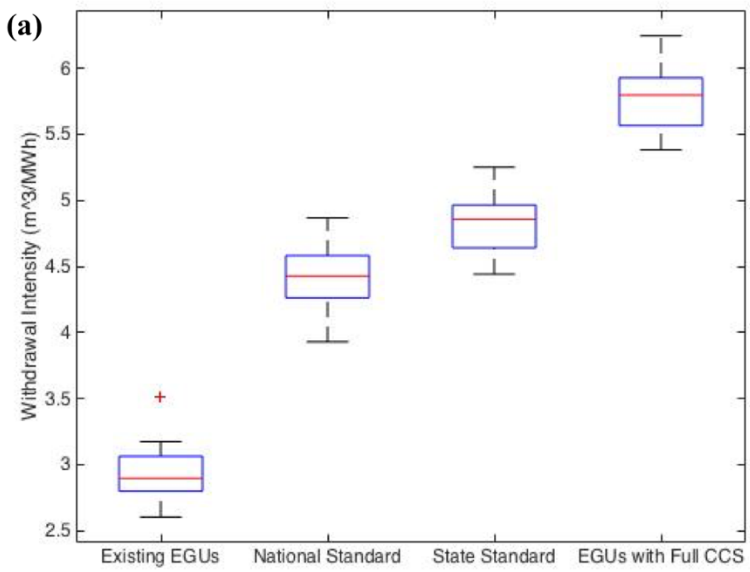


Figure S-3. Range of breakeven ERC prices under the state standard for EGUs with full CCS EGUs and EGUs with full CCS utilizing EOR

S-5. Water Use Analysis

To evaluate how CCS retrofits would increase water use, water use is calculated by IECM through its water system module, which estimates water use based on fundamental mass and energy balances.[19] This water use encompasses the steam cycle, the cooling system, and environmental control systems. A wet tower cooling system is assumed for existing EGUs as this is prevalent cooling type. [20] Further technical details on the water module are available in other sources.[21] Recirculating cooling water use is also dependent on ambient temperatures and relative humidity.[22] Using the most recent climate normal values for Texas from the National Climactic Data Center, water consumption and withdrawal values were calculated in IECM under changing emission rates.[23] Figure S-7a illustrates the change in water withdrawal intensities for the full range of EGUs for existing plants and utilizing different capture rates to meet different rate goals. Figure S-7b displays similar results for water consumption intensities. Ranging from existing EGUs with no CCS system to EGUs retrofitted with full CCS, water consumption ranges from an average of 2.04 to 4.12 m^3/MWh and withdrawal 2.93 to 5.78 m^3/MWh. As these values increase immensely with CCS retrofits, location of EGUs and water availability may be a major limiting factor for units considering CCS use.



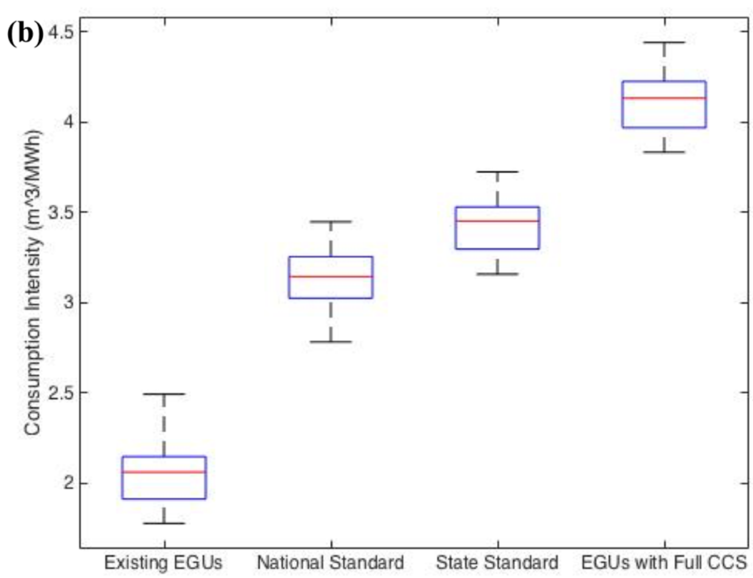


Figure S-4. (a) Range of water withdrawal intensities for all units under different retrofit scenarios. (b) Range of water consumption intensities for all units under different retrofit scenarios.

S-6. Cost Assessment for New Renewable Power Generation Systems

The LCOE for new renewable energy generation was calculated using cost data based on the Integrated Planning Model (IPM) v13-15.[24,25] These values were used by EPA in modeling for Clean Power Plan calculations for rate and goal setting. We used the input data for 2016 for solar photovoltaic and onshore wind generation. Within the supporting information, we additionally look at 2030 values to understand how projected values for these technologies may change over time. Table S-9 lists the values used for each technology type per year.

Table S-9. Input parameters for LCOE calculations for PV and wind

	PV – 2016	PV – 2030	Wind – 2016	Wind – 2030
Capital Cost (2011$/kW)	2145	1294	1695	1668
Fixed O&M (2011$/kW)	7.37	7.37	46.5	46.5
Heat Rate (Btu/kWh)	9756	9756	9756	9756
Capacity Factor (in Texas)	22%	22%	25%	25%
Net Power Output (MW)	150	100	150	100

The values given in Table S-9 were used to calculate the plant LCOE, along with a fuel cost of zero. To report the LCOE in 2009 dollars, the plant capital and O&M costs were converted from 2011 dollars to 2009 dollars using the Chemical Engineering Plant Cost Indices, which are 585.7 and 521.9, respectively.[26] The capital recovery factor used for estimating the plant LCOE is calculated in terms of book lifetime and discount rate. We assumed a rate of 7% and a book lifetime of 30 years, consistent with EIA assumptions, and calculated the CRF (in place of the fixed charge factor) through equation (5), yielding .081.[18,25]

$$\mathrm{CRF} = \frac{\text{Discount Rate} * (\,1 + \text{Discount Rate})^{\text{Book LIfetime}}}{(\,1 + \text{Discount Rate})^{\text{Book LIfetime}} - 1} \quad (5)$$

The CRF is used to annualize the capital cost of hypothetical plants.[25] Different discount rates can vastly change the value of the FCF and subsequently of the LCOE. Figure S-6 shows the sensitivity of LCOE of renewables in different years to a range of discount rates. The assumed rate value can thus have a significant impact on results.

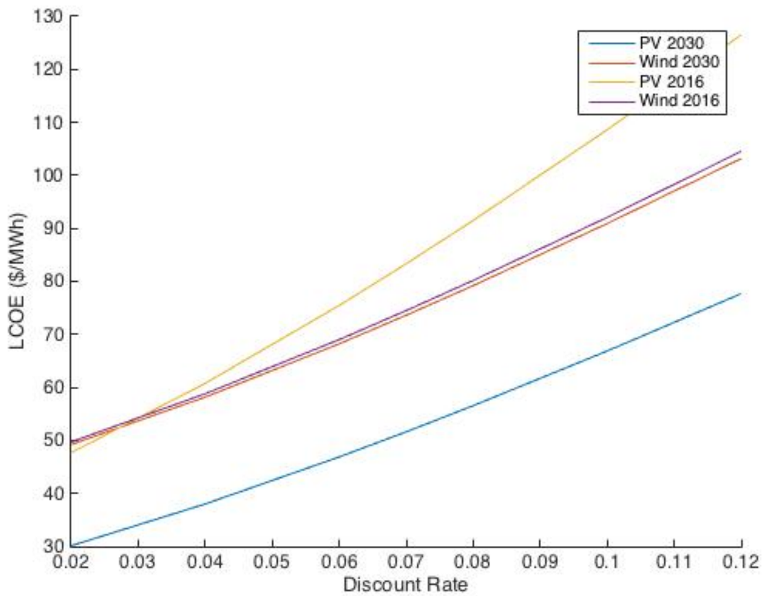


Figure S-5. Levelized cost of electricity generation of new PV and wind plants as a function of discount rate

IPM projects that costs of wind will change minimally by 2030, with a drop in LCOE values of 1.3%, while PV costs would drop dramatically by 38.5%.[24,25] Table S-10 lists the statistical values for the breakeven prices discussed in the manuscript as well as the breakeven price values for PV and wind power in 2030. In 2030, PV is far more affordable, with much lower breakeven prices than any CCS retrofit option. The maximum breakeven price is lower than the minimum of full or partial CCS. Thus, if the ERC market were realized, PV based on 2030 prices would become more economically viable than CCS retrofits. If EOR were employed, however, full CCS could potentially be more profitable.

Table S-10. Breakeven prices between renewables and existing EGUs under the state rate

	Min	**Mean**	**Max**
Existing Unit/New PV Plant (2030)	14.4	17.1	18.9
Existing Unit /New PV Plant (2016)	29.0	32.0	34.3
Existing Unit /New Wind Plant (2030)	24.5	27.4	29.6
Existing Unit /New Wind Plant (2016)	24.9	27.8	30.0

S-7. Mass-based Compliance

Though this study is focused on a rate-based compliance system, we conduct a simple analytical analysis to examine how CCS technology would potentially work within a mass-based compliance system. The final mass-based goal required by the Clean Power Plan for Texas is 189,588,842 short tons of CO_2 per year.[17] With assumptions of uniform coal type and consistent annual electricity generation for feasible coal-fired EGUs through 2030, we find that with a capture rate marginally higher than that needed for the final state rate-based goal, an average of approximately 68%, Texas could foreseeably achieve the necessary reduction through partial CCS at only the 18 viable EGUs for the entire coal-fired fleet. Total emissions from existing and partial CCS units were calculated using annual generation and the operating emissions rate from IECM.. Further analysis is merited to understand the viability and costs of CCS retrofits under a mass-based compliance plan.

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