Marching to the beat of an absent drummer: Carbon Dioxide Emissions Reduction in the U.S. Power Sector

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Acknowledgements

Pursuing a Ph.D. is much like training for multiple marathons: Neither is clearly a sprint and at the amateur level it is finishing that counts and not so much were one places, though it is nice to achieve personal bests and to end up in the top third of your class. Training for race (defense) day entails what seems like countless hours of preparation, working on specific skills and building up endurance to go the full course. It requires working under miserable conditions when it would be just so much more pleasant to put it off for another day, as well as slogging away when the pain starts because it will only be worse later if you can't get through it now. And when you do get through it, turn a corner and make a pleasant discovery, or hit a stride, the pain is momentarily forgotten so that one can press on and even look forward to the next day's effort. But, at least for me, training for and running a marathon is a solo activity punctuated with the occasional encouraging voice out of nowhere, a familiar face in the crowd, or a cheerful tail wag for motivation. The Ph.D. effort is one based on community.

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To those who were unable to complete the journey.

Abstract

As the call to limit the impact of climate change via decarbonization proliferates through global economies, the demand for power sector low- and zero-carbon generation intensifies. In the United States, there has been much debate on the merits and faults of increasing variable renewable energy, natural gas, and nuclear capacity; and because the depth to which all are willing to decarbonize is contested, direction from an overarching national policy is lacking. The absence of a formulaic policy offers the opportunity to explore fossil-fuel fleet reduction opportunities that do not advocate the wholesale replacement of the fleet with a zero-carbon technology, and allows for flexibility and the utilization of existing incentives to nudge the carbon-emitting fleet to emissions reduction. In this dissertation, I examine the role competing mitigation technologies under these conditions can play in decarbonizing the fossil-fuel fleet. To do so, I develop a tool for least-cost emission reductions, use this tool to quantify uncertainty and determine regret in the complex mitigation decision, and analyze the impact that the U.S. tax code has on this choice.

The Obama administration's Clean Power Plan (CPP) introduced in 2014 was intended to be such a policy to reduce power sector emissions in accordance with global efforts. While the CPP was never enacted, Chapter 2 examines historical and projected power sector emissions to determine if the emission reduction goals laid out in the CPP can still be achieved within the intended timeframe. The analysis demonstrates that marketplace mechanisms are sufficient to achieve the goals, as low natural gas prices propelled initial reductions, and low capital costs for renewable generation are projected to continue to drive emissions to below the 2030 CPP target. However, further value perceived by the market participants along this pathway seems

inadequate to achieve the deeper reductions for a low-carbon sector without the guidance of policy tools.

As a prelude for how the fossil-fuel fleet might respond to such emission reduction policies, Chapter 3 presents a novel method that uses unique coal-fired electric generating unit (CFEGU) characteristics to evaluate multiple mitigation-technology options under local fuel prices and varying emission reduction targets. This technique produces a least-cost mitigation frontier for nine CFEGU-specific mitigation solutions created within a common assessment framework with which the mitigation options can be ranked to determine the mitigation with the lowest capital cost and levelized cost of electricity to meet CO_2 emission-intensity reduction-targets in accordance with specific policy directives. To demonstrate the application of this tool in assessing uncertainty given the politically turbulent nature of emissions reduction policy, an analysis of mitigation decision-related regret and stranded assets under different reduction targets is presented.

In Chapter 4, the above method is expanded with more mitigation options and includes the 2030 projected natural gas combined cycle (NGCC) fleet. Again, absent a national policy for emission reduction and where market forces alone dictate generation, the carbon capture and storage (CCS) incentives in Section 45Q of the U.S. Internal Revenue Code are used for emission reductions and CCS capacity expansion in the coal-fired and natural gas-fired fleets under the current credit structure for immediate storage. The 45Q credit levels and durations are modified to further promote generation from CCS-equipped capacity as a means to nudge deeper reductions in the fossil-fuel fleet and to reduce total system cost for near-zero emissions in the power sector. This incentive is shown to be a possible marketplace tool to induce emission reductions; however, unique credit levels and durations are required for different generation technologies and unit ages to separately achieve the same percent of the projected 2030 net generation from CCS capacity.

This objective may be achievable on a bipartisan basis through modification of the existing tax code, and without the legal battles associated with a national policy based on regulations. Therefore, continued emissions reduction may be accomplished without a specific national policy but done so indirectly with tools designed for a more limited scope. However, for the fossil-fleet to attain net-zero emissions, direct air capture and storage is required to augment CCS capacity. Here, each can also benefit from increased federal research, development, and deployment funding for implementation of the current generation technologies, and for innovation in subsequent generations.

Preface

> "Why can't you scientists leave things alone? What about my bit of washing when there is no washing to do?" *The Man in the White Suit*

In Alexander Mackendrick's 1951 film *The Man in the White Suit,* Alec Guinness portrays a recently graduated Cambridge chemist (Sidney Stratton), in post-war England, who is eager to rid the word of shabbiness by developing a cloth that will never get dirty or wear out. Sidney's single-mindedness bears fruit, and all but he can see that this disruptive technology will have huge negative ramifications throughout the value chain. As mill owners and laborers chase Sidney (clothed in an iridescent white suit made of his invention) through the grimy and dark mill town streets, he comes across his aged landlady who takes in laundry to make ends meet. Her statement quoted above stops him in his tracks, and he appears to be dumbfounded having realized the implications of his invention. The mob catches up to him and they try to rip the suit off him; however, the cloth just falls away in their hands as the material is unstable. Sidney is fired the next morning; but as he somberly leaves the mill gate, a look of revelation comes over his face. He pulls out his notebook and scribbles some notes about how to make the cloth stable. He then continues down the lane with a now confident and eager stride.

While few will pursue groundbreaking research that is capable of transforming society, the work of some may profoundly impact the fringes of society. In both cases, it is important to understand how these efforts may affect the greater whole. This may not be the role that one such as Sidney to take on for while he may momentarily realize that there is something beyond his idea, his focus cannot take in more than the singular vision. However, it can be a role that others take on and a thought that many can retain as they pursue their research.

Amongst the fundamental elements of this program, the implication of research on society through governmental policy is one that is stressed. In this dissertation, while great pleasure was taken in the discovery of some obscure nuance that may have been overlooked by others, there is also an acknowledgement that what is presented is far from the optimal solution. It can be difficult to be disinterested in the work as a whole and to understand that the story told on so few pages is an incomplete one because it does not contain the voices of many others who tell a connected story from another point of view. The voices telling the stories of environmental justice, premature deaths, environmental impact, resource scarcity, energy poverty, life cycle assessment, and economic impact are just some that are not integrated. Even so, their stories are not complete without this voice.

These and other voices must be considered by the policymaker to quickly formulate a high probability solution to avoid a climate-change tipping point. This solution does not take the form of an "or" statement: mitigated fossil fuel or renewable, renewable or nuclear, mitigation or adaptation. The solution needs to be an "and" statement. What is presented here is only a minute and incomplete portion of the overall statement and may not even be part of the solution. Furthermore, the incentives influencing market forces discussed herein may not be all of the tools in the policymaker's toolbox, but they may be the only ones that can be used in this deeply divided political climate. For while incentives may take care of themselves, increasing their use should be encouraged as incentives can play a vital role as a policy tool that is the lever and fulcrum with which to move the U.S. towards a rapidly decarbonized power sector.

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Nomenclature

C_A	Cost of avoided carbon dioxide [$/tonne]
CC	EGU capital cost [dollars]
FCF	Fixed charge factor [fraction]
FOM	Fixed operation and maintenance [dollars]
G_{net}	EGU annual net generation [MWh]
$LCOE$	Levelized cost of electricity [$/MWh]
m_{cap}	Annual captured carbon dioxide emissions [tonnes]
m_{emit}	Annual emitted carbon dioxide [tonnes]
P_{CO2}	Carbon dioxide emissions price [$/tonnes]
TC	45Q emission tax-credit level [$/tonne]
VOM_{fuel}	Fuel variable operation and maintenance [$/MWh]
$VOM_{non\text{-}fuel}$	Nonfuel variable operation and maintenance [$/MWh]

Abbreviations

$/MWh	Dollars per megawatt-hour
ACE	Affordable Clean Energy rule
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
aux	Auxiliary
BACT	Best available control technology
BE	Bioenergy
BECCS	Bioenergy with carbon capture and storage

BSER	Best system of emission reduction
Btu	British thermal unit
CAA	Clean Air Act
CAP	Climate Action Plan
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization and storage
CEPCI	Chemical Engineering Plant Cost Index
CFEGU	Coal-fired electric generating unit
CH_4	Methane
CO_2	Carbon dioxide
CPI	U.S. Consumer Price Index
CPP	Clean Power Plan
DACS	Direct air capture and storage
ECD	Emission control device
eGRID	Emissions and Generation Resources Integrated Database
EGU	Electric generating unit
EIA	U.S. Energy Information Agency
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ESTEAM	EGU-Specific Techno-Economic Assessment Model
FCF	Fixed charge factor
FDG	Flue-gas desulfurization
FERC	Federal Energy Regulatory Commission

FOM	Fixed operation and maintenance
GE	General Electric
GHG	Greenhouse gas
GW	Gigawatt
HFC	Hydrofluorocarbon
Hg	Mercury
HRI	Heat rate improvement
IECM	Integrated Environmental Control Model
IPCC	Intergovernmental Panel on Climate Change
kW	kilowatt
kWh	kilowatt-hour
LCOE	Levelized cost of electricity
LDS	Long-duration storage
LNB	Low NO_x burner
MMBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDC	Nationally determined contribution
NEEDS	National Electric Energy Data System
NEMS	National Energy Modeling Systems
NETL	U.S. National Energy Technology Laboratory
NG	Natural gas

NGCC	Natural gas combined cycle
NO_x	Nitrogen oxides
NREL	U.S. National Renewable Energy Laboratory
NSPS	New source performance standard
O&M	Operation and maintenance
PCC	Process contingency cost
ppm	Parts per million
PFC	Process facility capital
PGP	Power-to-gas-to-power
PSD	Prevention of Significant Deterioration
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
RGGI	Regional Greenhouse Gas Initiative
SC	Supercritical
SCPC	Supercritical pulverized coal
SCR	Selective catalytic reduction
SI	Supplementary Information
SIP	State implementation plan
SMR	Small module reactors
SO_x	Sulfur oxides
UN	United Nations
U.S.	United States of America
USC	Ultra-supercritical

VOM	Variable operation and maintenance
VRE	Variable renewable energy

Chapter 1: Introduction

The path meanders
shrouded in moonlit snowfall
Peaceful start of dreams

"Scientific Method" by Jeffrey Anderson

At the time of this dissertation, carbon dioxide (CO_2) levels in the atmosphere have risen from the 280 parts per million (ppm) pre-industrial revolution global average [1] to 415 ppm [2].[1] This increase is driven by global CO_2-equivalent emissions that have made an overall steady rise from almost 1,000 million tonnes per year in 1945 [3] to 38,000 million tonnes per year in 2019 [4]. In that year, China was the largest emitter of greenhouse gases (GHG), producing 30% of total emissions [4]. The United States (U.S.) was the second-largest emitter at 13%, with India contributing the third most for a single nation at 7%. In an effort to evaluate the impact of these anthropogenic emissions on the climate and to establish a global structure for their reduction, the United Nations established the United Nations Framework Convention on Climate Change in 1992. Under the auspices of this group, many nations have pledged in the 2009 Copenhagen Accord [5] and the more stringent Paris Agreement in 2015 [6] to reduce emissions to a level such that any increase in global temperature will be less than 2 °C above pre-industrial levels. Reducing global electric power-sector emissions is a chief target in this effort, as this sector accounted for the largest share of the 2019 global emissions: 35% [7].

In the U.S., the power sector was the second largest emitter of GHG emissions behind the transportation sector and accounted for 25% of CO_2-equivalent emissions in 2019 [8]. Since

[1] By the time you finish reading this work, the figure may exceed 450 ppm. When the author entered the Ph.D. program, the quantity was 394 ppm.

1990, the emissions from this sector have decreased by almost 12%, based almost entirely on market forces alone, with peak emissions occurring in 2005, while net generation has increased by 36% [9]. It was not until 2014 that the U.S. Supreme Court [10] ruled that the U.S. Environmental Protection Agency (EPA), created in 1970 to carry out the directives of the Clean Air Act [11], could legally restrict GHG emissions and establish regulations restricting their emission by the power sector (See Section 1.3 for background on the EPA's authority to regulate CO_2). Since 2014, three presidential administrations have issued executive orders or their agencies have proposed regulations to curb these emissions; however, there is yet to be an overarching major policy or legislation to drive the deeper reductions called for in these international pledges or to manifest the United Nations' objective into implementable language. In 2015, the Obama administration established the Clean Power Plan (CPP) to reduce emissions in the power sector to 32% of the 2005 emissions by 2030 [12]. These regulations were withdrawn by the subsequent Trump administration in 2017 and replaced by the Affordable Clean Energy rule (ACE) in 2019 [13]. In 2021, the District of Columbia (D.C.) Court of Appeals vacated that regulation [14] and President Biden issued an executive order requiring the U.S. to achieve a carbon-free power sector by 2035 and a net-zero carbon economy by 2050 [15], an effort that aligns with the United Nations' International Panel on Climate Change's recommendations [16].

Policy direction and regulations have yet to be announced as to how this might be done and there is no guarantee that any succeeding administration will follow through on these actions. This reality strikes at the heart of the problem: in a democratic system the political party in power can overturn the executive orders, and alter or refuse to enforce and defend the regulations of previous administrations, and parties with standing can litigate the actions taken and not taken by government agencies. Without the political consensus required to produce stable, settled legislation and regulation indicating national objectives, how can further reduction be effectuated? Can incentive mechanisms create value for market participants to achieve further CO_2 reduction through the complementary proposition of least-cost and low-carbon, in the absence of a legislative or regulatory mandate? The absence of clarity in regard to these most basic questions has created daunting challenges not just for environmental regulators, but also for utilities and private sector investors.

1.1 Research objectives

Considering the political and legal chaos in U.S. energy and environmental policy, this dissertation has three research objectives that examine emission reduction driven by market forces rather than new policy. The first research objective is to determine if the CPP withdrawal is projected to hinder reaching President Obama's target for emissions reduction in the power sector by 2030; and if not, to understand if market mechanisms can be effective in lieu of the regulation to achieve deeper reductions. In the absence of an overarching regulation, or a clear policy direction, the market may not have the high-fidelity signal required to manifest the desired reductions or to do so in a manner that may avoid future technology lock-in or force stranding current and future assets to meet a necessarily rushed target. To this point, the second research objective is to determine a least-cost method to mitigate CO_2 emissions in the projected fossil-fuel fleet in 2030 as an aid for policymakers and generation owners to take advantage of current tools to guide the marketplace and to formulate future emission reduction policies. Modeling the coal-fired and natural-gas-fired electric generating units (EGU) with a myriad of mitigations options will allow policymakers to determine which mitigation technologies may be required to meet different emission reduction targets (from 10-100%) and how such assets can be used with zero-carbon generation to lower the total system cost while decarbonizing the power sector. One such tool applicable in this effort is Section 45Q of the tax code, created by a bipartisan Congress in 2008 during the G. W. Bush administration and later expanded and extended in 2018 under the Trump administration, that incentivizes capturing CO_2 immediately from power plant effluent or directly from the ambient air [17]. Therefore, the third research objective is to determine the impact of the 45Q tax credits on the mitigation decisions for the fossil-fuel EGUs, and to determine what modifications to these incentives may be required to drive market preference to promote carbon capture for near-zero and net-zero generation, absent a settled national policy.

1.2 Outline

Chapter 2 addresses the first research objective. I examine the historical and projected emissions of the power sector to determine if the emission-reduction goals laid out in the Obama administration's CPP can still be achieved within the intended timeframe (i.e., 32% by 2030). This examination uses historical data from the U.S. Energy Information Administration (EIA) and the projected 2030 power sector operational data concerning capacity, capital costs, and fuel prices from the EIA's Annual Energy Outlook to determine factors influencing future emissions. This work was published in *Energy Policy* and the pre-publication findings were cited on the U.S. Senate floor in 2018 by Senator Brian Schatz of Hawaii [18].

The second and third research objectives are explored in Chapters 3 and 4. Chapter 3 presents a model to evaluate emission reductions with various mitigation technologies for coal-fired EGUs in the projected 2030 coal-fleet. This model, the EGU-Specific Techno-Economic Assessment Model (ESTEAM), uses empirical performance data to characterize a unique coal-fired EGU to assess performance and cost parameters when the EGU is retrofitted in compliance with current clean air standards and equipped with various CO_2 mitigation technologies to achieve a continuum of emission intensity targets. An existing EGU is analyzed to illustrate how the site-specific attributes in this model result in a least-cost mitigation frontier that can be used to determine regret in the mitigation technology decision and evaluate stranded assets, given uncertainty in policy and projected costs. This work was published in *Applied Energy*.

In Chapter 4, this model is expanded with more mitigation options and includes the 2030 projected natural gas combined cycle fleet. The 45Q tax code is then applied to multiple EGUs in each fleet under the current credit structure to determine carbon capture and storage (CCS) capacity expansion for immediate storage when market forces alone dictate generation and fungible sources are present. The 45Q credit levels and duration are also modified to promote further generation from CCS equipped capacity from each fleet as a means of reducing total system cost for near-zero emission reduction. This work was published in the *International Journal of Greenhouse Gas Control*.

Chapter 5 summarizes the findings from the previous chapters and explores the policy implications of achieving net-zero generation with 45Q incentives (under review for *Environmental Science & Technology*) and the U.S. political landscape schism (published in *Environmental Science & Technology*).

1.3 Background for CO_2 regulation

In this section I present the evolution of the EPA's authority to regulate pollutants to provide the context for CO_2 emission reduction.

The 1970 amendments to the Clean Air Act (CAA) created the authority under which the federal government is authorized to establish national regulations for hazardous air pollutants that affect public health and safety, to direct the states to develop implementation plans (SIPs) to meet these regulations,[2] and to authorize said plans [11, 19]. The establishment of these National Ambient Air Quality Standards (NAAQS) is not limited to the six criteria pollutants named in the CAA under section 108(a): Section 112(b) authorizes the federal government to identify additional toxic air pollutants from categories of industrial sources and to establish technology-based standards to control these emissions from major sources. Additionally, the federal government under section 111(b) has the authority to set a New Source Performance Standard (NSPS) for other hazardous air pollutants that are not listed in the previous sections and are emitted from both mobile and stationary sources. Once this NSPS regulation is in place, a performance standard for existing sources of the regulated pollutant may then be introduced under section 111(d).

In December 1970, President Nixon signed an executive order that created the Environmental Protection Agency (EPA) as the federal agency to carry out the directives in the CAA [20]. While the directives as described appear to make the EPA the overseer for state and industrial emissions, it also allows the states, industries, non-government organizations, and private citizens to sue the EPA for failure to carry out the directives. One example of this occurred in 1999, when private organizations used section 202(a)(1) of the CAA to petition the EPA to impose regulations on carbon dioxide (CO_2) and other greenhouse gas emissions from mobile sources—automobiles [21]. In this litigation, the petitioners believed that it was reasonable to expect these emissions to endanger public health or welfare because the emitted gases are associated with climate change, thereby requiring regulation. However, the G. W. Bush EPA denied the petition in 2003; it interpreted the CAA as not giving the Agency the authority to regulate GHG emissions for climate change purposes [22]. Furthermore, the EPA cited that there

[2] In the absence of a SIP, the plan created by the federal regulating agency is implemented.

was uncertainty about the role of GHG in climate change, and that other parts of the federal government were taking actions domestically and abroad to reduce GHG emissions, so no regulatory actions were currently required by the EPA.

In response, the private organizations (along with the Commonwealth of Massachusetts and a coalition of other states, cities, and organizations) sued the Bush EPA in a case that was decided by the U.S. Supreme Court in 2007 (Massachusetts v. EPA) [23]. The Court's finding in favor of the plaintiffs determined that the greenhouse gases can be classified as air pollutants and regulated under the CAA as such. However, the decision did not order the EPA to take such action; but only to do so if the EPA determined that these gases cause or contribute to climate change, or otherwise that the Agency had a "reasonable explanation" as to why regulation should not occur under the CAA [11].[3] Upon further study, the Obama EPA did find in 2009 that well-mixed GHG emissions from new motor vehicles threaten current and future public health and welfare related to climate change [24].

This linkage between motor vehicle emitted GHGs, climate change, and detrimental effects on the public led the Obama EPA and Department of Transportation to issue regulations in 2010 that limited tailpipe emissions for CO_2, nitrous oxide (N_2O) and methane (CH_4), and limited hydrofluorocarbon (HFC) from air conditioning systems for model year 2012 through 2016 passenger cars, light-duty trucks, and medium-duty passenger vehicles [25-27]. Emissions of these GHGs from such light-duty vehicles accounted for over 70% of Section 202(a) mobile source GHGs in 2007 [27]; therefore, the objective of the 1999 petition was achieved.

[3] The phrase "reasonable explanation" is open to legal interpretation and goes beyond a statement of "Finding of No Significant Impact."

The regulation of these emissions from new, mobile sources also allowed the EPA to regulate GHGs from new, modified,[4] and reconstructed,[5] stationary sources. To regulate GHG emissions in stationary sources, such as fossil-fuel power plants, one obstacle that the EPA needed to overcome was a restriction in the CAA concerning the maximum annual allowable pollutant emission limit for exemption from requiring construction, modification, and operation permits. The Obama EPA felt that a change to this limit was necessary because the CAA required that stationary facilities emitting as little as 100 tons of "any air pollutant" must obtain a permit prior to construction or modification, and operation, under the Prevention of Significant Deterioration (PSD) and Title V provisions [28, 29].[6] Such a small threshold would force the EPA to regulate GHG emissions from many small facilities, such as schools and business, thereby making enforcement of any such regulation nearly impossible, because GHGs are emitted in much larger quantities than traditional pollutants. To circumvent this problem, the Obama EPA issued a "tailoring" rule [30] that interpreted the CAA as empowering the EPA to tailor the levels to make enforcement manageable, when the conditions for these permit triggers were met. Here, the EPA suggested limiting the regulation to cover stationary sources that emitted more than 100,000 tons per year—capturing 86% of the CO_2 emissions [29].

Seven states (predominantly Republican) and various industry groups challenged the Obama EPA backed by 17 states (predominantly Democratic) on this regulation concerning the EPA's determination 1) that stationary sources emit GHGs that are detrimental to the public, 2) that regulations for mobile sources automatically necessitates regulations for stationary source, and 3)

[4] Modified plants are those that undergo a physical or operational modification that increases the maximum achievable hourly rate of air pollutant emissions [28].

[5] Reconstructed plants are those in which components are replaced that exceed 50% of the cost of an entirely new and similar plant [28].

[6] A PSD permit pertains to construction and modification of the stationary source, while a Title V permit pertains to the operation of the source.

that the EPA's interpretation of the CAA to tailor regulatory limits is correct [29, 31]. While lower courts found in favor of the EPA, in 2014 the U.S. Supreme Court ruled that the EPA could not compel an emitting source to obtain a PSD or Title V permit, if it did not already need to do so, nor did the EPA have the authority to interpret the CAA legislation to allow for tailored limits to make enforcement of a regulation manageable. However, the Court did rule that the EPA could use these permit provisions to enforce the GHG regulation for stationary sources if the source was already required to obtain such permits for conventional pollutants. This allowed the EPA to regulate GHGs from new stationary sources, and effectively gave the Agency a tool that made enforcement manageable: thereby limiting the regulation to the larger-emitting sources that generated 83% of the GHG emissions [29].

Another important outcome of this case concerns how these harmful emissions are limited. To acquire the permit under the PSD provision, the emitter must use the best available control technology (BACT) to limit these emissions. While this end-of-stack control approach is considered acceptable for traditional pollutants, the Court allowing the EPA to apply BACT analysis to GHGs in the regulation meant that end-of-stack emission control for GHGs was also applicable. As such, the EPA's suggestion that CCS should be considered alongside energy efficiency as comparable BACT controls for CO_2 emissions indicates that CCS is a reasonable mitigation technology to consider [28], even though this technology had limited use in 2010 [32].

Based on the Court's findings, the initial version of the final regulation to limit CO_2 emission from these fossil-fuel sources, the Carbon Pollution Standards regulation, was entered in the Federal Register in January 2014 as part of the Obama administration's Climate Action Plan; a modified version was entered in August 2015 [33]. In the regulation, CO_2 emission limits are set for base load natural gas combined cycle (NGCC) plants and for coal-fired steam generators, according to limits achievable with the EPA-defined best system of emission reduction (BSER). For new and reconstructed NGCC plants, CO_2 emission rates are limited to 1,000 lbs/MWh-gross, which is achievable with the current generation of efficient NGCC baseload plants [33]. However, new coal-fired steam generating units must have a CO_2 emission intensity that is below 1,400 lbs/MWh-gross, which is lower than the emission rate for current generation coal-fired plants. The EPA suggests that the BSER to achieve this level of emission intensity is a new, efficient supercritical pulverized-coal (SCPC) boiler with a post-combustion CCS subsystem that captures 20% of the CO_2 emissions [33]. While 38% of the power sector net summer capacity in 2015 was derived from SCPC units, none of this capacity used CCS [34].[7]

With the initial version of the final Carbon Pollution Standards entered in the Federal Register, the EPA was then allowed to propose a regulation for existing stationary sources under CAA Section 111(d), which the Agency did in June 2014. After a six-month public comment period that resulted in 4.3 million comments [35], the EPA published the final rule for the Clean Power Plan in the Federal Register in October 2015 [12]. Not surprisingly, this action was immediately followed by West Virginia and 25 other states (all under Republican leadership) filing a petition for the D.C. Circuit Court of Appeals to review the regulation [36, 37]. While the EPA (supported by 18 predominantly Democratic states) argued that the regulation should stand and the actionable timelines in the CPP be advanced [37], the U.S. Supreme Court issued a stay until the Court of Appeals could issue a ruling on the petition [37]. This point was made moot in 2017, when President Trump signed an executive order directing the EPA to consider formally repealing the CPP, shortly after he entered office [38]. Under Trump-appointed EPA head Scott

[7] The standards for the remaining plants are less stringent [12]. Modified gas-fired combustion turbines are not required to meet an emission intensity standard. Emission intensity limits are set for modified and reconstructed coal-fired power plants and are based on the level of modification or the rate of energy input. For each of these cases, the BSERs are upgrades to equipment and implementation of best practice operations.

Pruitt, formerly a lawyer for a plaintiff in the case as the Attorney General of Oklahoma, the EPA issued a proposed repeal and replace of the CPP in October 2017 [13].

The roles were later reversed when the Trump EPA introduced ACE [39] as the CPP replacement on June 19, 2019, and 23 predominantly Democratic states filed suit in August 2019 [40, 41]. The Court of Appeals for the D.C. Circuit found for the plaintiffs and vacated the rule on January 27, 2021, shortly after President Biden was inaugurated [41, 42]. In its ruling, the Court found that the Trump EPA had fundamentally misinterpreted the CAA statutes for BSER by 1) limiting control methods to be performed at the source, 2) by adding terms not found in the CAA text, and 3) that the purpose and history of the section 111 of the CAA did not support the EPA's interpretation of ACE. Therefore, the Court remanded it back to the EPA (now under a Biden-appointed administrator) for further interpretation, essentially giving the current EPA the ability to enforce Obama's CPP or to formulate a Biden CPP that will undoubtedly also be litigated.

It is also noteworthy that in December 2018 the Trump EPA proposed to increase the emissions limit set in the NSPS regulation [33] for new coal-fired EGUs [43] so that the limit can be met without CCS. While this proposal was finalized on January 13, 2021 [44], the Biden EPA asked the D.C. Circuit Court to vacate and remand the rule because it was promulgated without public comment [45]. The Court did so in April 2021 [45], completely returning the CPP-related regulations to their status quo ante under during the Obama era.

It appears that while the CO_2 levels continue to rise, such political and legal posturing is akin to rearranging the deck chairs on a sinking ship—much effort is expended but little progress is made on solving the problem. However, it may be possible that broadly bipartisan-based efforts and market mechanisms can succeed where predominantly partisan-based regulations have so far failed.

Chapter 2: Reducing carbon dioxide emissions beyond 2030: Time to shift U.S. power-sector focus

You can't always get what you want
You can't always get what you want
You can't always get what you want
But if you try sometimes
Well, you just might find
You get what you need

(Jagger and Richards, 1969)

Despite the impending withdrawal of the U.S. from the Paris Agreement and the replacement of Obama's Clean Power Plan (CPP) with Trump's Affordable Clean Energy rule, the carbon-dioxide (CO_2) emission-reduction targets set as the contribution of the U.S. power sector to meet the Agreement goal appear likely to be met. Using data from the U.S. Energy Information Administration's Annual Energy Outlook (AEO) reports, we evaluate the impact of projected natural gas prices on these emissions. We find that while lower natural gas prices have historically resulted in lower CO_2 emissions, the projections from the 2017 and 2019 AEOs differ dramatically in both the projected gas price and the associated impact on CO_2 reduction. This change in the marginal emission-reduction rate relative to the natural gas price coincides with decreasing capital costs for solar and wind generation sources. As such, the contribution of the power sector to the Paris Agreement targets for 2020 and 2025, and the CPP 2030 target may be meet as early as 2020. With fulfillment of the shorter-term reduction targets now at hand without additional U.S. legislative or regulatory action, policy analysis should turn toward the strategies required to meet the longer-term, deeper-reduction targets.

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2.1 Introduction

While several different proposals to reduce carbon dioxide (CO_2) emissions have been advanced by regulators, politicians, and intergovernmental policymakers over the last decade, very few have overcome court challenges and been codified into regulation, law, or treaty, and fewer still have endured intact. Recent examples of coordinating domestic efforts in the United States with international programs to reduce overall greenhouse gas (GHG) emissions include the United Nations Climate Change Conference in Copenhagen [5] and the follow-on Paris Agreement [6]. To facilitate these reductions, Table 2.1, in order to slow and manage the impacts of climate change, President Obama implemented the Climate Action Plan (CAP) [46] for which a central element was the U.S. Environmental Protection Agency's (EPA) promulgation of the Clean Power Plan (CPP). This regulation targeted a reduction in CO_2 emissions from existing fossil-fuel power plants to meet the intended nationally determined contribution (NDC) reduction-targets in these non-binding treaties: intermediate targets in the CPP for 2020 and 2025 represented approximately 47% and 37–40% of the NDC for the corresponding years [47, 48].[8] The Trump administration subsequently announced its withdrawal from the Paris Agreement [49,50] and replaced the CPP [51] with the Affordable Clean Energy rule (ACE) [52].

Notwithstanding the repeal of the CPP and the impetus for the regulation, current U.S. government projections indicate that the contribution of the U.S. electric power sector to the NDC pledge will be fulfilled, depending on natural gas prices and market mechanisms. To illustrate this point, we expand on work done in the EPA's regulatory impact analysis of the CPP review [53] and documented in Ramseur [48] with further analysis of data from the U.S. Energy

[8] The potential regulatory contribution of the CPP to the development of more stringent climate polices for the deeper carbon reduction pledge in the NDC for 2050 is beyond the discussion herein.

Information Administration's (EIA) 2017 and 2019 Annual Energy Outlooks (AEO) [54, 55].[9] In particular, we examine historical and projected electric-power sector CO_2 emissions as a function of natural gas prices to determine under which cases the 2020, 2025, and 2030 emission targets set in the CPP can still be met in its absence.[10] We find that while the historical trend of decreasing emissions with decreasing natural gas prices is apparent in the 2017 AEO, the marginal emission-reduction rate of decreasing gas prices is dramatically altered in the 2019 AEO. Further analysis of the AEO assumptions reveals that this change in marginal rate coincides with the decrease in capital costs for renewable generation. As these complementary CO_2 emission-reduction mechanisms put the U.S. power sector on the path to achieving the 2030 Clean Power Plan goal ahead of schedule, we conclude by calling for the policy discussion to shift towards achieving longer-term and deeper decarbonization targets.

[9] The AEO CPP projections assume that the mass-based approach is taken by all states. Fugitive methane emissions for natural gas sources are not included.

[10] Many of the data used and the conclusions reached in this work are highly dependent upon the assumptions made in the referenced literature and made for the calculations. Changing these assumptions can lead to different conclusions. This work is a deterministic presentation that does not directly address the uncertainty in the data used.

Table 2.1. U.S. CO_2 emission-reduction targets for full economy [5, 6] and power sector [47, 56]. The Affordable Clean Energy rule reductions are relative to modeled baseline for the same year without the Clean Power Plan [56].

<table>
<tr><th>Policy Instrument</th><th>Pledge year</th><th>Base year</th><th>Target year</th><th>Relative CO_2 reduction</th><th>Reduction type</th></tr>
<tr><td rowspan="2">Copenhagen Accord</td><td rowspan="2">2009</td><td rowspan="2">2005</td><td>2020</td><td>17%</td><td rowspan="3">Full economy</td></tr>
<tr><td>2050</td><td>83%</td></tr>
<tr><td>Paris Agreement</td><td>2015</td><td>2005</td><td>2025</td><td>26-28%</td></tr>
<tr><td rowspan="3">Clean Power Plan</td><td rowspan="3">2015</td><td rowspan="3">2005</td><td>2020</td><td>23%</td><td rowspan="5">Power sector</td></tr>
<tr><td>2025</td><td>29%</td></tr>
<tr><td>2030</td><td>32%</td></tr>
<tr><td rowspan="2">Affordable Clean Energy rule</td><td rowspan="2">2019</td><td>2025</td><td>2025</td><td>0.7%</td></tr>
<tr><td>2030</td><td>2030</td><td>0.7%</td></tr>
</table>

2.2 Annual Energy Outlook projections: CO_2 emissions

Of the nine cases modeled in the 2017 AEO with the National Energy Modeling System [57] for the impact of economic growth, resource availability, and regulation on the projected commodity prices, capacities, generation mixes, and fleet emissions for the power sector [58], two are shown with and without implementation of the CPP: one pair is the reference case, and the other is for the high oil and gas resource and technology case (a high oil and natural-gas supply case that results in low oil and natural gas prices). When these pairs are compared to the CPP emission targets for the years in question, Table 2.2, the emissions for CPP cases follow a glidepath to the 2030 target, while the emissions for the non-CPP cases remain stable. The 2020 emission target is achieved without the CPP in both natural gas price cases, and the case pairs are almost indistinguishable given the uncertainty in the CO_2 emission projection [60].[11] This is not true for

[11] The EIA data for the average, absolute percent-difference between the EIA emissions projection and the actual result for one to six-year projections since 2010 is 3.4% percent [60].

the 2025 target. While the 2025 target is surpassed for the CPP cases,[12] the targets in the other cases are not met in the absence of the CPP. However, the non-CPP case with the lower natural gas price is within 12 million tonnes of the 2025 target, which is within the uncertainty of the projection. Though the NDC does not extend to 2030, the projections indicate that the 2030 CPP emission target would not be met without the associated CPP's emission cap and incentive mechanisms—signifying the positive role that the CPP was thought to have had in the 2017 AEO for deeper emission reductions beyond 2025.

Table 2.2. Clean Power Plan CO_2 emission targets and projected CO_2 emissions for 2020, 2025, and 2030 [54, 55, 59] from the 2017 and 2019 AEOs. Reference and high oil and gas resource and technology (high supply) cases from the 2017 and 2019 AEOs are shown with 2019 AEO low oil and gas resource and technology (low supply) case. Values in boldface indicate that the case meets the CPP target. The 2019 AEO does not model the CPP or ACE.

AEO	CPP	Case	Annual CO_2 Emissions (million tonnes)		
			2020	2025	2030
2017	Yes	Reference	**1,821**	**1,659**	**1,537**
		High Supply	**1,744**	**1,617**	**1,532**
	No	Reference	**1,836**	1,850	1,885
		High Supply	**1,756**	1,736	1,744
2019	No	Reference	**1,653**	**1,607**	**1,601**
		High Supply	**1,618**	**1,614**	**1,579**
		Low Supply	**1,688**	**1,601**	**1,545**
		CPP Target	1,881	1,725	1,646

[12] In some cases, the 2017 AEO projections for emission reduction surpass the CPP targets. This over-reduction may be viewed as an overcorrection inefficiency, or as establishing a surplus reduction that may be used to offset other GHG reduction programs that do not meet associated targets for the NDC.

In the 2019 AEO [55], the EIA updated[13] their projections for commodity prices and CO_2 emissions, absent the regulatory effects of the CPP or ACE. For the seven cases modeled, two cases can be compared directly to the 2017 AEO projections: the reference and high oil and gas resource and technology cases without the CPP. Such a paired comparison, Table 2.2, indicates that these projected emissions are at least 100 million tonnes lower than the 2017 AEO projections and are reduced beyond the CPP emission targets for each year, as well. Many factors could possibly account for this change in emissions. The rate of capacity expansion for renewable generation can be accelerated through adoption of state-level renewable portfolio standards and the extension of federal tax credits. Public pressure from evolving viewpoints on the urgency of climate change could put pressure on Congress to levy a tax on CO_2 emissions. Yet, there may be other non-regulatory mechanisms available, which had high uncertainty or were unpredictable in the AEO modeling two-years prior, that are significant levers for this emission reduction. Two such mechanisms affecting the marginal emission reduction rate are the price of natural gas and the capital cost for power generators.

2.3 Marginal emission-reduction rate mechanisms

2.3.1 Natural gas price

When the historical CO_2 emission levels relative to the 2005 base year are plotted as a function of natural gas price,[14] Figure 2.1, decreasing natural gas prices have been strongly associated with greater emission reductions.[15] This is in part a result of an economic preference for natural

[13] Core cases are updated annually; however, side cases are updated biennially, starting in 2014.

[14] Natural gas prices in dollars per million British thermal units ($/MMBtu) are converted to 2010 dollars with the Consumer Price Index (CPI) [61]. Natural gas prices from the EIA are based upon national averages.

[15] The correlation between price and reduction is not chronologically perfect, however. Coal prices, capacity planning, regulations and policy mechanisms (such as state-specific renewable portfolio standards and federal tax credits for solar and wind energy), unforeseen events, technology changes, and hedging related lags …continued

gas combined-cycle (NGCC) generation to coal-fired generation from a decadal reduction in natural gas prices (*Appendix A, Section A.2*) that resulted in an approximate marginal emission-reduction rate of 7% per dollar decrease in fuel price, from 2009 and 2018.[16] Plotting the 2017 AEO projected natural gas prices and the resulting fleet CO_2 emission reductions for the non-CPP cases with these historical data shows that the historical trend is maintained for each target year; the reference-case natural gas prices that are higher than the 2018 level lead to less emission reduction and the subsequent decreases in gas price for the high-supply cases results in emission reductions below the 2018 level, at a similar marginal emission-reduction rate of 6%. As the projected high-supply gas prices are still greater than those for 2018, the clustering of future emissions near the 2025 target may be due in part to a more rapid replacement of coal-fired generation with NGCC generation caused by already favorable natural gas prices, and to an increase for both cases in renewable generation[17] from policy mechanisms, such as state-specific renewable portfolio standards and tax credits for solar and wind energy (*Appendix A, Section A.2*).

When the 2019 AEO projections are added to the figure, the aforementioned relationship between lower natural gas prices and greater emission reduction changes. Now when the 2019 AEO reference-case projections for natural gas price are greater than the historical 2018 price, the projected emission reductions are substantially greater than the 2018 historical value.

[*Appendix A*, 59, 62] may account for some of the imperfect responses between the natural gas price and the reduction, as occurs from 2006 to 2008 and from 2012 and 2014, when the natural gas prices increase but the emission intensities remain constant.

[16] The reduction in emissions comes from the difference in the CO_2 emission intensity for the two sources, based upon net generation. The 2018 average CO_2 emission intensity (kg CO_2 per megawatt-hour) for the U.S. power sector coal-fired fleet was 1,010 kg/MWh [62]. The CO_2 emission intensity for a new, conventional NGCC plant is 337 kg/MWh [64]. Therefore, replacing the net generation from the average coal-fired electric generating unit with net generation from a new conventional NGCC plant reduces the total emissions by 67%.

[17] AEO 2017 projections indicate that the percent net generation from renewable sources increases for the case pairs in 2020, 2025, and 2030, relative to 2015 [54].

Furthermore, the similar natural gas prices projected in the 2017 AEO high natural-gas supply case and the 2019 AEO reference case result in the projected emission levels from the 2019 AEO being less than those from the 2017 AEO. Additionally, the lower projected natural-gas prices in the 2019 AEO higher-supply cases relative to the 2019 reference cases result in marginal emission-reduction rates that are in sharp contrast to those for the corresponding 2017 AEO cases. For the 2030 projections, there is only a 1% further decrease in emissions, given a 17% decrease in natural gas price in the 2019 AEO, as compared to an 8% decrease in emissions from a 27% decrease natural gas price in the 2017 AEO. Simply put, future declining natural gas prices no longer appear to have the same impact they once did on CO_2 emissions.

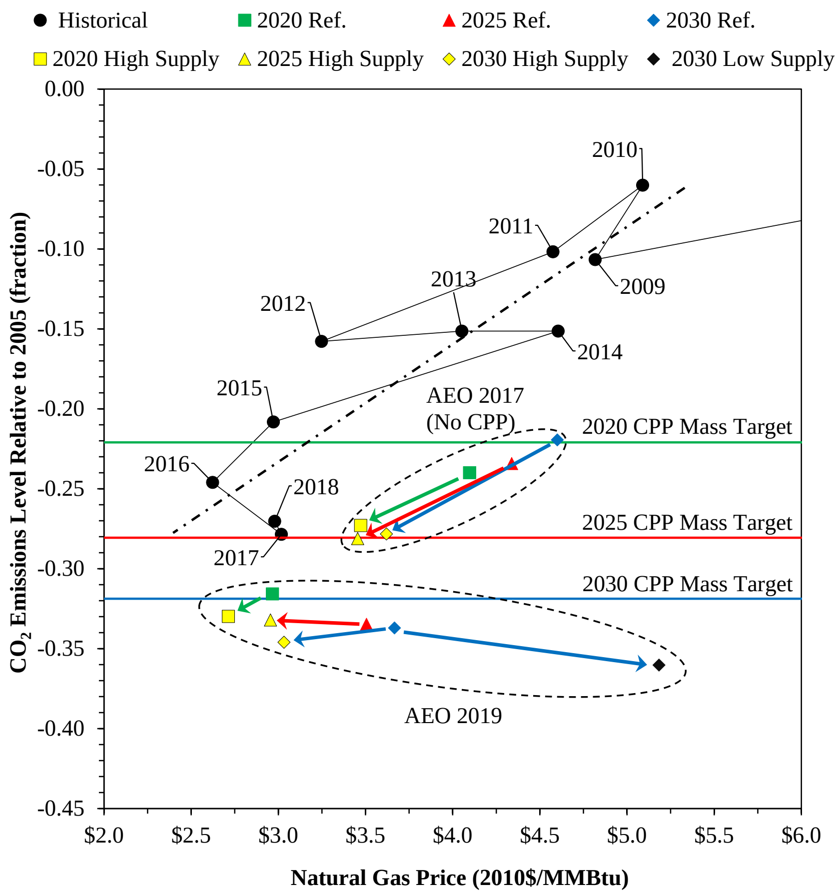


Figure 2.1. Historical [62] and projected 2020, 2025, and 2030 CO_2 emissions from the U.S. power sector in relation to natural gas price. Projected emissions and gas prices are national averages based on scenarios in the 2017 and 2019 AEO for the reference (Ref.) and the high oil and gas resource and technology cases (High Supply) that results in a low natural gas price, and for the low oil and gas resource and technology case for 2019 (Low Supply) that results in a high natural gas price [54, 55]. Only scenarios without the CPP are shown. Historical and projected natural gas prices from the 2017 and 2019 AEOs are converted to 2010 dollars with the Consumer Price Index [61].

2.3.2 Power-generator cost trends

Achieving the CO_2 reduction targets despite the declining marginal emission-reduction rate indicates that other mechanisms to lower emissions are present and can dominate the impact of natural gas prices. One such mechanism is the lower capital costs for competing generation sources that is particularly evident for the low oil and gas resource and technology (low natural-gas supply that results in higher oil and natural gas prices) case for which low natural gas prices from fracking and horizontal drilling disappear and exceed 2009 levels. Even with the higher natural gas price, the projected CO_2 emissions are less than that for any other case—a further 4% emission decrease given a 41% natural gas price increase, relative to the 2019 AEO reference case (Figure 2.1, Tables 2.2 and 2.3). This marginal gain in emission reduction is accomplished by increases in carbon-free generation to levels that are otherwise projected to be only slightly greater than those realized in 2017, Figure 2.2. Such a large increase in carbon-free electricity is driven primarily by a 90% increase in solar generation to a level at which this generation is only 10% less than that from wind, Table 2.3. The increase in reliance on solar generation in the 2019 AEO is also seen in the 2017 and 2019 AEO reference cases and the high natural-gas supply case comparisons: The 2019 AEO exhibits a tripling of solar generation from both capacity and capacity factor increases for the reference comparison, while solar generation is almost 140% greater in the high natural-gas supply comparison.

Table 2.3. National power-sector characteristics for 2030 from the 2017 and 2019 AEOs [54, 55]. AEO reference and high oil and gas resource and technology (High Supply) cases are shown with the 2019 AEO low oil and gas resource and technology (Low Supply) case, without the CPP. Dollar year converted to 2010 with the CPI [61].

	Parameter	Units	2017 AEO		2019 AEO		
			Reference	High Supply	Reference	High Supply	Low Supply
	Excess CO_2	Million tonnes	239	98	(44)	(66)	(101)
Capacity*	Coal	Gigawatts	217.1	184.9	161.8	139.4	182.6
	NGCC		239.1	267.6	343.8	402.9	299.1
	Wind		140.3	133.5	119.7	116.5	142.6
	Solar PV		37.9	32.9	92.3	66.4	169.9
	Nuclear		95.1	96.5	81.7	59.9	88.6
Net generation†	Coal	Terawatt-hours	1,389.4	1,099.9	986.9	787.7	1,131.6
	NG		1,060.5	1,431.9	1,487.3	1,985.1	934.3
	Wind		419.7	448.6	368.7	356.6	457
	Solar PV		72.4	63.4	219.5	151.1	417.7
	Nuclear		768.0	757.1	663.9	488.4	716.8
	Total‡		4,332	4,366	4,287	4,329	4,222
Price	Natural gas	2010$/MMBtu	4.6	3.6	3.7	3.0	5.2
	Coal		2.2	2.1	1.9	1.9	2.0
	Electricity§	Nominal cents/kWh	14.5	13.8	13.9	13.4	14.7

*net summertime capacity; †power only; ‡net generation to grid; §summation of generation, transmission and distribution costs

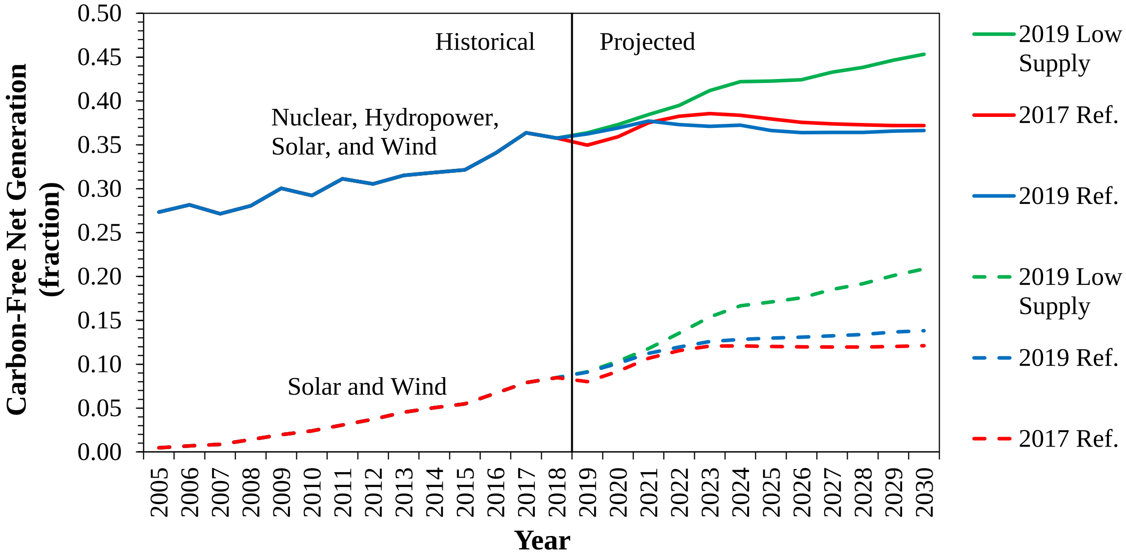


Figure 2.2. Historical [62] and projected carbon-free net generation for the U.S. power sector. Projected generation is for the reference cases (Ref.) in the 2017 and 2019 AEOs [54, 55]. Generation for low oil and gas resource and technology cases (Low Supply) case that results in a higher natural gas price is from AEO 2019 [55]. Carbon-free generation is comprised solely of nuclear, hydropower, solar and wind generation. Biomass and similar fuels are excluded.

Unpacking the power-generator cost trends from previous AEOs illustrates the emergence of these costs as an emission-reduction mechanism in the 2019 AEO. From the 2015 to the 2019 AEO, the projected capacity-weighted average levelized cost of electricity (LCOE) [18] without tax credits for solar generation decreases by 64% and that for wind decreases by almost 46%, Figure 2.3(a). Taking tax credits into account for the 2019 AEO scenario, these decreases result in a solar LCOE that is less than $1/MWh greater than that for wind, which illustrates the importance of these credits. Although most of these reductions relate to levelized capital costs that decrease by 41% and 33% for solar and wind generation, respectively, from the 2017 to 2019 AEO projections [63, 65], these reductions in levelized costs also reflect declines due to reductions in the cost of investment capital and changes in site-specific project attributes from modeled

[18] All costs are expressed in 2010 dollars, unless otherwise stated. The CPI [61] is used for conversion. LCOE is given for year of service entry from 2020 to 2023.

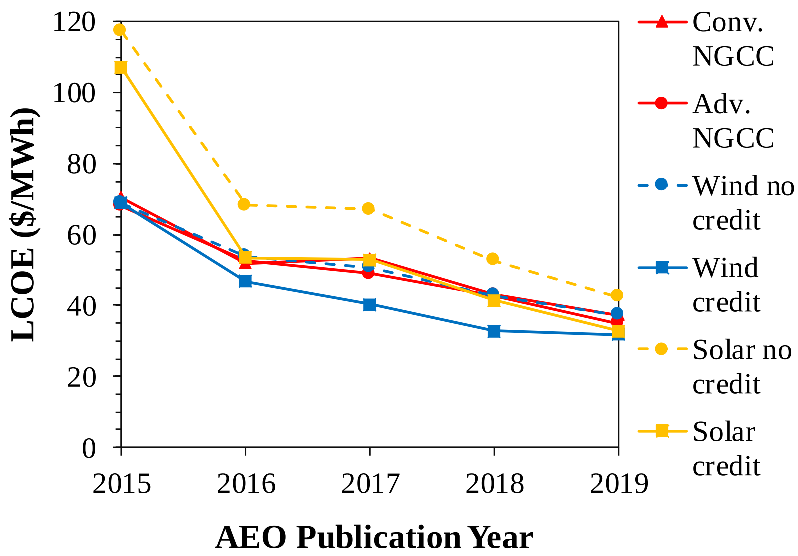
capacity expansion occurring in regions (each with region-specific cost adders) most favorable to the specific fuel types and available new technology. These changes affect not only the project capital costs but also the associated capacity factor for levelizing the costs [*Appendix A, Section A.2*; 63-67]. The remaining capital-cost reduction can be partially unpacked by looking at the total overnight capital-cost upon which these capacity-weighted average costs are based, Figure 2.3(b). Here, the overnight cost[11] continues to decrease for all solar technologies, as does that for wind; however, solar costs decrease at a faster rate. Overnight costs for fixed-solar fall by 50% from the 2015 to the 2019 AEOs, assuming the use of fixed-solar technology dominates the 2015 AEO total overnight-cost, and wind overnight costs decrease by 24%.[19]

The costs for natural gas generation also drop sharply, which is substantially due to conventional and advanced NGCC capacity [*Appendix A*, *Section A.2*; 73; 74]. The reference-case LCOE for these NGCC units each decreases by almost 50% from the 2015 to the 2019 AEO [63-67], Figure 2.3(a). For the conventional unit, almost 80% of this decrease results from a reduction in variable operation and maintenance (VOM) cost related to changes in fuel price [*Appendix A, Section A.2*; 54; 55; 70; 75-77] and from modeling a more efficient gas turbine from the 2016 AEO onwards [75]. The remaining decrease is due primarily to the levelized capital costs that decline related to finance cost and region-specific attributes rather than decreasing overnight capital costs (Figure 2.3(b)) [63]. Similarly, 71% of the decrease in LCOE for the advanced NGCC unit is due to a reduction in VOM related to fuel price. However, much of the levelized capital cost decrease can be attributed to a reduction in the overnight capital cost for this technology (Figure 2.3(b)) in the 2019 AEO [*Appendix A, Section A.2*; 65; 72]. This reduction is attributed to economies of scale from using the GE 7HA.02 combustion turbine for

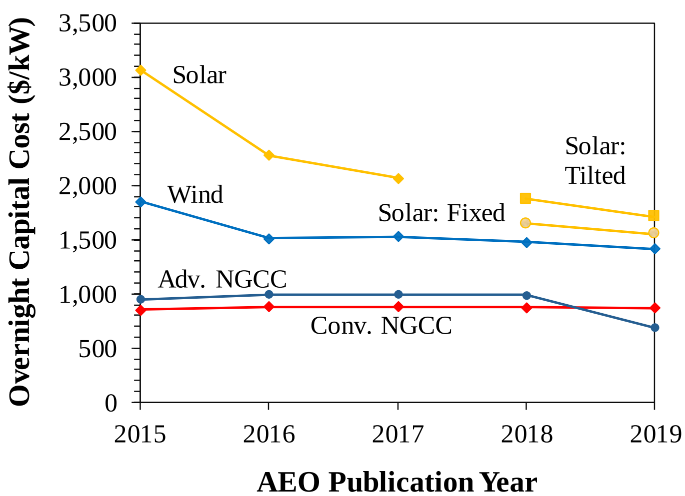
[19] Prior to the 2018 AEO, the AEO did not distinguish utility-scale photovoltaic generation into these two categories of collectors.

future NGCC plants and standalone combustion turbines [78]. Therefore, the difference in the 2017 and the 2019 AEO projections for VOM and levelized capital cost that results in a $16/MWh decrease in the conventional NGCC LCOE (from a $10/MWh decrease in VOM and a $6/MWh decrease in levelized capital cost) and a $14/MWh decrease in the LCOE for the advanced NGCC unit (from a $7/MWh decrease in VOM and a $7/MWh decrease in levelized capital cost) likely accounts for the observed increase in projected natural gas generation in the 2019 AEO, when the high-supply case in the 2017 AEO and the reference case in the 2019 AEO have similar projected natural gas prices (*Appendix A, Section A.2*)

The 2019 AEO-projected decrease in VOM for NGCC generation [65] and the decrease in capital cost for each of the three generation sources bring the respective LCOEs to similar levels for 2023 service entry [65], inclusive of the tax credits (Figure 2.3(a)). For service entry between 2020 and 2030, LCOE comparisons for these generation technologies can be established from the NREL's 2019 Annual Technology Baseline (ATB) projections [*Appendix A, Section A.2*; 79]. In the ATB projections, Figure 2.4, the average NGCC LCOE increases slightly over this period, while solar and wind LCOE fluctuate due to the combined effect of expiring tax credits and decreasing capital costs that results in the average NGCC LCOE being greater than both solar and wind LCOE by 2030. Even so, the economic victor for capacity expansion is not always apparent. This is evident both in the variation in regional cost, capacity factors, and projected natural gas prices, Figure 2.4, and when considering the marginal cost of energy and capacity—the levelized avoided cost of electricity [*Appendix A, Section A.2*; 65].



(a)



(b)

Figure 2.3. Conventional and advanced NGCC, wind and solar (a) LCOE and (b) total overnight capital costs ($/kW) from the 2015 to 2019 AEOs. LCOE values are based upon capacity-weighted averages [63-67], while overnight capital costs are not averaged and omit tax credit value [68-72]. Year of service entry varies from 2020 to 2023, with the dollar year converted to 2010 with the CPI [61].

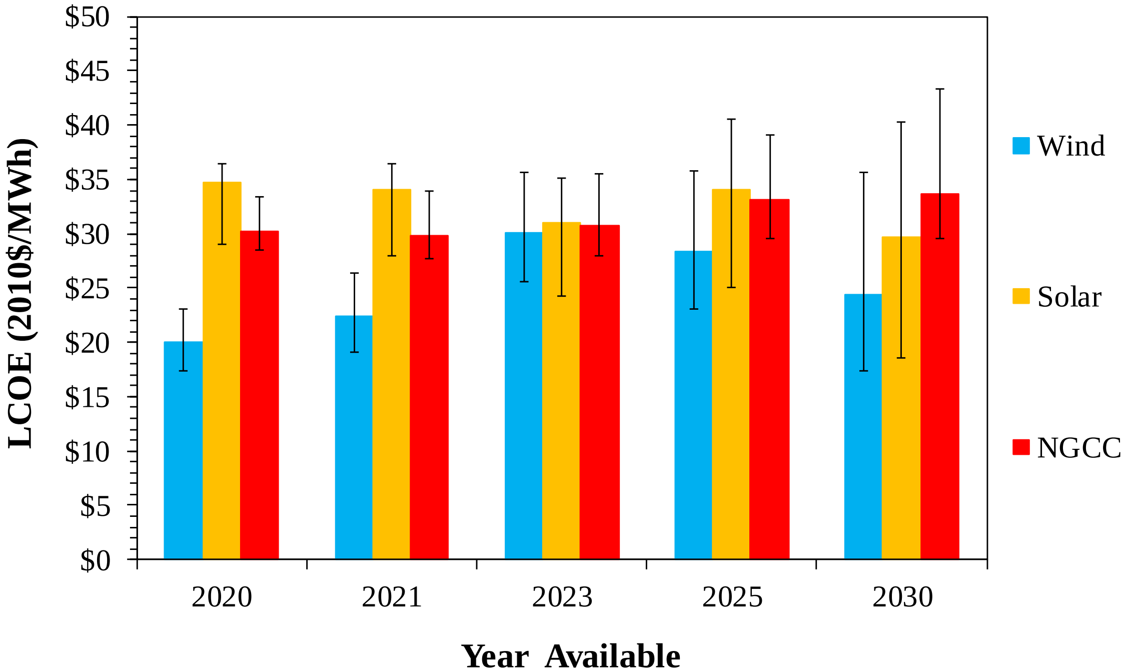


Figure 2.4. Average LCOE for future wind, solar and NGCC generation sources from the 2019 ATB [79]. Error bars for renewable generation are based on LCOE range for default comparisons defined in the ATB. NGCC error bars include low, mid, and high projections for fuel cost for a high-capacity factor unit.

2.4 Longer-term, deeper reductions targets required from all sectors

The Copenhagen Accord established a goal of limiting the increase in global average temperature to 2 °C above the pre-industrial levels and set forth emission targets to achieve this goal [5]. These targets were further refined in the Paris Agreement to meet a more stringent goal of limiting the increase to well below 2 °C, with the intent of limiting it to 1.5 °C [6]. The impetus behind this more aggressive goal was to reduce the risk of crossing critical thresholds and reaching tipping points that would lead to greater harm to marine and terrestrial ecosystems, and to human welfare. Yet measurements and modeling on action to date indicate that the NDC goals under these policies fall short of meeting either warming limit and that the temperature increase is on course to reach 3 °C by 2100 [80]. Therefore, emission targets now called for by the Intergovernmental Panel on Climate Change (IPCC) to limit future climate impact to the 1.5 °C warming threshold recommend a 45% global emission reduction from 2010 levels by 2030 and a net-zero carbon economy by 2050 [80].

For the U.S. power sector to meet these targets[20] requires an annual emission reduction of approximately 2% from the 2018 level, Figure 2.5. While the historical replacement of coal-fired generation with NGCC generation can drive the power sector far down this path and theoretically achieve a 59% reduction in emissions with total replacement of coal with natural gas, at the 2018 net generation level,[21] deeper reductions beyond the next decade will require more than a "business as usual" transformation. To achieve these deeper reductions, and to do so with greater generation to allow the other sectors to decarbonize through electrification, will require the further development and deployment of existing and new technologies and supporting infrastructure.

[20] As this target is global and may not be applied equally to developed and developing nations or to all sectors, we illustrate the reduction for the U.S. power sector as a direct application of the 45% to the 2010 emissions and then set it relative to the 2005 baseline.

[21] In 2018, the net generation from coal was 1.14 terawatt-hours and the average CO_2 emission intensity (kg CO_2 per megawatt-hour) for the U.S. power sector coal-fired fleet was 1,010 kg/MWh [19]. The CO_2 emission intensity for a new, conventional NGCC plant is 337 kg/MWh [63]. Replacing the coal-fired generation with an equivalent amount of new NGCC generation decreases the overall CO_2 emissions by 766.2 million tonnes.

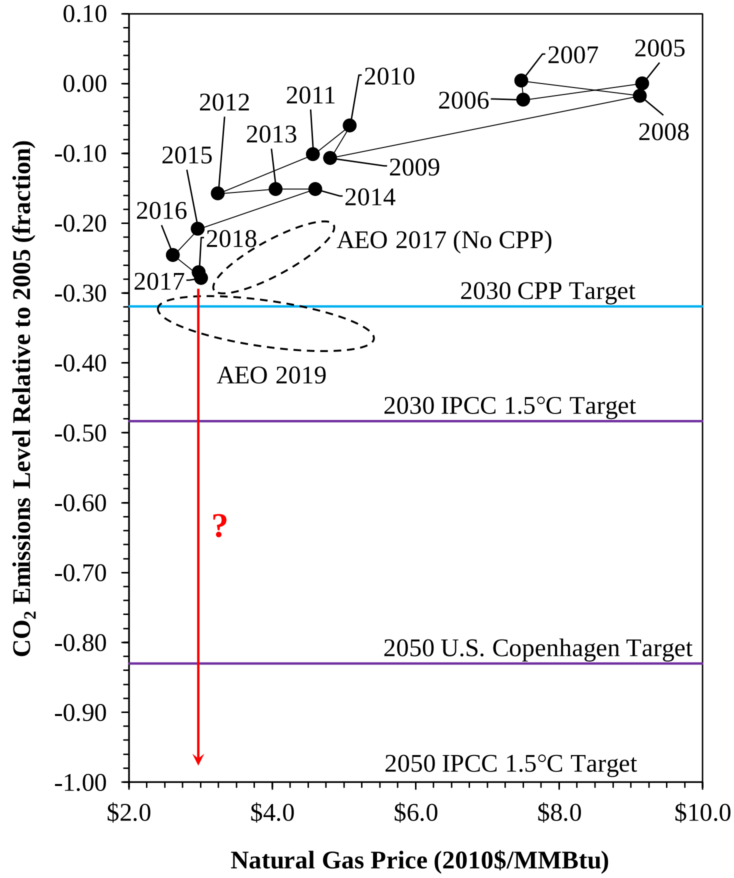


Figure 2.5. Historical [62] and projected regions for projected 2020, 2025, and 2030 CO_2 emissions from the U.S. power sector in relation to natural gas price. Projected regions are from the 2017 and 2019 AEO [54, 55] that are shown in detail in Figure 2.1. Historical and projected natural gas prices from the 2017 and 2019 AEOs are converted to 2010 dollars with the CPI [61]. Historical and projected region emission reductions are shown relative to CPP [5], Copenhagen Accord [5], and IPCC targets [80].

2.5 Conclusion and policy implications

In the 2019 AEO, the EIA projections for CO_2 emissions reduction indicate that targets set out in the CPP can be achieved even without the plan or subsequent ACE regulations but instead through market mechanisms and current environmental regulations and policies. As a result, the substantial contribution in emission reduction that the electric power sector was tasked with achieving in order to meet the Paris Agreement targets may be achieved and even exceeded ahead of schedule. While low natural gas prices are still a prominent factor in achieving these reductions, decreasing capital costs for generating sources have emerged as an additional mechanism that has diminished the impact of the marginal emission-reduction rate of natural gas prices. The decreasing capital cost of NGCC plants coupled with lower natural-gas price projections are enabling factors in the 2019 AEO for reductions beyond the 2030 emission target. However, these factors also hide the continued capital cost reductions for solar and wind generation. If the historical natural gas price decrease achieved through hydraulic fracking and horizontal drilling were to reverse (due to increasing liquified natural gas export, regulations curtailing such extraction, or a carbon tax[22]) and prices return to 2010 levels, the projected capital costs for these renewables (particularly solar) are low enough to mitigate the relationship of emissions increasing with increasing natural gas price.

Perhaps serendipitously, the absence of specific CO_2 emission-reduction targets and associated additional mechanisms in a regulatory framework has allowed decarbonization to occur at a heightened rate. Longstanding policies that incentivize clean energy and natural gas as a bridging fuel have allowed the market to make a flexible and effective transition to a lower-carbon electric grid without needing to resort to more heavy-handed regulatory actions. The complementary addition of lower capital costs to that of a lower natural gas price has now put us well on the path to achieving the 2030 goals in the Clean Power Plan ahead of schedule, thereby motivating a new policy discussions that lock-in these projected short-term power-sector gains

[22] If one assumes that the 7,649 Btu/kWh NGCC heat rate for the current fleet [81] were to decrease to that for a conventional NGCC plant (6,350 Btu/kWh [65]) by 2030, then a $25/ton carbon tax is sufficient to increase the equivalent price of natural gas from $3.7/MMBtu for the 2030 projected reference case to the $5.2/MMBtu projected price for low natural gas supply [55], *ceteris paribus*.

and look towards pathways to deeper reductions for the near and longer-term IPCC 1.5° C targets.

Further transformation of the power sector to enable emission reductions equaling or exceeding those of the past decade over the next 10-30 years will be much more challenging: We have already picked the inexpensive, low-hanging fruit. While incremental improvements for existing technologies are projected to reduce emissions by 32%, accelerating research, development, demonstration, and deployment of breakthrough technology innovations through increased investment by government and industry is required today to meet these deeper goals for 2030 and beyond. This is made more difficult, as decarbonizing other sectors through electrification will put pressure on the power sector to decarbonize deeper and faster. For example, electrifying private transportation could easily add a 30% increase in demand (which would require a 62% reduction in power sector emissions to achieve a 50% reduction over baseline emissions). Regional variation in current generation sources, available resources, and the needs of the local communities may make this transformation more difficult and require these innovative breakthroughs to be on multiple diverse generation-fronts. The higher penetration of intermittent renewable sources will require not only new transmission infrastructure, but also long-duration energy storage technologies with high roundtrip storage efficiency and storage density, such as closed-loop carbon fuels electricity generation, to achieve grid stability. Further technology innovations are required for other no-carbon generation; fuel cells and infrastructure are needed to create a hydrogen economy, while advanced nuclear and small modular fission reactors are needed to replace the nuclear fleet that will begin retiring in the 2030s [82]. Low-carbon generation sources will require advancements in carbon capture utilization and storage to meet these emission targets by locking up the CO_2 as valuable products or by storing it in geologic formations. Complementary to this investment is that for direct capture to achieve net-zero and negative emissions.

Putting a value on carbon is a lever to move the market towards these deeper reductions. A Pigouvian tax of a fixed amount, as currently proposed by many politicians, is one method to activate this lever. Another is a cap-and-trade policy in which the market sets the carbon price, as is done currently for CO_2 reduction in California and in the Northeast U.S. via the Regional Greenhouse Gas Initiative (RGGI). Each of these methods has advantages and disadvantages that depend in part upon the framework of the program, and whether the tax is complemented with other policy initiatives, such as energy efficiency [83], that could create a virtuous cycle. Furthermore, each method shares the ability to generate vast funding for these technology investments, while diminishing emissions. But in doing so, some have pointed to a need to also use policy to balance these investments with general consumer price concerns and with negative impacts of the lever on poor and minority communities—impacts such as those associated with immediate regressive costs and disproportionate placement of new infrastructure that might affect local property values and health risks. In addition to addressing social inequality, some also point to each method needing to have policies that address national concerns of repurposing the stranded generation assets, immediate job losses in the current workforce as we move to a clean-energy economy, and avoidance of international trade imbalances from potential unilateral application of the carbon lever. Yet job creation can also be achieved through policy integration with a carbon tax [84] and consumer and industrial power can be leveraged in trade negotiations to achieve mutually beneficial decarbonization through multilateral participation.

Even with such policies, it is uncertain if either method will support or undermine seemingly complementary incentives and regulations currently in place, such as renewable portfolio standards and low-carbon fuel standards, or cause price volatility from interacting measures in other sector initiatives. However, it is clear that continuing solely on the path of incentives, which are projected to achieve the 32% reduction soon, will not be enough to reach these deeper reductions targets without some mechanism that encourages continued reductions at the lowest marginal cost. Here, a carbon-price lever will permit this abatement and eliminate the ambiguity that is currently present in environmental goals. This is not to say that incentives should not be pursued; a balance can be struck between regulatory stringency and incentives that may be beneficial.

Societal decarbonization is a difficult challenge, one that is fraught with complex interactions at the regional, national, and international levels and for which more studies are required. Given the uncertainty in marketplace conditions from technology implementation timelines and capital costs, fuel costs, and changing political views affecting environmental policies, more than a single policy instrument, such as a carbon tax, will be required to navigate these complexities. While we may understand the destination, we must also understand that the policy path taken should remain flexible to allow for multiple technology solutions and to allow us to adapt our strategies in the face of the future uncertainties. The changing roles of natural gas price and the capital cost of renewable energy for CO_2 emissions reduction between the 2017 and 2019 AEOs demonstrates this need.

Chapter 3: Transitioning to a carbon-constrained world: reductions in coal-fired power plant emissions through unit-specific, least-cost mitigation frontiers

ripples greet the shore
abiding pain or pleasure
copy cut and paste

"Model Building" by Jeffrey Anderson

There is growing concern that progress towards reaching the carbon dioxide (CO_2) targets set forth in the Paris Agreement is falling short of the mark, and efforts to decarbonize the global economy must be hastened and the reductions deepened. Doing so quickly through a buildup of natural gas generating capacity as a replacement for coal-fired capacity can greatly aid in lowering near-term emissions towards the Agreement target to limit future climate impact to well below 2 °C but would incur stranded costs as natural gas assets are retired before their end-of-life age. The stranding of such capital investment may inhibit efforts to further decarbonize the world economy because of technology lock-in. One possible solution to reduce such stranded costs is to mitigate CO_2 emissions from the existing coal-fleet. For the evaluation of the costs and emissions, we develop a novel method that uses unique coal-fired electric generating unit (CFEGU) characteristics to evaluate multiple mitigation-technology options under local fuel prices; the result of which is a least-cost mitigation frontier for nine CFEGU-specific mitigation solutions created within a common assessment framework. With this EGU-specific method, we find the mitigation options that achieve the lowest capital cost and levelized cost of electricity to meet CO_2 emission-intensity, reduction-targets for a representative EGU in the U.S. coal-fired fleet and use this method to analyze the uncertainty for these deterministic solutions. For this CFEGU, we find that the portfolio of mitigations defining the frontier is sensitive to fuel price variation, as well as other EGU-specific factors such as efficiency and retirement age. A probabilistic analysis of projected fuel prices indicates that mitigation decision-related regret can be high but may be limited to specific intensity targets. A further insight is that for deep CO_2 mitigation, high capital costs and predominantly low natural gas prices may limit the viability of coal-fired EGUs retrofitted with carbon capture and storage with an auxiliary power system, even with a tax credit (e.g., Section 45Q of the Bipartisan Budget Act of 2018).

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3.1 Introduction

The Intergovernmental Panel on Climate Change (IPCC) recommended in 2018 that global greenhouse gas emissions (GHG) be reduced to 55% of 2010 levels by 2030 and that a net-zero carbon economy should be achieved by 2050 to limit future climate impact to the 1.5° C warming [80]. The pathways take by countries to reach these goals may differ given country-specific resources, economic and political considerations, and reduction requirements. In the U.S. for example, while power sector emissions have fallen sharply since 2005 (*Appendix B, Section B.1*; Figure B.1), meeting the power-sector's share of the new economy-wide 2030 target[23] requires an annual emission reduction of approximately 2% from the 2018 level, for each

[23] As this target is global and may not be applied equally to developed and developing nations or to all sectors, we illustrate the reduction for the U.S. power sector as a direct application of the 45% target to the 2010 emissions.

of the intervening years to 2030. This reduction could be met through the continued increase in natural gas combined cycle (NGCC) capacity associated with low natural gas prices and the continued increase in renewable capacity supported by declining capital costs [85]. The historical replacement of coal-fired generation with NGCC generation alone (*Appendix B, Section B.2*) could theoretically achieve a 56% reduction in emissions from 2010 levels by 2030 with total replacement of coal by natural gas, at the 2018 net generation level; however, this effort would require almost 150 gigawatts (GW) of new NGCC capacity, at an estimated cost of $125 billion (in 2017 dollars), excluding associated infrastructure. To do so solely with solar or wind generation would require an additional 650 GW of solar or 266 GW of wind at a cost of $552 billion and $325 billion, respectively.

To meet the overall economy-wide near-term goals for 2030 and the long-term goals for 2050, decarbonization in other sectors will require electrification, putting additional pressure on the power sector to decarbonize while increasing generation [86-93]. In the 2019 UN Emission Gap Report [94], recommendations to meet this need are made that in some cases are to not invest in fossil-fuel plants and infrastructure, particularly natural gas pipelines, as the report warns of carbon-infrastructure lock-in that will make further reductions beyond 2030 more difficult and costly. This is exemplified by the reported risk of the future stranding of NGCC assets in Canada with the expected phase-out of coal-fired generation by 2030 [94]. Such lock-in of a generation technology may also be a concern for the future U.S power-fleet, as well as for those in other countries, as CO_2 emission reductions are sought.

One costly method to overcome lock-in is to “strand” assets by removing the assets from service prior to the return on capital being fully realized [95-100]. If assets are to be stranded, the question then becomes how the power sector moves forward from 2020, given the unknown future of these new carbon-emitting assets after 2030. By 2050, assets built in 2030 could still have at least 10 years of remaining book life. As a result, investors would not yet have fully recovered their capital, and a fair return on that capital. In the U.S. power sector for example, depending on the construction timeline, a theoretical build of 150 GWs of NGCC capacity, could result in $42 billion dollars being stranded, (based on a simple straight-line amortization), or could require retrofitting with carbon capture and storage (CCS) at an estimated additional cost of more than $250 million per plant (*Appendix B, Section B.3*). The uncertainty in the retirement horizon from potential future regulation (or from the introduction of an as-yet unknown but less-costly means of net-zero generation) and the possible inclusion of a CO_2 penalty (be it explicit or implicit) creates a tension between different generation sources, as well as a tension between environmental policymakers and owners/stakeholders concerning the mid-term transition from *what is* to *what should be*. Tradeoffs between stranded asset costs and carbon emissions costs define breakeven curves that delineate preferences between different technologies. As a result, in some circumstances it may be less costly to continue to use coal-fired generation than to switch to that from an NGCC plant, highlighting the importance of incorporating stranded costs in any model framework.

Stranding assets is costly, not only because it impairs otherwise productive capital, but also because it can raise the initial costs of certain policy options by causing investors to make capital less available, to require amortization of the costs over a shorter life, or to increase the cost of such investment capital to account for the risk of becoming stranded. Yet, such a stranded-cost scenario may provide an opportunity to employ a generation portfolio of new NGCC and renewable capacity with existing coal-fired electric generating units (CFEGUs) mitigated for carbon dioxide (CO_2) to achieve the requisite emissions and generation for the fleet. A generation portfolio that includes mitigated coal could achieve a lower fleet-wide levelized cost of electricity (LCOE) than a generation mix with new NGCC capacity, once stranded costs are included.

Multiple mitigation technologies are possible for the coal fleet. Increasing the efficiency of the CFEGU through heat rate improvements has been studied in regard to emission reduction regulations [101-106]. Other plausible mitigations include improving the quality of the coal through upgrading rank or drying techniques [105-107] and co-firing the coal with biomass [108-112] or natural gas [113, 114] at variable levels. Fuel switching completely to natural gas has also been examined both while retaining the existing boiler and while partially repowering with a hot wind box, feedwater, or parallel with heat recovery steam generators integrations, or by fully repowering as an NGCC plant [113-115]. Other models studied the economic viability of employing CCS at 90% capture rate for both new [116-119] and existing [120-123] coal-fired EGUs. In particular, CCS has also been studied as part of a real options approach to consider the best timing for using this mitigation, given other enabling factors [119, 123-126].

In analyses of these mitigations, each is examined individually rather than in conjunction with other emission reduction approaches to determine which may be the least-cost solution to achieve an emission intensity for a given CFEGU. Many of these mitigation technologies are used in capacity-expansion or non-expansion models (Table 3.1 and *Appendix B*, *Section B.4*); however, not all mitigation options are jointly considered, nor are the options considered at all applicable levels [127, 128]. Therefore, a gap exists in the literature for establishing the least-cost pathways to mitigate an existing CFEGU, one for which component-level equations that utilize unique CFEGU attributes are required [120, 121, 129]. Hence, a bottom-up modeling approach from which the potential of the different mitigation options to achieve specific CO_2

emission intensity and associated mass targets is required to derive an CFEGU-specific, least-cost mitigation-technology frontier. Utilizing these frontiers allows one to determine the lowest LCOE to mitigate a specific CFEGU for a desired emission target, to evaluate the potential stranded assets for these options.[24]

The overall aim of this study is to identify CFEGU-specific least-cost frontiers for CO_2 emissions reduction that reveal the dependence of technological selection for carbon mitigation on CFEGU attributes and the level of emission reduction, by developing a model that can be used to improve mitigation-strategy development for the U.S. power-sector coal-fired fleet in 2030. This model can further be used to understand the key input factors to which the mitigation frontier is sensitive and how uncertainties in these factors, such as fuel price and CO_2 reduction policies, may affect CFEGU-mitigation choices. To achieve this, publicly available data are collected to construct econometric models to estimate CFEGU performance and cost without and with mitigations. These models are then compiled in the EGU-Specific Techno-Economic Assessment Model (ESTEAM) that uses empirical performance data to characterize each existing CFEGU and to assess performance and cost parameters for each retrofitted EGU in compliance with current clean air standards and associated CO_2 mitigation technologies. In Section 2, we describe the model structure, the mitigation technologies, and a probabilistic framework for analyzing model uncertainty. The model is applied to two CFEGUs in Section 3 to construct deterministic and probabilistic least-cost mitigation frontiers. Section 4 discusses the frontier sensitivity to CFEGU-specific factors such as heat rate, retirement age and fuel price. This section also presents applications of the model for evaluating regret from fuel-price

[24] The authors acknowledge that at this moment there is uncertainty in the regulatory environment, given the political ambiguity, in both the rate and horizon for transitioning to a net-zero carbon economy. The timelines used and emission-intensity targets discussed herein are for illustrating the function of the model as a policy tool.

uncertainty, determining breakeven conditions for mitigation choice under uncertain CO_2 tax and years to stranding assets, and to determine tax-incentive requirements for promoting CCS capacity. Conclusions are presented in Section 5.

Table 3.1. Carbon-dioxide reduction model mitigation technology options available for all existing coal-fired EGUs.

Model	EGU Treatment	HRI (Status)	Coal Rank	NG co-fire	Biomass co-fire	USC	NG retrofit	NGCC	CCS (NG aux)
DIEM [128, 129]	A	Y	Y	N	N	N	N	N	90% (N)
E4ST [128, 131]	I	N	N	N	N	N	N	N	N
EGEAS [106, 132]	I	N	N	N	N	N	N	N	N
Haiku [106, 133-135]	A	Y	Y	Y	Y	N	Y	N	N
ESTEAM	I	Y	Y	5-25%	N	Y	Y	Y	10-90% (Y)
IPM [106, 136, 137]	A	Y	Y	10%	10%	N	Y	N	90%(N)
MARKAL IN [138]	I	N	Y	N	10%	N	N	N	85% (N)
MARKAL OH [139]	I	N	N	N	10% or 15%	N	N	N	N
MARKAL 9 Region [140, 141]	A	N	N	N	N	N	N	N	90% (N)
NE-MARKAL [142]	I	N	N	N	N	N	N	N	N
NEMS [127, 130, 143, 144]	A	Y	Y	N	≤15%	N	Y	N	90% (N)
US-REGEN [130, 145]	A	Y	Y	Y	≤5%	N	Y	N	90% (N)

Notes: HRI: heat rate improvement; NG: natural gas; USC: ultra-supercritical; NGCC: natural gas combined cycle; CCS: carbon capture and storage; A: Aggregated; I: Individual; N: Not modeled; Y: modeled.

3.2 Materials and methods

3.2.1 ESTEAM model structure

In the bottom-up approach used in the ESTEAM model, five mitigating technologies making up nine mitigation options are evaluated: (1) CFEGU heat rate improvement (HRI), (2) upgrading coal rank, (3) retrofitting variable-bypass CCS with an auxiliary natural gas (NG) boiler to the existing CFEGU, and (4, 5) upgrading steam-generator type to supercritical (SC) or ultra-supercritical (USC) steam generators without the addition of CCS. In addition, we evaluate four scenarios for fuel switching from coal to NG: (6) co-firing NG with coal at levels from 5-25%, (7) conversion of the coal-fired EGU to a 100% NG steam generator, (8) replacement of the coal-fired EGU with a brownfield NGCC plant (a proxy for new NGCC capacity), and (9) supplanting generation from the brownfield NGCC plant with generation from a co-located utility solar or wind farm for deeper CO_2 emission reductions. These nine mitigation options constitute the CO_2 reduction solution space on which the least-cost mitigation frontier is defined. This frontier is determined by the intersection of the targeted CO_2 emission-intensity level and the mitigation option with the lowest LCOE to produce an intensity that is at or below the required level. In this analysis, CFEGU net generation is held constant before and after the mitigation, except for CCS retrofit; therefore, the intensity target can be inferred as a mass target for the CFEGU. When generation is variable, the mass frontier is the product of the net generation and the intensity results.

Performance and cost metrics to determine the least-cost mitigation frontiers for the existing coal-fired fleet modeled in ESTEAM are derived in part from the output of the Integrated Environmental Control Model (IECM) version 8.02, a power-plant simulation tool developed by Carnegie Mellon University [146]. The underlying equations for these metrics are developed,

Figure 3.1, in terms of unit configuration and operational data from several publicly available power-plant databases and categorized into six representative clusters, based upon coal rank and boiler type. Five or more representative CFEGUs with the same emission control configuration that span the range of net generation for each cluster are selected as proxies to model the cluster, from which the configuration and operational characteristics are used as inputs for IECM simulations to estimate the current capital and operation and maintenance (O&M) costs to calculate the LCOE (Eq. 3.1) and emission performance characteristics for the proxies.[25] The IECM is further used to estimate the proxy capital and O&M costs and CO_2 emission intensity with retrofits of traditional emission control devices (ECDs) necessary for compliance with nitrous oxide (NO_x) sulfur oxides (SO_x) and mercury (Hg) air-quality standards and with mitigation measures employed to meet different hypothetical CO_2 emission-intensity limits.

$$LCOE = \frac{CC \times FCF + FOM}{G_{net}} + VOM_{fuel} + VOM_{non-fuel} \tag{3.1}$$

where *LCOE* is the levelized cost of electricity (dollars per megawatt-hour, \$/MWh), *CC* is the EGU capital cost (\$), *FCF* is the fixed charge factor (fraction), *FOM* is the fixed operation and maintenance cost for the CFEGU(\$), G_{net} is the EGU net generation (MWh), VOM_{fuel} is the variable operation and maintenance cost related to fuel (\$/MWh), and $VOM_{non-fuel}$ is the non-fuel related variable operation and maintenance cost (\$/MWh).

[25] All modeled costs are in 2010 dollars.

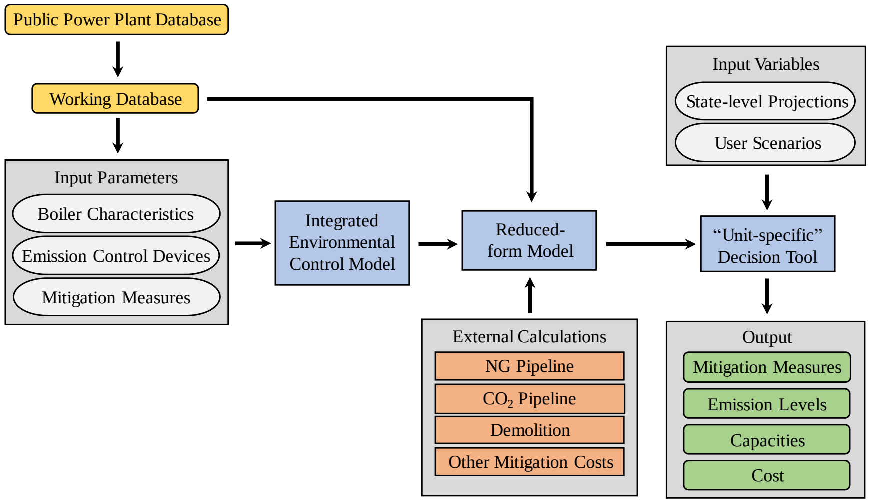

Figure 3.1. Schematic diagram of ESTEAM model construction and implementation for coal and boiler type clusters and resulting EGU mitigation equations.

Econometric analyses of the proxy results are then done to determine the emission and cost relationships that achieve both traditional air-quality and CO_2-compliance targets. These regression equations are augmented with those derived externally to the IECM that account for additional mitigations or mitigation-specific expenditures (e.g., demolition, and NG and CO_2 transportation costs) to complete the reduced-form model. The reduced-form model inputs concerning state-specific fuel prices, the capacity factor constraints placed on the historical dispatch of the CFEGUs, and the superposition of these mitigation technologies, then form the feasible set on which the least-cost frontier is defined for a specific CFEGU. Financial, operational, and mitigation assumptions used in the IECM and ESTEAM to determine the regressions and EGU least-cost frontiers are shown in Table 3.2, and the derivation of the regressions for LCOE and emission-intensity calculations for existing and mitigated EGUs are presented in *Appendix B, Section B.8*.

Table 3.2. IECM and modeling assumptions and parameters for ESTEAM: (a) financial, (b) operational, (c) mitigation.

(a) Financial

Parameter	Value
Year costs reported	2010
Dollar costs basis	Constant
Indexes for inflation	CEPCI*, CPI*
EGU project book life (years)	30 years
Solar Generation book life (years)	30 years
Wind Generation book life (years)	30 years
Discount rate (fraction)	0.071
EGU default fixed charge factor (fraction)	0.113
Renewable generation fixed charge factor (fraction)	0.11
EGU applied project life for fixed charge factor	Minimum 30-year book life or remaining life
EGU remaining value calculation	Straight-line amortization
Construction costs	Overnight

*Notes: CEPCI: Chemical Engineering Plant Cost Index; CPI: Consumer Price Index

(b) Operational

Parameter	Value
2030 CFEGU performance characteristics	2010
CFEGU retirement age	80 years
Transmission line loss (fraction)	0.075
Source coal and natural gas properties	IECM version 8.0.2
Source current and compliant CFEGU modeling and costing	IECM version 8.0.2
CFEGU current configuration	Pulverized coal, tangential wall, wastewater ash pond, no mixing fly ash disposal, wet-cooling tower, cold-side electrostatic precipitator
Year compliant with non-CO_2 air quality regulations	2016
NO_x compliance combustion controls	Low NO_x burner (LNB)
NO_x compliance post combustion controls	Hot-side selective catalytic reduction (SCR)
SO_x compliance post combustion controls	Wet flue-gas desulfurization (FGD)
Hg compliance post combustion controls	Carbon injection

(c) Mitigation

Parameter	Value
Regional construction adders	None
Source HRI improvement standard	IECM version 8.0.2
Maximum relative HRI (fraction)	0.5
Maximum absolute HRI (Btu*)	1,205
HRI cost ($/kW*-net)	100
Definition NG co-fire operation	Simultaneous firing coal and NG
NG co-fire performance calculation	Linear interpolation 5-25%
NG co-fire maintenance	None required for up to 25% co-fire
Steam generator upgrades	No CCS requirement
Baseline NG retrofit cost ($/kW)	62 (range: 50 to 75)
Baseline capacity for cited CFEGU retrofitted for NG (MW*)	215
Power rule coefficient for economy of scale	0.6
Increase in heat rate due to NG retrofit (Btu)	200
Increase in net capacity due to NG retrofit (MW)	5
NGCC turbines type	GE 7FB
NGCC net generation constraint	Matches 2010 generation
CCS net generation constraint	Extra generation sold to grid
CCS performance calculation	Linear interpolation 10-90%
CCS capture method	Post combustion, Fluor, FG+ amine
CCS capture efficiency (fraction)	0.90
CCS flue bypass control type	Bypass
CCS power and steam source	Auxiliary gas-fired boiler
CCS thermal efficiency of auxiliary gas power system (fraction)	0.35
CCS SO_x polisher use	Yes
CCS CO_2 purity (fraction)	0.995
CCS CO_2 transportation method	Pipeline
CCS CO_2 storage method	Geological
CCS pipeline distance	Line-of-site to center of reservoir
NG and CO_2 pipeline O&M cost ($/mile/year)	5,000
NG pipeline distance source	Modified EPA estimates
Pipeline electric compressor station spacing (miles)	50
Modeled solar generation capacity (MW)	150
Modeled wind generation capacity (MW)	100
Solar generation capital cost ($/kW)	825
Wind generation capital cost ($/kW)	1,189
Solar generation O&M cost ($/kW/year)	9.9
Wind generation O&M cost ($/kW/year)	39
NG co-fire, coal rank upgrade, steam-generator upgrade, NGCC, CCS CFEGU mitigation modeling and costing source	IECM version 8.0.2

*Notes: Btu: British thermal unit; MW: Megawatt; kW: kilowatt

3.2.2 Power plant databases

This study uses three databases to provide 2010 operational information to determine the model regressions and the least-cost frontiers: the U.S. Environmental Protection Agency's National Electric Energy Data Systems (NEEDS) version 5.13 from the [147], the ninth edition of the U.S. Environmental Protection Agency's Emissions and Generation Resources Database (eGRID) version 1.0 [148], and the Federal Energy Regulatory Commission's (FERC) Form 1 data [149]. The 2010 databases were chosen over more recent databases because the greater CFEGU population provides a richer dataset with more variation in unit attributes for the econometric analysis. While 2010 databases are used as the base year for illustrative purposes, we assume that these databases are still representative of operational parameters in subsequent years. Some parameters for the calculations are unlikely to vary with time (capacity, fuel type, boiler type, and configuration), whereas other parameters that will affect the CFEGU heat rate and emissions (capacity factor, coal quality, ambient and water temperature, scheduled and unscheduled maintenance) may change [150]. However, these EGU-specific parameters will vary on a yearly basis and the model assumes that these conditions are brought forward to 2030, for comparative purposes. Six hundred and thirty-five coal-fired EGUs from 2010 that meet the operational criteria outlined in *Appendix B, Section B.8* are modeled to determine the general regression equations and coefficients for the operational metrics of a generic CFEGU, and that CFEGU configured with the requisite ECDs and the mitigation technologies. For subsequent analysis, the input parameters (for configuration or operation) for any CFEGU in the database can be updated from the 2010 values with more recent or site-specific values to determine the current least-cost frontier for the CFEGU.

3.2.3 EGU-level mitigation technology frontiers

This section provides an overview of the modeled CO_2 mitigation options. Detailed discussions of the mitigations are presented in *Appendix B, Section B.8.6*. Carbon dioxide mitigation upgrades that may trigger a New Source Review because of excessive fixed capital costs [151], such as for the SC and USC upgrades, are not excluded from this study. Furthermore, to avoid triggering a possible modification review because of an increase in overall emissions mass or intensity [152], all required ECDs are applied to the CFEGU for mitigations that retain coal use, if lacking, to conform to new source non-CO_2 emission standards, and CFEGU net generation is not increased after the upgrade so as to limit the possibility of increasing the hourly emissions of these pollutants and CO_2. Mitigations using biomass as a fuel to achieve low- or net-zero emissions are not considered in this model because the availability, quality, and cost of biomass for specific CFEGUs varies greatly and the carbon mitigation benefit of biomass use for CFEGUs in 2030 should be evaluated on a life cycle basis, which are currently beyond the scope of the model.

3.2.3.1 Improving plant heat rate

The efficacy of any given HRI project may vary from site-to-site and multiple improvements are not necessarily additive [153, 154]. Furthermore, the maximum improvement may depend upon the coal rank, steam generator type, and operating pressure of the CFEGU. Therefore, any heat rate improvement modeled in ESTEAM is an incremental improvement relative to a “gold standard” [102] that is based upon the net heat rate for a newly-constructed subcritical or SC plant at IECM default conditions for different ECD configurations for each of the six CFEGU clusters, Table B.50. This modeled improvement is limited to a maximum of 50% of the gap between the current heat rate and the “gold standard” heat rate, up to a maximum improvement of 1,205 Btu for the mechanical upgrades that can be achieved at an improvement cost of $100/kW-net [155].

3.2.3.2 Upgrading coal rank

Retrofitting an CFEGU to consume high-quality coal to reduce fuel use and CO_2 emissions is a mitigation option that can be applied to some CFEGUs, depending upon the extent of the required redesign and existing coal contracts (the counterparties of which face their own issues with stranded assets) [76]. The study dataset only indicates the quality rank of coal consumed, so a proxy coal is employed for each of three ranks: North Dakota is the lignite proxy; Wyoming Powder River Basin is the sub-bituminous proxy; Illinois #6 is the bituminous proxy, Table B.33. To determine the change in heat rate, parasitic load, CO_2 emission intensity, and LCOE related to a fuel upgrade, the performance of the proxy CFEGUs are simulated in IECM for each fuel type from which regressions are estimated to evaluate these parameters for other CFEGUs in each ESTEAM cluster.

3.2.3.3 Upgrading steam generator

Upgrading the existing plant steam cycle with new SC or USC steam generators and turbines can improve efficiency, thereby decreasing CO_2 emission intensity by more than 23% and 48%, respectively, over a new subcritical boiler [105]. LCOE calculations for these measures comprise the capital costs for demolition of the existing steam generator and turbine, the capital costs for the new steam generator and turbine, and the related change in O&M costs to produce the same net generation.

Carbon capture and storage retrofitting for these upgrades is not considered. The primary reason for this is that application of this technology would greatly increase the capital cost to the point where this option would always be dominated by retrofitting CCS to the current boiler. A secondary reason is that upgrading the boiler is assumed to extend the life of the CFEGU to at least 30 years, for which stranded costs are a concern. This longer life than that for the existing CFEGU also enables the upgraded CFEGU to be a candidate for retrofitting with a second-generation CCS technology for deeper reductions should future regulation require this action, which avoids immediate CCS lock-in and may offer lower costs [122, 124].

3.2.3.4 Co-firing with NG

The CO_2 emission-intensity reduction from co-firing with NG for any CFEGU is proportional to the co-fire rate and dependent upon coal rank. Three assumptions are made to implement co-firing in ESTEAM. First, co-firing implies simultaneous, not sequential, use of coal and NG to produce steam. Second, linear interpolation between 5% and 25% can be used to determine performance at intermediate co-fire rates. Third, maintenance costs related to slagging in the boiler that may be required between 20-25% co-fire [114] are negligible. The LCOE calculation for this mitigation includes capital and O&M costs for retrofitting, construction and maintenance of any required pipeline to bring the NG to the CFEGU, and the cost of the NG fuel.

3.2.3.5 Conversion from coal to 100% NG steam generator

Operating the coal-fired EGU solely with NG will result in a decrease in CO_2 net emission intensity of almost 50%. This conversion (designated NG retrofit) necessitates some additional cost for retrofitting, but also avoids expenses related to upgrading the CFEGU for emission compliance and encompasses reductions in the nonfuel O&M costs. Therefore, the LCOE includes the retrofit costs, the remaining capital costs for the base plant and the fitted emission controls, any necessary NG pipeline costs, and the new O&M costs.

3.2.3.6 Conversion from coal-fired EGU to NGCC plant

Rather than add gas turbines and heat recovery steam generators to the coal-fired EGU and retain the coal-fired boiler to achieve a 6-31% reduction in CO_2 emission intensity [115], converting the CFEGU completely to NGCC may result in the CO_2 emission intensities expected for a new, conventional NGCC plant, 803 lbs/MWh—a reduction of up to 70% relative to the coal-fired EGU with the highest emission intensity in the dataset [146]. Furthermore, the NGCC plant can be 50% more efficient than a NG-retrofitted CFEGU. While the overall fuel cost may be substantially lower than that for a NG retrofit, the capital cost is higher. When the demolition cost for the old plant is included, the total cost is almost the same as the cost for building a new plant. A brownfield project may still be a more attractive option than building a new plant, since the existing general facilities, wet-cooling tower and transmission lines may still be used.

For the modeled conversion, based upon NGCC plants simulated in the IECM, the CFEGU is retained and only the steam generator and turbine are replaced, while now unnecessary assets are retired with the associated expenses considered as negligible or covered by previously-incurred asset-retirement obligations [157, 158]. The LCOE for the new plant then comprises the demolition cost for the coal-fired steam generator and turbine, the capital and O&M costs for the new plant, and the possible additional retrofit costs associated with installing a new NGCC in an old facility. If natural gas is not available at the site, any required NG pipeline capital and O&M costs are included. The number of turbine stages and the capacity factor for the plant are constrained to meet but not exceed the net generation of the coal-fired EGU; this constraint may impose a heat rate penalty that will increase the emission intensity because the plant is not operating at the maximum achievable load [159-163].

3.2.3.7 Conversion from coal-fired EGU to NGCC plant with co-located renewable sources

Substituting generation from the NGCC conversion with that from co-located renewable sources, such as a utility solar photovoltaic [164] or onshore wind [166], is one potential mitigation measure to immediately achieve deep CO_2 reductions with NGCC without the possibility of lock-in with first-generation CCS [123]. In this mitigation, the established NGCC plant capacity is augmented with renewable capacity sufficient to achieve emission-intensity reductions deeper than that obtained with the standalone NGCC plant, on a generation-weighted average basis. The NGCC plant is not resized according to the required generation mix to meet the emission intensity goal so that any deficiency in renewable generation due to a decrease in the renewable utilization can be offset with increased generation from the NGCC plant. Furthermore, a heat rate penalty is applied for an NGCC plant because of a decrease in its capacity factor from integration with the co-located renewable source [159, 163]. The resulting LCOE and CO_2 emission intensity for any intensity target are the generation-weighted averages from the standalone NGCC and the renewable plants.

3.2.3.8 Retrofitting CCS

Commercially-available amine-based CCS is adopted for CO_2 capture (with a removal efficiency up to 90% for the coal-fired steam generator) to meet the reduction goal, in which a bypass design is used to achieve partial CO_2 capture for retrofitting to the existing CFEGU [120, 121]. The choice of energy-supply configuration for the CCS solvent-regeneration process may affect the frontier solutions (*Appendix B, Section B.8.6.9*). For this model, the steam required for this process is provided by an auxiliary NG-fired power-generation system, from which CO_2 is not captured, rather than by extracting low-quality steam from the steam cycle to meet these requirements (thereby reducing net generation) [166], or by augmenting either the auxiliary boiler or the CFEGU with renewable energy to provide electricity to further reduce emissions [167]. Any surplus generation from the auxiliary boiler is available to the grid. The LCOE calculation includes the capital and O&M costs associated with the CCS subsystem, the pipeline networks for the NG and the CO_2 transportation, and the CO_2 sequestration. The siting of the CO_2 pipelines is determined by the lowest-cost transportation and storage cost for unique CFEGUs, based upon line-of-sight, rather than from aggregating EGU storage requirements and creating intricate networks [168-171].

3.2.4 Probabilistic confidence bounds

The relative position of the mitigation measures on and off the frontier can change given uncertainty in the values for the LCOE and emission intensity. This uncertainty can consist of at least three types of error: projected fuel price, capital and O&M costs, and model. The projected fuel price error relates to the accuracy of Energy Information Administration (EIA) projections for the percent increase in the NG and coal prices from 2012 to 2030. The capital and O&M errors reflect uncertainty in the process and project contingency capital-costs[26] for the emission

[26] The process contingency cost increase reflects the impact of performance and cost uncertainty for the device or mitigation technology on the overall related capital cost. The project contingency cost increase reflects the cost increases that may be seen with a more detailed cost estimate of the device or mitigation [172].

control devices and mitigation measures, and to the sequestration costs. Finally, the model error captures the residual error in the regression equations used to model the various CFEGU operating parameters, and also encompasses the historical variation in the calculated CFEGU net heat rate[27] (Table B.6) and the associated emission intensity from years other than 2010.[28] The resulting total estimated error, or tolerance limit, from the combination of the relevant error components for a mitigation measure is calculated from the summation of these components. When more than two components of these errors for a given mitigation are combined, the root-sum-squared tolerance technique is used to determine the 95% confidence LCOE and emission-intensity bounds for the mitigation; otherwise, the components are directly summed. Since these uncertainties are ultimately expressed in the frontier as LCOE and intensity pertaining to a specific CFEGU with unique geographical, operational, and financial parameters, a Wisconsin EGU (ORIS Unique ID 4050_B_5) is used to illustrate the various techniques applied to bound these uncertainties and the resulting tolerance limits. This CFEGU is also modeled in the IECM in the current, compliant, and mitigated states, which are modeled either entirely or partially in the IECM with the appropriate external calculations added, to validate the ESTEAM calculations for LCOE and intensity relative to these limits (See *Appendix B, Section B*.9).

3.2.4.1 Projected fuel price error

The error terms for the NG and coal prices in 2030 are determined from the difference between the projected and actual NG and coal prices, in constant dollars, at a 15-year horizon that is given in the EIA's 2017 Annual Energy Outlook Retrospective Review dataset [175, 176]. This

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[27] The heat rate variation is calculated from the yearly coal heat content, quantity consumed, and the net generation produced by the EGU, as found in EIA form 923 [173].

[28] Carbon dioxide intensity is calculated from this heat rate and the pounds of CO_2 per million Btu for the coal type, as defined by the EIA [174].

horizon was chosen because the 2016 Annual Energy Outlook (AEO) is the most recent report used in the 2017 retrospective, which examines the errors from other AEO reports to 2015: a 15-year horizon to 2030. With this horizon, nine data points are specified that start with the 2007 projected prices from the AEO 1994 report and end with the 2015 projected prices from the AEO 2002 report (Table B.7). Over this period the underestimation and overestimation of the EIA projections may have changed in a nonrandom manner because of several possible systematic externalities, such as changes in economic conditions and technology advances [177, 178]. Projection errors prior to the AEO 1994 report are excluded because of a change in projection protocol prior to this report [179].

An estimation of the possible projection errors in 2030, based upon the AEO 2016 percent increase in projected prices from 2014, is determined by fitting distributions to these nine points for the NG and coal errors and then simulating the mean errors and standard deviations in these projected fuel prices. The distribution for the NG error best fits a Fischer-Tippett Type II distribution, while the best-fit distribution for the coal error is a logistic distribution (Table B.8) that is negatively correlated to the NG error (Table B.9).[29] A 10,000 paired-point simulation to create these distributions (Figures B4-5, Table B.10) indicates that the EIA may be underestimating the projected fuel price by more than 10% for each commodity and that the projected percent coal price error may be greater than that for NG, in the examined time periods (Table 3.3). The standard deviations on these percent errors in the actual price are similar at about 24%.

[29] Best-fit is determined with the Kolmogorov-Smirnov two-tail test for $\alpha=0.05$.

Table 3.3. Simulation values for percent difference in projected natural gas and coal price error for a 15-year horizon, as determined in the EIA Annual Energy Outlook Retrospective Review [176]. Negative values indicate projected price underestimated actual price.

Fuel	Mean	Standard. Deviation
Natural Gas	-12.9%	26.7%
Coal	-29.1%	22.9%

These descriptive statistics and the underlying simulation are used in two ways. First, the standard deviations for the two fuels are applied in the tolerance analysis to determine the related LCOE for an EGU because of variations in fuel price related to this error. Second, the simulated projection of correlated error-paired distributions is used to determine the expected values for the projected fuel prices, given the prior for the percent change in fuel prices. The error range for this paired distribution, Figure B.6, is also partitioned into nine regions of equal area to determine the likelihood of the projected price error for each fuel to be in a given region and to calculate the expected values for that region, Figure 3.2 and Table B.12.

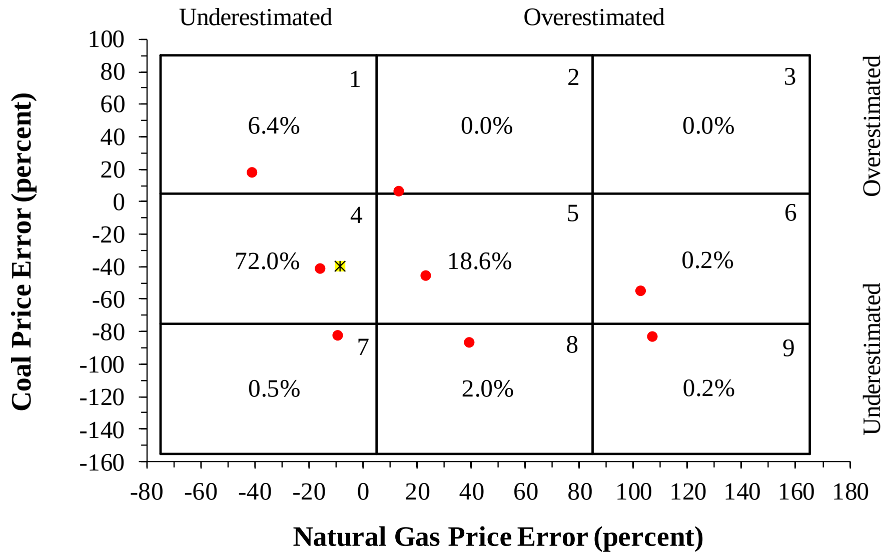


Figure 3.2. The likelihood and expected values of the percent difference in projected natural gas and coal price errors dividing into nine, equally-sized regions (identified in upper-right-hand corner of each rectangle). Red dots represent the expected value of the mean projected errors for the region. The expected value of the projected errors for all regions is marked with an asterisk. Negative values indicate underestimating projected price and positive values indicate overestimating projected price.

3.2.4.2 Capital and O&M error

For the cost errors, the initial capital and O&M costs of the various CFEGU subsystems used to calculate current and mitigated LCOE are EGU-specific and unknown. While some capital and O&M costs and variations are taken from the literature previously cited, the capital costs for the CFEGU subsystems used in the IECM to determine the regressions are non-probabilistic values from literature [116, 66, 172, 180, 181]. Therefore, the uncertainty related to the current and compliant configurations and to mitigate measures for a specific CFEGU cannot be known directly; however, the sensitivity to this uncertainty can be observed by bounding the associated parameters. For this analysis, two levels of various cost components are considered that are either set parametrically by the authors, taken from literature, or are the minimum and maximum values set in the IECM, Table 3.4. Uncertainty in emission control device capital cost for the IECM modeling is expressed as the percent change in the process facility capital (PFC) from variation in the device process contingency cost (PCC), while that for mitigation measures is expressed as the percent change in the PFC from variation in the mitigation process and project contingency capital costs, and in the variation for the retrofit cost. A further PCC cost adder is used for CCS retrofit calculations to represent the greater uncertainty in costing this early-development-stage technology. While some O&M errors are addressed through fuel price variation and modeling residuals related to regressions on factors, such as heat rate, the variation in CO_2 storage cost is taken parametrically as the 90th percentile and 10th percentile storage costs for the sequestration sites given in the National Energy Technology Laboratory (NETL) CO_2 Saline Storage Cost Model [182].

Table 3.4. Capital and O&M cost error levels for current, compliant and mitigated CFEGU configurations. Default levels represent those used in the deterministic modeling, while the Low, and High levels are used for uncertainty analysis.

Device or Mitigation	Parameter (units)	Default	Low	High
NO_x LNB	$retro/$new (fraction) *	1.00	1.00	1.20
NO_x Hot-side SCR	PFC for process contingency cost (fraction) *	0.07	0.00	0.20
SO_x Wet FGD	PFC for process contingency cost (fraction) *	0.02	0.00	0.20
Hg	PFC for process contingency cost (fraction)*	0.05	0.00	0.20
CCS	PFC for process contingency cost (fraction)*	0.05	0.00	0.70
	PFC for project contingency cost (fraction)*	0.15	0.00	0.35
SC	Retrofit multiplier (fraction)*	1.00	0.80	1.20
USC	Retrofit multiplier (fraction)*	1.00	0.80	1.20
Coal Rank	Retrofit multiplier (fraction)*	1.00	0.00	1.20
NG Co-fire	Gas reburn cost ($/kw-g) †	19.67	2.00	30.00
	$retro/$new (fraction)*	1.00	1.00	1.20
NG Retro	Retrofit cost ($/kW) ‡	62.00	50.00	75.00
NGCC	Capital cost multiplier (fraction)*	1.00	0.80	1.20
NG Pipeline	Miles multiplier (fraction)*	1.00	1.00	1.20
	Cost error multiplier (fraction)§	1.00	0.58	1.42
CO_2 Pipeline	Miles multiplier (fraction)*	1.00	0.80	1.20
	Cost error multiplier (fraction)§	1.00	0.58	1.42
CO_2 Storage	Storage cost ($/ton percentile) ¶	P50	P90	P10

*Author chosen limits; †Limits in IECM [172]; ‡Limits from [113]; §Limits based upon [183]; ¶Limits from [182].

3.2.4.3 Model error

As the regression equations in *Appendix B, Section B.8* that describe the mitigation measures are unique to the mitigations, so too are the model errors related to the regression residuals. However, errors associated with modeling the compliant CFEGU will propagate through mitigation measures that retain the emission control devices and the current base plant. Residual error components that affect the mitigation LCOE that are not already in terms of $/MWh are expressed so with the application of the appropriate net generation, FCF, and fuel prices. Similarly, the error components for the emission intensity that are not already in terms of intensity are expressed as such with the application of the appropriate net heat rates, net generation, and fuel properties.

3.3 Results

3.3.1 Deterministic least-cost frontier

As an example of the construction of the least-cost mitigation technology frontier, consider the sub-bituminous EGU in Wisconsin at the 2030 state-specific, base-case fuel prices (Table B.86). For this example (Figure 3.3), the EGU without HRI and in the 2010 configuration has a 2,130 lbs/MWh[30] emission intensity that does not meet a hypothetical CO_2 emission-intensity target of 1,500 lbs/MWh MWh (for illustrative purposes), defined by the black dashed line—a 30% emission intensity reduction (i.e., the “Current” point at 2,130 lbs/MWh is to the right of the dashed line). Furthermore, the addition of the necessary ECDs to the existing CFEGU increases the LCOE by 32%, while having almost no impact on the emission intensity, with implementation of the described HRI. In this case, the compliant CFEGU (labeled “Compliant”) does not meet the CO_2 emission-intensity target, so mitigation is required.

[30] Conversion factors from U.S. Customary units to Standard International units are provided in Table B.87.

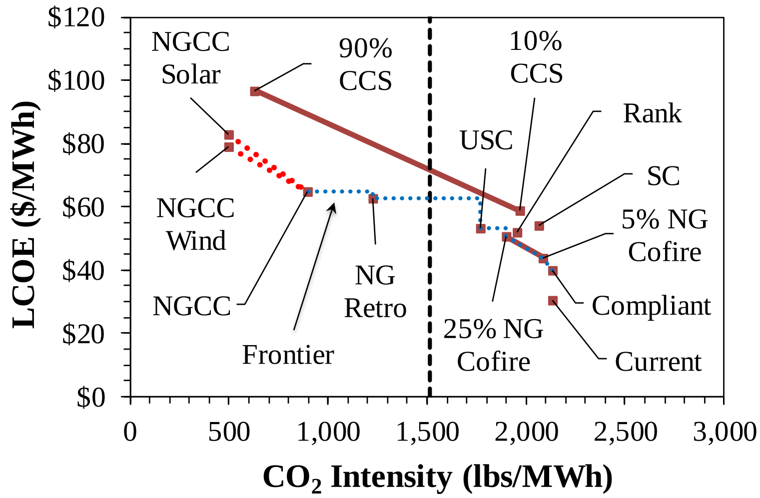


Figure 3.3. Least-cost frontier (dotted blue line) for a sub-bituminous-fired EGU in Wisconsin. The dashed, black line represents the target CO_2 emission intensity (net) for the CFEGU. Solid red lines represent the loci of solutions for different levels of NG co-fire and CCS capture rates. The dotted red lines illustrate the two paths for further CO_2 emission-intensity reductions with renewable energy for the NGCC mitigation. LCOE reported in 2010 dollars.

For an emission target lower than the 2,130 lbs/MWh in the compliant configuration, switching to NG co-fire (labeled "NG co-fire") at 5% to 25% levels is the least-cost measure, at a LCOE of $44-51/MWh, to affect an intensity decrease to 2,085-1,900 lbs/MWh. Below this intensity, the frontier must move to a singular point associated with the USC steam-generator upgrade (labeled "USC") for intensity targets between 1,900 to 1,770 lbs/MWh, as using CCS will incur greater costs. Therefore, the least-cost mitigation solution for this CFEGU to achieve a 17% emission intensity reduction is to upgrade to a USC steam generator. If reductions are required beyond this point, converting the boiler to a 100% NG steam generator is needed (labeled "NG Retro"). This mitigation will further reduce the emission intensity by 42% to 1,230 lbs/MWh, with an associated LCOE of $62.7/MWh. If reductions are required beyond this point, a brownfield conversion to an NGCC plant is needed (labeled "NGCC"). This conversion will reduce the existing emission intensity by 58% to 900 lbs/MWh, with an associated LCOE of $64.7/MWh. The least-cost mitigation options to achieve greater intensity reductions involve replacing the NGCC generation with that from co-located wind.

Alternative mitigation profiles can also result from different commodity prices, illustrating the importance of EGU-specific analysis to determine the frontier. For an CFEGU in Iowa without HRI, Figure 3.4 (a, c), the higher price of bituminous coal relative to both sub-bituminous coal and NG prices (Table B.86) results in NG co-fire dominating rank upgrade for co-fire rates up to 19%. With application of the HRI, Figure 3.4(b, d), NG-cofire dominates rank upgrade only to 15% co-fire. Beyond the rank upgrade intensity, the least-cost mitigation for each case is again USC. However, a higher NG price encourages deployment of CCS for partial capture rates between 18% and 43%, before the introduction of the NGCC conversion. NG retrofit mitigation is not on the frontier for this CFEGU, in part because the lower efficiency for this mitigation coupled with the higher NG price increases the VOM_{fuel} sufficiently to exceed the LCOE for the NGCC conversion.

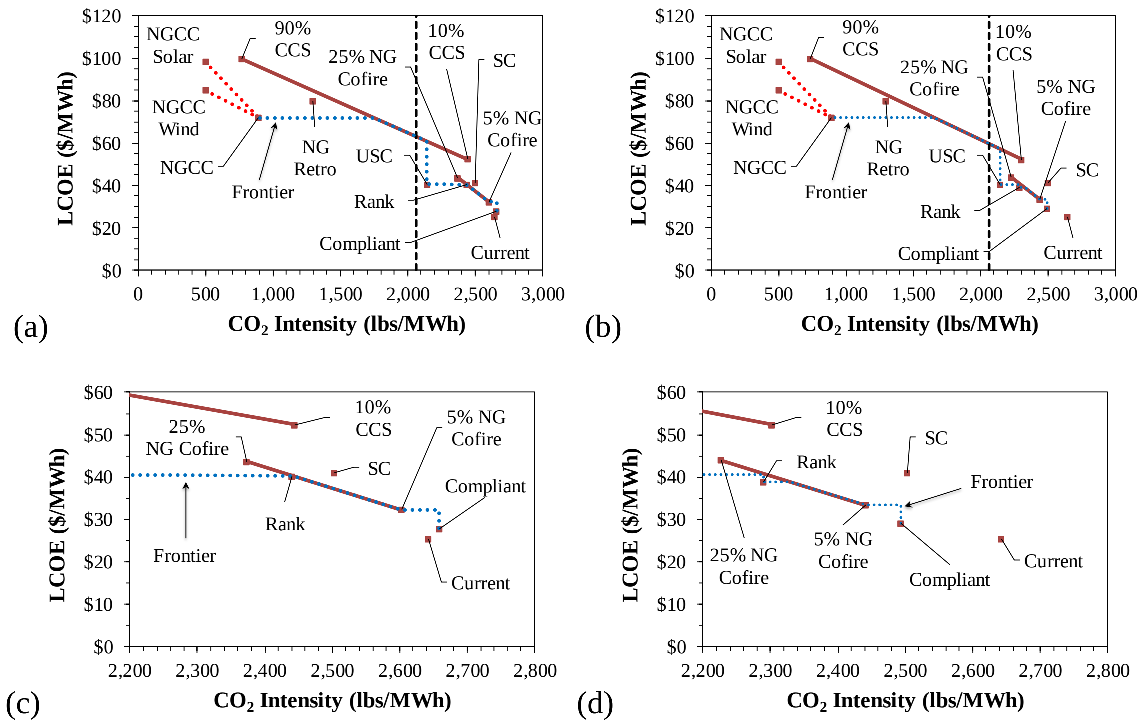


Figure 3.4. Least-cost frontier for a sub-bituminous-fired EGUs in Iowa. Panels (a) and (c) show the mitigation measures without the heat rate improvement. Panels (b) and (d) show the mitigation measures with the heat rate improvement.

The least-cost frontier for capital costs, which is relevant for stranded assets, presents a different profile for the Wisconsin CFEGU (Figure 3.5). Here, the lower cost for rank upgrade dominates NG co-fire for mitigations down to 1,960 lbs/MWh. Beyond this level, NG retrofit dominates for intensity reductions up to 42% of the current emission intensity, while deeper reductions again entail conversion to a brownfield NGCC plant, without and with co-located wind generation. The juxtaposition of the former preference of NG co-fire and USC-upgrade mitigations for rank upgrade and NG-retrofit mitigations at reduction levels up to 17% implies that information about the capital cost of the mitigation may change the mitigation decision, when stranded assets are also of concern. Additionally, the further dominance of NG retrofit for lower LCOE and capital costs for reductions up to 42% suggests that this may be a dominant mitigation for reductions targeted at IPCC 2030-levels in states where NG price is competitive with coal prices and there is concern for stranding assets beyond 2030. Such dominance may also be true for the higher capital cost NGCC mitigation when deeper reductions are required. Here, the combination of the NGCC generation with co-located wind generation dominates mitigating the existing CFEGU with CCS at 90% capture rate. Doing so to achieve the 90% capture intensity requires the addition of 306 MW of wind capacity for this CFEGU, however.

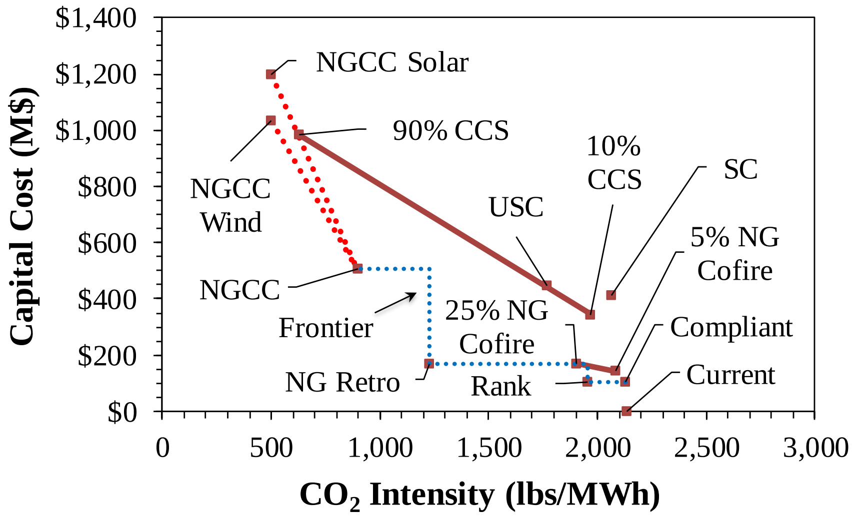
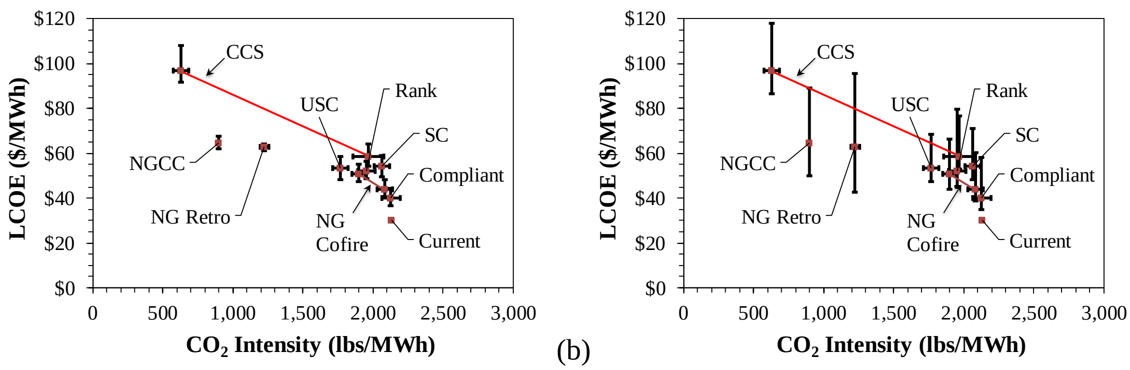


Figure 3.5. Mitigation capital cost frontier (dotted blue line) for a sub-bituminous-fired EGU in Wisconsin. Solid red lines represent the loci of solutions for different levels of NG co-fire and CCS capture rates. The dotted red lines illustrate the two paths for further CO_2 emission-intensity reductions with renewable energy for the NGCC mitigation.

3.3.2 Probabilistic confidence bounds

The 95% confidence limits for the mitigation LCOE and emission intensity can be considered without and with the projected fuel price uncertainties, Tables B.13-B.28. For the Wisconsin CFEGU, superimposing the confidence limits, without the fuel uncertainty, on the mitigation options shows that, in many instances, it is difficult to discern one mitigation from another for at least one attribute, Figure 3.6(a). While the emission intensities for CCS at 90% capture rate, NGCC, NG retrofit, and USC mitigations are statistically different for deeper reduction requirements, those intensities for the other mitigations are not and the sought gains in intensity reduction may not be achieved. Similarly, while CCS at 90% capture rate has a greater LCOE than any other mitigation, the LCOE for the NGCC and NG retrofit mitigations are not statistically different from each and all other mitigations, except 5% NG co-fire. Therefore, the least-cost frontier for a CFEGU may change given EGU-specific information about the cost of the mitigation project. Even so, it is still possible to discern that many CCS capture rates will be more costly than other mitigations to achieve the required emission intensity, and that NG co-fire may be the least-cost mitigation to achieve shallow CO_2 reductions.



(a) (b)

Figure 3.6. Mitigation model uncertainty, excluding NGCC co-located renewable source, for a compliant Wisconsin CFEGU. Ninety-five percent confidence limits are shown without (a) and with (b) fuel price uncertainty.

When the projected fuel price uncertainty from the correlated simulations of the EIA's 15-year fuel-price projections is included, the LCOE overlap between mitigations is even greater,

Figure 3.6(b). Therefore, the projected fuel price uncertainty dominates all other LCOE-related error components and minimizes the consideration of the choice of the high level for these components. However, it should be noted that the fuel price uncertainty is propagated through the mitigations rather than being random for each.

3.4 Discussion

In this section, we use the model to examine the sensitivity of the EGU-specific least-cost frontier to several factors. We first reference the CFEGUs in the previous section to show how parameters such as mitigation-option availability and EGU-specific characteristics can impact the frontier. The probabilistic analysis results are then input into the model to illustrate how the uncertainty in fuel price affects the least-cost frontier and can lead to regret from the *ex ante* mitigation choice. We conclude with an example of the sensitivity of mitigation choice to a CO_2 emissions tax and how this choice and the least-cost frontier may change with a CO_2 permanent sequestration tax credit. Additional discussion of using this technique to analyze the rate-based approach to reduce emissions in the CPP is found in *Appendix C*.

3.4.1 Sensitivity

The least-cost mitigation frontier is sensitive to several EGU-specific parameters that are mitigation dependent (See *Appendix B, Section B.*5 and *Section B.6* for dataset observations and *Section B.10* for a detailed sensitivity assessment). If boiler heat-rate degradation occurs (from cycling, insufficient maintenance, and age), the LCOE for mitigations that retain the boiler will increase because of the increased fuel costs. However, the LCOE for mitigations through repowering will not increase, thereby affecting the relative positions of the mitigations on the frontier. The LCOE for mitigations that require the addition of pipelines for fuel or effluent may move onto and off the frontier as the pipeline costs decrease and increase. Furthermore, the effective co-fire and capture rates for which NG-cofire and CCS mitigations are on the frontier will vary if some mitigation options are not available.

The CFEGU-specific boiler age may also affect the FCF for mitigations because of expected retirement, which can be a proxy for restricting the operation of any fossil-fuel mitigation solution beyond 2030. If the boiler is only able to operate until 2050, because of age or regulatory requirement, then the CFEGU FCF increases to 13%. This increase does not change the mitigations on the frontier, Figure 3.7(b), but does asymmetrically increase the LCOEs for all mitigations, according to capital costs from Figure 3.5. Restricting the operation further to 2040 increases the FCF to 18% and increases the mitigations with high capital costs further from the original frontier, Figure 3.7(c). Here, the low capital cost of NG retrofit as a moderate emission-reduction mitigation is less affected by the higher financial premiums that may come with possible stranding.

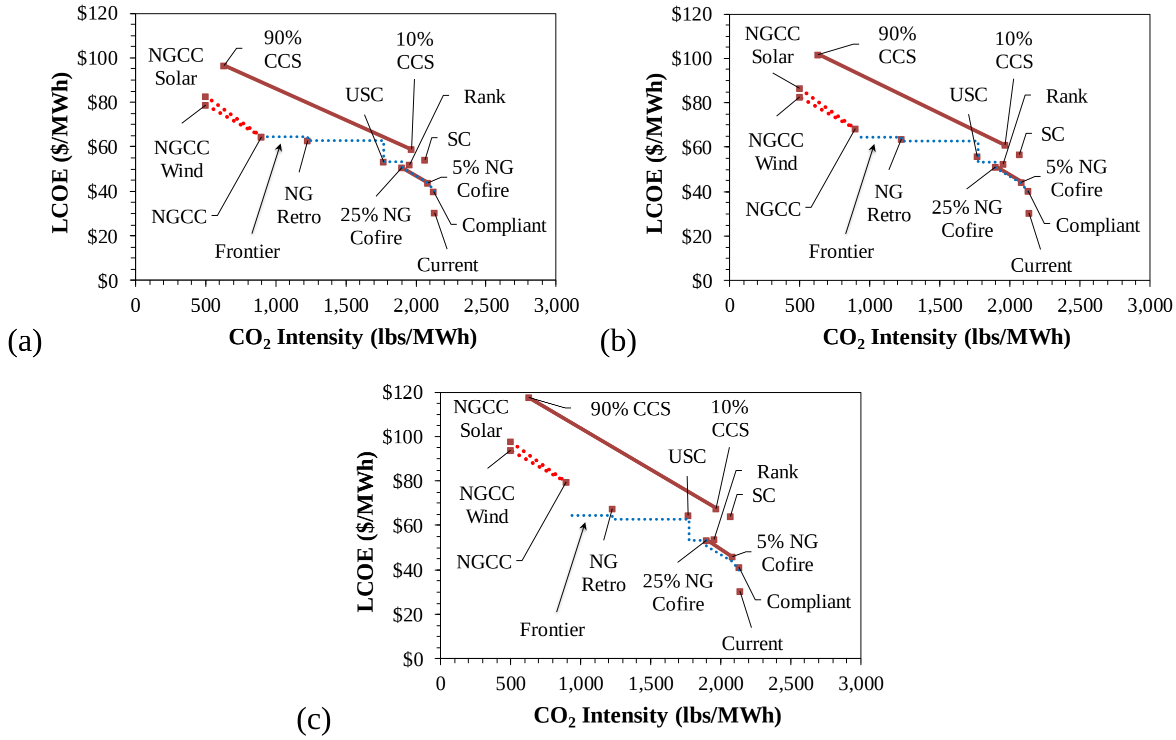


Figure 3.7. Sensitivity of the Wisconsin CFEGU least-cost frontier to FCF for multiple book lives: (a) default 30-year, (b) 20-year, and (c) 10-year.

Another EGU-specific characteristic is fuel price, for which a relative change in fuel prices can affect the rates for which CCS and NG co-firing are viable. A higher NG price relative to the coal prices (Figure 3.3, 3.4) may decrease the VOM_{fuel} costs for CCS and NG co-fire mitigations relative to those for mitigation options with full NG conversion, thereby expanding the range of viable rates. However, the higher NG price may also decrease the rates at which those options are viable relative to mitigation options that are exclusively coal-based. This sensitivity of mitigation choice to fuel price variation is seen directly in Figure 3.8. Here, the areas of interest for preference occur when the fuel price variation is such that the LCOEs for employing the competing mitigations are equal and the choice will depend upon the emission intensity target.

This is illustrated for a hypothetical 1,500 lbs/MWh intensity target that achieves a 30% reduction in emission intensity for the Wisconsin CFEGU, Figure 3.8(a), for which three mitigation technologies are possible: NG retrofit, NGCC conversion and CCS. At the default fuel prices, NG retrofit dominates for least-cost at approximately $63/MWh and achieves an over-reduction in intensity of 270 lbs/MWh. However, as the NG price increases at the default coal price, the NGCC conversion is preferred when the NG price increases more than 15%, due to the lower intensity achieved at a lower LCOE because of the higher efficiency for this technology. Therefore, at and to the right of this NG price increase, NGCC mitigations are preferred because of the lower LCOE and emission intensity than the NG retrofit mitigation. To the left of this NG price increase, NG retrofit is preferred to NGCC mitigation because of the lower LCOE and an emission intensity that is lower than the target.

If the coal price decreases by 15%, at the 15% NG transition price, CCS at a 38% capture rate will have a lower LCOE than the NGCC mitigation and achieve the original target of 1,500 lbs/MWh. It is at an approximate point of just more than a 15% increase in NG price and just less than a 15% decrease in coal price that the three mitigation technologies will have similar LCOEs, but NGCC is preferred because of its lower emission intensity. Here, for an increasing NG price coupled with an increasing coal price, a loci of similar NGCC and CCS (at a constant 38% capture rate) LCOEs can be formed at which NGCC is still preferred because of its lower intensity. Similarly, though at a different slope due to the lower efficiency of the NG retrofit mitigation, a loci for NG retrofit and CCS (at a constant 38% capture rate) LCOEs can be formed from a decreasing NG price coupled with a decreasing coal price for which NG retrofit is preferred over CCS. In each case, a variation in NG and coal prices can also be defined that results in a movement perpendicular to and below these loci for which NGCC or NG retrofit mitigations are still preferred over CCS (at a greater and constant capture rate) because of the lower achieved emission intensities, but the LCOEs along these new loci are again the same between the pairs of competing mitigations and are also greater than those for the original loci.

By doing so, a set of iso-intensity gradients are created that are parallel to and less than the 1,500 lbs/MWh target intensity loci. These gradients form a solution set of CCS mitigation frontiers for which CCS is preferred over the other mitigations for a constant LCOE. For example, one would prefer to mitigate with CCS at a 38% or greater capture rate rather than with NG retro at the default NG price, when moving down the $63/MWh isocost line, if the coal price decreased by more than 45%. Moving down a $65/MWh isocost line shows that the transition from preferring NG retrofit mitigation to preferring CCS mitigation at 38% capture will not occur until the NG price increases by more than 5% and the coal price decreases by more than 33%. While remaining on these isocost lines with further decreasing coal costs allows for greater emission reductions through greater capture rates, such an action will move one off the least-cost frontier for the targeted intensity. To remain on the frontier, the target intensity must also decrease. However, the sensitivity of the mitigation preference to fuel price variation will continually change as the target intensity continues to decrease, Figure 3.8(b, c).

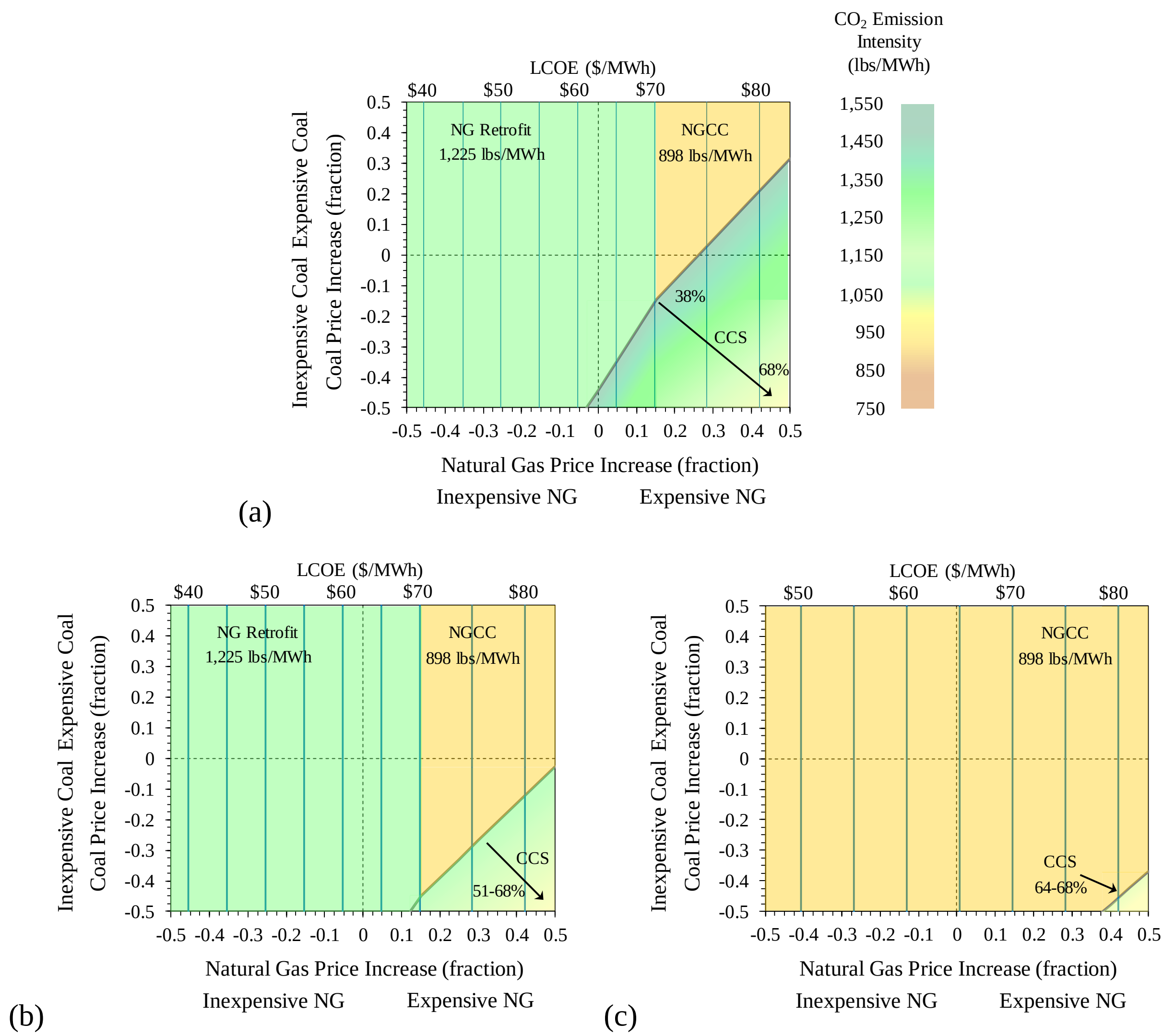


Figure 3.8. Sensitivity of mitigation technology choice to fuel price variation to achieve a (a) 30% reduction in emission intensity and mass (target intensity is 1,500 lbs/MWh), (b) 40% reduction in emission intensity and mass (target intensity is 1,280 lbs/MWh), and (c) 50% reduction in emission intensity and mass (target intensity is 1,070 lbs/MWh).

3.4.2 Uncertainty

As the analysis of the confidence limits indicates that fuel price has the largest impact on LCOE uncertainty, it is necessary to understand at the EGU-level the possible mitigation tradeoffs that may be required from uncertainty in these fuel prices. While the analysis in Figure 3.8 serves as a tool to indicate the intensity levels for which the decision about the mitigation choice for a targeted emission will be robust to variations in fuel prices and how much variation will be required to change the decision, with which the capital investment as well as the achieved emissions reduction will be altered, it tells us nothing of the probability of this occurring to aid in the decision. This probability can be derived from the uncertainty analysis of previous projections.

The simulation of the EIA projected fuel prices indicates that it is likely that both fuel prices will be underestimated, Figure 3.2, with the underestimation for coal being greater than that for natural gas. The inclusion of this underestimation has little impact on the least-cost frontier for the Wisconsin CFEGU; the frontier with the expected value for all regions (shown in Figure 3.9(b)) uses the same mitigation technologies at the same intensity levels as with the base case prices, Figure 3.9(a). The effect of the estimation uncertainties is particularly evident, when examining the mitigation frontiers for the likelihood regions, Figure 3.2. In general, when the EIA projection overestimates a fuel price, the employment of mitigations that use that fuel increases relative to the base case. As there is an asymmetry in the distribution for projected prices, there is a greater likelihood that each fuel price increase will be underestimated, Region 4. This will result in a mitigation frontier that looks similar to the centroid and base cases. When the natural gas price increase is overestimated relative to the coal price increase, Regions 5 and 6, the use of NG retrofit mitigation increases. The likelihood of this occurring is 19%. Similarly, when there is an underestimation of natural gas price increase and the coal price increase is overestimated, Region 1, mitigations that permit coal use (USC and CCS mitigations) increase. However, there is only a 6% likelihood that this will occur.

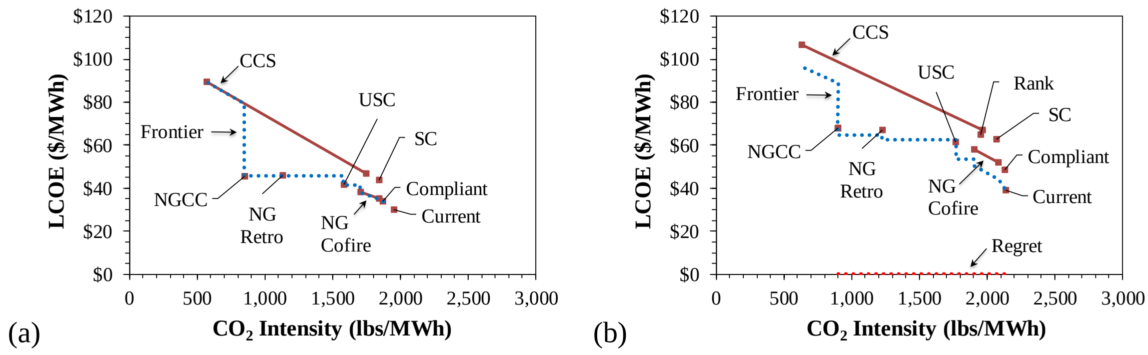


Figure 3.9. The least-cost frontier without NGCC co-located renewable generation for a compliant Wisconsin EGU, as modeled with base case (a) and centroid expected value (b) fuel prices. The blue dotted lines represent the least-cost frontier for the EGU with base case state-specific fuel price. For these fuel prices, there is no regret (the red-dotted line).

These projection uncertainties can have a significant effect on the EGU least-cost frontier that can be measured as regret—the difference in LCOE between the mitigation option chosen *ex ante* based upon the least-cost option for the targeted emission intensity reduction and the expected fuel prices and the corresponding *ex post* option with the projected fuel price uncertainties. Figure 3.9(a) shows the *ex ante* least-cost frontier for a CFEGU in Wisconsin, and Figure 3.9(b) shows this least-cost frontier superimposed on the mitigation options for the same CFEGU with the inclusion of the centroid expected value fuel prices. With these higher fuel prices, the *ex post* frontier still mitigates with the same mitigation technologies at the same intensity levels; therefore, there is no regret.

While there is a 72% likelihood of the fuel prices being in Region 4 and no regret occurring, the magnitude of the regret and the affected intensity range for this one particular CFEGU varies with the likelihood region as the least-cost mitigation frontier changes, Figure 3.10. In Region 1, the coal price is lower than projected and the NG price is higher than projected (similar to that modeled in Figure 3.8), thereby making CCS the least-cost option for an intensity range from approximately 1,800-1,200 lbs/MWh and leading to a maximum regret of $20/MWh with a likelihood of 6%, Figure 3.10(a). When the coal price is higher and the natural gas price is lower, as in Region 8, NG retro is the preferred mitigation for intensity values down to almost 1,200 lbs/MWh, Figure 3.10(h). Not having initially chosen this mitigation leads to a maximum regret of $23/MWh with a likelihood of 2 %. Regret will obviously vary by CFEGU, and it will also vary by region, with identical CFEGUs in different regions facing different potential regret costs. While regret is typically conceptualized as a "psychic" cost (the *ex post* wish that a different choice had been made *ex ante*), it is important to note here that in certain regulatory settings, regret can be made tangible when it is manifest as a stranded cost, or a regulatory obligation to retain a commitment to *ex post* suboptimal investment capital. Thus, regret avoidance in this context reflects an actual economic cost to ratepayers (and investors) that must be considered. As this analysis illustrates, the associated impact on capital investment, and on the regret associated with the possible stranded assets for an economically uncompetitive CFEGU, from the projected price uncertainty can be large enough that it should be taken into consideration for planning and that the impact on the specific intensity target needs to be addressed.

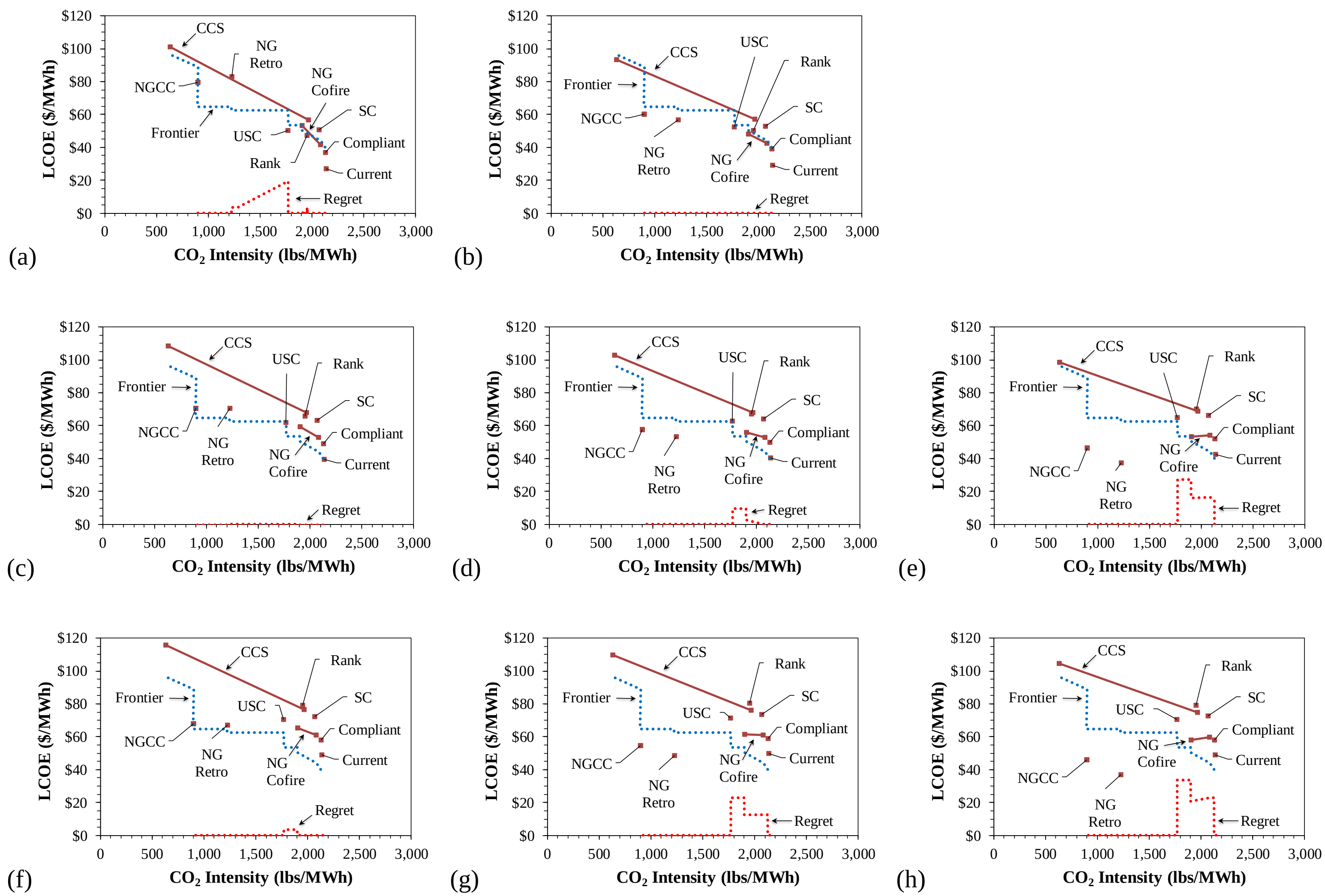


Figure 3.10. The least-cost frontiers without NGCC co-located renewable generation for a compliant Wisconsin CFEGU, as modeled with region-specific expected value fuel prices (Figure B.13). The blue dotted lines represent the least-cost frontier for the CFEGU with base case state-specific fuel price. Regret from using base case frontier mitigations with expected value region-specific fuel prices occur are indicated with red dotted lines. Expected value regions from Figure 3.2 are (a) region 1, (b) region 2, (c) region 4, (d) region 5, (e) region 6, (f) region 7, (g) region 8, and (h) region 9.

3.4.3 CO_2 emissions tax and sequestration tax credit

The implementation of a tax on CO_2 emissions from EGUs is one possible policy mechanism to reduce the production of this pollutant through mitigation or retirement in favor of lower or zero-carbon generation sources. Applying such a tax to the least-cost frontier will cause one mitigation option to be preferred over other options (or the compliant configuration) absent fungible zero-carbon options or retirement. The breakeven point at which one is indifferent with regard to cost to maintaining the compliant configuration or mitigating with one of the least-cost frontier technologies occurs at the point at which the LCOE for the compliant CFEGU is equal to that for the CFEGU mitigated with that technology. Above this CO_2 price, an operator will prefer the CFEGU equipped with the mitigating technology and below this price, an operator will prefer to maintain the compliant configuration. For the Wisconsin CFEGU, it is preferable to maintain the compliant configuration for a price up to $44/tonne, Figure 3.11. At this price, the operator will be indifferent to retaining the compliant EGU and doing a brownfield conversion to a NGCC plant. Above this price, up to $60/tonne, the other mitigations requiring full conversion to natural gas are preferred to any mitigation that retains the use of coal. While there is clear preference for one fuel type over the other for this CFEGU, which may be indicative of the results for similar CFEGUs, the variation in sensitivity of these mitigations to the applicable tax suggests that the marginal rates of the mitigations can be influenced by exogenous factors, such as other subsidies or tax credits, to prefer one mitigation over another.

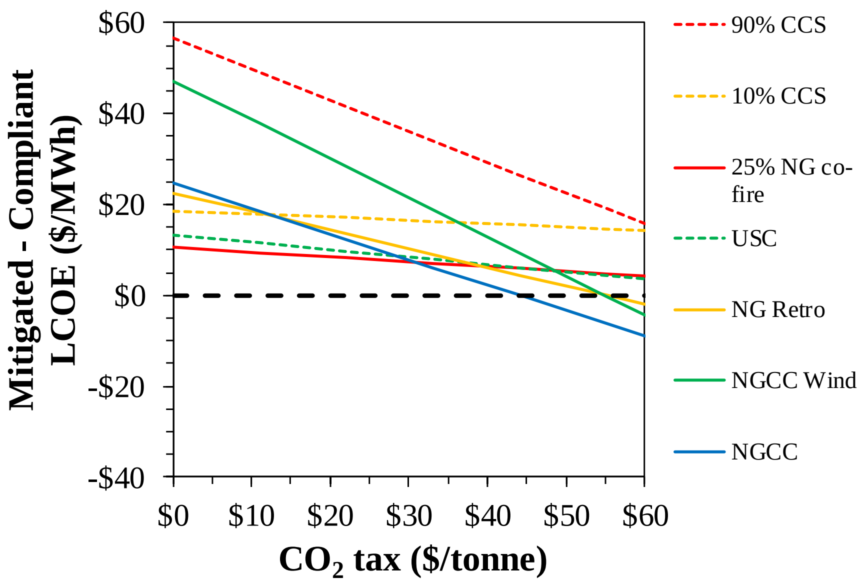


Figure 3.11. The effect of CO_2 tax on least-cost frontier mitigation choice as measured by the LCOE preference for the compliant configuration of the Wisconsin CFEGU. Coal-based mitigations are designated with dashed lines and natural gas-based mitigations are designated with solid lines.

The application of a CO_2 tax can also result in a different mitigation choice under scenarios that seek to avoid regret related to stranded asset costs because of an uncertain regulatory requirement. If one adds the alternative of replacing the coal-fired EGU with the NGCC plant discussed in the introduction (*Appendix B, Section B.2*), the loci for which the cumulative cost of the emissions and the unrecovered capital cost (from a straight-line amortization) for a mitigation equal those for the NGCC plant then define a preference boundary between the mitigation and the NGCC plant that is a function of the CO_2 tax and the number of years until the regulation is implemented. For a compliant EGU in Utah with the heat rate improvement, the breakeven horizon for implementing a net-zero emissions regulation moves along this boundary from 30 years to 3 years with increasing tax, Figure 3.12(a). Therefore, one would prefer to retain the compliant CFEGU to avoid regret when there is a $10/tonne CO_2 tax, if the retirement horizon is less than 13 years. Regret can be further avoided with the NG retrofit mitigation (Figure 3.12(b)) that expands this horizon to 20 years at the same tax, due to the savings from lower emissions cost exceeding the greater capital cost for this mitigation. For a more capital-intensive mitigation like USC upgrade, Figure 3.12(c), the savings from reduced emissions are not sufficient to offset the higher capital cost and results in the horizon decreasing to four years for this tax. CCS mitigation with 90% capture, Figure 3.12(d), requires a greater capital investment than does NGCC replacement; therefore, there is a reversal of the previous trends. NGCC is now preferred to CCS unless the emission tax is near $30/tonne and the horizon is near the full book life of the project, even though the emissions are greatly decreased with CCS. From this point, greater taxes result in coal-fired mitigation preference horizon decreasing to only 20 years. Consequently, there may be an overall preference for low capital-cost mitigation with natural gas over higher capital-cost mitigation with coal that suggests that the uncertainty in operation life for future fossil-fuel power generation may favor lower cost mitigations, such as NG retrofit, to avoid regret related to stranded asset costs. However, modeling the mitigation option pairs illustrates that information on both the expected retirement horizon and the CO_2 tax is valuable in making the mitigation decision.

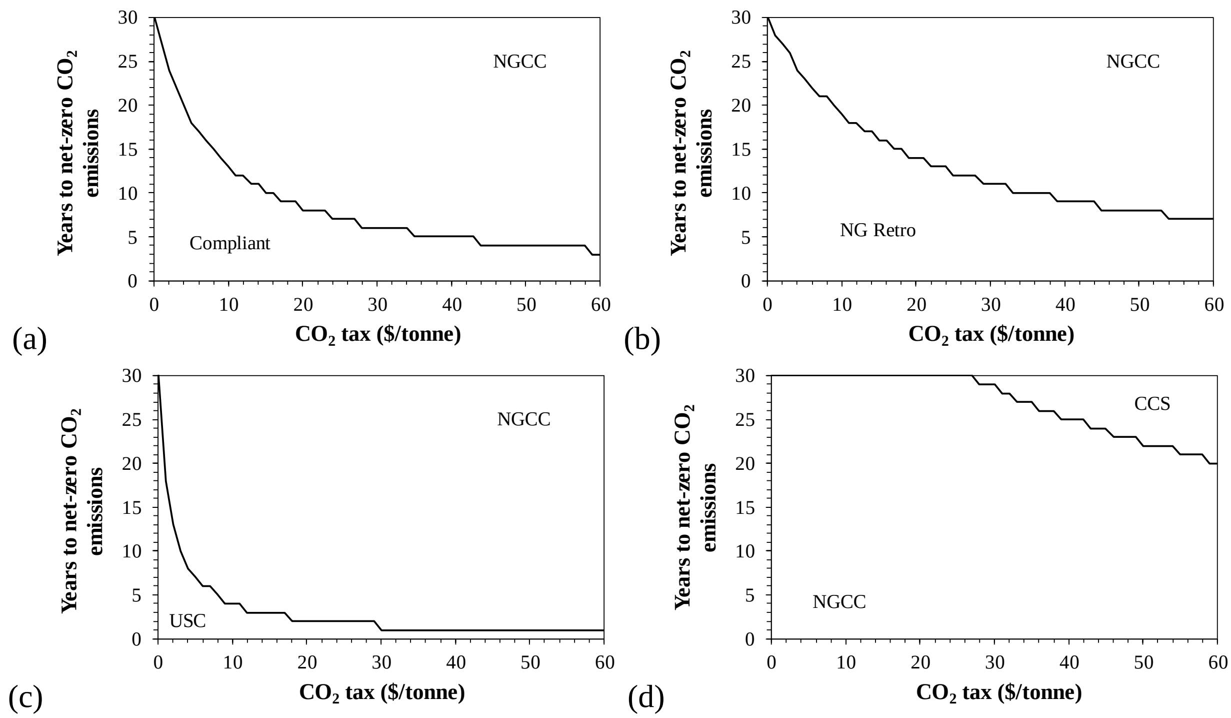


Figure 3.12. The effect of CO_2 tax on the breakeven-horizon for stranded capital and CO_2 emissions costs for a coal-fired EGU in Utah with (a) heat rate improvement, (b) NG retrofit, (c) USC upgrade, and (d) CCS with 90% capture mitigations in comparison to replacement with a similarly powered NGCC plant. The breakeven-horizon is defined by the number of years until the net-zero regulation is implemented so that one mitigation is not preferred over the other. Mitigations include all required emission control device and related mitigation capital costs. Generation requiring natural gas includes capital costs for the natural gas pipeline. For CCS, the costs for all required emission control devices, related mitigation capital costs, and CO_2 sequestration cost are included.

The difference between the CFEGU LCOEs for the compliant and CCS-mitigated cases can be diminished with the $50/tonne sequestration credit[31] for qualifying EGUs in the Amendments to 26 U.S. Code 45Q in the Bipartisan Budget Act of 2018 concerning CCS [184]. As the

[31] Tax credit is for permanently sequestered CO_2 above 0.5 million tonnes annually. While the tax credit is applicable for only 12 years after commencement of the operation of the CCS subsystem, for which construction must start before 2024 and be operational before 2030 [184], we assume for simplicity that this operation begins in December 2029. The worth of the credit ($/MWh) includes the generation from the natural gas auxiliary boiler.

decreasing marginal rate steepens with increasing capture rate (Figure 3.11) and the maximum value of this credit is realized at 90% capture, utilizing a 90% capture rate indicates that the credit must be greater than $123/tonne for one to prefer mitigation with CCS over NGCC or not mitigating, when there is a $44/tonne CO_2 tax (Figure 3.13). This credit must be further increased to continue to prefer CCS mitigation over the compliant configuration as the tax decreases; in the absence of a CO_2 tax, NGCC conversion is preferred unless the sequestration credit is almost $150/tonne. Such a large credit is required to overcome the difference in capital cost for the two mitigations. Therefore, EGU-specific modeling suggests that for some CFEGUs, the current sequestration credit, or the duration over which it may be applied, may be insufficient to promote CCS use by altering the least-cost frontier sufficiently for CCS with this energy-supply configuration (*Appendix B, Section B.8.6.9*) to dominate other mitigations even at a $60/tonne or less CO_2 tax, when fungible mitigations are present. However, CCS viability may be enhanced with alternative energy-supply configurations for CCS [167]. Furthermore, as the capital cost for the NGCC conversion is less than that for CCS at 90% capture for this EGU, in some cases it may be preferable to augment the NGCC generation with renewable generation to obtain deep reductions to meet the IPCC 2030 55% reduction target and to strand the NGCC plant in the future to meet the 2050 target than it is to invest the capital in retrofitting the existing EGU with CCS that also faces stranding.

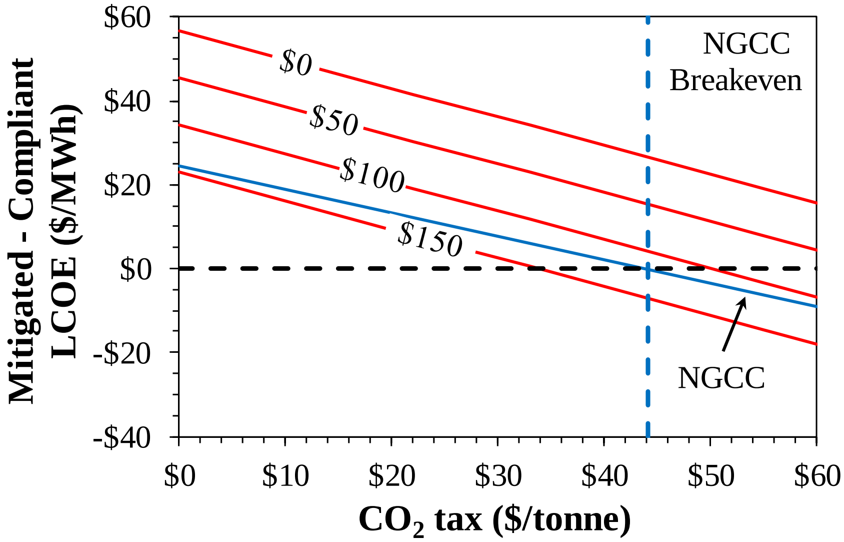


Figure 3.13. The effect of the 45Q tax credit [85] on the LCOE preference for CCS with 90% capture rate and NGCC brownfield mitigations relative to the compliant configuration for the Wisconsin CFEGU. A sequestration tax credit that ranges from $0-150/tonne is applied to the CCS mitigation (solid red lines).

When avoiding regret from stranded asset costs is used to evaluate CCS mitigation at 90% capture with the 45Q tax credit, the emissions cost reduction is insufficient to compensate for the high capital cost of CCS in this energy-supply configuration for this mitigation to dominate replacement of the CFEGU with the NGCC plant, Figure 3.14. However, CCS is preferred to avoid regret whenever the retirement horizon is greater than 16 years. This low sensitivity to the CO_2 tax shown in the preference boundary suggests that information on the horizon has greater value then information on the tax, when making the mitigation decision for this EGU-specific mitigation pair. Therefore, the existing tax credit can improve the economic feasibility of CCS regarding some regulatory uncertainty and regret for stranded assets, in the absence of other low or no-carbon generation sources.

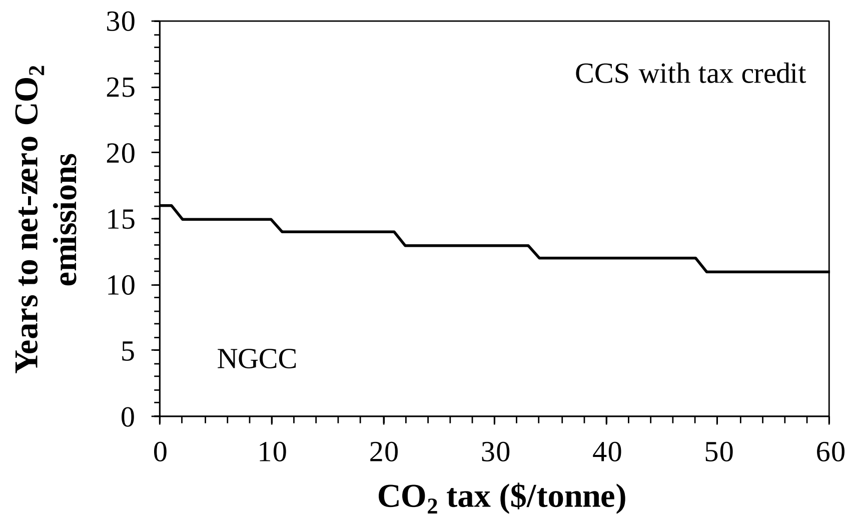


Figure 3.14. The effect of CO_2 tax on the stranded capital and CO_2 emissions costs breakeven-horizon for a coal-fired EGU in Utah mitigated with CCS at a 90% capture rate with the 45Q sequestration tax credit [184] in comparison to replacement with a similarly powered NGCC plant. Generation requiring natural gas includes capital costs for the natural gas pipeline. For CCS, all required emission control device, related mitigation capital costs, and CO_2 sequestration cost are included.

3.5 Conclusion

There are many paths that can be taken to obtain a low or no-carbon power sector; some are more costly than others. In this study, we developed a set of equations to calculate the cost for nine mitigation options to reduce the CO_2 emissions of EGUs in the existing U.S. coal-fired fleet. These equations are used to describe EGU-specific least-cost mitigation frontiers, in terms of both capital costs and LCOE, to achieve specific CO_2 emission intensities. As an illustration of the technique, a deterministic least-cost frontier for an CFEGU in Wisconsin was presented for which achieving deep emission reductions with NGCC brownfield conversions co-located with renewable generation dominated mitigating with CCS at a 90% capture rate for both capital cost and LCOE. This example further showed that fuel-switching to 100% NG incurred the lowest capital investment and had the lowest LCOE for moderate intensity reductions of 40%, thereby reducing possible future stranded assets. However, a sensitivity analysis indicated that the LCOE is most sensitive to fuel price uncertainty and that for some intensity targets the uncertainty in fuel prices can affect mitigation decisions. Furthermore, the portfolio of mitigations defining the frontier is sensitive to other EGU-specific factors, such as heat rate and retirement age; therefore, the mitigation choices for this CFEGU may not be appropriate for all CFEGUs. A probabilistic analysis of fuel prices indicated that the regret from making the wrong mitigation choice (including the tangible manifestation of regret as a stranded capital cost) when realized fuel prices differ from expected fuel prices, can be high but may be limited to specific intensity targets.

Fuel price was also shown to change the mitigation frontier so that CCS for specific capture rates may be preferred over mitigating with natural gas at certain emission intensity ranges. However, the high capital costs and the sustained low natural gas prices may limit the viability of CCS fitted with an auxiliary NG boiler, when fungible mitigations are present, even with CO_2 taxes as high as $60/tonne. In this instance, the application of a sequestration tax credit was insufficient in overcoming this barrier, unless it was increased to more than $120/tonne, for a $44/tonne tax. However, in a market faced with uncertainty in the horizon to net-zero emissions and the size of the CO_2 tax, mitigation with CCS is shown to be a viable alternative to replacement with NGCC to avoid regret associated with stranded costs with the inclusion of the 45Q sequestration tax credit.

This work illustrates that modeling CO_2 emission-intensity reduction in this bottom-up manner can provide policymakers and EGU operators with insights that might otherwise be missed. For example, expanding the mitigation-technology set to include both early-development and mature-stage options with variable ranges can be used to evaluate technology innovations, and to determine the characteristics of the CFEGUs that may benefit from particular technologies. Similarly, the mitigation frontier can be evaluated in direct comparison with additional generation technologies, such as solar and wind, to reduce the potential for stranded assets given regulatory uncertainty and to improve the productivity of capital investments given long-term reduction requirements. In addition to using LCOE to define the frontier, other metrics can be monetized and evaluated, such as water consumption, land use, and pollutants affecting health and the environment [185]. For a fossil-fuel fleet, such an approach can be incorporated to determine the robustness of EGU-specific mitigation solutions to reduce regret from uncertainty in fuel prices, demand, tax credits, and CO_2-reduction targets and prices. Furthermore, the least-cost frontiers for coal-fired EGUs aggregated at the state or regional level, with the inclusion of exogenous generation, can yield a set of economically feasible mitigations that lead to insights such as lower power-sector LCOE through greater utilization of existing coal-fired generation, while achieving deeper emission-intensity reductions than those accorded in other CO_2-reduction efforts. Determining the least-cost feasible CO_2-mitigation strategies in this manner may be increasingly useful to formulate and analyze future policies concerning the 2018 IPCC 2030 and 2050 targets that require greater dependence on variable renewable energy; as these policies may necessitate mid-term reliance on existing fossil-fuel-based power-sector infrastructure, while the development and deployment of the requisite technology, operation, and market transformations necessary to insure grid resilience are underway [4, 6, 186-190].

Chapter 4: A techno-economic assessment of carbon-sequestration tax incentives in the U.S. power sector

"45Q" by Jeffrey Anderson

Sung to *Waterloo* by ABBA

Oh yes,
greenhouse gases give us global warming.
And so,
the glaciers melt and the sea level starts to rise.
The tundra is getting soft too,
is there nothing that we can do?!
45Q,
incentives to capture that CO_2.
45Q,
negative emissions that we can do.
CCS,
we need to sequester or we may lose.
Sí-sí-sí-sí,
CCS, we need to sweeten 45Q!

Oh yes,
our weather trends are getting more severe.
And so,
more floods and droughts and hurricanes are here.
Our climate is going down the drain,
what can we do to sustain?!
45Q,
incentives to capture that CO_2.
45Q,
negative emissions that we can do.
CCS,
we need to sequester or we may lose.
Sí-sí-sí-sí,
CCS, we need to sweeten 45Q!

It may seem the choices are few,
but we know what we have to do!
45Q,
incentives to capture that CO_2.
45Q,
negative emissions that we can do.
CCS,
we need to sequester or we may lose.
Sí-sí-sí-sí,
CCS, we need to sweeten 45Q!

Carbon capture and storage (CCS) is a prominent mitigation technology in many of the pathways to achieve global net-zero carbon-dioxide (CO_2) emissions. Despite this proposed importance, only one operational power facility in the U.S. is currently equipped with CCS. Further CCS capacity may be promoted with recently-enhanced tax credits for carbon sequestration in Section 45Q of the U.S. Internal Revenue Code. In this paper, we expand the unit-specific techno-economic model ESTEAM to include coal-fired and natural gas combined cycle (NGCC) retrofitted CCS capacity and new NGCC-CCS capacity to evaluate CCS for sequestration in the projected 2030 U.S. fossil-fuel fleet. Using this model in a parametric study, we conclude that unique credit levels for each CCS option are required for each option to separately achieve the same percent generation level of the projected 2030 net generation. We further find that increasing the credit duration can lower the CO_2 avoided cost for the fleets and increase CCS-capacity bridging from 2030-2050. Overall, we determine that a higher avoided cost for immediate sequestration is achieved through promoting new and existing NGCC CCS.

This chapter is based on work published as: Anderson JJ, Rode D, Zhai H, Fischbeck P. International Journal of Greenhouse Gas Control A techno-economic assessment of carbon-sequestration tax incentives in the U . S . power sector. Int J Greenh Gas Control 2021;111:103450. https://doi.org/10.1016/j.ijggc.2021.103450.

4.1 Introduction

4.1.1 Role of CCS in the power sector

As one of the technologies included in many of the integrated assessment models (IAMs) and energy models that are used to generate the Intergovernmental Panel on Climate Change reports [80, 86], and other global and country-specific studies [191-194], carbon capture and storage (CCS) is recognized as one of the most prominent global mitigation technologies in many of the pathways to deep decarbonization and is considered in these reports to be pivotal to meeting net-zero requirements. When incorporated in the construction of new fossil-fuel projects, a 90% capture rate (with feasible capture rates of up to 98% [195]) allows for long-lived, low-carbon generation from fossil-fuel sources that can serve as firm capacity for intermittent or variable renewable energy sources (VRE) in a net-zero carbon economy to lower total system cost [196-202].

On the pathway to this economy, CCS can reduce the committed emissions [99, 203, 204] from power plants when retrofitted to existing coal-fired electric generating units (CFEGUs) and natural gas combined cycle (NGCC) plants during the transition to load-following capacity and when used for storage charging [205]. Furthermore, CCS retrofitting may decrease the probability of stranded assets that might otherwise occur in a deep decarbonization trajectory should these capacities be abandoned [94]. When incorporated without this role to decarbonize the power sector, CCS can be employed to remove carbon dioxide (CO_2) directly from the air via direct air capture and storage (DACS) or with bioenergy (BECCS) for carbon dioxide removal of existing emissions—an application thought to be necessary to limit warming to 1.5 °C [206].

The utilization of the captured CO_2 for other products (termed carbon capture utilization and storage (CCUS) and used interchangeably herein with CCS) can further decrease apparent emissions. If the effluent is not immediately placed in dedicated geological storage in saline reservoirs, it can be utilized for enhanced oil recovery (EOR), a use for which each million tonne (Mtonne) of injected CO_2 can result in a net emissions reduction of less than 0.2 Mtonne when the related oil emissions are also included [207, 208].[32] Near-zero emissions may even be achieved when the captured CO_2 is used as an input for bioenergy or converted to synthetic fuels for other sectors, depending upon the source of the power for conversion [209]. While the overall net life-cycle reduction in emissions is uncertain, a positive externality from the secondary use of the CO_2 is that a revenue stream[33] for the capture facility is provided to offset the capital costs and expenses associated with the CO_2 capture and transportation in both applications.

Despite the importance of CCS, the worldwide large-scale development of this technology is viewed as being behind schedule [94, 210, 211]. In the U.S. for example, there are as of 2020 only ten large-scale,[34] operational power plants and industrial facilities that primarily capture CO_2 from ethanol, fertilizer, and hydrogen production for EOR [212]. These facilities have the capacity to capture 21 Mtonnes of anthropogenic CO_2 per annum of which 20 Mtonnes are used for EOR [212]; this bias toward EOR further indicates the importance of an associated revenue stream and the geographic restrictions that this dependence may impose. To this end, CCS is usually not an economically-dominant technology for emissions reduction in IAMs and other deep-reduction models, unless the CO_2 emission price levied is high enough to make the technology competitive with other generating sources, including fossil fuel without CCS [194, 213, 214].

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[32] Oil use does increase from this use, as each barrel of oil from CO_2-EOR is estimated to displace 0.80 barrels of conventional oil production [207].

[33] Other revenue streams such as from the capacity and ancillary service markets, and state-level clean energy standards are not considered in this study.

[34] The Global CCS Institute defines large-scale facilities as those facilities with a capacity of capturing at least 0.4 Mtonnes of CO_2 per annum [211].

4.1.2 Applicability of existing 45Q financial instrument

As a mechanism to bolster emission reductions in the absence of a sufficient CO_2 price, studies emphasize the need for subsidies or other incentives to stimulate initial commercial use and large-scale deployment [201, 215, 216]. The U.S. provides for such subsidies for CO_2 sequestration and utilization in the form of tax credits provided under Section 45Q of the Internal Revenue Code (hereafter referred to as 45Q) [217]. The intent of legislators in providing these credits was *both* to incentivize "energy production" *and* "conservation" [218]. Therefore, the dual nature of these incentives is both to promote CCS in its infancy *and* to acquire emissions reductions in an environment for which implementing a CO_2 price may be politically difficult. These credits were recently enhanced in 2018 when the credit level for captured CO_2 used for EOR and other applications was increased to $35/tonne for 12 years after commencement of operation, while that for immediate storage was increased to $50/tonne.[35,36]

However, research on the ability of these enhancements to promote CCS in the power sector is inconclusive. Some research indicates that 45Q may lead to an increase in power plant capacity capturing CO_2 for EOR in deference to immediate sequestration, as the 45Q tax credit will be supplemented by revenue from the sale of the CO_2 [220, 221]. In these works, CCS is retrofitted to existing CFEGUs and NGCC plants that are located close to existing CO_2 pipelines [221], from which approximately 50 million tonnes of CO_2 are captured annually for EOR, predominately from CFEGUs. However, sequestration is preferred to EOR, if the cost of CO_2 for EOR is less than $10/tonne [220], indicating that the $50/tonne credit alone may be adequate to supplement CCS-associated costs in some cases, dependent upon the study's assumptions.

[35] The levels were previously set at $10/tonne for EOR and enhanced gas recovery, and at $20/tonne for immediate storage, with a total program cap of 75 million tonnes from 2008-2018 [219].

[36] Fiscal year for monetary values is 2018 and values for 2026 onward are indexed with inflation. A minimum captured capacity of 500,000 tonnes per annum is required for credit.

Similarly, a techno-economic model assessing the application of EOR revenue and 45Q tax credits to promote retrofitting CCS to existing CFEGUs in Ohio shows that the presence of 45Q does improve the feasibility of CCS for an illustrative EGU [222].

CCS promotion in the power sector under 45Q is also indicated in a study using five models that encompass the electric power sector and refining and other industrial facilities [223]. While the model results vary, power-sector CCS in 2030 is estimated to also increase by 19-50 Mtonnes per annum over the counterfactual. In these models, which omit plant-level detail, the CO_2 generation source is not directly categorized for utilization; however, the effluent is primarily used for EOR when EOR is an option. A sensitivity analysis for captured CO_2 is also presented for 45Q, CCS capital cost, and CO_2 policy parameters. This broadly-scoped analysis indicates that CCS application increases greatly when no limit is placed on the construction start date, the credit duration is indefinite, CCS capital costs decrease, or a carbon tax is present. In this analysis, however, the impact on refining and other industrial facilities and on the power sector is indiscernable, as is that for EOR and immediate storage.

Still, other research points to the inadequacy of 45Q to promote CCS. In a broader assessment of installing CCS on illustrative existing and new coal-fired and NGCC generators, for which additional revenue from EOR is excluded, researchers demonstrate that the 12-year life of the credit may be inadequate to make CCS economically feasible for these facilities [224]. Analysis of CCS retrofits exclusively on the current NGCC fleet, using site-specific modeling of CCS related costs, finds that the 45Q tax credits alone are insufficient to cover all CCS-associated costs for sequestration or EOR [225]. While this study does not explore sufficiency for credit level or duration, it finds opportunities for EOR when the plant is located near a region with EOR opportunities and existing CO_2 pipeline infrastructure, and indicates that lowering the credit qualifying threshold may result in greater capture opportunities. Another study that uses a series of financial models, under two ownership/revenue structures, determines that 45Q alone is inadequate to promote CCS on illustrative existing subcritical, pulverized-coal EGUs and NGCC plants [226]. Furthermore, the financial gap to make the project economically viable is greater for NGCC retrofits, thereby highlighting the importance of evaluating project finance and other incentive structures when formatting policy.

4.1.3 Objective/organization

The literature highlights two gaps, the first being the range of decisions faced by the facilities. Some of the models in the studies in the preceding paragraph have simplified the decision problem into a binary outcome for the fossil-fuel source: do not use or use CCS. In addition to this decision, the power facility operator may be faced with economic decisions concerning competing generation sources. Retrofitting a CFEGU with CCS may not be the least-cost configuration for the EGU. Even with 45Q, in the absence of a CO_2 emission price, it may be more cost-effective to lower operation costs through heat-rate improvements, to repower the CFEGU as an NGCC plant (without or with CCS), or to retire the plant and invest in a new solar or wind facility. Similarly, adding CCS to an existing NGCC plant may not be cost-effective; it may again be more economical to replace the plant with renewable energy. In this manner, the CCS decision also entails ensuring that the configuration is the least-cost generation option.[37]

The second gap is determining what 45Q structure may be sufficient to promote CCS for immediate sequestration for new and existing plants of each fuel type. The two-tiered incentive system in 45Q recognizes the possibility of a public/private-sector role in emissions reduction.

[37] Other factors may include environmental impact, immediate and secondary employment, tax base, grid reliability, transmission availability, and existing contracts, which are not considered in this analysis.

Setting a \$50/tonne tax credit recognizes the public good that can occur through immediate CO_2 sequestration. Having a reduced credit of \$35/tonne for utilized CO_2 recognizes a private benefit in the form of CO_2 as an input to a commercial product at a \$15/tonne value. While this policy is meant to incentivize private-sector participation and may lower federal program costs, the studies indicate that such a division is potentially "putting all of the CCS eggs in one basket": EOR. This preferred outcome may make the emissions reduction subject to the volatility of future oil demand and prices [207, 227], a postulate proven correct when Petra Nova (a CCS-equipped power plant in the U.S.) paused capture operations due to lower oil prices related to Covid-19 [228]. Therefore, in addition to some studies finding 45Q inadequate to promote CCS, those that do find economic justification for it predominantly promotes CCS for EOR and show that the policy is limited in geographic application and purpose.

The objective of this paper is to fill these two gaps by exploring what enhancements to the current 45Q tax-credit level and duration may be required to promote immediate sequestration of CO_2 in the projected 2030 coal and NGCC fleets in the U.S., when other fungible CO_2 mitigations and generation sources are available. This is accomplished by expansion of the EGU-Specific Techno-Economic Assessment Model (ESTEAM) (Chapter 3), which uses site-specific information for generators and sequestration sites, to create least-cost mitigations frontiers. These frontiers are used for analysis of the generation decisions for these fleets to identify the characteristics of the CFEGUs and plants that prefer CCS under the current 45Q policy. We then parametrically solve for the credit levels and duration necessary to generate the same percent of the total 2030 net generation separately from CCS technology retrofitted to the existing coal fleet, the NGCC fleet, and from repowering coal-fired capacity as new NGCC CCS capacity.

Further, we show how the fleet generation-mixes, capacities, emissions, tax credit expense and performance metrics change with the addition of a price on CO_2 emissions.

The remaining paper is organized as follows. In Section 4.2 we describe the model structure, the mitigation technologies, 45Q, and a probabilistic framework for analyzing model uncertainty. Section 4.3 presents and discusses model results from applying the current 45Q to two CFEGUs and to the fossil fuel fleet, and from a parametric study of the fleet. This section also presents a sensitivity analysis on fuel price, CCS retrofit cost, capacity factor, and renewable cost. Conclusions and policy implications are presented in Section 4.4.

4.2 Materials and methods

In Chapter 3, the concept of a least-cost frontier for CO_2 mitigation is presented for an existing CFEGU in which one mitigation-technology configuration will dominate other configurations on a cost-basis to achieve a desired emission intensity target. In the absence of a specific target, as now analyzed in this work, the frontier collapses onto the levelized cost of electricity (LCOE) resulting in one configuration with the lowest LCOE, inclusive of applicable incentives and taxes, dominating all others for all emission intensities. In this study, the ESTEAM model put forth in Chapter 3 is expanded in this study to include techno-economic modeling of CCS-mitigation without an auxiliary natural gas boiler for both existing CFEGUs and NGCC plants. Additionally, the LCOEs for new solar and wind capacity are now considered on the frontier to expand the least-cost generation-technology options for both coal- and NG-fired fleets, as the existing capacity can be replaced with these zero-carbon sources absent capacity limitations exogenous to the model.

For the coal-fired capacity, three mitigation technologies making up six mitigating options are evaluated: (Option 1) EGU heat-rate improvement (HRI) and (Options 2 and 3) retrofitting bypass CCS (fixed 10-90% capture rate), without and with an auxiliary (aux.) natural-gas (NG) boiler energy system for solvent regeneration. In addition, we evaluate three scenarios for fuel switching from coal to NG: (Option 4) replacement of the CFEGU with a brownfield NGCC plant (a proxy for building a new NGCC plant as the total conversion cost may almost be the same as that for building a new plant when the demolition cost for the old plant is included (Chapter 3), (Option 5) supplanting generation from the brownfield NGCC plant with generation from a co-located utility solar or wind farm for deeper CO_2 emission reductions, and (Option 6) replacement with a brownfield NGCC plant with bypass CCS (a proxy for the replacement of the coal-fired generation with a new NGCC plant equipped with CCS). For the NGCC fleet, CCS retrofitting is modeled.

Two metrics are used to evaluate the generation source technologies: LCOE and the cost of CO_2 avoided. LCOE is used to make the least-cost configuration decisions for the individual generation sources, the general form of which is given in Eq. 4.1. The cost of CO_2 avoided is used to compare the cost of removed CO_2 for the considered fleet from the aggregated individual decisions, Eq. 4.2.

$$LCOE \ = \frac{CC \times FCF + FOM}{G_{net}} + VOM_{fuel} + VOM_{non-fuel} + \left(\frac{(P_{CO_2} \times m_{emit} - TC \times m_{cap})}{G_{net}} \right) \tag{4.1}$$

where *LCOE* is the levelized cost of electricity ($/MWh), *CC* is the EGU capital cost ($), *FCF* is the fixed charge factor (fraction), *FOM* is the fixed operation and maintenance cost for the EGU($), G_{net} is the EGU annual net-generation (MWh), VOM_{fuel} is the variable operation and maintenance cost related to fuel (\$/MWh per year), $VOM_{non\text{-}fuel}$ is the non-fuel related variable operation and maintenance cost (\$/MWh), P_{CO_2} is the CO_2 emissions price (\$/tonne), m_{emit} is the annual CO_2 mass emitted (tonnes per year), TC is the 45Q emission tax-credit level proportionally derated for the EGU economic lifetime (\$/tonne), and m_{cap} is the annual CO_2 captured emissions mass (tonnes per year).

$$C_A = \left(LCOE_{study} - LCOE_{ref}\right) / \left(\left(\frac{m_{emit}}{G_{net}}\right)_{ref} - \left(\frac{m_{emit}}{G_{net}}\right)_{study} \right) \tag{4.2}$$

where C_A is the cost of CO_2 avoided (\$/tonne), $LCOE_{study}$ is the LCOE of the fleet with the aggregated decisions studied (\$/MWh), $LCOE_{ref}$ is the LCOE of the reference case for the aggregated fleet (\$/MWh), $\left(\frac{m_{emit}}{G_{net}}\right)_{ref}$ is the emission intensity for the aggregated fleet under the reference 45Q condition (tonnes/MWh), $\left(\frac{m_{emit}}{G_{net}}\right)_{study}$ is the emission intensity of the fleet with the aggregated decisions under the studied 45Q condition (tonnes/MWh), m_{emit} is the emitted CO_2 mass (tonnes), and G_{net} is the net electric power generation (MWh).

4.2.1 Model implementation of 45Q

In the 2018 revised code [217], fossil-fuel power plants capturing at least 500,000 tonnes per annum[38] of CO_2 are allowed a tax credit that will increase from \$17/tonne in 2018 to \$35/tonne in 2026 for EOR and other special utilizations.[39] Credit for immediate sequestration of the CO_2 in dedicated storage starts at \$28/tonne in 2018 and ramps up to \$50/tonne in 2026. Thereafter,

[38] Eleven CFEGUs in this study fail to meet this requirement with 90% capture at the capacity factors used in this study. All NGGC plants meet the criterion under the same conditions.

[39] Other diverse uses may include feedstock for chemicals and plastics, synthetic fuels, biofuels, building materials, fertilizers, and food [229].

the credits will be indexed to inflation with no total cap on available credits for a CCS facility or the program. Industrial facilities and DACS can receive these credits at a lower annual criteria (100,000 tonnes per annum). The credits are transferrable from the owner of the CCS facility to a downstream operator and are available for 12 years once CCS operation commences, with construction of the CCS facility needing to start before 2024.

Three assumptions are made concerning the tax code structure for modeling. While the deadline for commencing CCS construction is within three years of this study (and as such demonstrates that the deadline should be extended to permit greater CCS promotion), operation of the CCS facility in this study is assumed to commence in 2030, with construction beginning in 2023 and meeting the criteria for physical work and safe harbor throughout this period [230].[40] Furthermore, when the operational life of the source exceeds the duration of the credit, the base credit level will be proportionally derated over the life of the source. The power plant operator is assumed to have taken on the capture-related capital costs and has a sufficient tax appetite to fully monetize the credits; therefore, the power plant retains credit ownership, rather than transferring the credits to another party.

4.2.2 ESTEAM model structure

ESTEAM uses empirical data to characterize performance and cost parameters for each existing CFEGU or NGCC plant in a bottom-up modeling approach to determine the dominant technology option.[41] The underlying equations for these parameters are developed, Figure 4.1, in terms of unit configuration and operational data from several publicly available power-plant

[40] Legislation was recently introduced in the U.S. Senate to extend the construction cutoff date through the end of 2030 [231].

[41] See Chapter 3 for a detailed explanation of ESTEAM.

databases. For the coal-fired fleet, these historical data from a selection of EGUs are modeled in the Integrated Environmental Control Model (IECM) version 8.02, a power-plant simulation tool developed by Carnegie Mellon [146], to determine the general econometric relationships for the operational metrics of a generic CFEGU. Modeling of the selected CFEGUs is also done with these CFEGUs configured with the requisite traditional emission-control-devices (ECDs) necessary for compliance with air-quality standards (nitrogen oxides (NO_x), sulfur oxides (SO_x), and mercury (Hg)) and with the employed CO_2 mitigation technologies to expand the equation set. For the NGCC plants, the historical capacity data are used to determine the number of turbines for each existing plant. The future emissions and cost performance of each plant, with and without mitigation measures, is determined by IECM-derived regression equations from modeling theoretical plants with varying number of turbines (differing capacities). For each generating source, these equations are augmented with those derived externally to account for mitigation-specific expenditures and renewable generation to complete the reduced-form model. With inputs such as state-specific fuel prices, capacity factor constraints placed on future dispatch, mitigation incentives, and CO_2 emissions price, the reduced-form model then produces a feasible mitigation set that defines the least-cost frontier from the superposition of these technologies and the fungible generation sources.

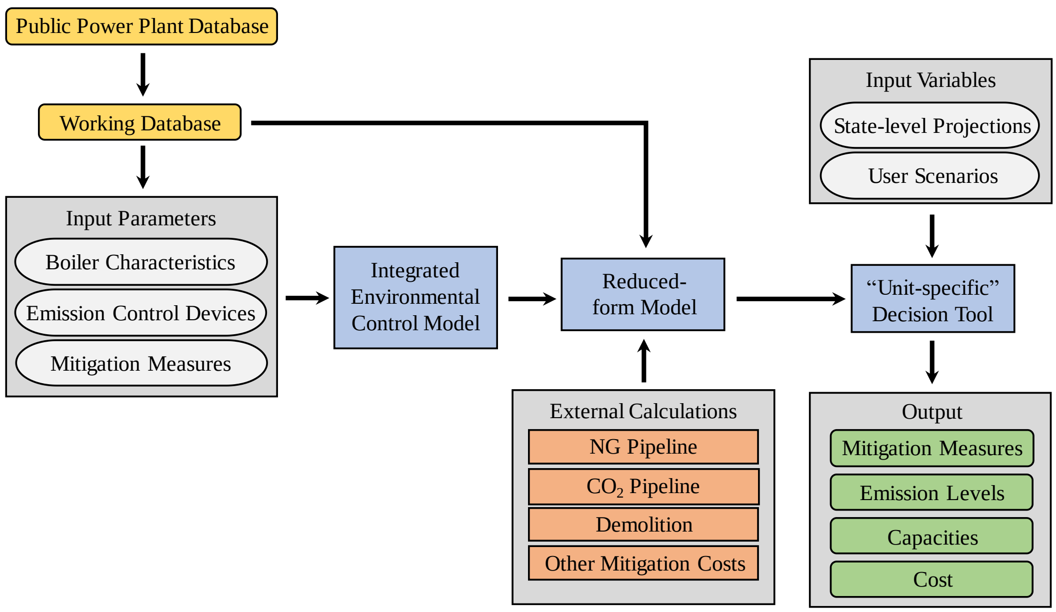


Figure 4.1. Schematic diagram of ESTEAM model construction and implementation for coal and boiler-type clusters and resulting CFEGU mitigation equations.

4.2.3 Power plant databases

In addition to the databases used to create the model equations and analyze the performance of the existing CFEGUs (Chapter 3), the capacities of the existing and planned NGCC plants in this study are taken from the thirteenth edition of the U.S. Environmental Protection Agency's (EPA) Emissions and Generation Resources Database (eGRID) version 2.0 [232]. The eGRID2018 documentation also provides the commercial operation year for existing and many planned generators, as well as planned and actual retirement dates. For this study, two of the criteria that the NGCC plants must meet are that existing plants have a first year of commercial operation after 2009 (so that the plant may have at least 10 years of operation remaining after 2030 over which a retrofitted CCS facility can be amortized) and that planned plants have a listed year for commercial operation. These and other criteria result in a fleet of 154 unique NGCC plants with 106.9 GW of total capacity (Other criteria are listed in *Appendix D, Section D.3*). If more than one NGCC plant is located at the same site, based upon plant longitude and latitude coordinates in eGRID, then the capacity of these plants is combined as retrofitting only one CCS facility may be sufficient. Combining the plants in this manner reduces the dataset to 133 NGCC plants (See *Appendix D, Section D1.1*).

For the ESTEAM coal fleet (Chapter 3), we assume that the historical databases used to derive the econometric relationships are still representative of operational parameters in subsequent years and are brought forward to 2030, for comparative purposes. As some CFEGU-specific parameters may vary on a yearly basis (e.g., capacity factor, coal quality, ambient and water temperatures, scheduled and unscheduled maintenance), the configuration and operation input parameters for any CFEGU (or NGCC plant) in the ESTEAM model can be updated with more recent or site-specific values to determine the current least-cost frontier, for subsequent frontier analysis. To this end, 267 of the 635 CFEGUs have been removed from the model due to actual or planned retirement prior to 2030. The retirement age is set at 65 years for the remaining coal-fired fleet. EGUs meeting this milestone in 2030, which encompass 6% of the remaining fleet capacity, are repowered as NGCC plants (without or with CCS) or replaced with renewable capacity, whichever option has the lowest LCOE from a 30-year expected operating life. (See *Appendix D, Section D.1.2*). EGU life extensions from incorporating new boilers, turbines, or heat recovery steam generators are not considered in this study. However, doing so could increase the amortization period for some EGUs sufficiently to make retrofitting CCS financially viable in some instances.

4.2.4 EGU-level mitigation technology frontiers for NGCC

The details for the operation, costs, constraints, 2030 fuel prices, the derivation of the associated techno-economic equations for the existing CFEGUs, and the six mitigations and the renewable sources that comprise the least-cost frontier in this study are discussed Chapter 3 and *Appendix B*. This section contains an additional overview on modeling NGCC plants and NGCC plants with CCS, details for which is given in *Appendix D, Section D.3.* Financial, operational, and mitigation assumptions used in the IECM and ESTEAM model runs to determine the regressions and least-cost frontiers are shown in Table 4.1.

4.2.4.1 NGCC modeling

The capital and O&M costs for the existing NGCC plant are calculated as a function of the number of turbines required to meet the nameplate capacity specified in eGRID2018, the formulaic structure[42] for which is presented in *Appendix B, Section B.8.6.6.* For simplicity, the default NGCC plant configuration in IECM that uses a GE 7FB turbine is used to simulate all capacity in this model (247.3 MW_{net} per turbine). Furthermore, a wet-cooling tower is assumed for each NGCC plant. When more than one NGCC plant is located at the same site, the capacity of these plants is combined, and the capital and O&M costs are scaled according to the number of these turbines required to meet the total site capacity. As IECM only models up to five turbines, costs and performance for plants requiring more than five turbines are extrapolated with the NGCC and CCS regression equations as a function of turbine number. Overall, 14 of the 133 simulated plants require more than five turbines (seven plants require six turbines, four plants require seven turbines, and three plants require eight turbines).

[42] The additional costs for necessary CFEGU demolition and the natural gas pipeline are excluded in these calculations.

4.2.4.2 NGCC capacity factor

The capacity factor for all non-mitigated NGCC capacity is set to 60% based upon the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 historical data and reference-case projections that indicate that the fleet-average capacity factor for NGCC without CCS is expected to decrease from 63% in 2019 to 47% by 2030 [233]. Since the AEO does not contain capacity-factor projections for NGCC with CCS, simulations of this configuration employed on the British grid [234] serve as a proxy. These simulations indicate that new CCS capacity may initially achieve a 60% capacity factor, which diminishes over time as next-generation CCS capacity is added. Therefore, ESTEAM modeling also uses a 60% capacity factor for new and retrofitted NGCC CCS in 2030. The implication of using the same capacity factor for all NGCC capacity is that one technology does not have an inherent generation advantage over the other so that the incremental costs incurred with CCS must be overcome through incentive and CO_2 emissions price advantages to be a preferred configuration. This can be seen in increased marginal costs for the CCS equipped plant for which the increase in heat rate from the addition of the CCS subsystem will increase fuel costs and negatively impact the merit order placement of the plant. However, the 45Q incentive or lower CO_2 expense can improve this position relative to unabated plants.

4.2.4.3 Retrofitted and new CCS

Partial CO_2 capture for existing and new fossil-fuel generation sources [120, 225, 235, 236] is achieved with commercially-available amine-based CCS, with a removal efficiency of up to 90%, combined with a bypass design to meet the desired capture rate. Two energy-supply configurations for the CCS solvent-regeneration process are used in this study for coal-fired CCS and one configuration is available for NGCC CCS, retrofitted or new. In one coal-fired configuration, the steam required for this process is provided by an auxiliary NG-fired power-generation system from which CO_2 is not captured and any surplus generation from the auxiliary boiler is available to the grid. In the other configuration and the NGCC applications, low-quality steam from the steam cycle is extracted to meet these requirements; in this case, the net generation is reduced because of the CCS parasitic load [166]. For CCS mitigation, additional components of the LCOE calculation include the capital and O&M costs associated with the CCS facility, the pipeline networks for the NG and the CO_2 transportation, and the CO_2 sequestration (See *Appendix D, Section D.3* and *Appendix B Section B.8* for more detail). As each CCS project is independent of other projects, the siting of the CO_2 pipeline is unique and is determined by the lowest-cost for the combined line-of-sight transportation and sequestration costs for the given capture rate, rather than from aggregating storage requirements and creating intricate networks [168-171].

4.2.5 Probabilistic confidence bounds

There are three types of error described in Chapter 3 and *Appendix B* that give rise to uncertainty in the LCOE and emission-intensity calculations that affects the relative position of each mitigation on the frontier: projected fuel price, capital and O&M costs, and modeling. The fuel price error is defined as the accuracy of EIA projections for the percent increase in the natural gas and coal prices from 2012 to 2030, based upon the EIA's 2018 Annual Energy Outlook Retrospective Review dataset [175, 176]. The uncertainty from capital and O&M error is defined as the sensitivity found by bounding the associated parameters at two levels that are either set parametrically by the authors, taken from literature, or are the minimum and maximum values set in the IECM for various cost components. Finally, the modeling error is defined as the historical variation in the calculated net heat rate and emission intensity for the fossil-fuel generation sources, and includes the regression-equation residual errors used to model the various operating parameters. In this work, the methods used in Chapter 3 to determine and combine these errors are also employed with the values augmented for the renewable and NGCC CCS capacity (Details are provided in *Appendix D, Section D.2.1*). For illustrative purposes, the various methods are applied to bound these uncertainties and the resulting tolerance limits on a Wisconsin CFEGU (ORIS Unique ID 4050_B_5). This EGU is also modeled in the IECM in the current, compliant, and mitigated states, with the appropriate external calculations added, to validate LCOE and emission intensity calculations relative to these limits (See *Appendix D, Section D.5*).

4.2.6 Sensitivity analysis

Several parameters not related to 45Q can affect the capacity profile of the combined fleet by changing the mitigation LCOE. Those factors relevant to the set of CCS assumptions are the CCS retrofit multiplication-factor[43] for all existing capacity, the capacity factor for the NGCC-based sources, and the renewable capital cost of a competitive technology. Of those factors examined in the least-cost frontier analysis, fuel price is the most important.[44] The sensitivity study range for the retrofit multiplication factor is set by the authors, while those for the other

[43] The CCS retrofit multiplication factor is defined as the fraction by which any additional capital cost of any subsystem in the existing EGU that arises from retrofitting the CCS facility is multiplied. This additional cost is determined in the IECM from the difference in the subsystem capital cost with and without CCS, at the given capture rate.

[44] While coal price variations are used in calculations, the sensitivity is not presented because no mitigation variation results.

factors are taken from literature. The capacity factor range is based upon the results of Mac Dowell and Staffell [234], and the availability limit used for advanced NGCC plants in the EPA's Integrated Planning Model [237]. The range for the renewable capital cost is represented as the average percent change from the mid and low, and the mid and high technology cases in the National Renewable Energy Laboratory's (NREL) 2019 Annual Technology Baseline report concerning the highlighted overnight capital costs for the utility solar and land-based wind capacity cases [79]. For the impact of fuel price, an increase in price is only considered because the AEO 2020 projections [233] indicate that future mandates for emissions reduction or restrictions on the availability and use of fossil fuels are likely to increase prices above the reference case projections. In these projections, the highest fuel prices are observed in the case in which a $35/tonne CO_2 fee (emissions price) is applied, Table D.19. Values for sensitivity analysis are listed in Table D.20.

Table 4.1. IECM and modeling assumptions and parameters for ESTEAM: (a) financial, (b) operational, (c) mitigation.

(a) Financial

Parameter	Value
Year costs reported	2010
Dollar costs basis	Constant
Indexes for inflation	CEPCI*, CPI*
Fossil-fuel project book life (years)	30 years
Solar generation book life (years)	30 years
Wind generation book life (years)	20 years
Discount rate (fraction)	0.071
Fossil-fuel default fixed charge factor (fraction)	0.113
Wind generation fixed charge factor (fraction)	0.106
Solar generation fixed charge factor (fraction)	0.104
Fossil-fuel applied project life for fixed charge factor	Minimum 30-year book life or remaining life
Fossil-fuel remaining value calculation	Straight-line amortization
Construction costs	Overnight

*Notes: CEPCI: Chemical Engineering Plant Cost Index; CPI: Consumer Price Index

(b) Operational

Parameter	Value
Reference year of CFEGU performance characteristics	2010
2030 fuel prices	AEO 2020 projected change relative to 2010 state-specific prices
CFEGU retirement age	65 years
NGCC retirement age	30 years
CFEGU capacity factor	historical
NGCC capacity factor	60%
Source coal and natural gas properties	IECM version 8.0.2
Source current and compliant CFEGU and NGCC modeling and costing	IECM version 8.0.2
CFEGU current configuration	Pulverized coal, tangential wall, wastewater ash pond, no mixing fly ash disposal, wet-cooling tower, cold-side electrostatic precipitator
NGCC default configuration	wet-cooling tower
Year compliant with non-CO_2 air quality regulations	2016
NO_x compliance combustion controls	Low NO_x burner (LNB)
NO_x compliance post combustion controls	Hot-side selective catalytic reduction (SCR)
SO_x compliance post combustion controls	Wet flue-gas desulfurization (FGD)
Hg compliance post combustion controls	Carbon injection

(c) Mitigation

Parameter	Value
Reference year for mitigation decision	2030
Regional construction adders	None
Source HRI improvement standard	IECM version 8.0.2
Maximum relative HRI (fraction)	0.5
Maximum absolute HRI (Btu*)	1,205
HRI cost ($/kW*-net)	100
Power rule coefficient for economy of scale	0.6
NGCC turbines type	GE 7FB
CCS net generation constraint	Extra generation sold to grid
CCS performance calculation	Linear interpolation 10-90%
CCS capture method	FG+ amine
CCS capture efficiency (fraction)	0.90
CCS flue bypass control type	Bypass
CCS thermal efficiency of auxiliary gas power system (fraction)	0.35
CCS SO_x polisher use	Yes
CCS CO_2 purity (fraction)	0.995
NGCC CCS retrofit multiplication factor for base plant and WT* (fraction)	1.10
CCS CO_2 transportation method	Pipeline
CCS CO_2 storage method	Geological
CCS pipeline distance	Line-of-site to center of reservoir
NG and CO_2 pipeline O&M cost ($/mile/year)	5,000
NG pipeline distance source	Modified EPA estimates
Existing NGCC pipeline diameter	Sized for increased flow for CCS retrofit
Pipeline electric compressor station spacing (miles)	50
Modeled solar generation capacity (MW)	150
Modeled wind generation capacity (MW)	100
Solar generation capital cost ($/kW)	825
Wind generation capital cost ($/kW)	1,189
Solar generation O&M cost ($/kW/year)	9.9
Wind generation O&M cost ($/kW/year)	37.8
CFEGU, NGCC, CCS mitigation modeling and costing source†	IECM version 8.0.2

*Notes: Btu: British thermal unit; MW: Megawatt; kW: kilowatt; WT: wet-cooling tower
†Cost modeling in the IECM assumes n^{th} of kind capacity.

4.3 Results and discussion

4.3.1 Deterministic least-cost frontier and probabilistic confidence bounds

The least-cost frontiers for the illustrative CFEGUs in Wisconsin and Wyoming, with state-specific 2030 fuel prices (Table D.42), are shown in Figure 4.2. For each CFEGU, Figure 4.2(a, c), the emission intensity for each mitigated option is generally lower than that for the compliant configuration.[45] Furthermore, all mitigated options have a higher LCOE than the compliant configuration. The LCOEs for these mitigations differ between the two CFEGUs in part because of the relative differences in the projected coal and natural gas prices. As the natural gas price in Wisconsin (Figure 4.2(a)) is projected to be lower than in Wyoming (Figure 4.2(c)), NGCC CCS at 90% capture has a lower LCOE than any coal-fired 90% capture CCS option in Wisconsin, but coal-fired CCS without an auxiliary boiler has a lower LCOE than any other CCS option in Wyoming. Other factors that can affect the LCOE are CFEGU-specific attributes such as the remaining years of operation, the capital costs for the mitigations, and the capacity factor for the CFEGU, as well as the state-specific fuel prices and capacity factors for renewable sources. For this example, the total capital costs for the mitigation technologies for these CFEGUs are similar, Figure 4.2(b, d), though these costs depend upon the CFEGU capacity, and the assumed distances for the site-specific natural gas and CO_2 pipelines.

[45] The exception in this figure is CCS without an auxiliary boiler near a 10% capture rate for which the intensity is greater because the parasitic load from the CCS facility increases the CFEGU heat rate.

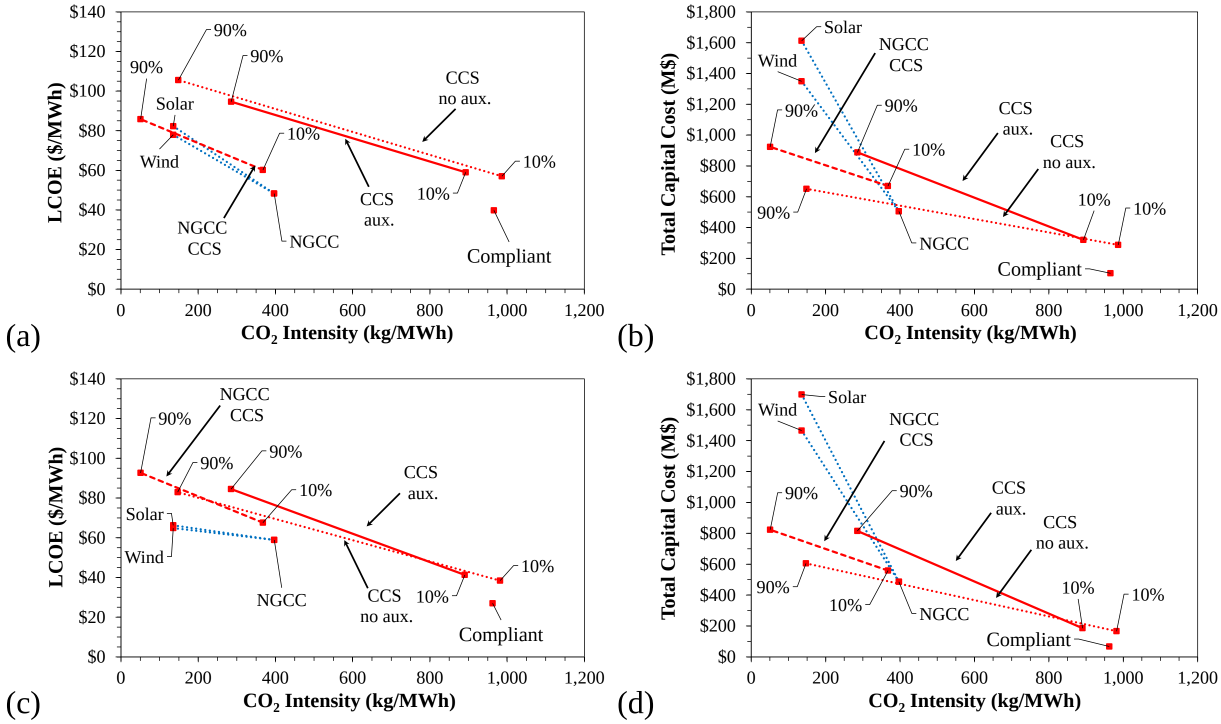


Figure 4.2. Least-cost mitigation frontier for compliant CFEGU with CCS and NGCC mitigation options, without 45Q tax credit. Panel (a) shows the Wisconsin CFEGU least-cost frontier and Panel (b) shows capital costs for this frontier. The least-cost frontiers for the Wyoming CFEGU are shown in Panels (c) and (d), respectively.

In the absence of a restriction on emission intensity or total emitted mass for an CFEGU, a mitigation option will not dominate other options unless the LCOE for that option is lower than those for all other options. In Figure 4.2, for which no 45Q tax credit is applied, the compliant mitigation dominates. When the current 45Q is applied to the Wisconsin CFEGU, Figure 4.3(a), the compliant mitigation remains the least-cost option, though the marginal cost of increasing the capture rate for all CCS options is decreased. In such a comparison, the compliant mitigation will continue to dominate all CCS options unless the tax credit is sufficient to more than offset the additional CCS capital cost. For the Wisconsin CFEGU, a hypothetical $100/tonne tax credit is sufficient to meet this condition for the coal-fired CCS mitigation without an auxiliary boiler,

Figure 4.3(b). However, the current tax credit is sufficient to promote CCS in some instances, Figure 4.3(c). In both cases, the lowest LCOE is achieved at a 90% capture rate because the capital cost and the LCOE can be approximated as linear functions. Therefore, one can expect the optimal capture rate to be 90% for the given assumptions.

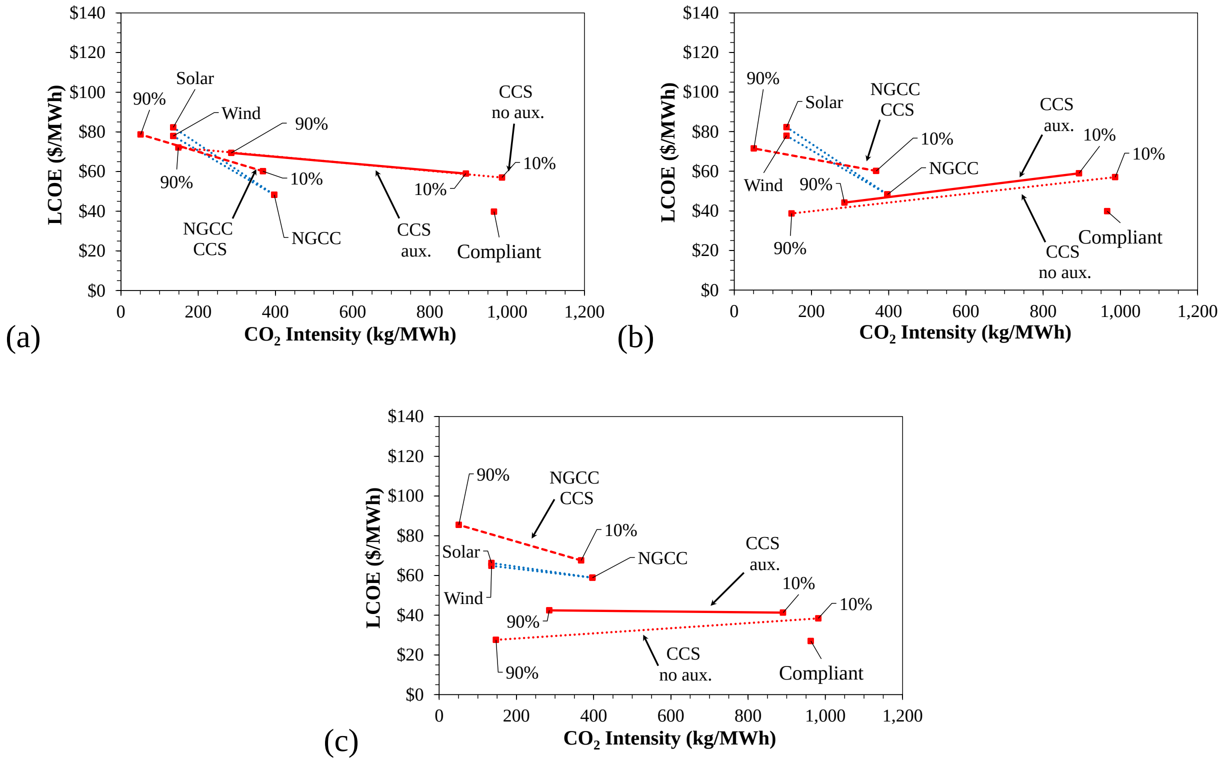


Figure 4.3. Least-cost frontier for a Wisconsin CFEGU with (a) \$50/tonne, 12-year duration 45Q tax credit and (b) \$100/tonne, 12-year duration 45Q tax credit. Panel (c) illustrates the least-cost frontier for a Wyoming CFEGU with a (c) \$50/tonne, 12-year duration 45Q tax credit.

Adding the 95% confidence limits, Tables D.6-D.18, to the deterministic mitigation LCOEs and emission intensities for the Wisconsin CFEGU shows that in many instances it is difficult to statistically discern one mitigation from another for at least one metric, Figure 4.4(a). While the emission intensities for the compliant configuration and 10% capture rate coal-fired CCS are statistically different from deeper reduction mitigations, the LCOE for coal-fired CCS and NGCC with CCS at the 10% capture rate are not statistically different. Furthermore, the emission intensities for the high capture-rate CCS options can be discerned, but not all of the differences in LCOEs are statistically significant. The overlap for emissions and LCOE values illustrates that the least-cost mitigation option for an CFEGU may change given CFEGU-specific information about the cost of the mitigation project. Incorporating the projected fuel price uncertainty further increases the LCOE overlap for all mitigations, Figure 4.4(b); the NGCC LCOE may now be as low as that for the compliant configuration. Therefore, the projected fuel-price uncertainty is the dominant LCOE-related error component.[46]

The analysis of the deterministic least-cost frontier and probabilistic confidence bounds for the coal-fleet NGCC mitigations serve as proxies for those for the NGCC fleet without and with CCS (Tables D.9, D.10, D.14 and D.15), as deviations in resulting LCOE from excluding demolition, NG pipeline, and other brownfield costs and errors components are small (Table C.18). Here, too, the renewable-specific LCOE terms for the co-located renewable generation are a proxy for the probabilistic error terms for the alternative renewable sources (Tables D.16 and D.17) for both the coal and NGCC fleets.

[46] The fuel price uncertainty is propagated through the fuel-specific mitigations rather than applied randomly to each.

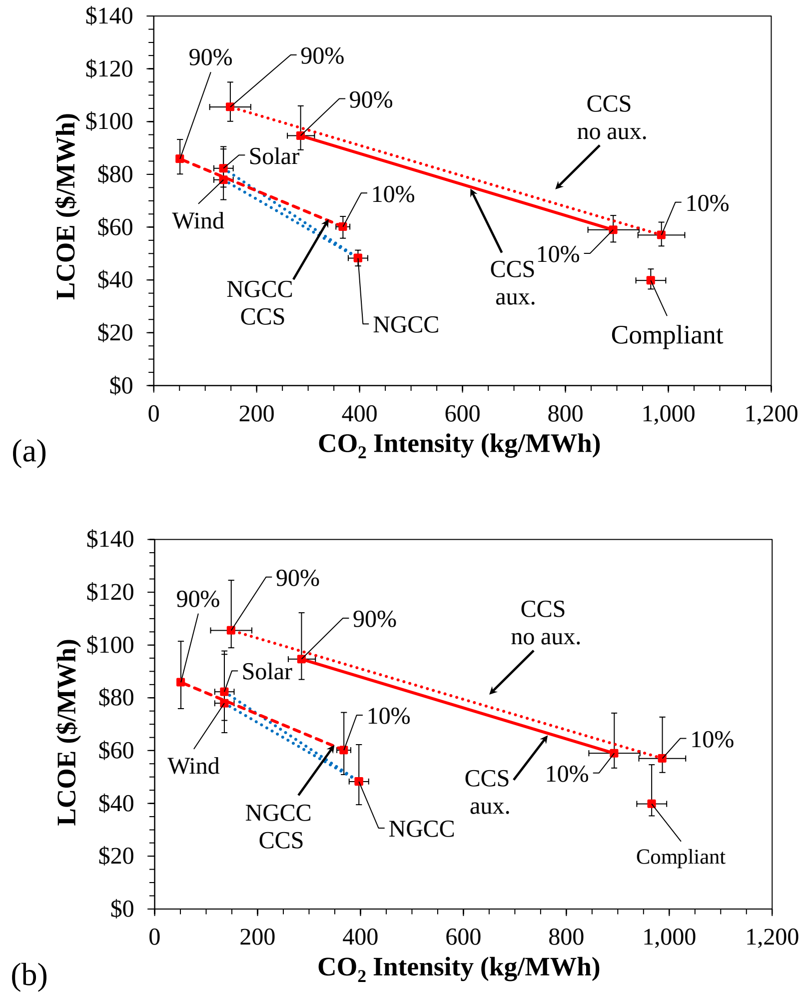


Figure 4.4. Least-cost frontier for Wisconsin CFEGU under default conditions with (a) non-fuel uncertainty, and (b) fuel and non-fuel uncertainty.

4.3.2 Application of current 45Q to the coal and NGCC fleets

Applying the 2030 coal and natural gas prices only to the 2030 coal fleet shows that while much of this capacity may remain as coal in the absence of a CO_2 emissions price, 15% may be repowered as (replaced[47] by) NGCC plants as lower natural gas prices make NGCC generation more competitive, Figure 4.5(a). Furthermore, the decreasing renewable generation capital costs

[47] Forty percent of this capacity is from CFEGUs beyond 65-year limit being replaced by NGCC plants.

[62] cause 4% of the coal capacity to be replaced[48] with renewable capacity. These fuel price and capital cost reductions together results in a 16% drop in the coal-fleet emissions from the 2010 level, Table D.43. The trend of replacing coal capacity with that from alternative sources changes little with the addition of the current 45Q, Figure 4.5(b), with which only 3 GW of CCS capacity is added absent a CO_2 emissions price, Table 4.2. This capacity captures 26 Mtonnes of CO_2 per annum, a similar result to that in Edmonds et al. [223] when EOR is not an option; however, this effluent is captured from retrofitted CFEGUs. Total CCS capacity remains low with increasing CO_2 emissions price, as the retrofitted capacity never exceeds 14% of the projected 2030 total capacity.

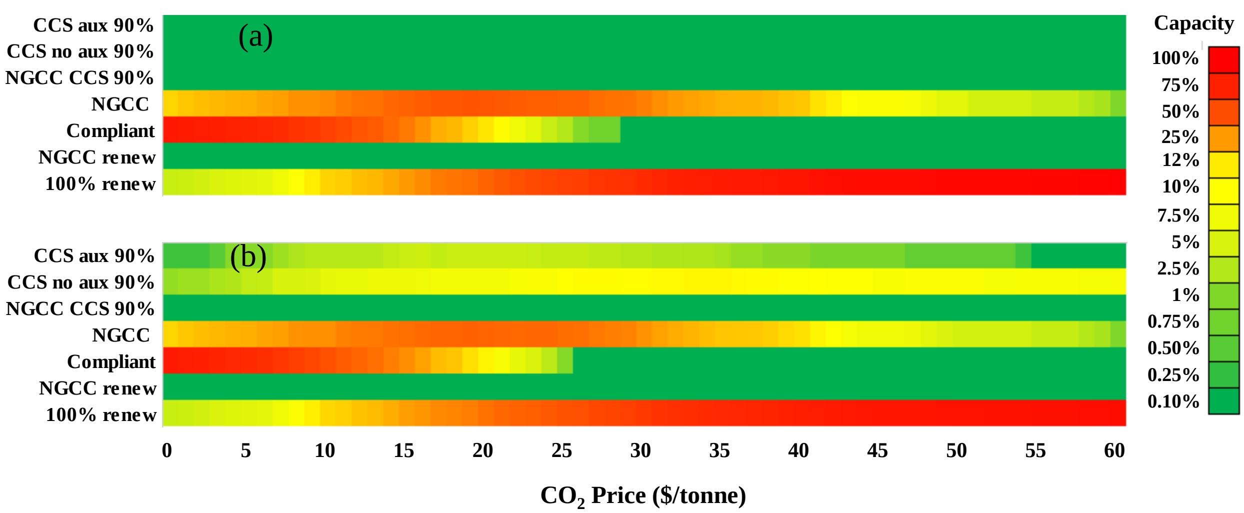


Figure 4.5. Heat map of coal-fleet capacity for different mitigation options as a function of CO_2 emissions price for (a) $0/tonne 45Q tax credit and (b) $50/tonne, 12-year duration 45Q tax credit.

[48] Twenty percent of this capacity is from CFEGUs beyond 65-year limit being replaced with renewable capacity.

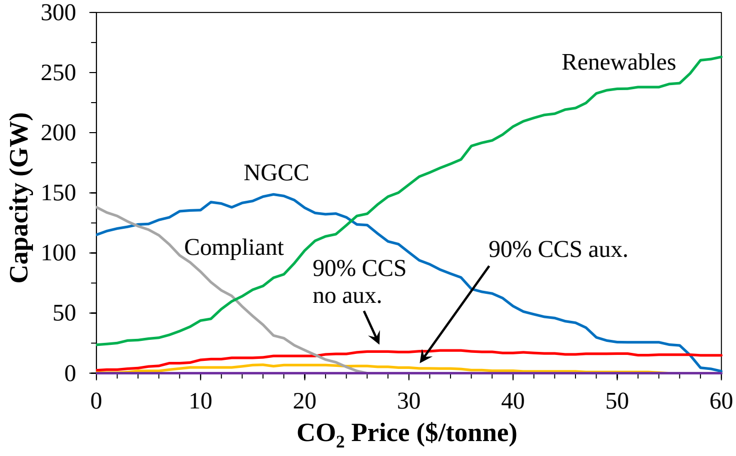
Table 4.2. Location, number of sites, and capacity of CFEGUs for which preferred generation technology is CCS with 90% capture, when a \$50/tonne CO_2 tax credit for a 12-year duration is applied without a CO_2 emission price.

	No Auxiliary Boiler		Auxiliary Boiler	
State	**Sites**	**Capacity (MW)**	**Sites**	**Capacity (MW)**
Illinois	1	598	0	0
Indiana	0	0	1	536
Texas	2	1,322	0	0
Wyoming	1	527	0	0
Total	**4**	**2,447**	**1**	**536**

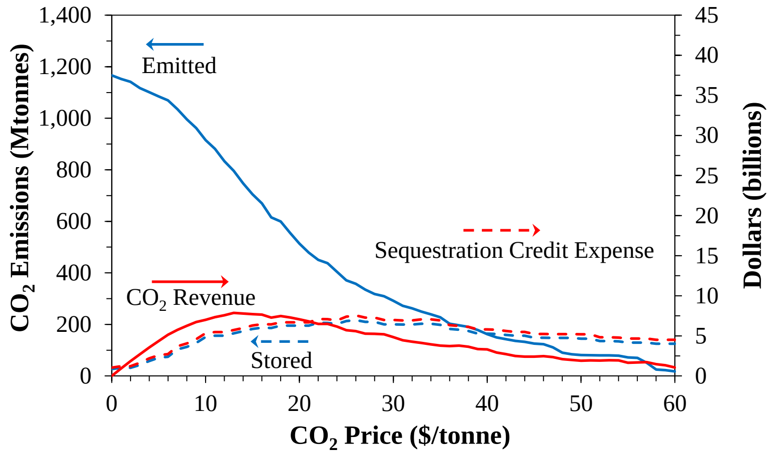
The composition of the NGCC fleet in this study does not allow for plants in operation for more than 20 years by 2030 to be carried forward and is inclusive of planned capacity; therefore, a comparison to historical emissions is not as meaningful as it is for the coal fleet. One can calculate a proxy fleet emission level from the eGRID2018 database [232] and the assumption that all planned plants would have operated at the fleet average capacity-factor had these plants been operational in 2018. Doing so shows that while the theoretical fleet emissions increase by 6 Mtonnes from an increase in generation, the emission intensity decreases 16% primarily from replacement of NGCC plants with renewable sources, Table D.44. Applying the current 45Q to the NGCC fleet produces the same result as in the coal fleet, Figure D.4(a), as NGCC capacity continues to be supplanted by less-expensive renewable capacity rather than by CCS retrofitted capacity, even as the CO_2 emissions price increases. If renewable sources are not fungible, CCS capacity is not available until the CO_2 emissions price is greater than \$45/tonne, Figure D.4(b).

The capacity of the modeled fossil-fuel power-sector fleet in 2030 having almost no CCS capacity absent a CO_2 emissions price, Figure 4.6(a), is contrary to previously-cited findings that are based upon EOR utilization. At first, the \$15/tonne difference between the EOR and immediate storage tax credits for the current 45Q suggests that the market places a \$15/tonne value on the CO_2, though other sources suggest that the value is higher [207, 238, 239] and is tied to the oil price [207, 227], and that this equivalence indicates an indifference to utilize the effluent or to immediately store it. Even so, the dearth of CCS capacity absent a CO_2 emissions price for the current 45Q suggests that the immediate sequestration premium should be greater and that the existing pipeline networks for CO_2 utilization for EOR [240] add value [225, 241].[49] The lack of CCS capacity also means that emissions reduction for the fossil-fuel fleet comes primarily from repowering CFEGUs as NGCC plants and from renewable replacement for both fleets, Figure 4.6. Hence, the current 45Q may be adequate to replicate the EOR levels, assuming the presence of a CO_2 emissions price, but CCS is not a primary source of emission reduction.

[49] Capacity and performance metrics for coal-fired fleet alone are shown in Figure D.5.



(a)



(b)

Figure 4.6. The effect of CO_2 emissions price and a $50/tonne, 12-year duration 45Q tax credit on (a) the combined fleet mitigation capacity and (b) performance parameters.

4.3.3 Modified 45Q to promote retrofitted CCS in the coal fleet

While the current 45Q for immediate storage may not result in as much tonnage as that for EOR, absent a CO_2 emissions price, increasing the credit level will further decrease the LCOE to make CCS more competitive with fungible generation sources. As there are no fleet requirements or limitations for total CCS capacity or tonnage stored, the credit level can be studied parametrically to determine the necessary credit levels to obtain 5-20% of the AEO reference case projected 2030 net generation from retrofitted coal-fired CCS.[50] Such an exercise indicates that there may be decreasing marginal gains in net generation with increasing credit level, as many of the equipped CFEGUs are too costly without even greater credit levels to retrofit relative to the alternatives, Figure 4.7. However, increasing the credit level by only $20/tonne can supply between 6-12% of net generation from the addition of 40-70 GW of CCS capacity, Figure D.6.

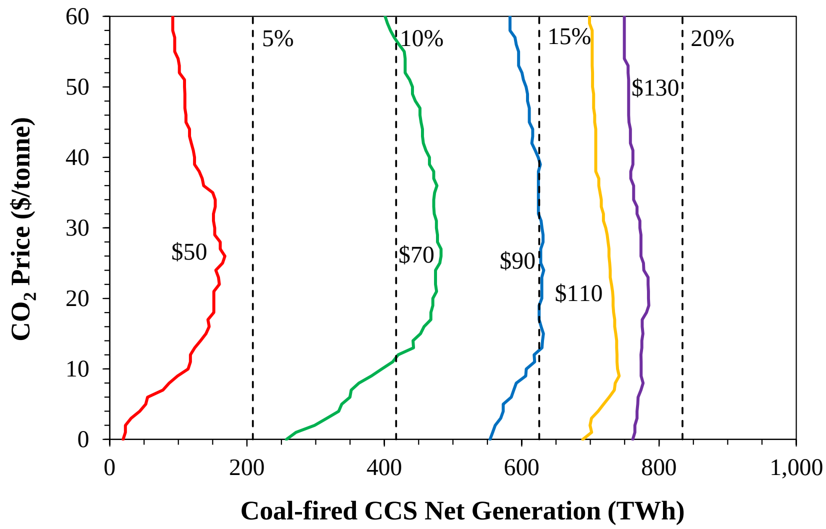


Figure 4.7. Net generation contours from coal-fired CCS capacity with 90% capture for alternative 45Q credit levels ($50-130/tonne) with 12-year duration to achieve AEO 2020 projected levels of power sector generation [233].

For illustrative purposes, if the credit level is increased to $66/tonne absent a CO_2 emissions price, 5% of the coal-fired net generation can be supplied by CCS,[51] Table 4.3. This greater

[50] These targets are taken from the AEO 2020 reference case for power-sector net generation for power only [233].

[51] This is a larger percent of total generation from CCS than that simulated in the 45Q scenario 1 in Edmonds et al. [223] for which the total CCS net generation from all generation sources in each model is between 0.2% and 3.6% in 2030.

credit level increases the total CCS capacity to 32 GW, of which approximately two-thirds of the capacity employs CCS without an auxiliary boiler, and 55% of the total capacity is in Texas, Wyoming, Utah, and Illinois (with 25% overall located in Texas). Therefore, modeling both CCS energy-supply configurations is necessary to fully capture CCS deployment. Absent a CO_2 emissions price, this new CCS capacity comes from otherwise compliant CFEGUs at the current 45Q level, Figure D.7(a, c), to further lower emissions by 153 Mtonnes when compared to the current 45Q, doing so at a marginal $10/tonne avoided cost, Table D.45.

Table 4.3. Location, number of sites, and capacity of CFEGUs for which the preferred generation technology is CCS with 90% capture, when a $66/tonne CO_2 tax credit for 12-year duration is applied without a CO_2 emissions price.

	Without Auxiliary Boiler		With Auxiliary Boiler	
State	**# Sites**	**Capacity (MW)**	**# Sites**	**Capacity (MW)**
Alabama	1	637	0	0
Arizona	1	372	0	0
Colorado	4	1,566	0	0
Florida	0	0	2	830
Georgia	1	872	0	0
Illinois	5	2,341	2	358
Indiana	1	622	4	2,066
Kentucky	0	0	3	1,175
Michigan	2	1,587	0	0
Missouri	2	1,206	0	0
Mississippi	0	0	2	1,020
North Dakota	3	1,453	0	0
New Mexico	0	0	2	828
Ohio	0	0	2	1,020
Oklahoma	1	522	0	0
Texas	15	8,796	0	0
Utah	0	0	5	2,247
Wyoming	7	3,593	0	0
Total	**42**	**22,731**	**22**	**9,544**

For the CFEGUs that employ CCS for this credit level, all will have been operational for between 46-57 years by 2030, Figure 4.8. This tight distribution indicates that those likely to retrofit will be fully amortized [120] and have at least 8 years of remaining life. Only 5% of those CFEGUs will receive the full credit, while the credit for the others will be derated because the remaining operating life extends beyond the 12-year credit duration. For all CFEGUs, the remaining operating life is not sufficient to allow for amortization of the CCS capital, under these assumptions. As such, there is a relationship between boiler age and CCS retrofitting for which retrofitting is preferred for CFEGUs with a capacity from 200-800 MW and a compliant heat rate from 10,000-12,000 Btu/kWh, Figure D.8. This relationship may be because of the higher levelized costs from the lower net generation of the low capacity CFEGUs and the higher capital cost for larger capacity CFEGUs, and to the higher VOM cost for the higher heat rate CFEGUs related to the CCS parasitic load. Therefore, the credit level must exceed the CCS-related capital and operational costs to lower the LCOE below that of the fungible sources.

When the difference between the CCS-related LCOE from the capital and sequestration costs and the levelized value of the credit is determined for the CCS without auxiliary boiler CFEGUs (Figure 4.9(a)), the credit value for those CFEGUs exceeds these costs by \$20-45/MWh.[52] While this credit surplus increases with capture rate, there are still some CFEGUs that are not retrofitted, even though the credit surplus falls within the range. However, all CFEGUs for which the credit value exceeds the costs by more than \$26/MWh are retrofitted with CCS without or with an auxiliary boiler, Figure 4.9(b). Those that are not retrofitted with CCS remain compliant, indicating that natural gas and renewable generation sources have higher LCOEs than the compliant configuration and that further tax credits are required to prefer retrofitting.

[52] Capital costs and sequestration costs are shown separately in Figure D.9.

The assumption of an *ad hoc* operating life indicates that the coal-fired CCS capacity in 2030 is not constant. For each CCS configuration, Figure 4.10, the capacity is constant through 2037 and then declines to near zero over the next decade. This results in most of the storage occurring within the 12-year duration of the credit. Therefore, if more coal-fired CCS generation leading up to 2050 is beneficial, the duration of the credit could be extended allow for newer CFEGUs, with lower heat rates, to be included in the CCS generation portfolio.

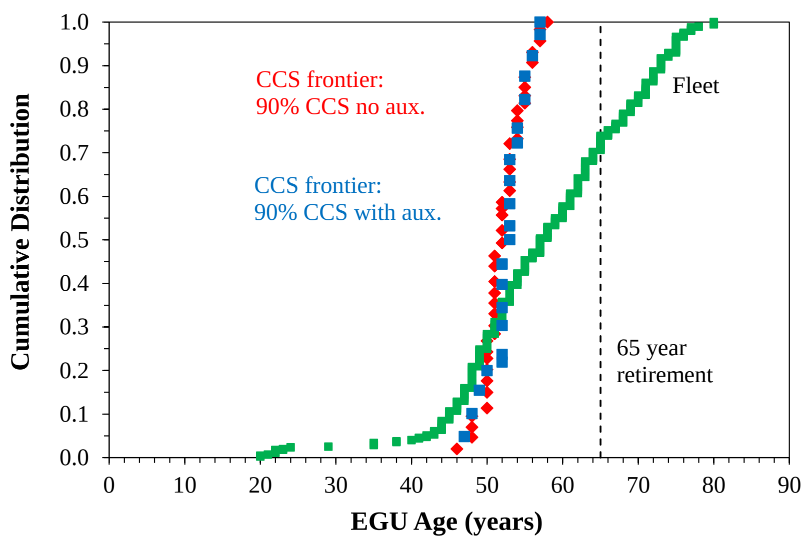
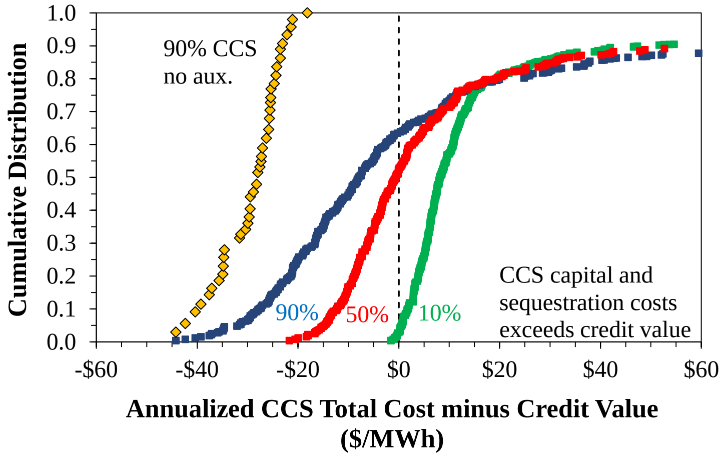
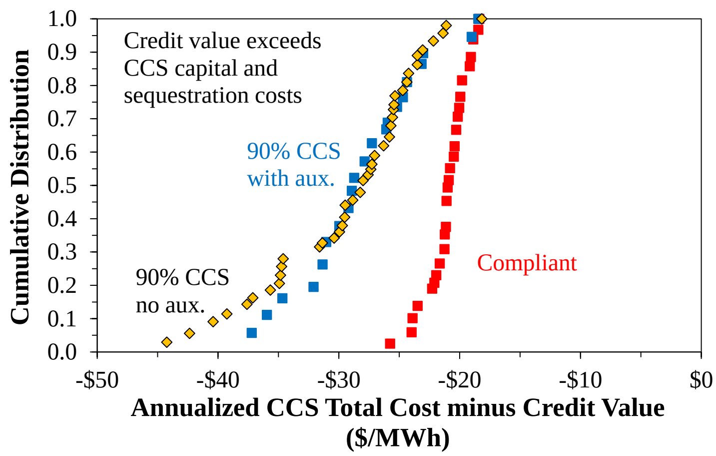


Figure 4.8. Capacity-weighted cumulative age distribution for CFEGU population employing coal-fired CCS when a \$66/tonne tax credit for 12 years is applied without a CO_2 price.

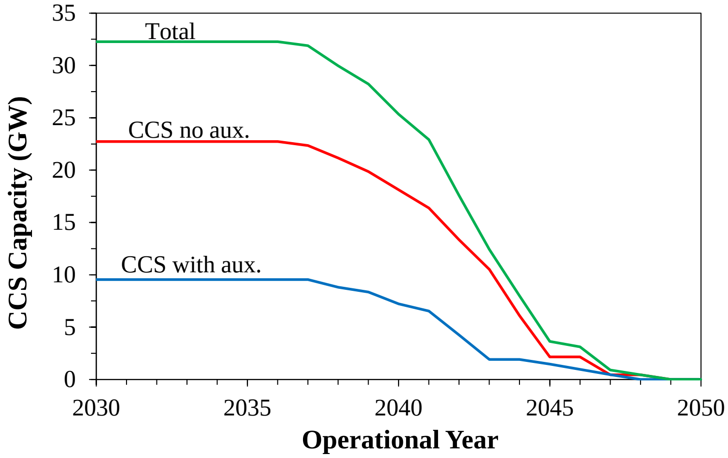


(a)



(b)

Figure 4.9. Capacity-weighted cumulative distribution of the amount of capital and sequestration costs covered by a tax credit at $66/tonne for 12 years for the coal-fired fleet for (a) CCS without an auxiliary boiler at 10-90% capture rates, absent a CO_2 emissions price. Panel (b) shows the capacity-weighted cumulative distribution for the amount of capital and sequestration cost covered by a tax credit of $66/tonne for a 12-year duration applied to the coal fleet and segregated by preferred mitigation technology within the range defined by that for a preference for CCS technology at 90% capture without an auxiliary boiler. No CO_2 emissions price is applied.



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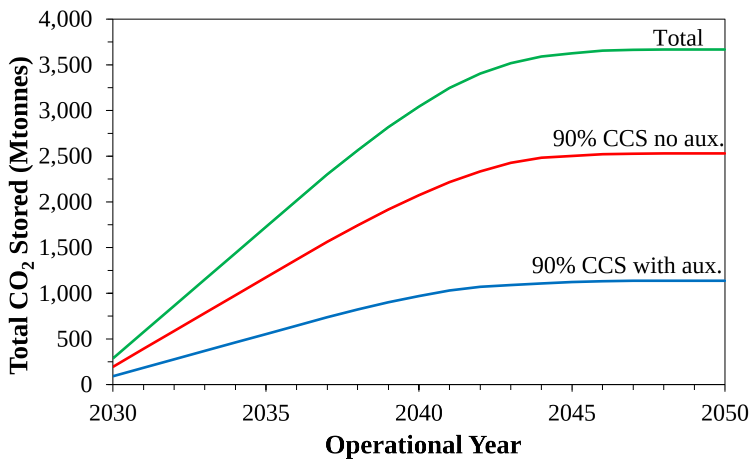


(b)

Figure 4.10. Evolution of the coal-fired fleet with preference for CCS technology at 90% capture with $66/tonne tax credit for 12 years and without a CO_2 emissions price. A 65-year retirement is assumed for (a) capacity and (b) cumulative sequestered CO_2 performance metrics.

4.3.4 Modified 45Q to promote retrofitted CCS in the NGCC fleet

Setting the 45Q tax credit level to that determined for the coal-fired fleet results in no retrofitted CCS capacity for the NGCC fleet. This result is expected because the lower emission intensity of the NGCC plants produces a smaller revenue stream from the tax credit. If one uses the previously outlined procedure, retrofitted generation is not obtained without a CO_2 emissions price until the credit level is above $90/tonne, Figure 4.11 and Figure D.10, and a $142/tonne credit is needed to achieve 5% net generation. At this credit level, CCS retrofitting does not occur unless the credit value exceeds the capital and sequestration cost by more than $13/MWh, Figure 4.12. Even at such a premium, only 72% of these NGCC plants retrofit with CCS.

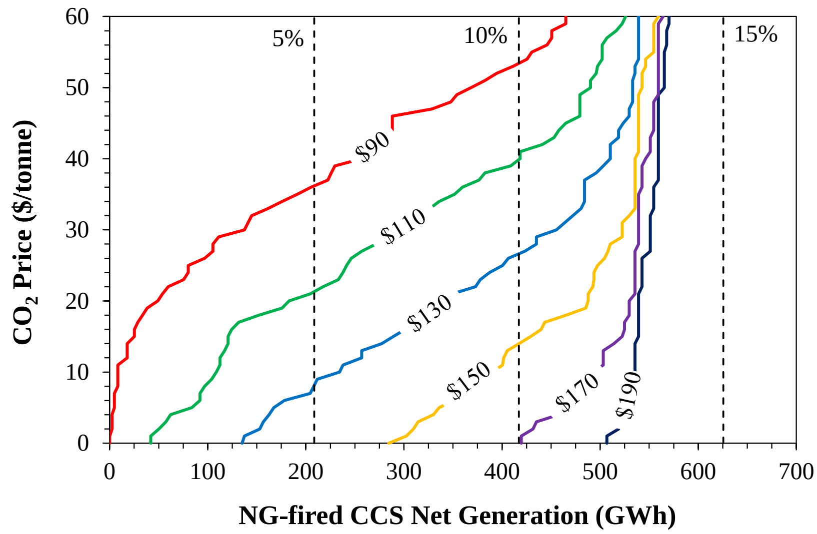


Figure 4.11. Net generation contours from NGCC-fleet retrofitted CCS capacity with 90% capture for alternative 45Q credit levels ($90-190/tonne) with 12-year duration to achieve AEO 2020-projected levels of power sector generation [233].

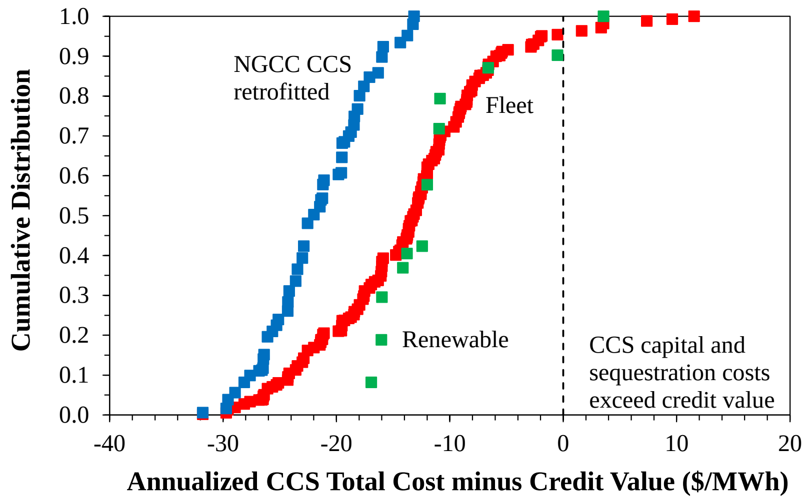


Figure 4.12. Capacity-weighted cumulative distribution for the amount of capital and sequestration cost covered by a tax credit of $142/tonne for a 12-year duration applied to the existing and planned NGCC fleet and segregated by preferred mitigation technology, absent a CO_2 emissions price.

Given a 30-year operational life, only 20% of the plants can receive the full credit value, Figure 4.13(a). This results in a bias toward retrofitting older plants, as 35% of those retrofitted retire by 2050. While this does not bias the CCS-fleet capacity profile, Figure 4.13(b), it does mean that the low-carbon capacity remaining beyond 2050 is limited. Should having more CCS capacity beyond 2050 be desirable, increasing the credit duration to create a longer-term support mechanism will promote retrofitting for younger plants. When the credit duration is extended to 20 years to bridge until 2050, a $104/tonne credit can achieve a 5% generation target, Figure D.11. Doing so biases the retrofitted fleet to younger units and to those with greater capacity, Figure 4.13(c, d). The longer duration also decreases the extent to which the credit exceeds the cost and decreases the range over which this premium effectively promotes retrofitting, Figure D.12. While this extension decreases the number of retrofitted plants and impacts the geographic distribution of these plants, Table 4.4, it also increases the initial capacity and delays the decline by four years, Figure D.13. In 2030, this difference results in 5% lower emissions and emission intensity for the NGCC fleet, which comes from a reduction in NGCC capacity rather than projected renewable capacity, and a 17% lower avoided cost, Table D.46 and Figure D.14 (e, f). Over 20 years, the added capacity sequesters almost 350 million additional tonnes of CO_2 at a marginal cost of $16.3 billion ($47/tonne).

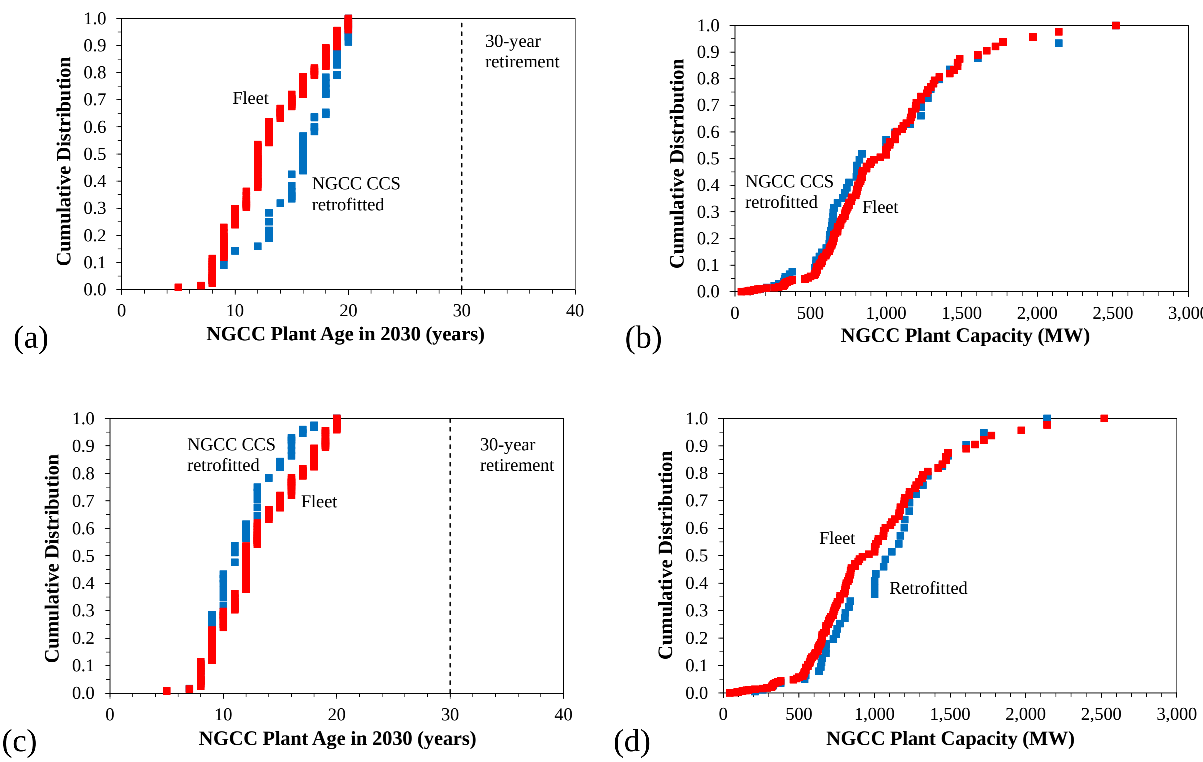


Figure 4.13. Plant age (a, c) and capacity (b, d) cumulative distributions for NGCC fleet and plants for which the least-cost option is to retrofit with CCS at 90% capture and no CO_2 emissions price. 45Q sequestration levels are set to $142/tonne for a 12-year duration in Panels (a, b) and $104/tonne for a 20-year duration in Panels (c, d). No CO_2 emissions price is applied.

Table 4.4. Comparison of NGCC retrofitted fleet characteristics for two scenarios to achieve 5% net generation from CCS generation. No CO_2 emissions price is applied.

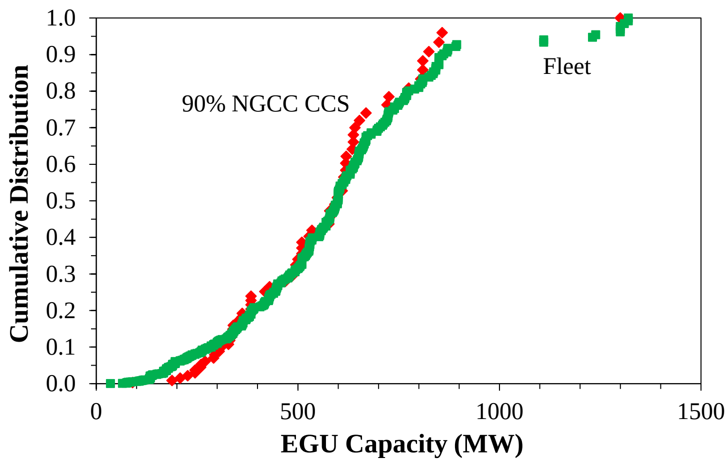
State	$142/tonne, 12 years		$104/tonne, 20 years	
	# Sites	Capacity (MW)	# Sites	Capacity (MW)
Alabama	1	823	0	0
California	6	2,650	6	3,167
Colorado	1	626	0	0
Delaware	1	361	0	0
Florida	6	5,255	2	3,075
Georgia	1	2,520	0	0
Illinois	2	1,904	2	2,476
Indiana	2	2,786	2	2,786
Kentucky	2	1,967	2	1,967
Louisiana	3	2,274	3	2,650
Maryland	0	0	4	3,968
Michigan	1	98	1	1,171
Mississippi	2	1,007	1	840
New Jersey	1	755	0	0
New Mexico	0	0	1	680
New York	1	650	0	0
Ohio	3	2,478	3	2,924
Oklahoma	1	535	0	0
Pennsylvania	0	0	3	3,718
Tennessee	2	1,410	0	0
Texas	11	8,567	12	10,362
Utah	1	728	1	728
Virginia	1	559	0	0
Total	**49**	**37,953**	**43**	**40,242**

4.3.5 Modified 45Q to promote repowering a CFEGU as an NGCC-CCS plant

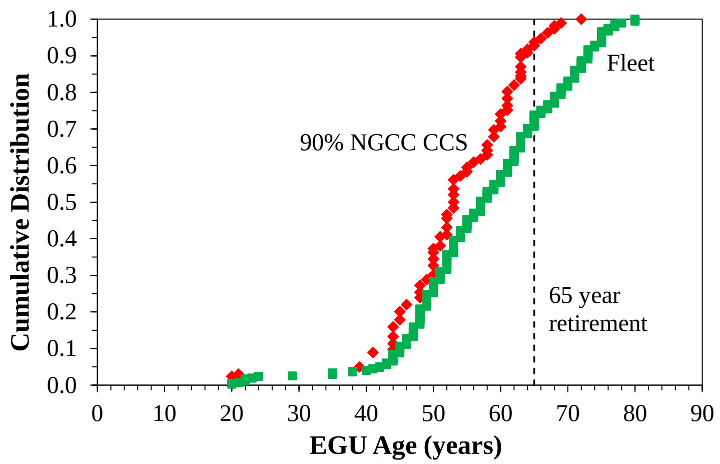
As with the current 45Q, increasing the credit level and duration to those that promote CCS retrofitting of NGCC plants does not promote replacement of CFEGUs with new NGCC plants equipped with CCS. For this to occur at a 20-year duration, the credit level, without a CO_2 emissions price, must be increased to at least $110/tonne and a $144/tonne credit level is needed for 5% generation from this technology, Figure D.15.[53] Those CFEGUs that do repower using NGCC with CCS show no capacity bias; however, there is a bias toward repowering newer CFEGUs, Figure 4.14, which is a complementary outcome to applying the $66/tonne credit to promote coal-fired CCS. At the greater level and duration, 31 GW of NGCC-CCS capacity is available, most of which is located in Texas, Illinois, Indiana, and Maryland (Table 4.5).

With CCS employed solely for NGCC, the total emissions for the coal fleet increase by only 2% and the emission intensity by only 3%, relative to those when the $66/tonne 45Q credit for coal-fired CCS is solely applied, but the overall reduction is achieved at a $24/tonne lower avoided cost (Table D.45 and Table D.47). Given similar CCS capacities, the lower avoided cost results from a tax credit expense that is almost half that for coal-fired CCS, because of the difference in the initial emission intensities between the CFEGUs and the NGCC plants without CCS. Therefore, it may be possible to lower the total tax credit expense and the avoided cost through changing the distribution of the credits.

[53] More detailed analyses are shown in Figures D.16 and D.17.



(a)



(b)

Figure 4.14. Plant (a) capacity and (b) age cumulative distributions for coal fleet EGUs for which the least-cost option is to repower with NGCC and CCS at 90% capture, when no CO_2 emissions price is applied. 45Q sequestration levels are set to \$144/tonne for a 20-year duration for NGCC CCS mitigation only.

Table 4.5. Location, number of sites, and capacity of CFEGUs for which the preferred generation technology is repowering with NGCC CCS with 90% capture, when a $144/tonne CO_2 tax credit for a 20-year duration is applied without a CO_2 emissions price. No credit is given for coal-fired CCS.

State	# Sites	Capacity (MW)
Alabama	2	1,088
Delaware	1	438
Florida	1	219
Illinois	12	4,887
Indiana	9	3,949
Louisiana	2	1,124
Maryland	7	3,474
Michigan	4	2,078
Missouri	1	493
Mississippi	2	1,020
Pennsylvania	3	2,084
Texas	15	9,246
Wisconsin	3	861
Total	**62**	**31,141**

4.3.6 CCS capacity sensitivity

In the previous sections, the parametric development of the 45Q credit levels and duration for promoting CCS deployment was done independently for each application, as it was seen that sufficiency for 5% generation did not extend between applications. When the unique 45Q levels and duration for promoting CCS retrofitting and repowering as new NGCC CCS plants are both available credits to the coal fleet, the interaction between the competing CCS technology options is apparent (See *Appendix D, Section D.4.3*). Applied individually, each modified tax credit yields greater CCS capacity for the targeted technologies (Tables 4.3 and 4.5) than when applied in unison (Tables D.48 and D.49), the result of which is the new NGCC CCS generation not meeting the 5% generation target, Figure D.19(c). This generation deficiency is due to 7.4 GW becoming coal-fired CCS EGUs rather than repowering as NGCC CCS plants. However, only 2.2 GW of coal-fired CCS EGUs convert to NGCC CCS mitigation. Therefore, when the credit level and duration are determined for the unique CCS mitigation technologies, thought must be given to the interaction of these two options and to the impact on the overall emissions reduction achieved.

In Section 4.2.6, the CCS retrofit multiplication-factor, the NGCC capacity factor, the overnight capital-cost for solar and wind generation, and the fuel price were identified as other factors relevant to the CCS assumption set that can affect the CCS capacity profile. When each factor level (Tables D.50 and D.51) is applied separately in the model to determine the sensitivity of the mitigation capacities and the combined fleet metrics to these factors, the capacity factor and natural gas price have the largest impact on the CCS technologies, Figures 4.15 and 4.16.

Increasing the capacity factor to 87% greatly increases the NGCC CCS capacity and results in an overall drop in emissions from a reduction in coal-fired capacity and increased retrofitting of NGCC plants, Figures 4.15(a) and 4.16(a). This capacity increase is due to the increase in generation that both increases the credit income and decreases the LCOE. When the capacity factor is decreased to 40%, the decrease in credit income and net generation results in all potential NGCC CCS capacity to remain in the current configuration or to be replaced by renewable sources, Figure D.18(a), with the resulting emissions increasing. Therefore, the assumptions made concerning the capacity factors for NGCC capacity without and with CCS [234] are critical for evaluating CCS and renewable capacity deployment and the impact on fleet emissions. The implication of this is that NGCC with CCS may retain more of a baseload role as reduced emissions capacity is sought, while NGCC without CCS may continue a projected trend as lower-utilization firm capacity.

When the natural gas price increases by 44%, absent any CO_2 emissions price, NGCC-based CCS capacity is greatly decreased, Figure 4.15(b), with these capacities being replaced predominantly by renewable capacity, Figure D.18(b). However, coal-fired CCS capacity is insensitive to this fuel price variation. Therefore, while a large natural gas price increase may reduce NGCC-CCS deployment, the corresponding increase in renewable capacity may retain most of the emission reductions in the projected case, Figure 4.16(b).

The CCS-capacity sensitivity to the other factors is less pronounced. CCS capacity is sensitive to renewable capital costs, but only when the cost projections are lower. This is because renewable capacity is seldom preferred to CCS mitigation for these modeled 45Q levels (Figures 4.9, 4.12, and Figure D.16). When the renewable capital costs are lower so that this technology is more competitive (Figure D.18 (a)), coal-fired CCS capacity decreases; however, the new and retrofitted NGCC CCS capacities reductions are greater at 25% and 50%, respectively. These reductions in fossil-fuel capacity result in an emissions reduction that is almost as large as that from the NGCC capacity-factor increase, Figure 4.16(a). A lower CCS retrofit multiplication-factor will increase CCS capacity for both coal-fired and NGCC CCS with a corresponding decrease in emissions, but coal-fired CCS capacity is more sensitive to higher retrofit multiplication factors because both compliant CFEGUs and new NGCC CCS, for which there are no retrofitting costs, are viable alternatives.

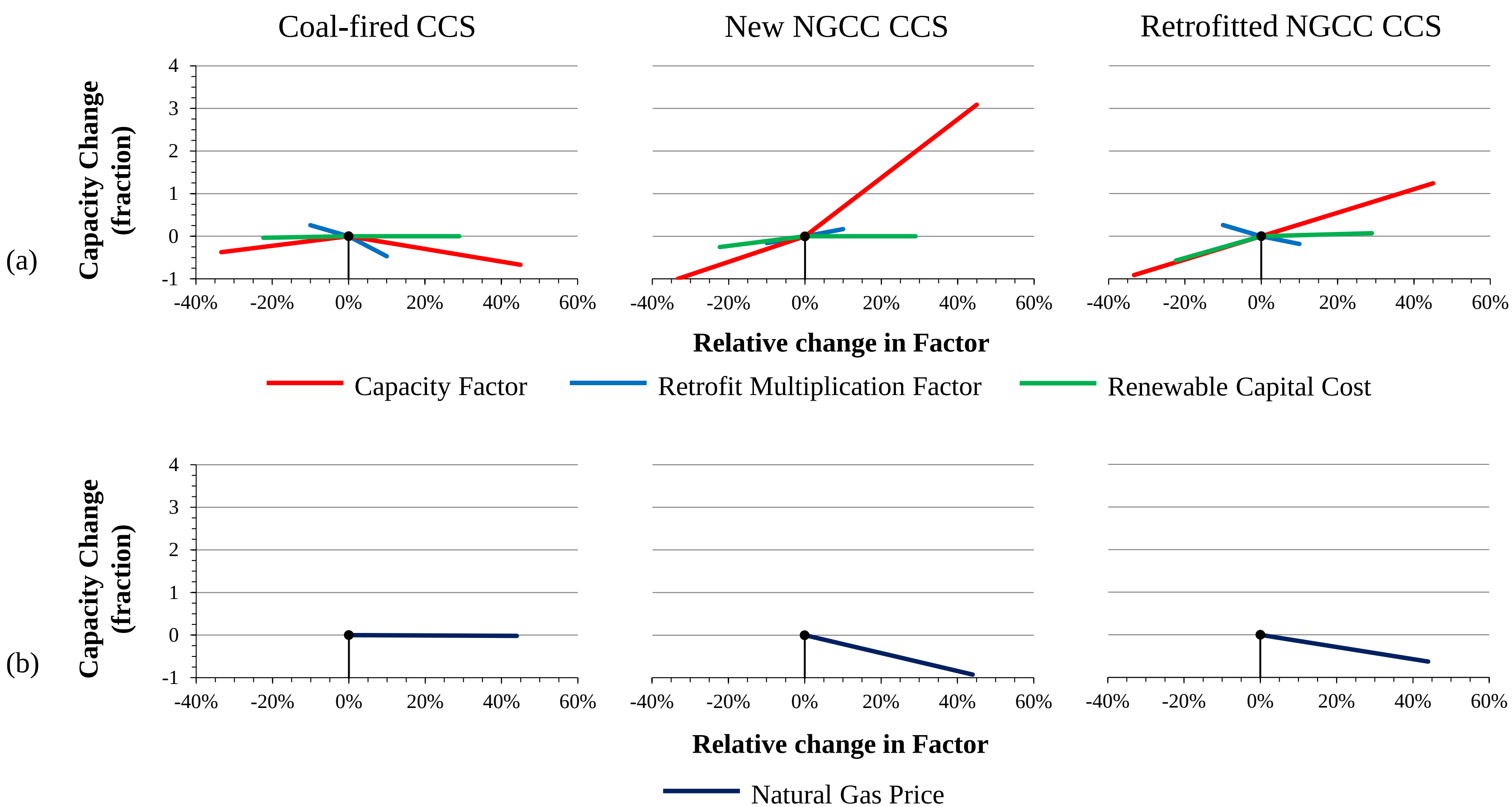


Figure 4.15. Sensitivity of capacity for CCS technologies to (a) NGCC capacity factor, retrofit multiplication factor, renewable capital cost, and (b) natural gas price relative to baseline levels for unique 45Q tax credit levels and durations applied to different technologies. A \$66/tonne credit with a 12-year duration is applied to the coal fleet for retrofitting CCS, while a \$144/tonne credit with a 20-year duration is applied for repowering CFEGUs as new NGCC plants with CCS. A \$104/tonne credit with a 20-year duration is applied to the NGCC fleet for retrofitting existing NGCC plants with CCS. No CO_2 emissions price is applied.

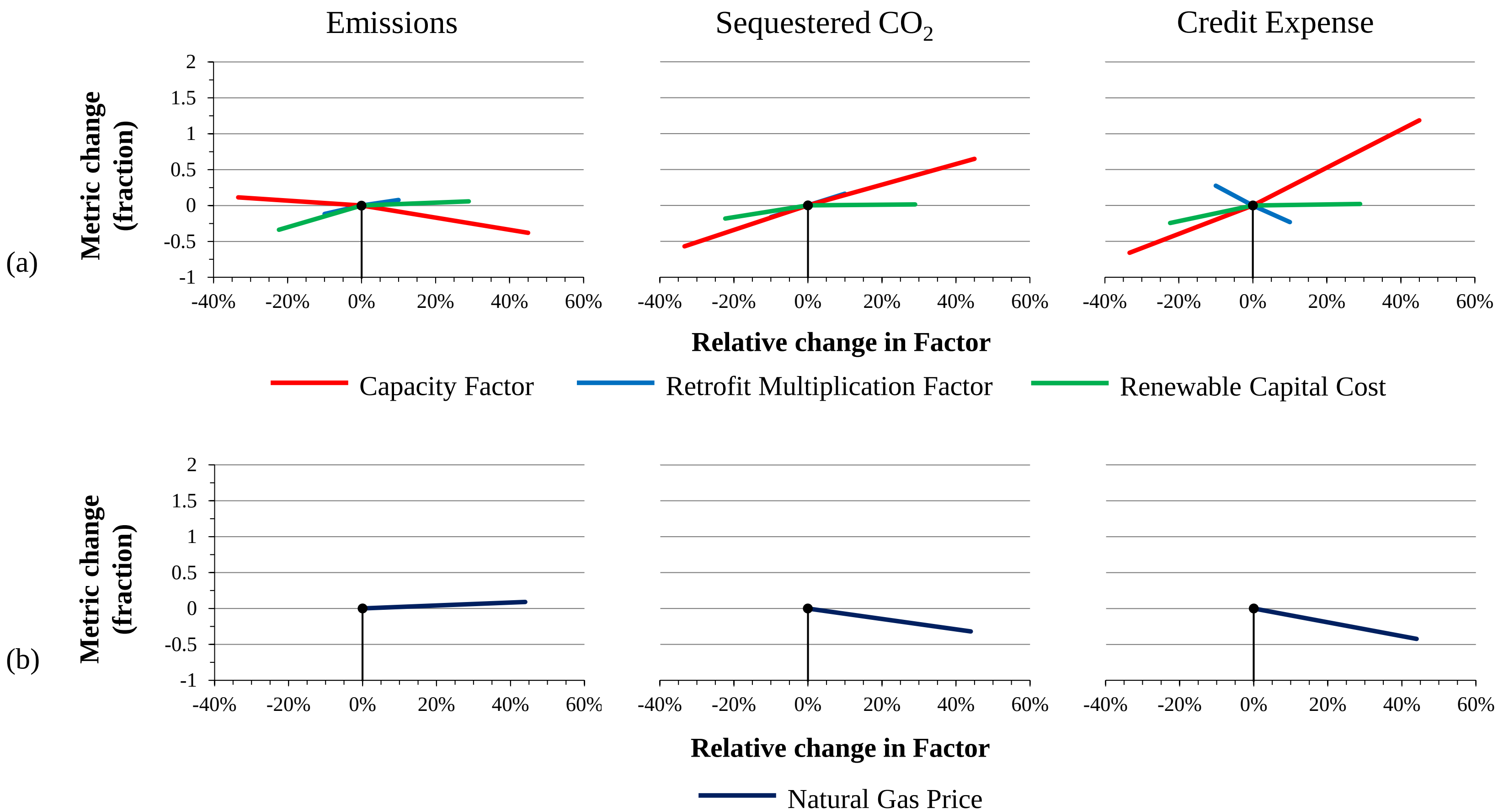


Figure 4.16. Sensitivity of fleet metrics to (a) NGCC capacity factor, retrofit multiplication factor, renewable capital cost, and (b) natural gas price relative to baseline for unique 45Q tax credit levels and durations applied to different technologies. A $66/tonne credit with a 12-year duration is applied to the coal fleet for retrofitting CCS, while a $144/tonne credit with a 20-year duration is applied for repowering CFEGUs as new NGCC plants with CCS. A $104/tonne credit with a 20-year duration is applied to the NGCC fleet for retrofitting existing NGCC plants with CCS. No CO_2 emissions price is applied.

4.4 Conclusion and policy implications

CCS is often viewed as a crucial technology to decarbonize the power sector in a manner that adds firm capacity while reducing committed emissions, stranded assets, and lowers total system costs in the effort to limit the global temperature rise to 1.5 °C. In a U.S. climate policy landscape generally void of a Pigouvian price for CO_2 emissions and mandates for limiting said emissions in the power sector, market forces dictate the generation technologies and associated emissions, thereby requiring incentives and other revenue streams to promote CCS deployment because of the associated higher total generation costs when compared to other fungible sources.

In an analysis of the current 45Q tax credit incentives for such promotion with the projected 2030 fossil-fuel fleet and absent a CO_2 emissions price and emission restrictions, we determined that CCS capacity expansion for immediate geological storage is limited to retrofitting 3 GW of coal-fired capacity that results in an annual sequestration of only 27 Mtonnes—a level that is lower than the projected impact of 45Q on capture for EOR and is supplanted when this utilization option is present. In a parametric study to increase CCS capacity to account for 5% of projected 2030 net generation, we determined that the 45Q credit level for CO_2 geological storage needs to increase from $50 to $66/tonne to promote retrofitted CCS for the coal fleet and to $142/tonne for the NGCC fleet. The promotion of new NGCC-CCS capacity requires the level to increase to $144/tonne and the credit duration to extend from 12 to 20 years, thereby creating a longer-term support mechanism. In each case, the resulting CO_2 sequestration is greater than that projected for EOR under the current 45Q, with CCS capacity and tonnage increasing with an increasing CO_2 emissions price.[54]

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[54] Recent Congressional activity suggests that efforts in the direction we investigated may be underway. After this paper was submitted for review, legislation aligned with the concepts of increasing 45Q credit levels and duration

…continued

From this analysis several policy implications can be drawn for the policymaker to consider if modifications to the 45Q tax structure are made. While the current 45Q is projected to promote CCS capacity related to EOR opportunities primarily from coal-fired generation, stimulating CCS growth in other capacity for immediate sequestration benefits from setting the level and duration of the tax credit differently for each capacity: existing coal-fired, and existing and new NGCC. This approach is necessary because of competition with fungible sources, and to the differing emission intensity and age of the originating capacity. The underlying reason being that the premium for such sequestration over utilization needs to increase the revenue stream sufficiently to more than compensate for the capture and storage related added costs, as other generation options may have a lower LCOE.

The policymaker should explicitly consider the credit duration because of the impact on fleet age bias. The current 45Q duration for the higher credit levels examined biases the age of the retrofitted coal fleet toward the oldest EGUs and NGCC plants. One negative impact of this bias is that the efficiency of these units may be lower than those for younger units, thereby resulting in higher mitigated fleet emissions than otherwise possible. Furthermore, these units will have less remaining operational life, thereby shortening possible future utilization. While U.S. policy may soon target net-zero emissions in the power sector by 2035, having a CCS power generation presence until 2050 and beyond may still be important (the emissions from which may be offset by means such as using synthetic fuel, DACS, and soil and forestry sequestration [209, 243]). For the coal fleet, a 12-year duration that results in the coal fleet capacity decaying to zero between 2030 and 2050 may be a desired effect for policymakers and a suitable option for

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was introduced separately in each chamber of Congress [231, 242]. The express purpose of these efforts is to promote different CCS technology pathways.

owners. Lower emitting NGCC with CCS may still be desirable as a generation source after 2030; therefore, it may be more appropriate to increase the credit duration from 12 years to allow for this CCS capacity in 2050 and beyond. Furthermore, this longer duration may act as a bridge to second-generation CCS to be applied to advanced NGCC designs with lower emission intensities and greater operational flexibility [234, 244].

Providing different settings for these levers to independently promote CCS for the different capacities also extends to policymakers the ability to gain emissions reduction in the fossil-fuel fleet at a lower avoided cost. Here, increasing the duration of the credit from 12 to 20 years decreases the avoided cost for the NGCC fleet but still results in one greater than that for promoting CCS in the coal fleet. Using both 45Q levers to target emissions reduction in the coal fleet through repowering existing CFEGUs with new NGCC-CCS plants reduces the avoided cost by 33%, thereby implying that a cost-effective strategy may be to target emissions reduction by promoting NGCC-CCS plants. Given that many of the CFEGU and NGCC plants identified in the analysis are in states that have EOR opportunities and existing EOR pipelines [221, 225, 241], such a multitiered policy coupled with a backbone of pipelines for immediate storage also provides the opportunity to spread investment costs over longer periods and more projects to foster greater CCS capacity expansion and CO_2 sequestration, and the ability to maintain the emissions reduction through multiple revenue sources when faced with oil price volatility. Finally, in making the decisions for credit level and duration, the policymaker must consider the interactions of CCS capacity with fungible capacity and the sensitivity to several factors such as fuel price, NGCC capacity factor, renewable energy capital costs, and CO_2 emissions price. Each of these factors impacts emissions reduction through CCS or renewable capacity but does so at a different overall policy expense.

Chapter 5: Conclusion and policy implications

And what rough beast, its hour come round at last,
Slouches towards Bethlehem to be born?

(William Butler Yates, “The Second Coming”)

The academic and policy debate on climate change is no longer about whether it is real. Rather, it concerns issues at the expanding edge of the problem—how bad it will be, how we can adapt to it, how we can mitigate it, how quickly all of this needs to be done, and at what costs. This dissertation examined the mitigation issue from the perspective of reducing CO_2 emissions from the U.S. power sector fossil-fuel fleet in 2030. With only fleeting glimpses of policy direction in the quest for lower emissions, the requisite least-cost mitigation objective for an individual EGU has gone from one to achieve modest reduction levels to one aimed at near-zero and even net-zero emissions. These transient mitigation requirements mimic the ambitions of the leaders who set the targets and the actions of their appointed administrative heads who determined the path.

This inability or unwillingness to create an overarching reduction policy does not mean that emissions have not been reduced since the 2005 highs. Market forces from power-sector deregulation policies and incentives for natural gas exploration, coupled with technological innovation in the extraction process, have lowered natural gas prices and enabled the market to replace high-emission coal-fired EGUs with lower-emitting NGCC plants.[55] Concurrently, state-mandated renewable portfolio standards, domestic tax incentives, foreign policy support, innovation, and economies of scale have lowered the LCOE for solar and wind sources and

[55] Another recent example of a political/legal reversal of energy policy is the Federal Court temporarily blocking the Biden administration’s suspension of the sale of new leases for oil and natural gas drilling on public land [287].

spurred on installed capacity growth for these zero-carbon sources. However, the ability of lower natural gas price and renewable capital costs to further influence market participants towards emissions reduction through the virtuous alliance of low-carbon options being the least-cost solution has been shown to be limited. While the LCOE for variable renewable energy (VRE) sources may now be lower than that for other technologies, their inherent intermittency means that VRE is not truly fungible with other sources and that costs for such generation will increase should it need to be so. Yet even at a greater LCOE, VRE has one attribute that is lacking in firm fossil-fuel capacity—it has no CO_2 emissions. Further reductions are now presented as a multi-attribute problem in which three constraints must be satisfied: zero carbon, reliable, and least cost. Given current climate concerns, options that don't satisfy all three won't work.

Emissions reduction in the fossil-fuel fleet comes with a cost, and while there are many mitigation options for different reduction levels, greater reductions incur greater costs. As we are no longer in a scenario where a modest reduction in power sector emissions is sufficient to combat climate change, almost all options have become moot. For the fossil-fuel fleet to go forward as firm, low-carbon capacity, CCS has been shown to be the sole viable mitigation, but one that requires tax incentives for the market to value the technology in the absence of federal policy. However, where existing tax incentives encouraged VRE capacity growth (e.g., solar-investment and the wind-production tax credits), the existing Section 45Q incentives for CCS are insufficient to spur large-scale emissions reduction in the power sector. This dissertation is the first comprehensive work to determine and demonstrate that both the credit level and duration must be modified jointly *and* differentiated according to fuel type to induce large-scale reductions from immediate CO_2 storage. Such modifications may lead to rapid decarbonization while maintaining grid reliability and minimizing cost by utilizing existing and new near-zero fossil-fuel sources as an economical backup capacity for a power sector with high VRE penetration. This is an objective that can be achieved on a bipartisan basis through Congressional modification of the existing tax code [217], and without the need for the protracted legal battles associated with the regulations and executive orders of a national policy because the effort is narrowly focused.

For the fossil fleet to attain the called-for net-zero and negative emissions, direct air capture and storage (DACS) is required to augment CCS capacity. Yet even with the hope that these technologies bring for decarbonization, one must remember that there is a gap in CCS deployment [94, 211, 212] and that achieving DACS at scale by 2035 may be a deadline that is difficult to achieve [31, 269]. While commercial adoption of both technologies can benefit from modifications to 45Q, each can also benefit from increased federal-agency sponsored research, development, and deployment funding that can hasten implementation of the current generation technologies, and drive innovation to lower costs and increase capture rates for subsequent generations. Such spending should be expanded to support CO_2 utilization efforts to commercialize the effluent and reduce or eliminate the need for these tax incentives through alternative revenue streams from bioenergy or synthetic fuels applications [209].

5.1 Summary

In Chapter 2, I examined the historical and projected power sector emissions to determine if the emission reduction goals laid out in President Obama's Clean Power Plan can still be achieved in the intended timeframe, despite its withdrawal and the absence of regulations for such a reduction. This work demonstrated that emissions levels are projected to continue a downward trajectory due in part to market forces. Here, low natural gas prices propelled initial reductions, and low LCOE for NGCC and renewable generation are projected to continue to drive emissions to below the 2030 target, almost a decade ahead of schedule. However, a pathway to the deeper reductions to be sought by the "then-future" Biden administration was not apparent with these marketplace mechanisms alone. Policy tools such as a carbon tax or incentives for technology innovation may be required to transition to such a net-zero power sector.

In Chapter 3, a model was presented to describe various mitigation methods for coal-fired EGUs for emission reductions in the projected 2030 coal-fleet. This model demonstrated that while many options are possible, there is no "one size fits all" solution for a given target reduction, as site-specific attributes are important. Furthermore, fuel price was determined to be an overriding factor in the decision, one for which the uncertainty in the projected prices and reduction policy could lead to mitigation-decision regret and stranded assets. This model also showed that the current level and duration of the 45Q CO_2 sequestration tax-credits may not be adequate to promote retrofitting existing coal-fired EGUs for immediate storage.

In Chapter 4, the model was expanded with more mitigation options and to include the projected NGCC fleet. The application of the current 45Q tax code, as a marketplace tool when market forces alone dictate generation and fungible sources are present, to the fossil-fuel fleet showed that the existing credit structure provided only limited expansion of CCS capacity for immediate storage. Setting a fuel-specific fleet generation target from CCS-equipped capacity of as little as 5% of the projected 2030 generation required the credit level and duration to be increased, the amount of which depended upon the fuel type and the age profile of the respective fleets. This differentiation was necessary to overcome the age differential of the fleets, the age bias of the tax code, and the CO_2 emission intensity of the EGU technology. It further allowed policymakers, in the absence of a regulation, to have projected CCS capacity available to bridge from 2030 to 2050, and to allow more time for cost reduction of existing zero-carbon firm capacity technologies and for the development and deployment of new ones.

5.2 Policy implications

While there has been no overarching policy in place to reduce emissions, market forces have been shown to be effective in doing so. Several factors in addition to a lower natural gas price and lower renewable capital costs have allowed emissions reduction to be a "free-rider." Some may say that the market has been nudged by a consumer preference and willingness to pay for *clean* energy. Others may say that feed-in tariffs, state regulatory mandates in the form of renewable portfolio standards and renewable energy credits, and tax codes (such as the solar-investment tax credit and the wind-production tax credit) have aligned the governmental value of a lower-carbon power sector with a consumer preference for lower-cost energy generation. This dissertation has shown that another tax code, 45Q, may also be an important lever to continue to direct the market towards net-zero emissions, absent a clear directive due to regulatory and political chaos. In particular, the least-cost method for analyzing mitigation options for EGUs has shown that 45Q tax incentives are a feasible tool to promote CCS in fossil-fuel EGUs; however, this tool must be fashioned for a specific purpose to promote carbon capture for different fuel types and EGU ages. In this section, I return to the third research objective and look at the policy implications of using this tool to aid in decarbonizing the power sector by 2035 through providing dispatchable, net-zero carbon capacity to supplement generation from a power sector with high VRE penetration.[56] As 45Q is only part of the solution to achieve a net-zero

[56] This full text for this section is under review in Environmental Science & Technology and is given in *Appendix E*.

power sector, a policy gap remains that must be addressed. To examine this gap based on the results of my research and the extant literature, I return to the question first asked in the introduction concerning how further emissions reductions can be effectuated without a political consensus, and discuss how this consensus could be achieved and the political and legal chaos avoided.[57]

5.2.1 Incentivizing CCS and direct air capture and storage for a net-zero power sector

The call to decarbonize the power sector has intensified since the EPA was first petitioned to regulate CO_2 emissions in 1999 [21] and even since President Obama introduced the Clean Power Plan in 2015 to limit these emissions [12]. As the IPCC target dates to limit future climate impact to the 1.5 °C warming threshold draw near, the sense of urgency and the onerousness of the required action increase and may necessitate embracing a broader set of mitigation technology options. President Biden's desired outcome for a yet to be detailed energy and environmental policy is to decarbonize the power sector by 2035 and to achieve a net-zero economy by 2050 [15]. The apparent path forward in the U.S., and for many other nations, to achieve these goals is to incorporate high levels of VRE capacity [245]. Such an approach may be feasible [187, 197, 198, 246-261]; however, a heavy reliance on VRE capacity may not lead to a least-cost solution [187, 197, 198, 257-262]. Achieving both net-zero carbon emissions and reliable coverage of 100% of the forecasted demand becomes both difficult and expensive for such portfolios as VRE penetration surpasses 80% [198, 256, 261].

At these penetration levels, the inherent variability of solar and wind patterns leads to periods of generation and demand imbalances [256, 263]. Adding more VRE capacity to cover

[57] This section is based on a Viewpoint that appeared in Environmental Science & Technology. The full Viewpoint is in *Appendix F*. Anderson J, Rode D, Zhai H, Fischbeck P. Future U.S. Energy Policy: Two Paths Diverge in a Wood - Does It Matter Which Is Taken? Environ Sci Technol 2020;54:12807–9. https://doi.org/10.1021/acs.est.0c04155.

generation shortfall periods can lead to dramatic asset overbuilding and many hours of excess generation curtailment. This curtailed overcapacity can be as high as 3.4 times the annual generation [256] and has a direct effect on the LCOE calculations. Balance can be restored in high-penetration VRE systems by shifting both generation and demand. The addition of technologies to store the excess energy in chemical, mechanical or thermal states [264-266] allows the available electricity to shift from periods of resource abundance and low demand to periods of resource scarcity and high demand [266, 267]. However, large-scale shifting of electricity availability will lead to much greater system costs, as more storage—12 hours of annual generation in the same U.S. study [256]—is required for balancing. On the demand side, flexibility strategies [266-268] can be employed to reduce some of the need for additional VRE capacity and the increase in VRE LCOE from underutilized assets. This shifting of demand is not without costs; the variability of the VRE assets must still be designed for, and the consumer inconvenience must be considered and possibly compensated. Another balancing option is to incorporate carbon-free firm capacity from fossil-fuel and co-fired bioenergy (BE) EGUs, whose carbon emissions are either captured immediately with CCS technology or are captured indirectly from the ambient air with DACS technology, a negative emissions technology (NET). Generation with such options employing carbon capture is made more attractive with from incentives in the current 45Q tax code.

To examine the role that firm capacity and 45Q can play in these net-zero emissions scenarios, one can construct proxy EGUs representative of those technologies that may be in the projected 2030 national fleet (shown in Table E.1) and compare the performance on a LCOE basis. Such generation technologies must satisfy two constraints: 1) net-zero or zero-carbon emissions, 2) 100% resource adequacy. In such a LCOE comparison, resource adequacy can be simulated as the addition of the next zero- or net-zero carbon generation capacity for which each technology must meet a common target generation (see *Appendix E* for details).

Without a resource adequacy requirement, VRE technologies have the lowest LCOE. However, satisfying the resource adequacy constraint during generation shortfall conditions increases the costs of VRE technologies to such a degree that they become non-competitive. When low/no generation periods for VRE capacity require battery storage, solar and wind generation becomes non-competitive to multiple fossil fuel technologies. With a requirement of four hours of battery storage duration to maintain the target generation, Figure E.1, the LCOE of VRE options are dominated by two net-zero fossil fuel options. The first fuel option is coal with 20% co-fire bioenergy configured as existing subcritical and new USC coal-fired EGUs equipped with carbon capture and storage (BECCS). The second fuel option is natural gas-fired NGCC plants, existing and new, equipped with CCS and relying upon DACS to remove the remaining emissions. Such options are even preferred to zero-carbon technologies that are typically modeled such as dedicated BE and BECCS, small module reactors (SMR), and long-duration storage (LDS) employing power-to-gas-to-power (PGP) technology. This dominance at a small battery requirement suggests that at the current 45Q levels ($50/tonne tax credit for immediately-sequestered CO_2, applicable for 12 years), decarbonized fossil-fuel EGUs have an important role in the carbon transition as VRE penetration reaches high penetration levels.

The 45Q code can be tailored to further incentivize other fossil-fuel generation sources by modifying the credit level and duration. When these components are segregated for fuel and capture technology type (i.e., the CFEGUs and DACS technology credits are maintained at the current level), the credit level and/or duration must be increased before other fuel types dominate, Figure E.3.[58] In general, the credit duration must be increased beyond 15 years before existing assets that are not fully depreciated dominate. Therefore, retrofitting existing NGCC assets with CCS and DACS is the net-zero technology next-best to retrofitted existing co-fire BECCS. These characteristics suggest that any modifications to the 45Q incentives should consider alignment between project life and the credit duration and should incentivize NET differently from net-zero emission technologies, as the latter are less expensive alternatives.

This resource adequacy analysis illustrates the various interdependencies of resource capital cost and availability, and fuel type and asset age that 45Q must balance to successfully promote carbon capture. It further illustrates the role that such an incentive can play in decarbonizing a U.S. power sector with high VRE penetration. When the modeling is extended to a region-specific fleet of existing fossil-fuel EGUs and future capacity additions, the combination of credit level and duration within this broad set of technology options should be determined such that it achieves the required generation from net-zero technologies at a minimum total system cost, inclusive of resource intermittency. For this, promotion of existing and new assets to build a net-zero power sector in 2035 that can bridge to a net-zero economy in 2050 will require extending the 45Q eligibility construction-start date beyond 2030 and lengthening the credit duration. Such actions would make the economic proposition for higher capital cost and newer assets more attractive to investors, Table E.2. In concert, the credit level should be set to adequately decrease the LCOE and VOM such that the CCS and DACS technologies are promoted in merit order relative to other options, Table E.4. These parameters will need to be set

[58] Recent proposal for $85/tonne with 20-year duration also promotes NGCC with DACS for existing plants but may be insufficient to promote such for new plants [242].

separately for coal and natural gas, as the carbon content, technology heat rates, and existing fleet ages differ.

Notwithstanding this, such modifications in credit level and duration have little impact on DACS, because promoting this technology comes from coupling it with already low emission NGCC CCS to achieve net-zero generation, Table E.5. This reliance may accelerate adoption of DACS and decrease the cost for future applications [243, 269-271]. Similarly, increasing credit levels for immediate sequestration will drive CCS and DACS deployment to be applied for deeper decarbonization while new applications and markets for CO_2 utilization develop (e.g., as an input for bioenergy and conversion to synthetic fuels for other sectors) [209, 223, 269, 272] and these net-zero technologies become viable without the 45Q incentives.

The emergence in this analysis of existing and new co-fire BECCS and NGCC CCS with DACS as lower-cost, firm-capacity solutions for generation/demand imbalances (at LCOEs lower than more conventional options such as SMR, LDS, and additional storage) indicates the importance of these fossil-fuel assets. Therefore, policymakers and capacity expansion modelers should consider these technologies for providing the resource adequacy required to achieve a net-zero grid and economy at a lower total system cost. As CCS and DACS are both seen as highly necessary technologies to meet the 1.5 °C threshold [16, 191, 273, 243], it is important to promote these technologies with incentives [223, 271, 274, 275] in the power sector now to avoid delays in using them in industrial and other sectors to achieve a net-zero economy by 2050. Furthermore, this analysis finds that co-fire BECCS can be on the least-cost path to net-zero emissions in the U.S. and is a potentially faster decarbonization path forward for the U.S. Mountain West subregion that is coal-rich and natural-gas-poor. It is even faster for regions bereft of strong solar (New England) or wind (South Atlantic) resources. Such an option may also be a decarbonization path for similar-situated regions in developing nations that are heavily reliant on coal, such as in China [276] and India [277].

5.2.2 Politics

As the U.S. is currently the second-largest global emitter of greenhouse gases, efforts to reduce emissions globally are profoundly impacted by U.S. environmental policy and inextricably linked to the chaos of the U.S. political and regulatory system outlined in Chapter 1. This association may mirror the dynamics in other countries in Europe and Asia with similar systems facing similar contentious policy trade-offs. Since the 1970s, the gulf between the U.S. conservative (Republican) and liberal (Democratic) parties' prioritization of environmental issues has widened to the extent that adherence to the party line on environmental issues is seen as a litmus test of party membership [278, 279]. Such political polarization also creates a societal schism [279] concerning the causes, degree, and even existence of climate change, and what actions—if any—should be taken to manage it. In recent polling, Democrats contend that climate change should be a "very high" governmental priority [280, 281] and is an issue for which they overwhelmingly feel that government is doing too little [282]. Contradistinctively, Republicans view it less so and contend that the government's action is at least adequate. Many in the Republican establishment with more conservative views even strongly maintain that the societal status quo of a fossil fuel-based economy is the correct energy pathway [279, 283] and that there should be an expansion of oil and gas drilling, hydraulic fracturing, and coal mining [282]. In contrast, the Democrats oppose such an expansion [282] and call for a dramatic reduction. It seems that the visions of climate change and future energy policy are propelling the country in opposite directions.

Yet, this political rift does not foreshadow a difference in actual *outcomes* of the resulting energy policies by 2030. The longer-term impacts of these dichotomous approaches to energy policy can be simplified to two cases in the EIA 2020 AEO—the high-oil-and-gas-supply case (Republican) and the low-oil-and-gas-supply case (Democrat) [233]. Here, Figure F.1(a), the greater availability of fossil fuels in the high-supply case results in the average price of natural gas for the power sector being only 6% greater than the 2019 price, while the coal price is 10% lower. In the low-supply case, restrictions on natural gas production cause the price to be 70% higher than in 2019, while coal prices are essentially unchanged—only 2% higher. The result by 2030 is an increase in natural gas generation of 30% for high supply, and a decrease of 31% for low supply, relative to the 2030 reference case.

There are market-driven consequences for these different outcomes. While greater electricity generation using natural gas results in an 8% decrease in generation from renewable resources, it also reduces the generation from nuclear power plants by 17% and that from coal-fired generation by 28% (i.e., from generation sources advocated by conservative Republicans) [282]. Equally puzzling is the Democratic case. While generation from green sources increases by 15%, generation from nuclear sources increases by 8% and (since the energy policy directive announced by President Biden does not include a price on CO_2 or a regulatory mandate for net-zero emissions [15]) generation from coal increases by 20%.

The impact of the fuel price reversals on comparative annual CO_2 emissions for each resulting electricity generation portfolio is surprisingly inconsequential (differing only by 1%) in the near-and long-term (Figure F.1(a, b)). More perplexing is that the emissions for each case are more than 400 million tonnes below the goal of President Obama's 2015 Clean Power Plan to limit power-sector emissions to 1.6 billion tonnes by 2030: an outcome that may indicate that the

CPP was meant to be a political statement rather than an environmental reach (Appendix C). *Each* party can boast of a 48% overall reduction from the U.S. historical 2005 power-sector emissions [12, 284]. Therefore, both parties' policies are arguably beneficial for reducing CO_2 emissions, in the near-term. However, both fall short of the Biden administration's and the IPCC's near- to long-term decarbonization goals for the power sector [15, 16].

The path forward for the two parties to meet future decarbonization targets is unclear. Currently, deep political polarization has caused wide swings in environmental policy as political power transitions between administrations. This trend will likely continue unless a bridge can be built between the parties to bypass court delays and policy resets. Democrats must reach out to like-minded Republicans [280-283] and appeal to their free market, growth, and innovation-orientation values [283, 285] to foster CO_2 emissions reduction without crushing a weakened economy—an action that will also have international impact. Foresighted policy tools reminiscent of the Carter administration's Public Utility Regulatory Policies Act (PURPA) can educe these values and speed innovation in clean-energy technology platforms that are lagging in global readiness for net-zero emissions [286]. Such tools should invoke economic stimulus in public and private sectors through continuing and increasing tax incentives and investments to promote renewable energy, electrification, energy efficiency, low-cost long-duration power storage, and advanced carbon capture, utilization and storage technologies to permit fossil fuel use beyond 2030 to levels sufficient to achieve a net-zero power sector by 2035. Furthermore, a national price on carbon that enables the free market to spur competition, promote consumer choice, and further nurture innovation is a necessary tool for the global community's net-zero future.

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Appendix A: Supplemental information for Chapter 2

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A.1 Carbon Dioxide Reduction in the U.S. Electric Power Sector without the Clean Power Plan: Is there a path to Paris Agreement Compliance?

A.1.1 Background

At the December 2009 United Nations Climate Change Conference in Copenhagen, the United States (U.S.) pledged to reduce overall domestic greenhouse gas (GHG) emissions in 2020 by approximately 17% from 2005 levels with the intent to further reduce levels by 2050 by 83% of 2005 levels [1]. An additional early target horizon was set for 2025 with the 2015 Paris Agreement, in which the U.S. nationally determined contribution (NDC) to GHG emission reduction was set at 26–28% below the 2005 levels [2]. To facilitate these reductions, President Obama implemented the Climate Action Plan (CAP) [3] to slow and manage the impacts of climate change. A central element in meeting the CAP's goal to reduce national carbon emissions is the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan (CPP) that promulgates a reduction in carbon dioxide (CO_2) emissions from existing fossil-fuel power plants to 68% of the 2005 level by 2030 [4].[1] This CPP reduction represents the substantial contribution that the electric power sector makes to meeting the Paris Agreement targets: Intermediate targets in the CPP for 2020 and 2025 represent approximately 47% and 37–40% of the Paris Agreement reduction for the corresponding years [5].

The Trump administration is taking different actions concerning GHG emissions. On 28 March 2017, Executive Order 13783 revoked the Climate Action Plan and started a review of the CPP [6]—a review that is leading to the EPA's proposed repeal of the CPP [7]. The U.S. also notified the United Nations on 4 August 2017 of its intent to withdraw from the Paris

[1] The potential regulatory contribution of the CPP to the development of more stringent climate polices for the deeper carbon reduction pledge in the NDC for 2050 is beyond the discussion herein.

Agreement, when it is eligible to do so in 2020 [8, 9]. Notwithstanding the repeal of the CPP and the impetus for the regulation, it may still be possible for the U.S. electric power sector to meet its contribution to the NDC pledge, depending on natural gas prices. To illustrate this point, this note summarizes work done to expand on the EPA's regulatory impact analysis of the CPP review [10] and work documented in Ramseur [5] with further analysis of data from the U.S. Energy Information Administration's (EIA's) 2017 Annual Energy Outlook (AEO) [11].[2] In particular, we examine projected electric power sector CO_2 emissions under different natural gas prices to determine if the 2020, 2025 and 2030 emission targets set in the CPP can still be met in its absence.[3]

A.1.2 Analysis

In the AEO, projected commodity prices, capacities, generation mixes, and fleet emissions are determined by the National Energy Modeling System (NEMS) model, which incorporates, *inter alia*, the impact of economic growth, resource availability, and regulation [12]. Of the nine cases modeled for these three factors, two are shown with and without implementation of the CPP: one pair is the reference case, and the other is for the high resource availability case (which results in low natural gas prices).[4] When these pairs are compared to the CPP emission targets for the years in question, Table A.1, one observes that the CPP cases continue on the decreasing glidepath to the 2030 target, while the emissions for the non-CPP cases remain stable. The 2020

[2] The AEO projections assume that the mass-based approach is taken by all states.
[3] Many of the data used and the conclusions reached in this work are highly dependent upon the assumptions made in the referenced literature and made for the calculations. Changing these assumptions can lead to different conclusions. This work is a deterministic presentation that does not directly address the uncertainty in the data used.
[4] The low natural gas price cases used are specified in the AEO 2017 literature [11] as "high oil and gas resource and technology" and "high resource without Clean Power Plan."

emission target is achieved without the CPP in both natural gas price cases, and the case pairs are almost indistinguishable given the uncertainty in the CO_2 emission projection [17].[5] This is not true for the 2025 target. While the 2025 target is surpassed for the CPP cases,[6] the target in the other cases is not met in the absence of the CPP. However, the non-CPP case with the lower natural gas price is within 13 million tons of the target, which may be within the uncertainty of the projection. Though the NDC does not extend to 2030, the projections indicate that the 2030 CPP emission target will not be met without the associated emission cap and incentive mechanisms. This indicates the positive role that the CPP has on deeper emission reductions beyond 2025.

When the projected natural gas price[7,8] and the resulting fleet CO_2 emission reduction for the non-CPP cases are plotted with historical data (see the Figure A.1),[9] one observes that the historical trend for CO_2 emissions decreasing with lower natural gas prices[10] is maintained in each case. Furthermore, the emissions for each case are greater than the estimated 2017 level,

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[5] The EIA data for the average, absolute, percent difference between the EIA emissions projection and the actual result for one to six-year projections since 2010 is 3.4% percent [17].

[6] In some cases, the AEO 2017 projections for emission reduction surpass the CPP targets. This over-reduction may be viewed as an overcorrection inefficiency, or as establishing a surplus reduction that may be used to offset other GHG reduction programs that do not meet associated targets for the NDC.

[7] Natural gas prices in dollars per million British thermal units ($/MMBtu) are converted to 2010 dollars with the Consumer Price Index (CPI) [14]. Natural gas prices from the EIA are based upon national averages.

[8] Unless specified otherwise, all dollar values are in 2010 dollars.

[9] Historical data are from EIA *Monthly Energy Review* [15] and are converted to 2010 dollars with the CPI [14]. The 2017 emission data are estimated from the nine months of 2017 historical data with a 23% adder for the emissions from the remaining three months. This adder is based upon the average increase in 2015 and 2016 nine-month emissions to achieve the annual total emissions. The natural gas price estimate for 2017 is based upon the average monthly price from the nine months of 2017 historical data.

[10] The correlation between price and reduction is not chronologically perfect, however. Coal prices, capacity planning, regulations and policy mechanisms (such as state-specific renewable portfolio standards and federal tax credits for solar and wind energy), unforeseen events, technology changes, and hedging related lags [16, 17, 18] may account for some of the imperfect responses between the natural gas price and the reduction, as occurs from 2006 to 2008 and from 2012 and 2014, when the natural gas prices increase but the emission intensities remain constant.

which may already meet the 2025 mass target.[11] The 2017 emission level, and the clustering of future emissions near the 2025 target, may be due in part to a fuel-switch from coal to renewable and natural gas sources[12] related to policy mechanisms for renewable energy[13] and/or a favorable natural gas price.[14] Therefore, one market-based mechanism to achieve the NDC emissions target for 2025 would be through an increase in fuel-switching to natural gas sources—to natural gas combined cycle (NGCC) plants[15]—that would occur if natural gas prices were below $3.40/MMBtu.[16] Reaching the 2030 target may require natural gas prices below the 2017 level.

The emission targets can also be met, *ceteris paribus*, through policy by building more NGCC and/or onshore wind sources. For the 2025 reference case with NGCC replacement, this will require eliminating 138 million tons of CO_2 by replacing approximately 31.5 gigawatts (GW) of coal-fired capacity with 26.5 GW of NGCC capacity, at a CO_2 avoidance cost of $34.8/ton and a total annual cost of $4.8 billion, Table A.2. Reducing the same amount of CO_2 emissions through onshore wind generation will require an additional 56.3 gigawatts (GW) of wind capacity at a CO_2 avoidance cost of $11.2/ton[17] and a total annual cost of $1.5 billion. The

[11] While the emission level for 2017 may meet the 2025 target, the net generation produced is less than that projected for 2025. AEO 2017 projections for net generation are 3.9 billion megawatt-hours (MWh) in 2017 and 4.2 billion MWh in 2025. Therefore, the emission intensity of the fleet in 2025 will need to be lower than that for the fleet in 2017.

[12] Fugitive methane emissions for natural gas sources are not included.

[13] Such as state-specific renewable portfolio standards and federal tax credits for solar and wind energy.

[14] AEO 2017 projections indicate that the percent net generation from renewable sources increases for the case pairs in 2020, 2025, and 2030, relative to 2015 [11]. The percent-generation from coal decreases in the case pairs for these years, whereas the natural gas generation increase depends upon the gas price and emission target or cap for that year.

[15] The reduction in emissions comes from the difference in the CO_2 emission intensity for the two sources, based upon net generation. The 2015 average CO_2 emission intensity (lbs CO_2 per megawatt-hour) for the U.S. power sector coal-fired fleet was 2,200 lbs/MWh [15]. The CO_2 emission intensity for a new, conventional NGCC plant is 772 lbs/MWh. Therefore, replacing the net generation from the average coal-fired EGU with net generation from a new conventional NGCC plant reduces the total emissions by 65%.

[16] The projected natural gas price for 2030 may need to be lower than the 2015 price to achieve the CPP target, based upon the historical 2014-2015 relationship between natural gas price and CO_2 emission reduction.

[17] This assumes the 2025 wind sources enter service in 2022 and are eligible for the current production tax credit valued at $11.6/MWh (2016 dollars) [20].

required emission reduction to meet the target for the low natural gas price case is almost an order of magnitude less than the reference case; therefore, the associated capacity requirement and cost for each substitute source is also almost an order of magnitude lower.[18] Thus, it is possible to meet the 2025 NDC emission target at projected fuel prices by replacing coal-fired capacity with NGCC and/or wind sources. The required capacity of these sources and the total cost of meeting the target is dependent upon the natural gas price and a mechanism to promote this reduction.

The gap between the projected emissions and the target is greater for the 2030 cases, and requires more alternative source capacity at a greater cost to bridge, Table A.3. In the 2030 reference case, almost twice as many excess CO_2 emissions must be replaced as in the 2025 case; therefore, the 2030 retired coal-fired electric generating units (CFEGUs), alternative NGCC capacity, and cost requirements are almost twice as large. This scaling is also true for wind replacement; however, the wind avoidance cost is now twice as great as that for 2025 due to expiration of the production tax credit. Replacement in 2030 when the natural gas price is low results in the avoidance cost and overall cost for the NGCC replacement to be lower than that for the wind. This is due to the increased levelized cost of electricity for the wind source in the absence of the tax credit, and to the lower variable cost for the NGCC plant because of the low natural gas price.

While the Paris Agreement NDC is non-binding and the U.S. currently intends to withdraw prior to the target dates, the portion of the target that is represented by the reductions present in the CPP may still be met in 2020 and 2025, even if the CPP is repealed. Projections from the EIA indicate that the CO_2 emission reduction with or without the CPP may be substantially the

[18] The avoidance cost for the NGCC source in the low natural gas price case is lower than that for the reference case because of the natural gas price.

same in 2020. Furthermore, the 2025 reduction may be met without the CPP, if natural gas prices are below \$3.40/MMBtu. In lieu of lower natural gas prices, some coal-fired generation can be replaced with generation from NGCC and wind sources to meet the 2025 target and to achieve the 2030 CPP target. In the absence of the CPP's incentives and mechanisms to achieve these deeper reductions, the fuel choice for the replacement source and the cost for future reductions will depend upon the policy maker's decisions on renewable subsidies and mechanisms to incentivize the reductions, and on the actual natural gas price, however.

Table A.1. Clean Power Plan CO_2 Emission Targets and AEO 2017 Projected CO_2 Emissions with and without the CPP for 2020, 2025, and 2030 [13, 15]. [19] Values in boldface indicate that the case meets the target.

Case/Year	Annual CO_2 Emissions (million short tons)		
	2020	2025	2030
Target	2,073	1,901	1,814
Reference with CPP	**2,007**	**1,829**	**1,694**
Reference without CPP	**2,024**	2,039	2,078
Low Natural Gas Price with CPP	**1,922**	**1,782**	**1,689**
Low Natural Gas Price without CPP	**1,936**	1,914	1,922

Table A.2. 2025 Cases without CPP for Replacement Sources to Decrease CO_2 Emissions to CPP Target.

Parameter	**Units**	**Reference**		**Low NG Price**	
Excess CO_2	Million short tons	138		13	
Retired coal capacity[20]	Gigawatts	31.5		3.2	
Retired coal EGUs[21]	Number	82		8	
Natural gas price[22]	2010$/MMBtu	4.34		3.41	
New Generation Source Cases (units)		**NGCC**[23]	**Wind**[24]	**NGCC**	**Wind**
New source capacity (GW)		26.5	56.3	2.5	5.4
New sources (number)		38	18,755	8	1,795
CO_2 avoidance cost[25] (2010$/ton)		34.8	11.2	26.4	11.2
Annual Cost[26] (billion dollars)		4.8	1.5	0.3	0.1

[19] The AEO projections assume that the mass-based approach is taken by all states.

[20] The calculation for the required retirement capacity for the coal-fired fleet is based upon four parameters: (1) the projected profile of the coal-fired fleet in 2020, 2025, and 2030 (the fleet capacity, average emission intensity), and net generation), (2) the required reduction in coal-fired generation, (3) the CO_2 emissions emitted from the replacement source to match the reduced coal-fired generation, and (4) the required reduction in CO_2 emissions to meet the target. The projected coal-fired emission intensities are calculated from AEO 2017 coal-fired emission and net generation data [11]. The resulting values for 2020, 2025, and 2030 are 2131, 2143, and 2132 lbs/MWh, respectively. The replaced coal-fired net generation is found by setting the coal-fired emission intensity multiplied by replaced net generation plus the emissions from the replacement source equal to the required reduction in CO_2 emissions to meet the target and solving for the net generation. The retirement capacity is then determined from the calculated coal-fired fleet capacity factor, based upon the projected capacity and net generation [11], and the coal-fired net generation that needs to be replaced.

[21] The required number of coal plants to be retired to reach the emissions goal serves as a reference only and is based upon the capacity of a proxy coal EGU emitting CO_2 at the emission intensities described in the previous endnote. This capacity of this proxy plant is the average net summer capacity of the 669, operational coal plants with capacity greater than 25 MW that use bituminous, subbituminous, lignite and waste coal, as …continued

listed in the August 2017 EIA form 860M [19]. The calculated average capacity is 386 MW. The number of actual plants that might be retired in this scenario will depend upon many factors and is beyond the scope of this work.

[22] The EIA data for the average absolute percent difference between the EIA emissions projection and the actual result for one to six-year projections since 2010 is 21% percent [17].

[23] The replacement NGCC plant is a conventional NGCC plant that is constructed in 2022 for the 2025 scenario and in 2030 for the 2030 scenario. The capacity is taken as 702 MW net summertime capacity [21]. This plant operates at an 87% capacity factor [20], has a heat rate of 6,600 Btu/kWh and the fuel CO_2 emission intensity is 117 lbs/MMBtu [21].

[24] The replacement onshore wind turbine enters into service in 2022 for the 2025 scenario and in 2030 for the 2030 scenario. The capacity is taken as 1.79 MW [20] and operates at a 41% capacity factor [20].

[25] The CO_2 avoidance cost is based upon the difference in the generation levelized cost of electricity (LCOE) between the base case and the case to obtain the reduced emissions divided by the associated change in CO_2 emission intensity. The projected baseline generation LCOE for the projected fleet is given in the AEO 2017 [11]. This is adjusted for the replaced coal-fired generation with an assumed generation LCOE for the coal-fired fleet taken from Jean et al [22] as $33/MWh (assumed in 2016 dollars). The coal-fired LCOE is held constant for all years, given a projected maximum 0.6% annual increase in delivered coal price between 2016 and 2050 for the cases [11]. The 2025 and 2030 generation LCOE for the conventional NGCC plant is taken as $57.5/MWh and is adjusted with the plant heat rate for variation in natural gas price from the 2022 reference case with CPP level [20]. The 2025 generation LCOE for the wind turbines is taken as $41.4/MWh, which is the LCOE for service entry in 2022 inclusive of a $11.6/MWh tax credit [20]. The 2030 LCOE is taken $55.0/MWh, which includes a linear approximation of the LCOE increase between 2022 and 2040 and excludes the tax credit [20]. Dollar values in this endnote are given in 2016 dollars. The replacement LCOEs exclude any additional transmission investments.

[26] These costs are the annual costs, based upon the avoidance costs and the necessary emission reduction.

Table A.3. 2030 Cases without CPP for Replacement Sources to Decrease CO_2 Emissions to CPP Target

Parameter	Units	Reference		Low NG Price	
Excess CO_2	Million short tons	264		108	
Retired coal capacity	Gigawatts	58.9		25.9	
Retired coal EGUs	Number	153		67	
Natural gas price	2010$/MMBtu	4.60		3.62	
New Generation Source Cases (units)		**NGCC**	**Wind**	**NGCC**	**Wind**
New source capacity (GW)		50.6	107.4	28.6	44.1
New sources (number)		72	35,785	30	14,706
CO_2 avoidance cost[27] (2010$/ton)		37.2	29.2	28	29.4
Annual Cost[28] (billion dollars)		9.8	7.7	3.0	3.2

[27] The CO_2 avoidance cost is based upon the difference in the generation levelized cost of electricity (LCOE) between the base case and the case to obtain the reduced emissions divided by the associated change in CO_2 emission intensity. The projected baseline generation LCOE for the projected fleet is given in the AEO 2017 [11]. This is adjusted for the replaced coal-fired generation with an assumed generation LCOE for the coal-fired fleet taken from Jean et al [22] as $33/MWh (assumed in 2016 dollars). The coal-fired LCOE is held constant for all years, given a projected maximum 0.6% annual increase in delivered coal price between 2016 and 2050 for the cases [11]. The 2025 and 2030 generation LCOE for the conventional NGCC plant is taken as $57.5/MWh and is adjusted with the plant heat rate for variation in natural gas price from the 2022 reference case with CPP level [20]. The 2025 generation LCOE for the wind turbines is taken as $41.4/MWh, which is the LCOE for service entry in 2022 inclusive of a $11.6/MWh tax credit [20]. The 2030 LCOE is taken $55.0/MWh, which includes a linear approximation of the LCOE increase between 2022 and 2040 and excludes the tax credit [20]. Dollar values in this endnote are given in 2016 dollars. The replacement LCOEs exclude any additional transmission investments.

[28] These costs are the annual costs, based upon the avoidance costs and the necessary emission reduction.

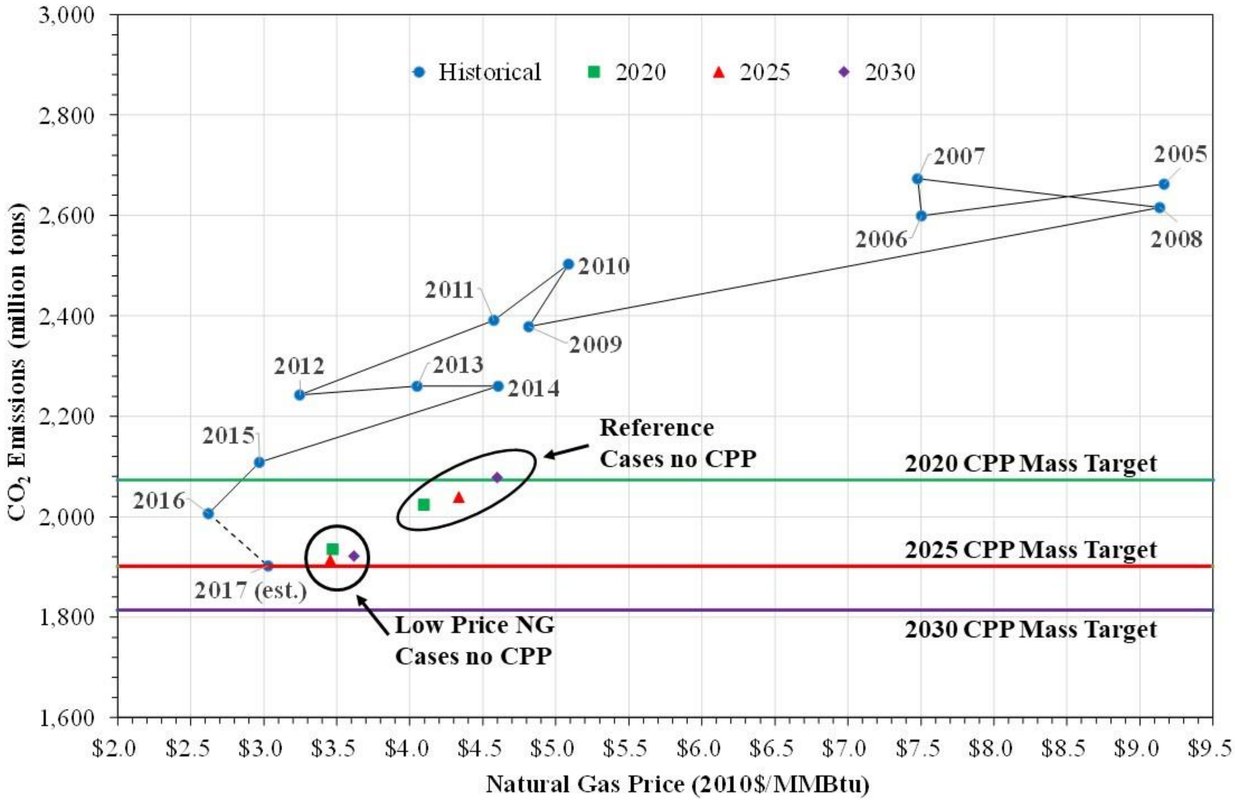


Figure A.1. Historical[29] and projected 2020, 2025, and 2030 CO_2 emissions from the U.S. power sector in relation to natural gas price [15]. Projected emissions and gas prices are national averages based on scenarios in the Annual Energy Outlook (AEO) 2017 for the reference case, and the high oil and gas resource and technology case [11]. While complementary scenarios with and without the CPP from AEO 2017 are discussed, only the scenarios without the CPP are shown. Historical and projected natural gas prices from AEO 2017 are converted to 2010 dollars with the Consumer Price Index [14].

[29] The slight increase in emissions from 2012 through 2014, during a period of increasing natural gas prices, was due to a 1.3% increase in fleet net generation contribution from coal-fired sources, as that from NGCC sources decreased by 2.9%. This migration from lower CO_2 emitting NGCC sources was partially offset by increases in net generation from nuclear (0.5%) and renewable sources (0.9%) [15]. The estimated emissions for 2017 are lower than those from 2015 due to a projected decrease in contribution to fleet net generation from coal-fired sources and an increase in that from renewable sources [15]. While coal-fired generation is projected to decrease from 34% to 31% of the fleet net generation from 2015 to 2017, net generation from renewable energy is projected to increase from 13% to 17%. Over this same period, generation from natural gas is projected to decrease from 32% to 31%.

A.2 Recent Projections for Carbon Dioxide Emission Reduction in the U.S. Power Sector

A.2.1 Abstract

The replacement of the CPP with the Affordable Clean Energy act brings into question the extent to which future CO_2 emissions may decrease in the U.S. power sector to meet the emission reduction targets set out in the Paris Agreement, despite the impending withdrawal. To answer this question, we use data from the U.S. Energy Information Administration's Annual Energy Outlook reports to evaluate the impact of projected natural gas price on these emissions. We find that while lower natural gas prices historically result in lower CO_2 emissions, projections from AEO 2017 and AEO 2019 differ dramatically in both the projected gas price and the associated impact on CO_2 reduction. This change in marginal emission-reduction rate with natural gas price emanates from decreasing capital costs for solar and wind generation sources. As such, the power sector's contribution to the Paris Agreement targets for 2020 and 2025 may be achieved on schedule and the CPP 2030 target may be meet as early as 2020, even with a stagnant or rising natural gas price. The question now becomes what policies are required to meet new reduction targets.

A.2.2 Introduction

Previous analysis of the EIA 2030 projections for natural gas price and CO_2 emissions for the electric power sector reported in the 2017 AEO [11] done in Section A.1 and Chapter 2 indicated that the sector's total emissions would not meet the CPP 2030 or 2025 mass targets, in the absence of the CPP regulation [4]. To meet the 2025 target, *ceteris paribus*, the 2030 projected natural gas price would need to be less than \$3.40/MMBtu.[30] It was further speculated that either a greater reduction in natural gas price (which would increase NGCC capacity) or further incentives for renewable energy to increase wind capacity were required to meet the 2030 mass target.

In the 2019 AEO, the EIA updated their projections for natural gas prices and CO_2 emissions from the electric power sector [24].[31] For the seven cases modeled, none of which incorporate the CPP or the Trump administration's ACE rule [7], two cases can be compared directly to the AEO 2017 projections: the reference and high oil and gas resource and technology (which results in low natural gas prices) cases without the CPP. Such a paired comparison relative to the CPP emission targets for the years in question, Table A.4, indicates that the projected emissions for AEO 2019 are reduced beyond the targets for each year, whereas the AEO 2017 projections only meet the 2020 emission target.

Table A.4. Clean Power Plan CO_2 emission targets and AEO 2017and 2019 projected CO_2 emissions for 2020, 2025, and 2030 [4, 11, 24]. AEO reference and high oil and gas resource and technology (high natural gas supply) cases are shown with AEO 2019 low oil and gas resource and technology (low NG supply) case, without CPP. Values in boldface indicate that the case meets the target.

Case/Year	Annual CO_2 Emissions (million short tons)		
	2020	2025	2030
Target	2,073	1,901	1,814
2019 Reference	**1,822**	**1,771**	**1,765**
2017 Reference without CPP	**2,024**	2,039	2,078
2019 High Natural Gas Supply	**1,784**	**1,779**	**1,741**
2017 High Natural Gas Supply without CPP	**1,936**	1,914	1,922
2019 Low Natural Gas Supply	**1,861**	**1,765**	**1,703**

30 Natural gas prices in dollars per million British thermal units (\$/MMBtu) are converted to 2010 dollars with the Consumer Price Index (CPI) [14]. Natural Gas prices for the EIA are based upon national averages.

31 Core cases are updated annually; however, side cases are updated biennially, starting in 2014.

A.2.3 Results and discussion

A.2.3.1 Natural gas price and emission reduction

The comparison also shows that the aforementioned relationship between lower natural gas prices and greater emission reduction is broken, Figure A.2. Historically, decreases in natural gas prices have led to decreases in emissions, related primarily to increases in generation from natural gas sources and decreases from coal-fired sources, Figure A.3. Hence, the higher natural gas price projections in AEO 2017 were associated with higher projected emission levels, relative to recent historical levels. Correspondingly, when the projected natural gas prices are lower, due to high oil and gas resource and technology (high natural gas supply), the projected emissions are significantly reduced. Yet when the AEO 2019 reference case projections for natural gas price are greater than the historical 2018 price, the projected emission reductions are substantially greater. In further contradiction, when similar natural gas prices were projected for the AEO 2017 high natural gas supply case and the AEO 2019 reference case, the projected emission levels for 2019 are less than those for 2017. Application of lower natural gas prices from higher supply to AEO 2019 reference case then results in marginal emission-reduction rates that are in sharp contrast to those for the AEO 2017 cases. (See Figures A.4 and A.5 for historical and projected steam coal and natural gas prices from 2005 to 2030.)

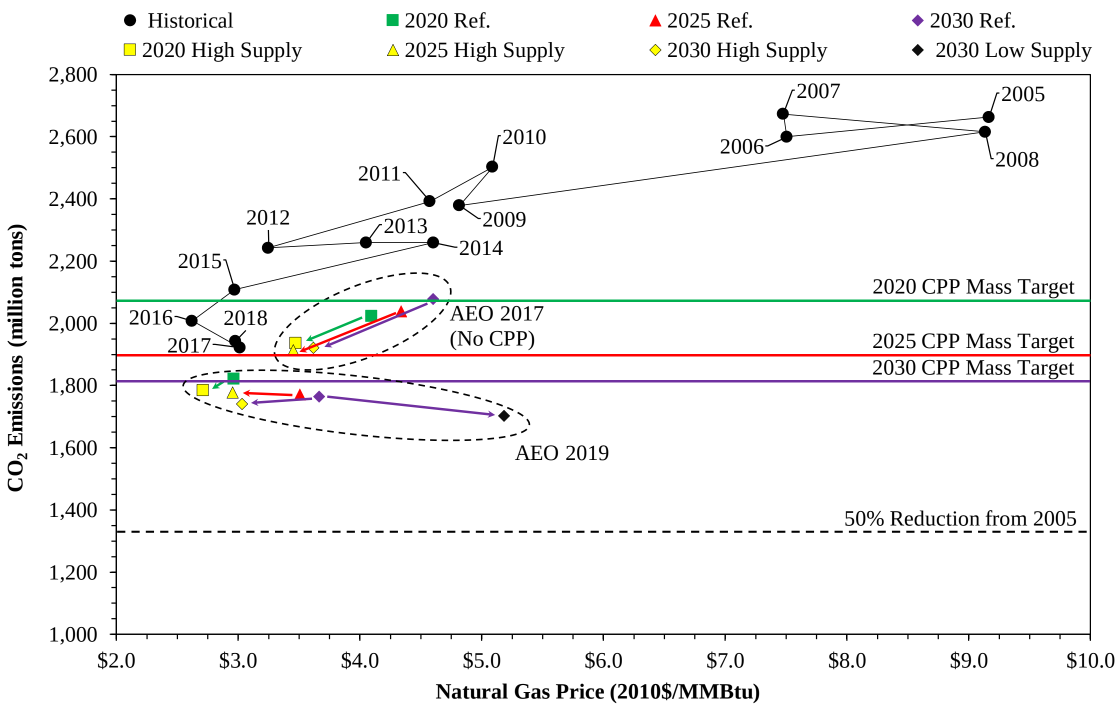


Figure A.2. Historical[32] and projected 2020, 2025, and 2030 CO_2 emissions from the U.S. power sector in relation to natural gas price [40]. Projected emissions and gas prices are national averages based on scenarios in the 2017 and 2019 Annual Energy Outlook (AEO) for the reference (ref.) and the high oil and gas resource and technology cases (high supply), and for the low oil and gas resource and technology case for 2019 (low supply) [11, 24]. Only the scenarios without the CPP are shown. Historical and projected natural gas prices from AEO 2017 and 2019 are converted to 2010 dollars with the Consumer Price Index [14].

[32] The correlation between price and reduction is not chronologically perfect, however. Coal prices, capacity planning, regulations and policy mechanisms (such as state-specific renewable portfolio standards and federal tax credits for solar and wind energy), unforeseen events, technology changes, and hedging related lags [16, 18, 43] may account for some of the imperfect responses between the natural gas price and the reduction, as occurs from 2006 to 2008 and from 2012 and 2014, when the natural gas prices increase but the emission intensities remain constant.

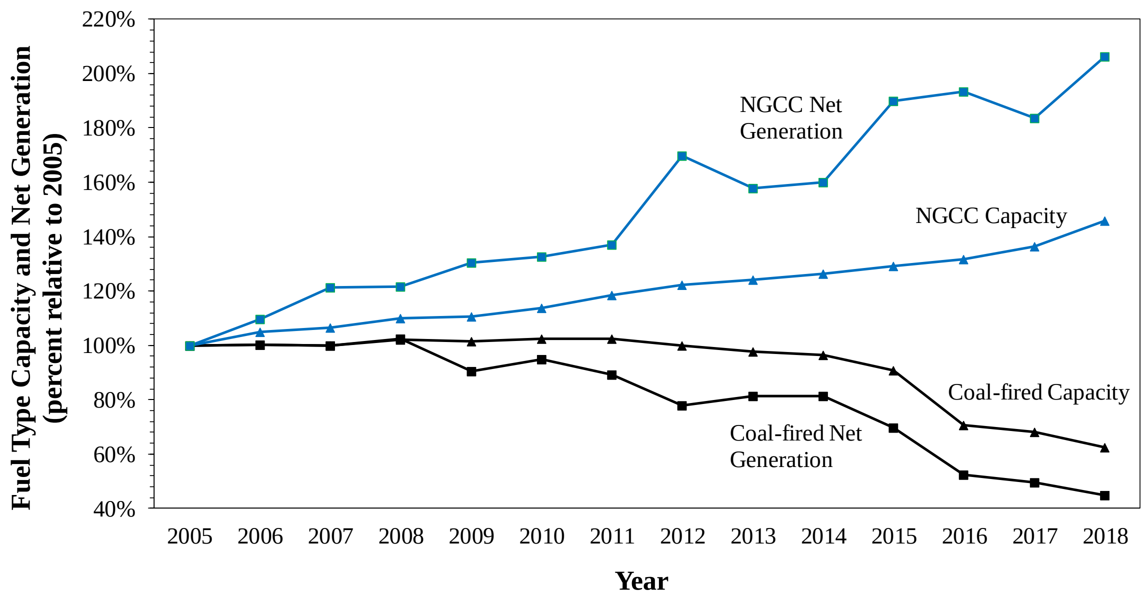


Figure A.3. Historical coal-fired and NGCC net generation and capacity levels relative to 2005 [19, 41].

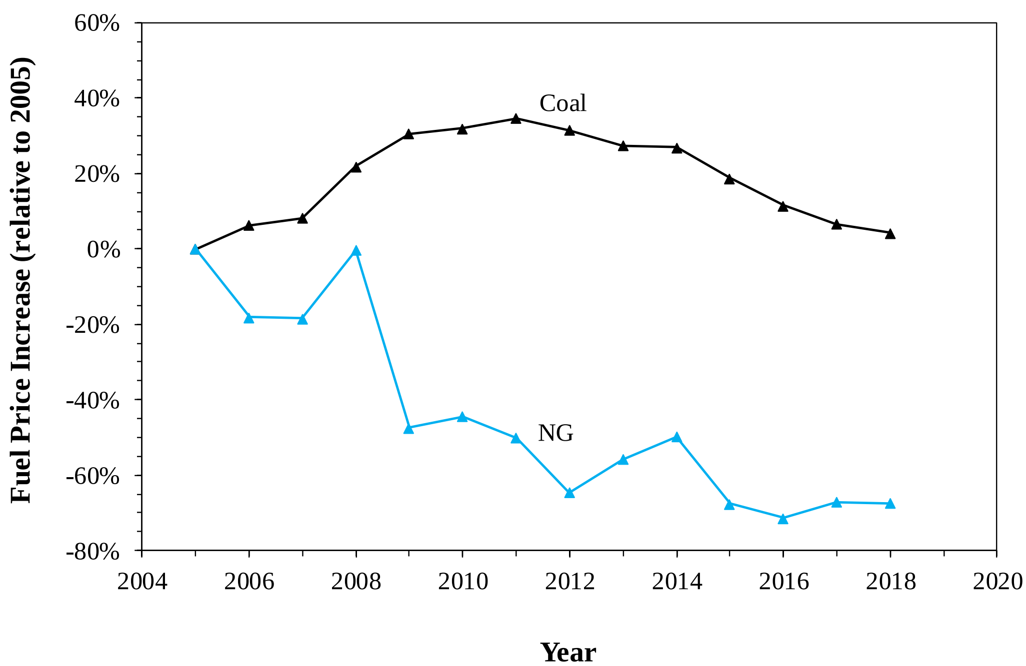


Figure A.4. Historical steam coal and natural gas prices relative to 2005 levels [40].

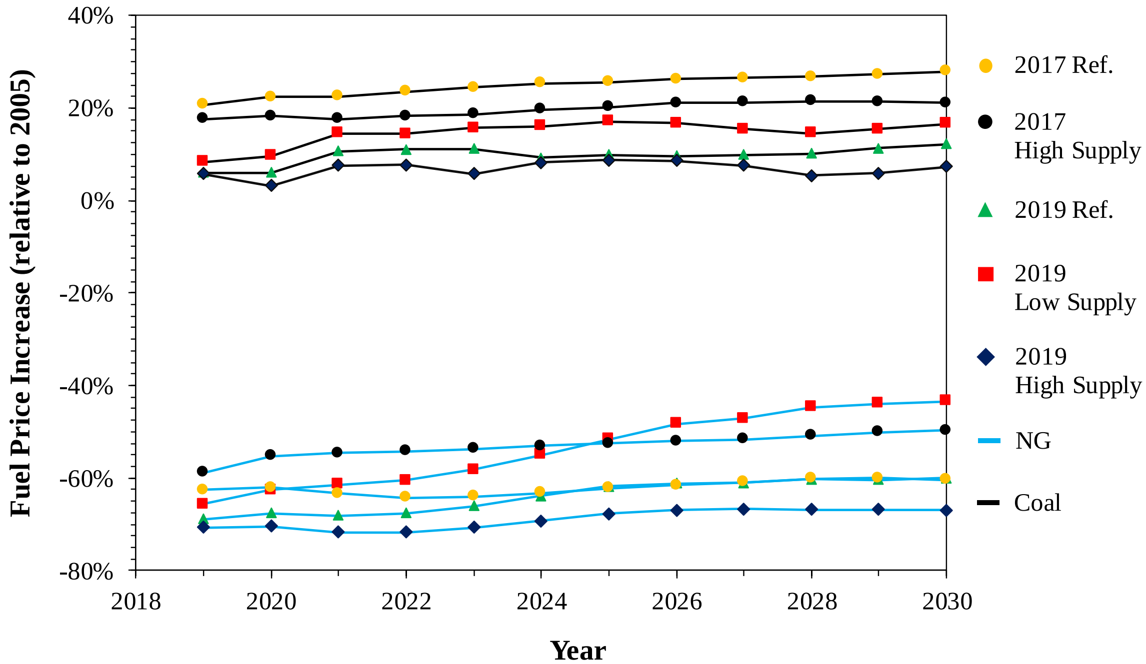


Figure A.5. Projected steam coal and natural gas prices from AEO 2017 and 2019 relative to 2005 levels [11, 24].

A.2.3.2 Marginal emission-reduction rate

The data underlying these projections offer some model insights as to why the relationship has changed. In comparing the 2030 projections for the reference and high natural gas supply cases from AEO 2017 and AEO 2019 (Table A.5, Figures A.6-12), the variation in net generation between the corresponding cases is less than 1%; however, coal-fired generation in AEO 2019 is approximately 28% less than that for the corresponding cases in AEO 2017. This lost generation is replaced primarily with additional natural gas generation related to projected natural gas prices that are at least 16% less in AEO 2019, while coal prices decrease by no more than 12%. Such a change in generation fuel-type does follow the expected trend of natural gas generation replacing coal-fired generation with decreasing gas price and indicates an accelerated decrease in coal-fired capacity that may be due to more than lower natural gas prices. Yet in AEO 2019, there is only a 1% further decrease in emissions when the natural gas price in the reference case is further reduced by 17% for the high natural gas price case, as compared to a 8% decrease in emissions from a 27% decrease natural gas price in AEO 2017.

This marginal emission-reduction rate change in the natural gas price and emissions relationship may relate to the decreased reliance on nuclear generation—a 13% and 35% decrease for the two AEO 2019 cases in question. In the reference case comparison, this generation decrease is almost offset by a 20% increase in renewable generation that comes from a tripling of solar generation related to both increased capacity and capacity factors. The further reduction in emissions for the AEO 2019 high natural gas supply, notwithstanding a greater relative decrease in nuclear generation, is due to the greater absolute reduction in coal-fired generation and 33% increase in natural gas generation. Even so, while onshore wind and solar generation is only 1% lower in the AEO 2019 high natural gas supply case, solar generation is almost 140% greater. This overall decrease in reliance upon wind generation in favor of solar generation suggests a decrease in solar capital costs that may also be a component of the trajectory change.

The relationship change is particularly evident for the low oil and gas resource and technology (low natural gas supply) case for which gains in natural gas price reduction from fracking and horizontal drilling are diminished beyond 2009 levels, yet the CO_2 emissions are projected to be less than that for any other case—a further 4% emission decrease given a 41% natural gas price increase, relative to the AEO 2019 reference case. While coal-fired generation is increased by 15% to offset a 37% reduction in natural gas-fired generation, Figures A.13 and A.14, this reduction is accomplished by increasing carbon-free generation to levels that are otherwise only slightly greater those achieved in 2017, Figure A.15. Nuclear generation is increased by 8%, wind and solar generation by 49% for an overall reduction of only 2% in total net generation. Such a large increase in renewable electricity is driven primarily by a 90% increase in solar generation to a level where solar generation is only 10% less than wind generation.

Table A.5. AEO 2017 and 2019 national power sector characteristics for 2030 [11, 24]. AEO reference and high oil and gas resource and technology (high NG supply) cases are shown are shown with AEO 2019 low oil and gas resource and technology (low NG supply) case, without CPP. Dollar year converted to 2010 with CPI [14].

Parameter	Units	AEO 2017		AEO 2019		
		Reference	High NG Supply	Reference	High NG Supply	Low NG Supply
Excess CO_2	Million short tons	264	108	(49)	(73)	(111)
Coal capacity*	Gigawatts	217.1	184.9	161.8	139.4	182.6
NGCC capacity*	Gigawatts	239.1	267.6	343.8	402.9	299.1
Wind capacity*	Gigawatts	140.3	133.5	119.7	116.5	142.6
Solar PV capacity*	Gigawatts	37.9	32.9	92.3	66.4	169.9
Nuclear capacity*	Gigawatts	95.1	96.5	81.7	59.9	88.6
Coal net generation†	Terawatt-hours	1,389.4	1,099.9	986.9	787.7	1,131.6
NG net generation†	Terawatt-hours	1,060.5	1,431.9	1,487.3	1,985.1	934.3
Wind net generation†	Terawatt-hours	419.7	448.6	368.7	356.6	457
Solar PV net generation†	Terawatt-hours	72.4	63.4	219.5	151.1	417.7
Nuclear net generation†	Terawatt-hours	768.0	757.1	663.9	488.4	716.8
Total net generation‡	Terawatt-hours	4,332	4,366	4,287	4,329	4,222
Natural gas price	2010$/MMBtu	4.61	3.63	3.67	3.03	5.18
Steam coal price	2010$/MMBtu	2.20	2.08	1.93	1.85	2.00
Electricity price§	Nominal cents/kWh	14.5	13.8	13.9	13.4	14.7

*net summertime capacity; †power only; ‡net generation to grid; §summation of generation, transmission and distribution costs

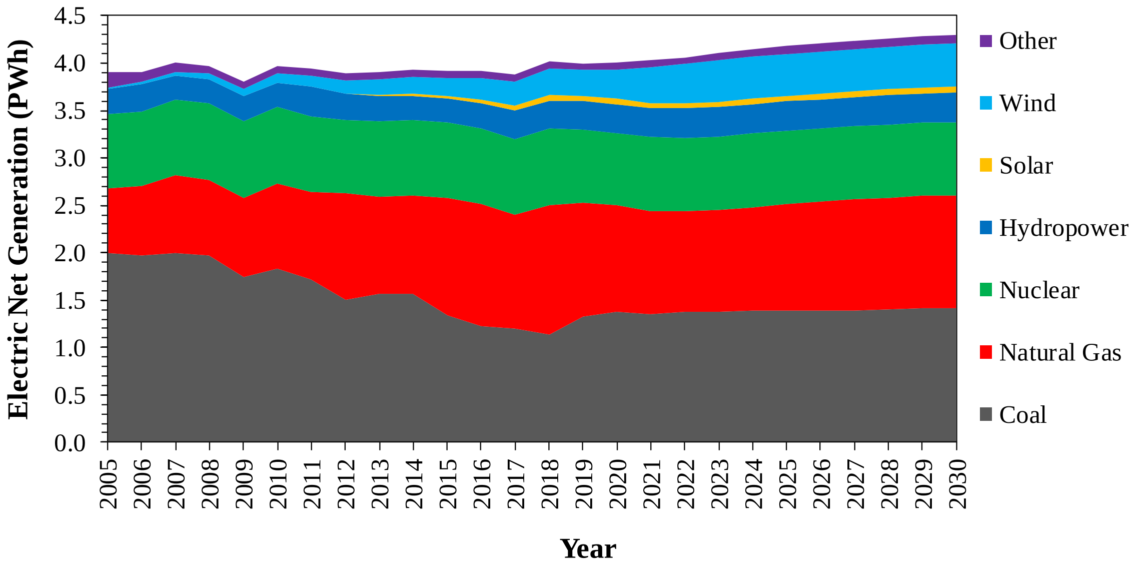


Figure A.6. Historical [40] and projected net generation for the U.S. power sector by source. Projected generation is for the reference case in AEO 2017 [11].

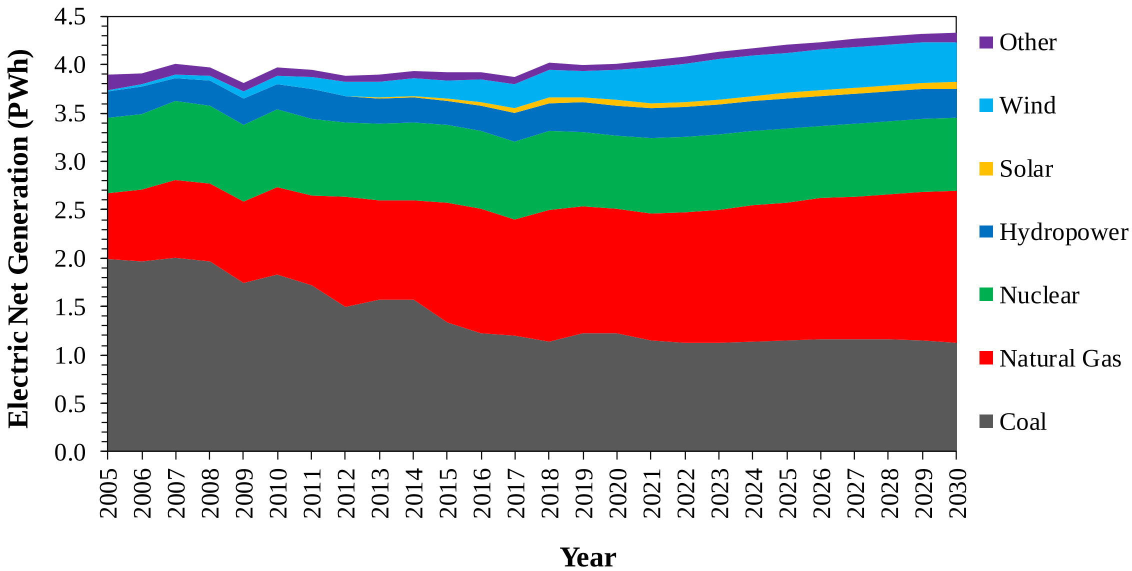


Figure A.7. Historical [40] and projected net generation for the U.S. power sector by source. Projected generation is for the high oil and gas resource and technology cases (high natural gas supply) case in AEO 2017 [11].

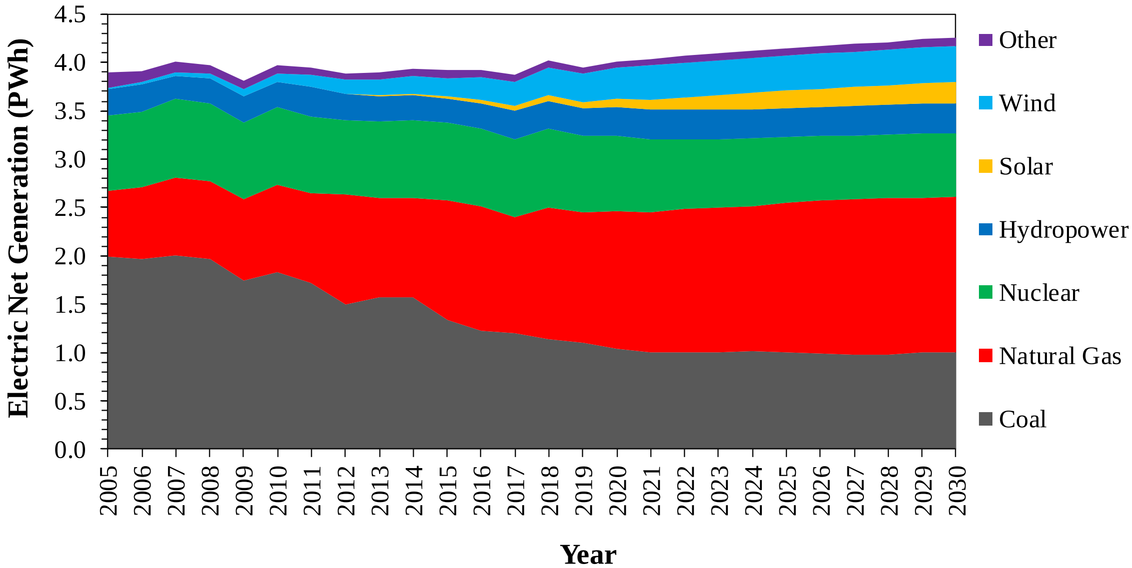


Figure A.8. Historical [40] and projected net generation for the U.S. power sector by source. Projected generation is for the reference case in AEO 2019 [24].

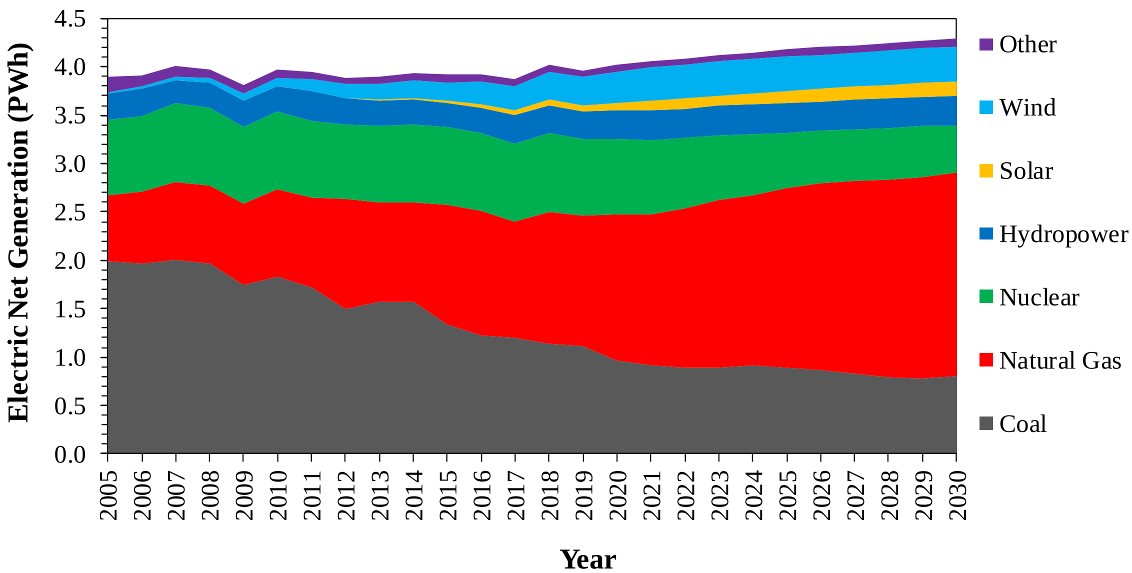
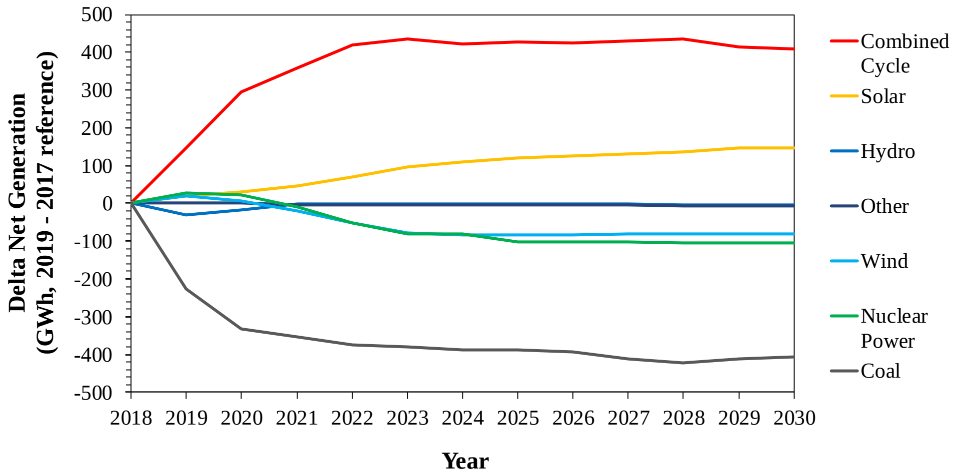
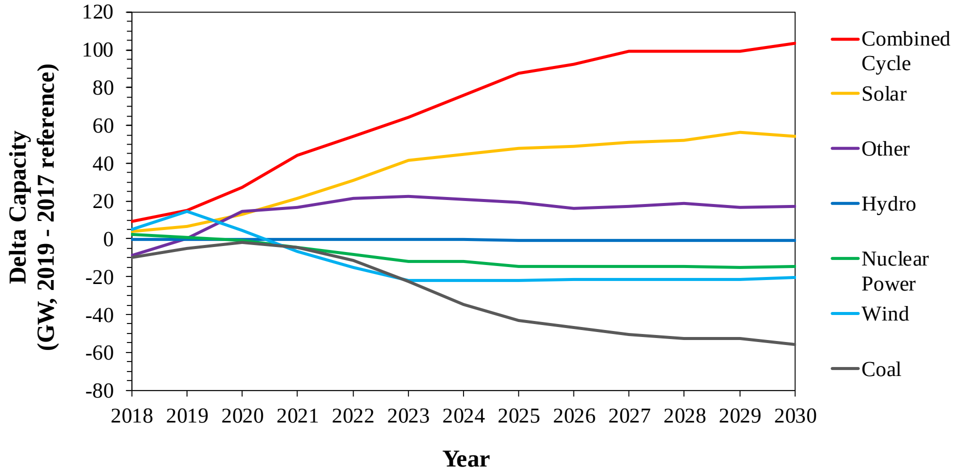


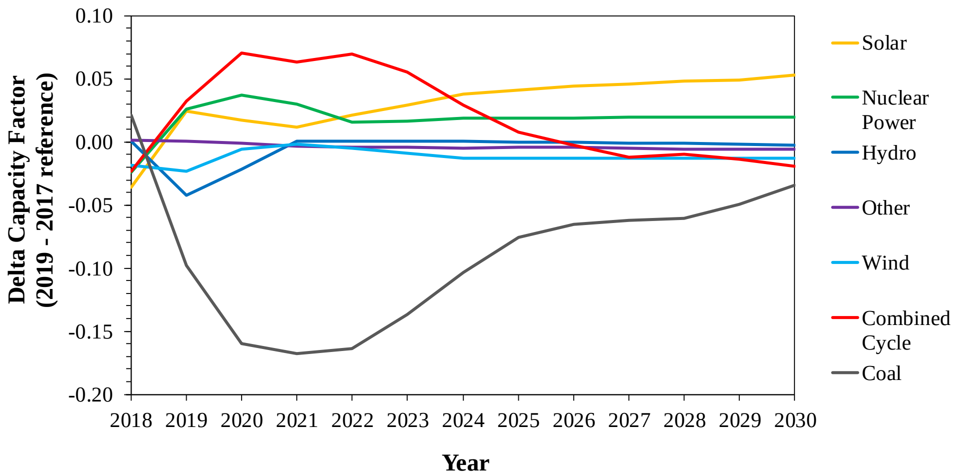
Figure A.9. Historical [40] and projected net generation for the U.S. power sector by source. Projected generation is for the high oil and gas resource and technology cases (high natural gas supply) case in AEO 2019 [24].



(a)

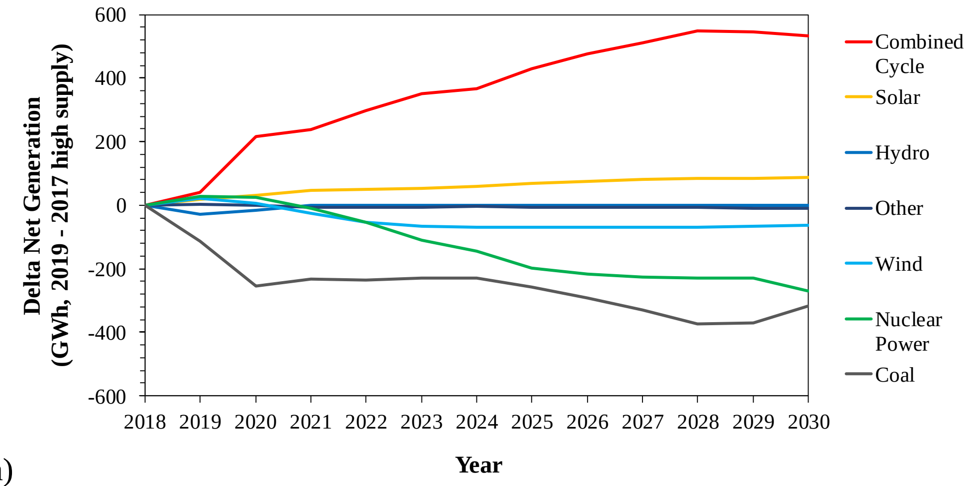


(b)

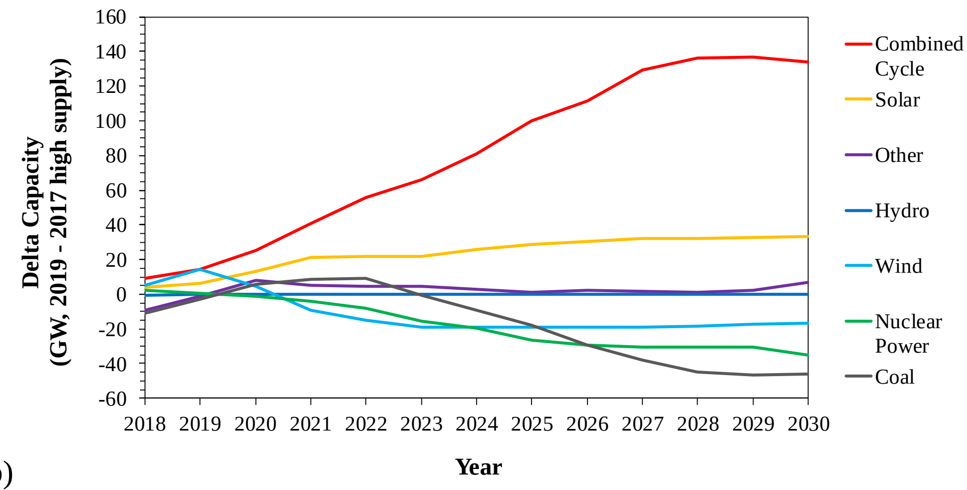


(c)

Figure A.10. Difference in projected (a) net generation, (b) capacity, and (c) capacity factor for the U.S. power sector by source, as projected for the reference case in AEO 2017 and 2019 [11, 24]. Capacity factor is based upon net summertime capacity.



(a)



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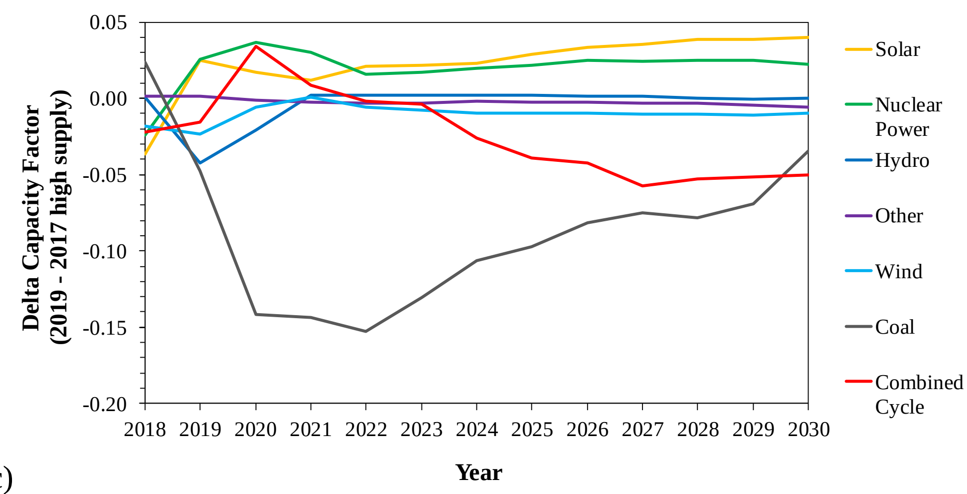
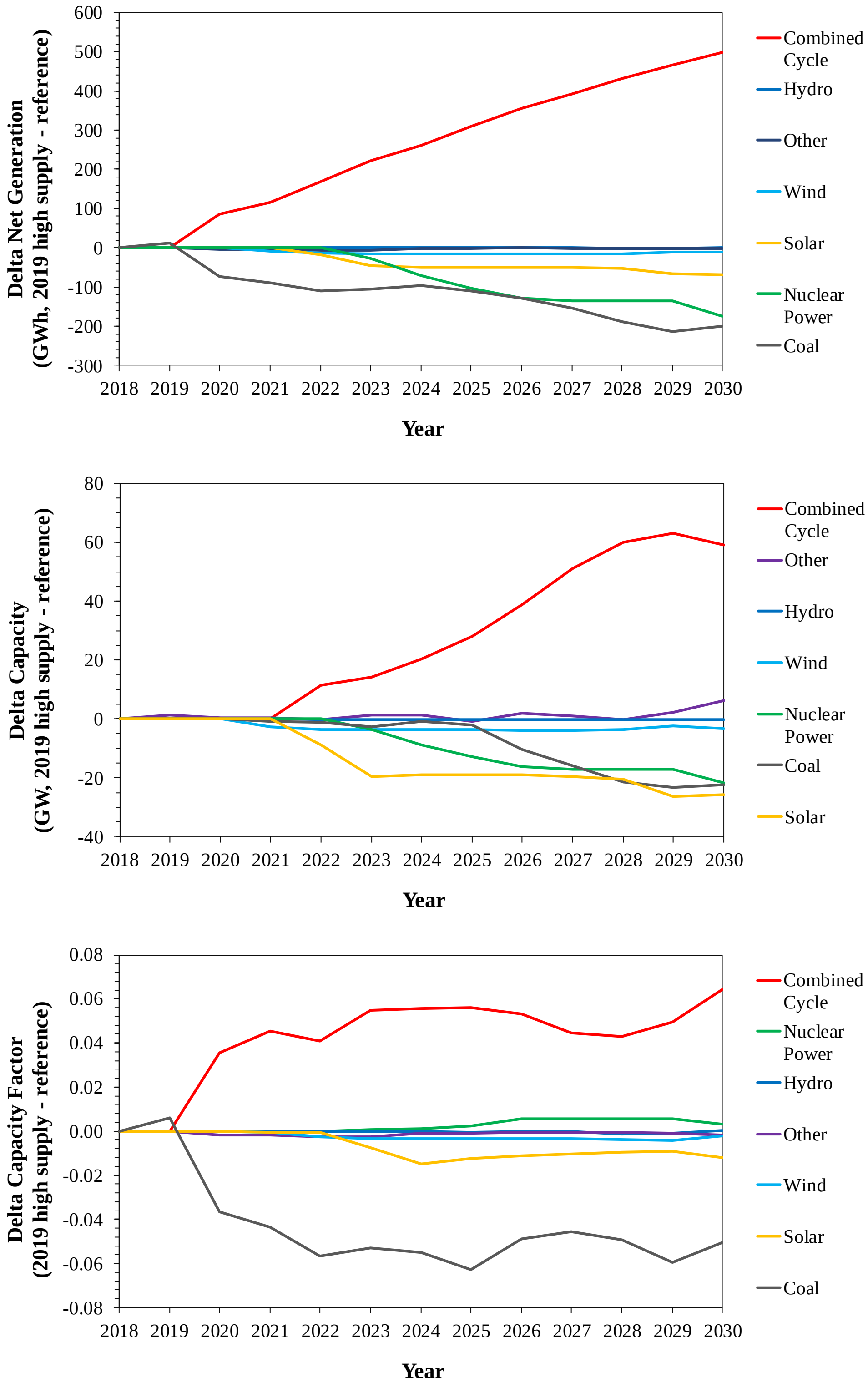


(c)

Figure A.11. Difference in projected (a) net generation, (b) capacity, and (c) capacity factor for the U.S. power sector by source, as projected for the high oil and gas resource and technology cases (high natural gas supply) case in AEO 2017 and 2019 [11, 24]. Capacity factor is based upon net summertime capacity.



(a)

(b)

(c)

Figure A.12. Difference in projected (a) net generation, (b) capacity, and (c) capacity factor for the U.S. power sector by source, as projected for the high oil and gas resource and technology cases (high natural gas supply) and reference case in AEO 2019 [24]. Capacity factor is based upon net summertime capacity.

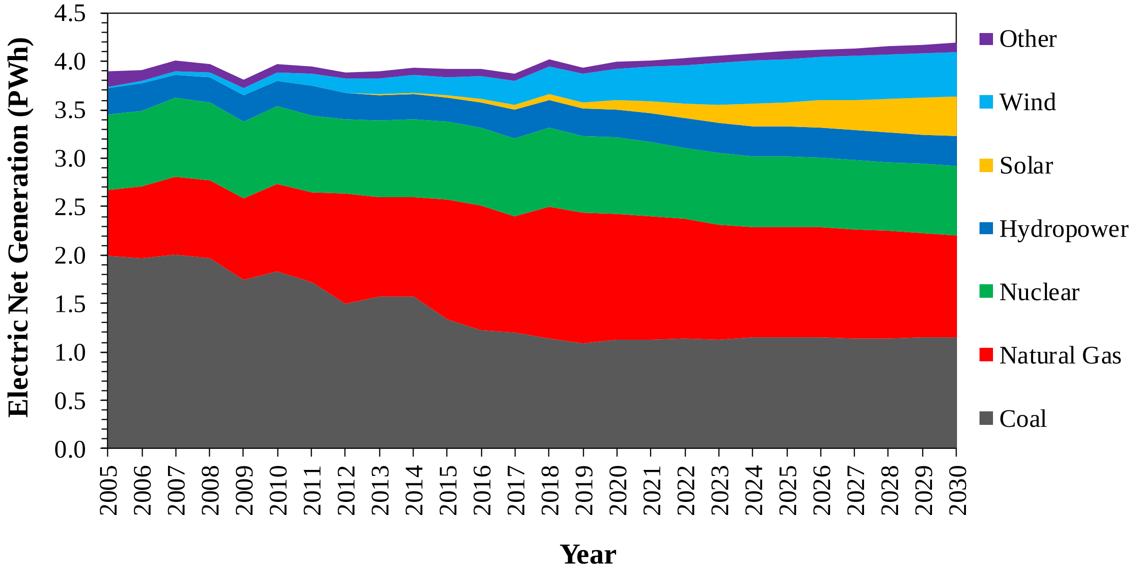


Figure A.13. Historical and projected net generation for the U.S. power sector by source. Projected generation is for the low oil and gas resource and technology cases (low natural gas supply) case in AEO 2019 [24].

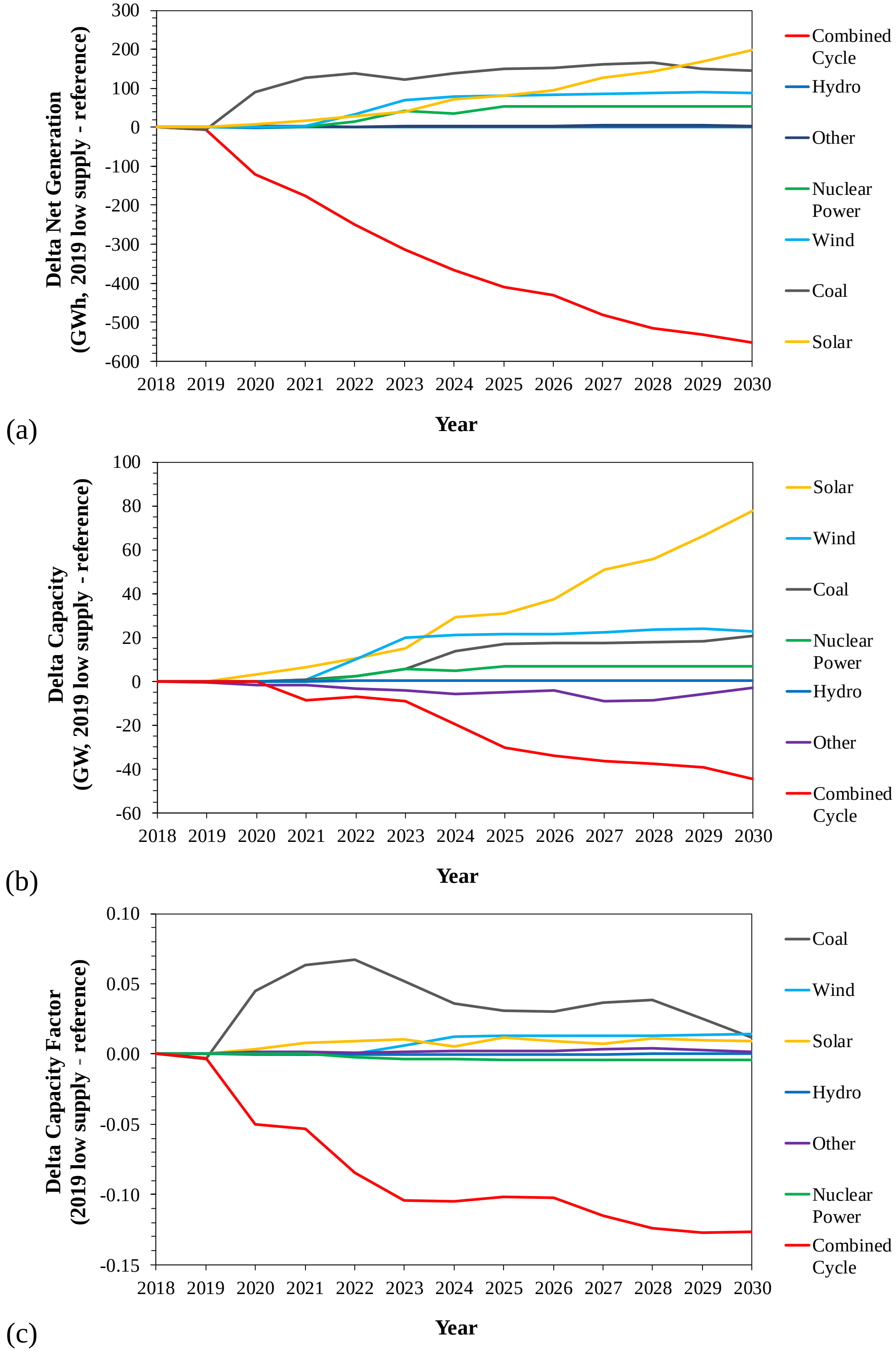


Figure A.14. Difference in projected (a) net generation, (b) capacity, and (c) capacity factor for the U.S. power sector, as projected for the low oil and gas resource and technology cases (low natural gas supply) and reference cases in AEO 2019 [24]. Capacity factor is based upon net summertime capacity.

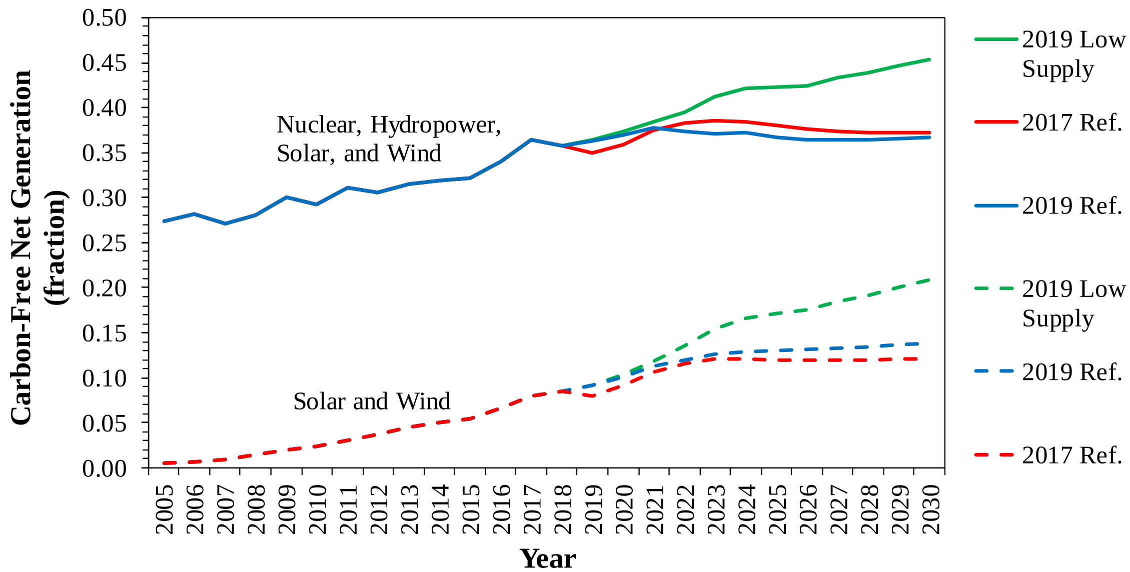


Figure A.15. Historical [40] and projected carbon-free net generation for the U.S. power sector. Projected generation is for the reference cases in AEO 2017 and 2019 [11, 24]. Generation for low oil and gas resource and technology cases (low natural gas supply) case is from AEO 2019 [24]. Carbon-free generation is comprised solely of nuclear, hydropower, solar and wind generation. Biomass and similar fuels are excluded.

A.2.3.3 Power generator cost

Examining the power-generator cost trends from previous AEOs is useful to understand the source of the deeper emission reductions now projected and the source of the trajectory change. For natural gas generation, which is substantially due to NGCC capacity, Figure A.3, the levelized cost of electricity (LCOE) for the reference case unit decreases significantly from AEO 2015 [25] to AEO 2019, Table A.6. This capacity-weighted average cost, based upon region-specific cost adders, decreases by almost 50% from AEO 2015 to AEO 2019. Some of this decrease results from a reduction in variable operation and maintenance (VOM) cost related to changes in fuel price and from modeling a more efficient gas turbine from AEO 2016 [26] onwards, which causes a 33% decrease in VOM and an increase in capacity factor from AEO

2015 to 2016. The levelized capital cost (CC) also drops by 39% in AEO 2019 to further decrease the LCOE by $4.5/MWh, year-over-year. The EIA attributes this reduction to economies of scale from using the GE 7HA.02 combustion turbine for future NGCC plants and standalone combustion turbines, as observed in net cost of new entry modeling for the PJM Interconnection [27]. Therefore, the difference in AEO 2017 and 2019 assumptions for VOM and CC that results in a $15/MWh decrease in NGCC LCOE likely accounts for the observed increase in natural gas generation. When faced with similar natural gas prices for the high supply case in AEO 2017 and the reference case for AEO 2019, the greater emission reduction for AEO 2019 can be attributed in part to the $5.7/MWh lower CC.

The costs for wind and solar generation also decreased sharply. From AEO 2015 to 2019 without tax credits, the capacity-weighted average LCOE for wind generation decreased by 46% and that for solar decreased by almost 64%, Table A.7. Taking tax credits into account for the AEO 2019 scenario, these decreases result in a solar LCOE that is less than $1/MWh greater than that for wind, which exemplifies the importance of these credits. Most of these reductions relate to levelized capital costs that decreased by 33% and 41% for wind and solar generation, respectively, from the 2017 to 2019 AEO Assumptions, Table A.8. These reductions vary year-over-year, Table A.9, as modeled capacity expansion will occur in regions (each with region-specific cost adders) most favorable to the specific fuel types and available new technology—an attribute that is also observed in the AEO capacity-factor variation, Table A.10. The capital-cost reduction can be partially unpacked by looking at the total overnight capital-cost upon which these capacity-weighted average costs are based, Table A.11. Here, the overnight cost continues to decrease for all solar technologies, as does that for wind. Fixed-solar overnight costs are reduced by 50% from AEO 2015 to 2019, assuming the use of fixed-solar technology dominates the AEO 2015 total overnight-cost, and wind overnight costs decrease by 24%.[33]

Table A.6. Change in NGCC LCOE from AEO 2015 to AEO 2019, based upon capacity-weighted averages [20, 31-34]. Dollar year converted to 2010 with CPI [14]. VOM includes fuel cost.

AEO	Service yr	LCOE	VOM	CC	VOM	CC	Capacity factor
		$/MWh			Year-over-year change (fraction)		
2015	2020	70.39	56.54	13.48	-	-	0.85
2016	2022	51.89	38.18	12.76	-0.325	-0.051	0.87
2017	2022	53.24	38.16	12.72	-0.001	-0.005	0.87
2018	2022	43.02	29.21	11.58	-0.234	-0.09	0.87
2019	2023	37.26	28.12	7.05	-0.038	-0.391	0.87

Notes: VOM: variable operation and maintenance cost, including fuel; CC: levelized capital cost.

Table A.7. Wind and solar LCOE from AEO 2015 to AEO 2019, based upon capacity-weighted averages [20, 31-34]. Dollar year converted to 2010 with CPI [14].

AEO	Service yr	Wind ($/MWh)		Solar ($/MWh)	
		No credit	Credit	No credit	Credit
2015	2020	68.89	68.89	117.29	106.99
2016	2022	53.83	46.83	68.26	53.46
2017	2022	50.70	40.25	66.96	52.79
2018	2022	42.75	32.87	52.64	41.51
2019	2023	37.26	31.86	42.48	32.73

[33] Prior to AEO 2018, the AEO did not distinguish utility-scale photovoltaic generation into these two categories of collectors.

Table A.8. Change in wind and solar LCOE components from AEO 2015 to AEO 2019, based upon capacity-weighted averages [20, 31-34]. Value of tax credits is omitted. Dollar year converted to 2010 with CPI [14].

AEO	Service yr	Wind ($/MWh)		Solar ($/MWh)	
		OM	CC	OM	CC
2015	2020	11.98	54.01	10.67	102.78
2016	2022	11.50	39.84	8.74	56.30
2017	2022	11.9	36.16	9.18	54.33
2018	2022	11.31	29.39	6.68	42.93
2019	2023	10.97	24.20	7.66	32.29
Fractional change (2017-2019)		-0.08	-0.33	-0.17	-0.41

Notes: OM: operation and maintenance cost; CC: levelized capital cost.

Table A.9. Year-over-year change in wind and solar LCOE components from AEO 2015 to AEO 2019, based upon capacity-weighted averages [20, 31-34]. Value of tax credits is omitted.

AEO	Service yr	Wind (fraction)		Solar (fraction)	
		OM	CC	OM	CC
2015	2020	-	-	-	-
2016	2022	-0.040	-0.262	-0.181	-0.452
2017	2022	0.035	-0.092	-0.05	-0.035
2018	2022	-0.05	-0.187	-0.272	-0.21
2019	2023	-0.030	-0.177	0.147	-0.248
Fractional change (2015-2019)		-0.085	-0.552	-0.282	-0.686

Notes: OM: operation and maintenance cost; CC: levelized capital cost.

Table A.10. AEO 2015 to AEO 2019 capacity factors for new generation capacity entering service [20, 31-34].

AEO	Capacity factor (fraction)	
	Wind	Solar
2015	0.36	0.25
2016	0.40	0.25
2017	0.41	0.25
2018	0.43	0.33
2019	0.44	0.29

Table A.11. NGCC, wind and solar total overnight capital costs ($/kW) from 2015 to 2019 AEO Assumptions [35-39]. Dollar year converted to 2010 with CPI [14]. Value of tax credits is omitted.

AEO	NGCC	Wind	Solar	Solar Fixed	Solar Tilt
2015	854	1,853	3,069		
2016	880	1,512	2,282		
2017	880	1,532	2,069		
2018	875	1,476		1,649	1,875
2019	870	1,414		1,552	1,714

A.2.3.4 Model comparison

One can benchmark of the assumption that solar costs will decrease sufficiently to displace new NGCC and wind generation in the low supply case by 2030 with modeling done by other agencies: the Environmental Protection Agency (EPA) and the National Renewable Energy Laboratory (NREL). The EPA uses the Integrated Planning Model (IPM) to determine future U.S. power-sector dispatch, least-cost capacity expansion, and emission-control strategies for environmental policies formulation and evaluation. As part of this, the EPA publishes the assumed total overnight-costs and other LCOE components for the generation technologies for various service introduction years, for which they use the EIA fuel-price projections [28].

NREL's 2019 Annual Technology Baseline (ATB) documents detailed projected cost and performance assumptions about renewable and conventional electricity-generating technologies, using EIA fuel-price projections, for least-cost capacity expansion modeling [29]. For wind, a national wind-resource profile for potential wind generation is grouped into ten techno-resource groups (TRGs) to define the appropriate wind turbine technology and associated costs for each region. The TRGs are then used to identify the group for which the plant characteristics best align with recently installed and projected near-term installation as a baseline for constant, mid- and low-technology cost scenarios, and to provide the upper and lower bounds for these scenarios. Similarly, the solar-generation projected cost and performance characteristics are based upon a potential solar-resource profile. Rather than use TRGs to define the best aligned and bounding plant characteristics, the solar profile uses collectors sited in specific cities. Projected NGCC costs are determined as an average of the EIA reported conventional and advanced unit costs, where the representative unit has a high-capacity factor and natural gas price determines the high and low bounds.

In a comparison of the projected overnight capital-costs for solar generation, Figure A.16, the IPM values fall within the bounds of the ATB values, with each showing a decline in capital cost as the available service-year horizon increases. However, the point value for AEO 2019 is almost $600/kw greater than the ATB value for 2020. Projections for wind capital costs also show agreement between IPM and ATB values for declining costs and the AEO 2019 value is near the ATB 2021 upper bound, Figure A.17. For NGCC capital costs, the AEO value falls between the IPM and ATB projections, Figure A.18, for which the projected costs are almost constant. Therefore, the agreement between the ATB and IPM values for these technologies indicates that the declining capital costs are expected for wind and solar. As such, the ATB projection for a solar LCOE[34] being similar to that for wind and NGCC, Figure A.19, reinforces the AEO 2019 projection that solar generation may replace some of the wind generation from AEO 2017 and that high natural gas prices may lead to greater use of solar capacity.

[34] LCOE for solar and wind generation includes the reduction and expiration of investment and production tax credits.

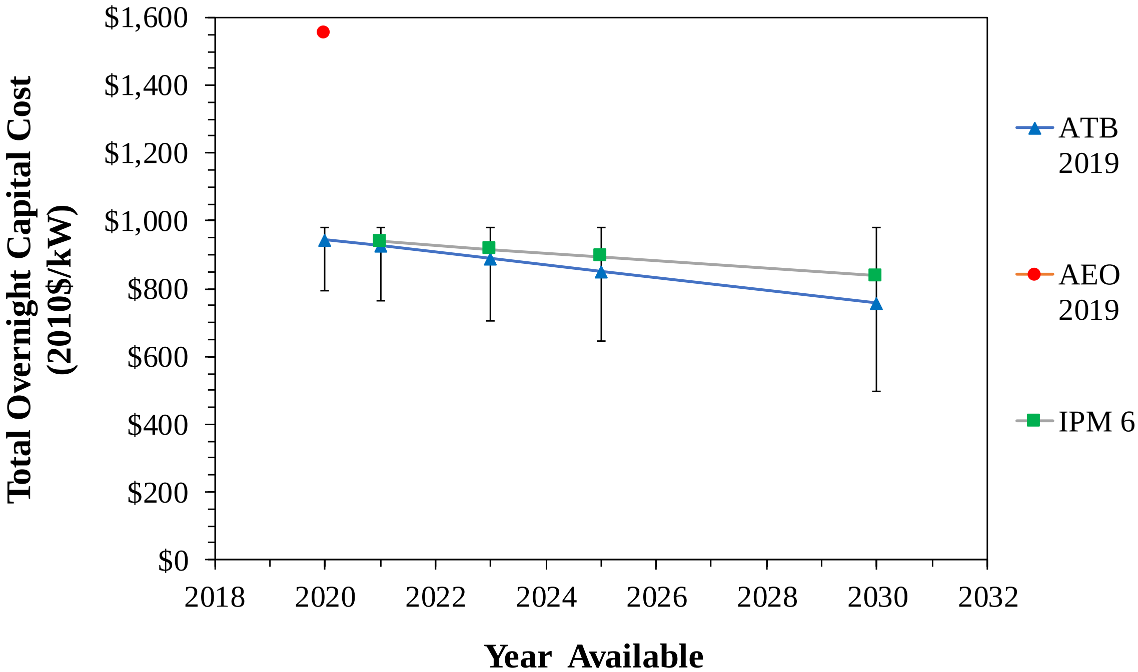


Figure A.16. Comparison of total overnight capital cost for solar sources from 2019 ATB [29], AEO 2019 [24], and IPM 6 [28]. Value for ATB is representative of a site in Kansas City, MO. Upper bound of error bar on ATB values is that for a site in Daggett, CA and lower bound is that for a site in Seattle, WA, as defined in the ATB. Values are not capacity weighted.

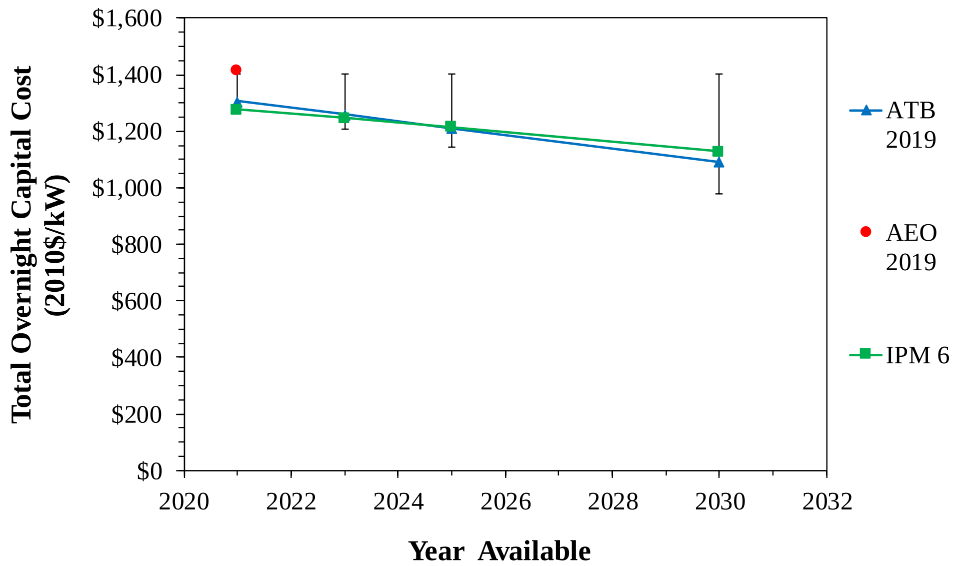


Figure A.17. Comparison of total overnight capital cost for wind sources from 2019 ATB [29], AEO 2019 [24], and IPM 6 [28]. Value for ATB is representative of techno-resource group 4. Upper bound of error bar on ATB values is representative of techno-resource group 10 and lower bound is representative of techno-resource group 1, as defined in the ATB. Values are not capacity weighted.

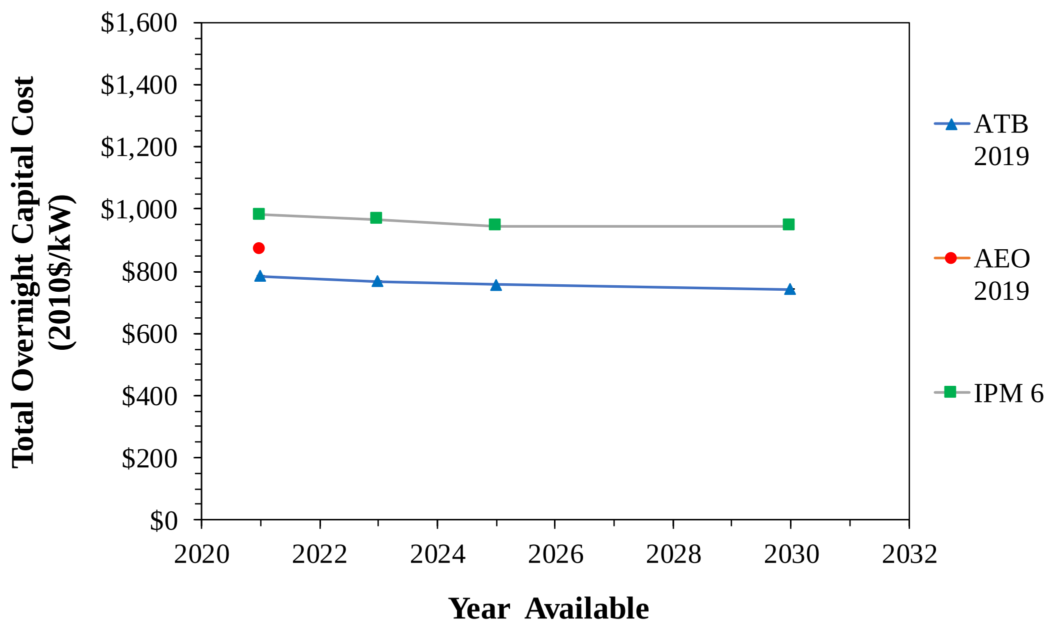


Figure A.18. Comparison of total overnight capital cost for NGCC sources from 2019 ATB [29], AEO 2019 [24], and IPM 6 [28]. Upper and lower bounds for ATB values are determined by natural gas price and are omitted. Values are not capacity weighted.

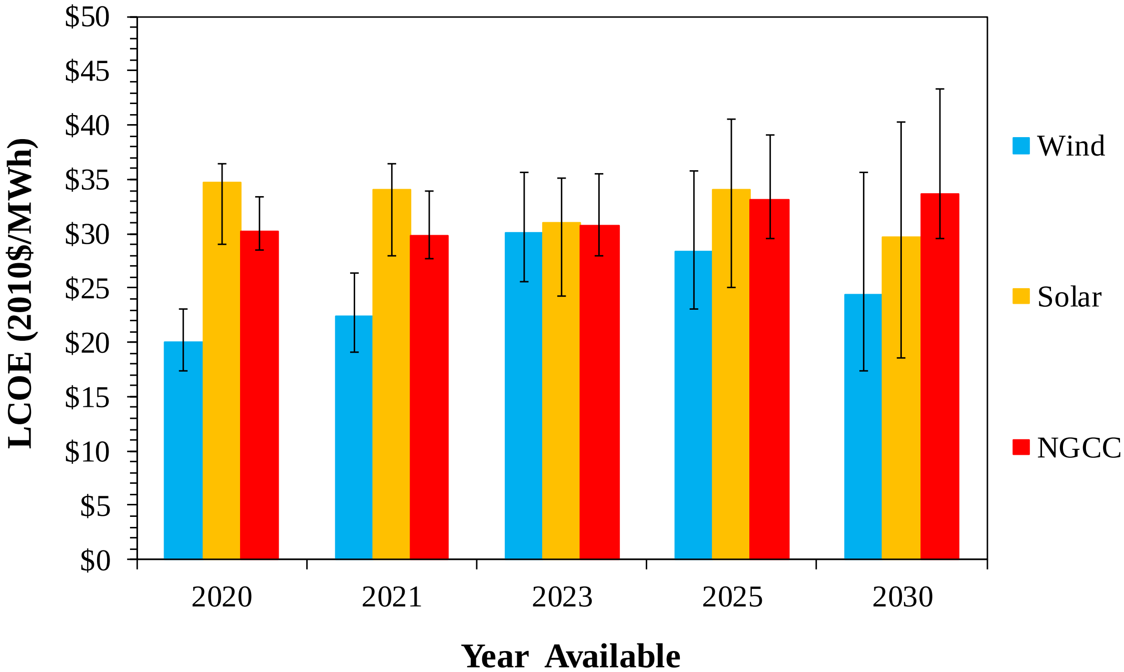


Figure A.19. LCOE for NGCC, solar, and wind sources from the 2019 ATB [29]. Error bars are based on LCOE range for default comparisons defined in ATB. NGCC error bars include low, mid and high projections for fuel cost for a high-capacity factor unit.

A.2.3.5 Levelized avoided cost of electricity

However, if one compares only the generation technology LCOEs to make capacity investment decisions, not all economic-competitiveness factors are being considered. Consideration can be given to other factors such as the value of capacity-related grid services, the ability of the generator to meet load given the existing fleet generation-profile, and the generation technology that may be replaced. One method used to account for these additional factors is to determine the levelized avoided cost of electricity (LACE). LACE can be considered as the marginal cost of energy and capacity, as it is the cost of electricity if the considered technology is not available and another technology must be used instead for the new capacity. Here, if LACE is greater than LCOE for the same technology, then it is favorable to invest in that technology relative to the alternative technologies, absent other investment factors.

While the EIA does not use LACE for decisions in the AEO capacity expansion modeling, LACE is determined and the value-cost ratio (LACE divided by LCOE) is calculated for various available service-years, Table A.12. From this analysis, both solar and wind generation are seen as favorable investments for AEO 2016 to 2018 [30]. However, only solar generation is a favorable technology to the alternatives in AEO 2019, due largely to expiration of the production tax credit that is applicable to onshore wind generation. In subsequent available service-years when the investment tax credit also expires, neither technology has a value-cost ratio greater than 1 in the AEO 2019 reference case [31], Figure A.20. However, the value-cost ratio for each technology is projected to be greater than 1 by 2030, due to decreases in capital costs and improved capacity factors [31]. Therefore, additional solar and wind capacity may be favorable when higher priced natural gas makes expansion of NGCC capacity less favorable.

Table A.12. Change in value-cost ratio from AEO 2015 to AEO 2019 [20, 31-34], based upon capacity-weighted averages. Value-cost ratio is the levelized avoided cost of electricity (LACE) divided by the LCOE. When ratio is greater than one, the generating source is favorable to alternatives. Dollar year converted to 2010 with CPI [14].

AEO	**Service yr**	**LACE ($/MWh)**			**Value-cost ratio**		
		NGCC	**Wind**	**Solar**	**NGCC**	**Wind**	**Solar**
2015	2020	66.83	60.47	75.26	0.95	0.878	0.703
2016	2022	49.40	49.40	62.01	1.094	1.056	1.156
2017	2022	53.06	49.06	60.69	0.997	1.219	1.15
2018	2023	41.42	38.21	64.49	0.963	1.163	1.554
2019	2023	33.34	29.34	35.08	0.895	0.921	1.072

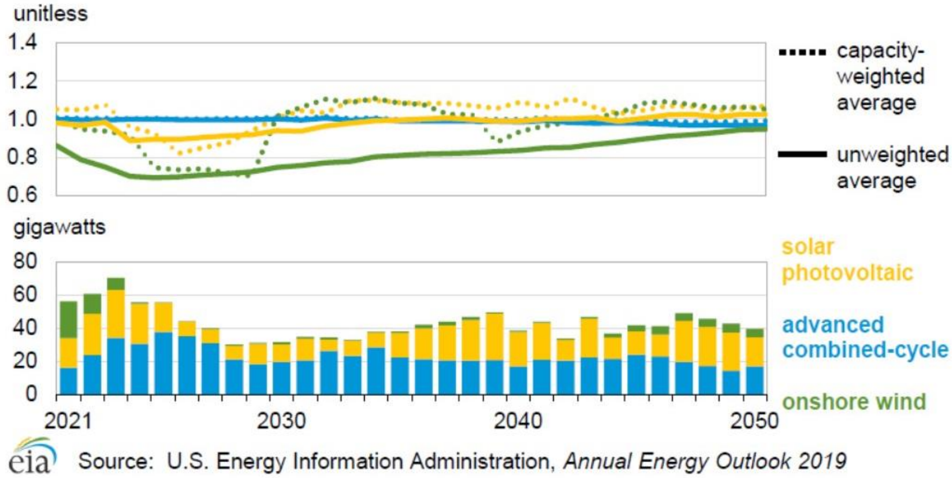


Figure A.20. EIA projected levelized avoidance cost of electricity (LACE) for onshore wind, advanced NGCC, and solar photovoltaic generation from AEO 2019 [31].

A.2.4 Conclusion

In AEO 2019, the EIA projects that the CO_2 emission-reduction targets set out in the CPP can still be achieved without the plan or subsequent ACE regulations but through current environmental regulations and policies, and market mechanisms. As such, the substantial contribution in emission reduction with which the electric power sector was tasked to meet the Paris Agreement targets may be achieved and even exceeded. While low natural gas price is still a prominent factor in achieving these reductions, decreasing capital cost for generating sources is also important.

The decreasing NGCC plant capital cost coupled with lower natural gas price projections are enabling factors in AEO 2019 for reductions beyond the 2030 emission target. However, these factors also hide the continued capital cost reductions for solar and wind generation. If the historical natural gas price decrease achieved through hydraulic fracking and horizontal drilling were to disappear (due to increasing liquified natural-gas export, regulations curtailing such extraction, or a carbon tax[35]) and return to 2010 levels, the lower projected capital costs for these renewables (particularly solar) are low enough to reverse the trend of emissions increasing with increasing natural gas price. The dramatic change between AEO 2017 and 2019 in the capital costs for these generating sources, even with similar service years, also indicates how difficult it may be to set policy for 5-20 years in the future, given the uncertainty in fuel prices and rapidly changing technology fronts in energy generation and storage. Therefore, both promotion of technological improvement and economies of scale from installed capacity in these renewable technologies to ensure lower levelized costs may serve as one backstop to avert increased emissions with higher natural gas prices and to promote higher penetration of carbon-free generation by 2030.

[35] If one assumes that the 7,649 Btu/kWh NGCC heat rate for the current fleet[28] were to decrease to that for a conventional NGCC plant (6,350 Btu/kWh)[24] by 2030, then a $25/ton carbon tax is sufficient to increase the equivalent price of natural gas from $3.7/MMBtu for the 2030 projected reference case[5] to the $5.2/MMBtu projected price for low natural gas supply,[5] *ceteris paribus*.

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Appendix B: Supplemental information for Chapter 3

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B.1 Intergovernmental Panel on climate change 1.5° C implications

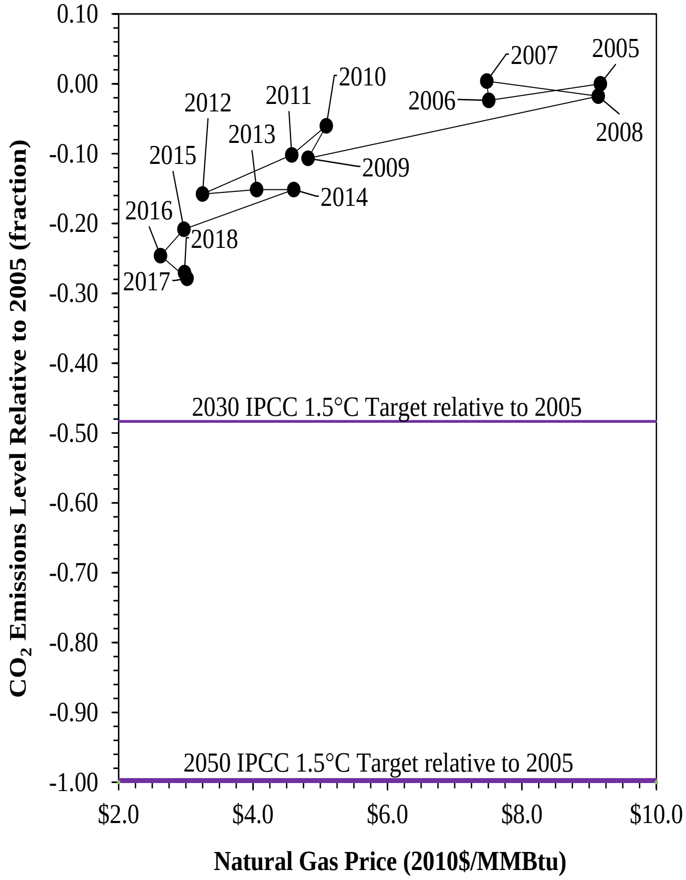

Figure B.1. Historical CO_2 emissions from the U.S. power sector in relation to natural gas price [1]. Historical natural gas prices are converted to 2010 dollars with the Consumer Price Index [2]. As the Intergovernmental Panel on Climate Change (IPCC) 2030 target is global and may not be applied equally to developed and developing nations or to all sectors, we illustrate the reduction for the U.S. power sector as a direct application of the 45% reduction target to the 2010 emissions and then set it relative to the 2005 baseline.

B.2 Coal fleet replacement calculations

In 2018, the net generation from coal for the power sector was 1,140 terawatt-hours (TWh), Table B.1, with an average carbon dioxide (CO_2) emission intensity (pounds of CO_2 per megawatt-hour) of 2,229 lbs/MWh [1]. The CO_2 emission intensity for a new, natural gas combined cycle (NGCC) plant is 755 lbs/MWh, as defined by the National Renewable Energy Laboratory (NREL) [3]. This plant is defined as the average of the characteristics of the advanced and conventional NGCC plants described by the Energy Information Administration (EIA) in the 2019 Annual Energy Outlook (AEO) [4]. Therefore, replacing the coal-fired generation with an equivalent amount of new NGCC generation decreases CO_2 emissions by 839 million short tons (MMtons). In 2010, the total CO_2 emissions for the power sector was 2,503 MMtons.

Replacing the 2018 coal-fired generation, Table B.1, with new NGCC plants requires 150 gigawatts (GW) of capacity on the net basis operating at an 87% capacity factor. In the 2019 Annual Technology Baseline (ATB) report by the NREL [3], the 2030 overnight cost for this plant is projected to be $833 per kilowatt ($/kW), in 2017 dollars. For replacement with solar generation, the capacity required is 650 GW, using ATB utility-scale photovoltaic profiles representative of the mid-range solar irradiance in the U.S. (a 20% capacity factor for a collector located in Kansas City, Missouri). The associated overnight cost is $850/kW for the mid-technology cost scenario [3]. For replacement with onshore wind generation, the required capacity is 266 GW, given the 49% capacity factor with an associated overnight cost of $1,225/kW for the ATB representative techno-resource group 4 wind turbine in the mid-technology cost scenario [3].

While the build rate required for any of these individual solutions is greater than historical rates since 2005, the necessary NGCC rate is within those projected by the Energy Information Administration (EIA) [5] and represents a yearly capacity addition of 5% of the 2018 installed base [5]. For solar or wind generation sources, such annual capacity growth requirements far outpace any 13-year average historical or projected rates by about 3-28 times and are up to four times any peak historical or projected yearly rate [5-16]. Furthermore, the required annual installed solar and wind capacity represents a large proportion of the 2018 installed base—195% and 25%, respectively [5].

In a projected "business as usual" case without the need to decarbonize, the EIA projects that generation will increase 6% between 2018 and 2030 [4]. But decarbonization in the transportation sector alone may increase demand by an additional 30% [17]. Therefore, new capacity from natural gas and renewables will likely be part of the solution.

Table B.1. U.S. power sector 2018 generation and CO_2 emissions from coal and in aggregate [1].

Metric	Units	Coal Fleet	Total Fleet
Net Generation	TWh	1,139	4,018
CO_2 Emissions	MMtons	1,269	1,899

Table B.2. Year-over-year historical NGCC, solar, and wind capacity increases (GW per year) from 2005 to 2018 [5-16].

Source	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Mean
NGCC	7.2	6.1	6.3	4.6	4.2	6.7	6.4	3.0	9.2	3.1	4.6	8.3	17.4	**5.82**
Solar	0.0	0.0	0.0	0.1	0.2	0.6	1.6	2.5	3.3	3.2	8.3	5.0	5.4	**2.07**
Wind	2.6	5.2	8.1	9.6	4.8	6.5	13.4	0.9	4.2	8.3	8.7	6.3	7.2	**6.57**

Table B.3. Year-over-year projected NGCC, solar, and wind capacity increases (GW per year) from the 2019 Annual Energy Outlook (AEO) for the reference case, the low oil and gas resource and technology case (Low Supply) that results in a high natural gas price, and the high oil and gas resource and technology cases (High Supply) that results in a low natural gas price [5].

	Reference (GW/yr)			**Low Supply (GW/yr)**			**High Supply (GW/yr)**		
Year	**NGCC**	**Solar**	**Wind**	**NGCC**	**Solar**	**Wind**	**NGCC**	**Solar**	**Wind**
2019	6.6	3.4	11.3	6.6	3.4	11.3	6.6	3.4	11.3
2020	9.9	7.3	4.8	9.9	10.3	4.8	9.9	7.3	4.8
2021	15.2	8.4	6.3	6.3	11.8	7.0	15.3	8.4	3.5
2022	6.2	9.6	0.9	8.1	13.6	10.4	17.7	0.7	0.0
2023	9.6	11.1	0.0	7.4	15.6	9.7	12.2	0.4	0.0
2024	12.6	3.3	0.0	1.9	17.9	1.1	18.7	4.0	0.0
2025	14.0	3.3	0.0	3.4	4.8	0.5	21.9	3.3	0.0
2026	8.0	2.1	0.2	4.5	8.5	0.3	18.5	2.1	0.0
2027	8.7	3.0	0.3	6.4	16.5	1.1	21.3	2.3	0.1
2028	4.9	3.2	0.2	3.3	8.0	1.2	13.6	2.2	0.5
2029	5.0	6.4	0.0	3.5	17.1	0.3	8.2	0.7	1.4
2030	10.1	0.9	1.0	4.7	12.1	0.1	6.0	1.3	0.1
Average	**9.8**	**5.2**	**2.5**	**6.4**	**11.2**	**4.2**	**14.4**	**3.2**	**2.2**

B.3 NGCC CCS retrofit

The cost estimate for a carbon capture and storage (CCS) retrofit on an existing NGCC plant is derived from the ATB estimates of overnight costs for this plant as a new plant with and without CCS [3]. The retrofit cost is estimated simply as the difference in overnight cost for these two cases, \$1,110/kW, assuming that the costs are sized for the same capacity plant—approximately 900 MW from the average of the advanced and conventional NGCC plants modeled in the EIA's 2019 AEO [5]. This yields a retrofit cost of \$250 million per plant, excluding the transportation infrastructure costs for the CO_2. Using a similar technique from previous work on conventional NGCC plants indicates a lower retrofit cost of $623/kW [18], when converted to 2017 dollars with the Chemical Engineering Plant Index [19]. These costs are likely to be overestimated because they are based upon 400-550 MW net capacity plants, rather than scaled for a 900 MW plant. However, as these costs are estimates for new plants with and without CCS, the actual cost for retrofitting may be greater than the estimated cost [20].

B.4 Carbon-dioxide reduction models

DIEM (Duke University)

The Dynamic Integrated Economy/Energy/Emissions Model (DIEM) is composed of a computable general equilibrium module and an electricity dispatch module for the U.S. regional markets [21,22]. In the electricity module, decisions about generation, transmission, capacity planning, and unit dispatch to analyze environmental policies are made with dynamic linear programming with intertemporal foresight.

E4ST (Arizona State University, Cornell University, Rensselaer Polytechnical Institute, Resources for the Future)

The Engineering, Economic, and Environmental Electricity Simulation Tool (E4ST, pronounced “east”) is an open-source software toolbox, built on MATPOWER optimal power flow software, for estimating power grid operating and investment. The software models present and future response to such inputs as fuel price, environmental regulations, and policy incentives [23,24]. Detailed responses include generator dispatch, generator entry and exit, transmission line investment, air emissions, and environmental damage.

EGEAS (Electric Power Research Institute)

The Electric Generation Expansion Analysis System (EGEAS) is a generation expansion model use by utility planners for future operations modeling [23,25]. Optimizer can produce resource plans for environmental compliance for dispatchable and non-dispatchable generation technologies for objective functions such as minimizing societal cost, minimizing total cost, and maximizing earnings. Operational and cost characterizations for CO_2 mitigation technologies to be used in optimization must each be determined and entered separately by user for unit-specific electric generating units.

Haiku (Resources for the Future)

Haiku is a partial equilibrium simulation model using perfect foresight and dispatch for operation and investment in the U.S. electricity market with a sectoral and geographical coverage like that for IPM and NEMS [23,26-28]. Haiku can simulate current regulations for sulfur oxide, nitrous oxide, mercury and CO_2 emissions; and can be used to evaluate pollution abatement policies and strategies for compliance, including mitigation investments.

ESTEAM (Carnegie Mellon University)

The EGU-Specific Techno-Economic Assessment Model (ESTEAM) evaluates performance and cost parameters for individual coal-fired electric generation units (CFEGUs) in compliance with current clean air standards and equipped with nine CO_2 mitigation technologies. Using state-specific fuel prices, the model creates a least-cost mitigation frontier for each CFEGU in a given state. The model then identifies the fleet-wide mix of mitigation solutions for the state coal-fleet to satisfy an emission-intensity target for the state power-sector, at the minimum levelized cost of electricity for the coal-fleet. The state-level fuel prices, expected net generation from non-coal sources, and total electricity demand are determined exogenously to the model, with perfect foresight.

IPM (U.S. Environmental Protection Agency)

The Integrated Planning Model (IPM) is a dynamic, deterministic linear-programming model for dispatch, least cost capacity expansion, and emission control strategies for environmental policy formulation and evaluation in the U.S. power sector [23,29,30]. The partial-equilibrium model uses perfect foresight and can endogenously forecast fuel prices.

MARKAL

The MARKet ALlocation model (MARKAL) is bottom-up, dynamic linear-programming model that is used as a framework to develop other models of energy systems that are specific to cities, regions or countries [23,31-33]. The partial-equilibrium optimization model uses the MARKAL framework that uses “life-cycle” cost analysis to find the least-cost solution to meet end-use energy demand that is constrained by user-defined economic, environmental and technology constraints. Users can modify the electricity generator database to include CO_2 mitigation technologies.

IN-MARKAL (Purdue University)

The Indiana MARKet ALlocation model (IN-MARKAL) covers major portions of the energy system in Indiana [32].

OH-MARKAL (The Ohio State University)

The Ohio MARKet ALlocation model (OH-MARKAL) covers major portions of the energy system in Ohio [34].

MARKAL 9r (U.S. Environmental Protection Agency)

The MARKet ALlocation Nine-region model (MARKAL 9r) is a distinct representation of the energy system in the US [35,36].

NE-MARKAL (NESCAUM)

The Northeast MARKet ALlocation model (NE-MARKAL) covers major portions of the energy system in 12 states (inclusive of the New England region, Delaware, Maryland, Pennsylvania, New Jersey, New York, and the District of Columbia) [37].

NEMS (U.S. Energy Information Administration)

The National Energy Modeling System (EGEAS) is a general equilibrium model that uses 12 interacting modules and an integrating module for long-range U.S. energy system planning [4,23,38,39]. The Electricity Market Module uses linear programming and perfect insight for future demand and fuel prices to determine the least-cost capacity planning and dispatch for multiple technology blocks.

US-REGEN (Electric Power Research Institute)

The U.S. Regional Economy, Greenhouse Gas and Energy Model (US-REGEN) is an inter-temporal optimization model that combines a dynamic computable general equilibrium economic model with a detailed dispatch and capacity expansion model of the power sector [23,40]. The bottom-up framework of the electric sector model allows for environmental and energy policy analysis.

B.5 Dataset analysis

The performance of the 635 CFEGUs that comprise the working dataset in this study is representative of the coal-fired fleet in the U.S. electric power sector in 2010. The dataset CFEGUs account for 79% of the coal-fired nameplate capacity in the U.S. electric power sector in 2010 and have an associated net generation that is 84% of the 1,860 terawatt-hour (TWh) of electricity generated with coal in that year [41]. Correspondingly, the dataset covers 83% of the coal-fired carbon dioxide (CO_2) emissions from the power sector [41]. The resulting generation-weighted average CO_2 emission intensity of 2,166 pounds of CO_2 per megawatt-hour (lbs/MWh), on the net basis, for the dataset is similar to the overall calculated emission intensity of the power sector coal fleet in 2010—2,171 lbs/MWh [41]. Therefore, while the maximum available coal-fired generation possible in 2030 to cover the remaining national requirement is derated by 16% in the dataset, the average emission intensity that may require mitigation remains constant.

Insights into which CFEGUs may be predisposed to retirement or to requiring more extensive CO_2 mitigation techniques to meet future emission intensity standards may be gained through an examination of the dataset. Within the dataset fleet, approximately 15% of CFEGUs produce CO_2 at an emission rate greater than 2,500 lbs/MWh, while 12% have an emission intensity below 2,000 lbs/MWh, Figure B.2(a). Throughout this range, the emission intensity distribution is not correlated with CFEGU age, Figure B.2(b), though 50% of the dataset fleet has been online for over 39 years in 2010, Figure B.2(c). The net summertime capacity distribution is nonlinear with age, however. Almost 25% of the CFEGUs are older than 50 years and represent only 10% of the fleet summertime capacity, Figure B.2(d). There is a propensity for summertime capacity to be linked to emission intensity, Figure B.2(e); while 8% of the summertime capacity is greater than 800 megawatts (MW), none of these CFEGUs has an emission intensity greater than 2,500 lbs/MWh. Conversely, 11% of the EGUs have a summertime capacity less than 100 megawatt (MW); these EGUs account for 50% of the capacity with an emission intensity greater than 2,500 MWh, and all capacity with an emission intensity greater than 2,900 MWh. Therefore, it is not apparent that the age of the CFEGU is a predictor of emission intensity nor an indicator that older EGUs should be retired in 2030 to reduce overall emission intensity. Rather, smaller capacity EGUs may be more likely to retire, in the absence of power-line distribution constraints.

The age distribution may be an important factor when determining the EGU-specific mitigation technology that is most cost-effective, as approximately 23% of the EGU dataset CFEGUs will have no more than ten years of expected remaining service by 2030, for an assumed useful 80-year life. In the absence of variable operation and maintenance (VOM) considerations, it may not be economically feasible in 2030 to use carbon capture and storage (CCS) on an CFEGU that was 40 to 60 years old in 2010, unless the associated capital costs can be amortized over a sufficient period to reduce the levelized cost of electricity (LCOE) to be competitive with alternative technologies and other CFEGUs regulated for CO_2 [20]. Another consideration is the additional cost of upgrading emission controls. Figure B.2(f) indicates that over 40% of the units may require emission control devices (ECD) to limit sulfur oxide (SO_x) and nitrous oxide (NO_x) emissions, and almost all may require mercury (Hg) devices to meet current standards. With these additional considerations, it may be more economical to retire older EGUs than to make them compliant with the aforementioned emission standards and regulated for prospective CO_2 emission standards.

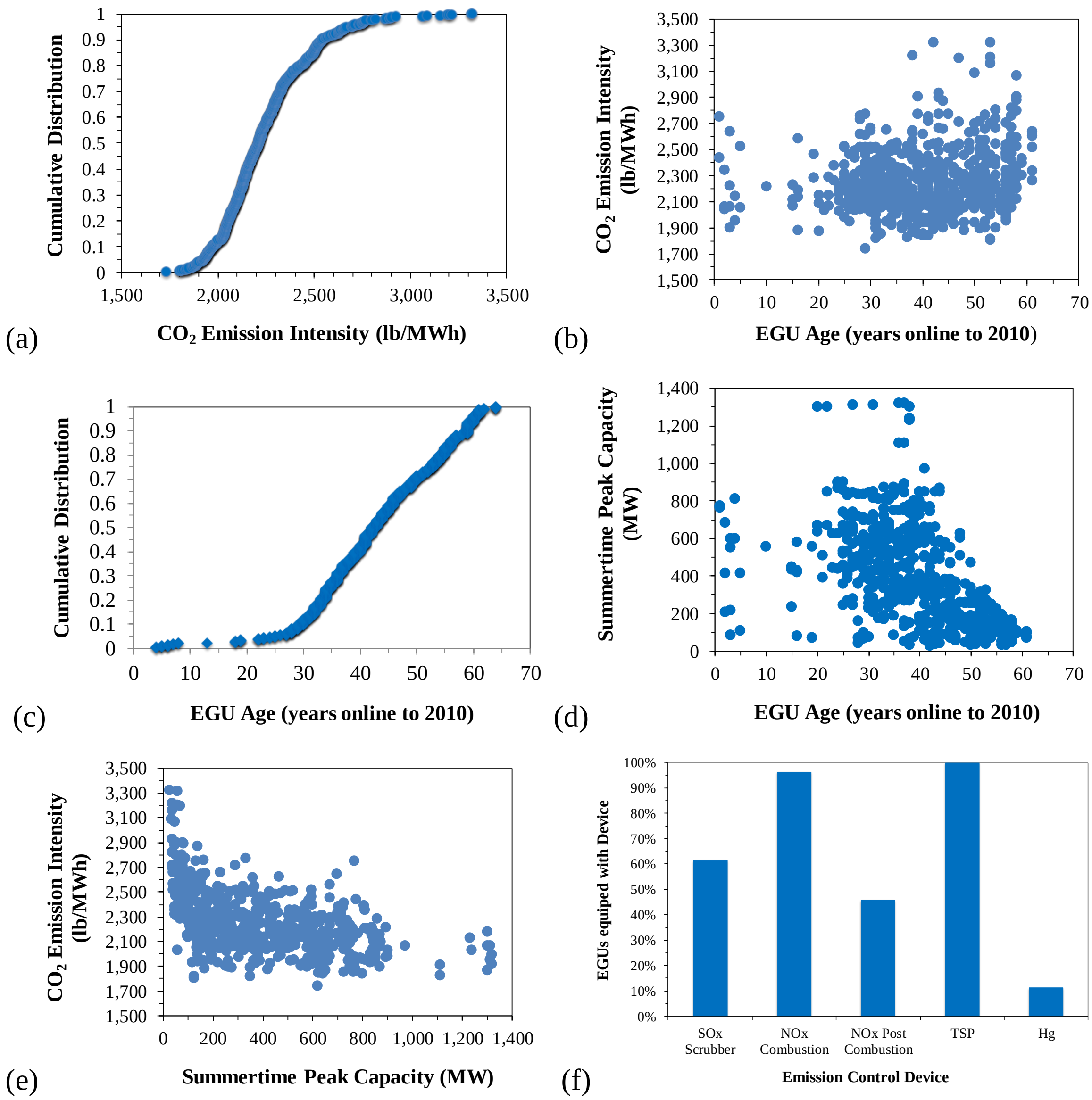

Figure B.2. Characteristics of the 635 CFEGUs compiled in the study dataset: (a) CO_2 net emission intensity (lbs/MWh) cumulative distribution for 2010; (b) CO_2 net emission intensity as a function of CFEGU service age in 2010; (c) service-age cumulative distribution in 2010; (d) summertime peak capacity (MW) as a function of CFEGU service age in 2010; (e) CO_2 net emission intensity as a function of summertime peak capacity; (f) percentages of CFEGUs equipped with specific emission control devices.

B.6 Cluster analysis

Insight into the effectiveness of the CO_2 mitigation technologies for the existing US coal fleet can be gained through clustering the EGUs characteristics by coal rank and boiler type. Examination of the cluster variation in EGU age, Figure B.3(a), shows that the mean boiler age for each cluster exceeds a typical book life of 30 years, and fewer than 20% of the CFEGUs from any cluster has less than 30 years of service. These 20% may be suitable candidates for CCS mitigation as the base plant will be fully amortized around 2030 and the remaining expected service life is enough to fully amortize the CCS subsystem [20]. Cluster analysis of the CO_2 emission intensity profiles for the CFEGUs, Figure B.3(b), indicates that the mean intensities of the lignite clusters are within 6% of that for the bituminous/subcritical cluster and those of the sub-bituminous clusters are below or within 4%. Therefore, the expected intensity reduction from upgrading coal rank decreases each cluster mean intensity to below the mean value of the bituminous/subcritical cluster and often below the first quartile value. This implies that upgrading coal rank for each of these clusters may be enough to reduce emission intensity to the required level in some states.

Simulations in Carnegie Mellon University's Integrated Environmental Control Model (IECM) [42] indicate that a newly constructed, new source performance standards (NSPS) CFEGU with a supercritical (SC) steam generator should have a net heat rate that is 6% lower than one with a subcritical steam generator, and a corresponding 6% lower emission intensity. In the dataset fleet, 16% of the CFEGUs have SC steam generators; however, this expectation for a lower intensity is not apparent in the cluster analysis, Figure B.3(b). While the emission intensity for the SC CFEGU cluster that uses bituminous coal has at least as large a difference from that for all other clusters, the cluster using sub-bituminous coal has only a medium significant difference from the lignite subcritical cluster, Table B.5. Some of these between-cluster differences can be attributed to differences in the site-specific coal properties.

The cluster differences and similarities are further evident in the cluster analysis of the net heat rates Figure B.3(c). Here, the mean heat rates for the SC and subcritical CFEGUs are similar within coal rank for the sub-bituminous and lignite clusters, while the mean heat rate for the bituminous SC EGUs is lower than that for any other cluster and has less variation than any cluster, other than the four lignite/SC EGUs. Even so, the net heat rate of these bituminous/SC EGUs, and all but six EGUs in the dataset, are less than that for newly constructed, NSPS CFEGUs, as simulated in the IECM with the proxy coal ranks (*Section B.8*), Table B.5. This gap in CFEGU existing and theoretical heat rates may be primarily due to degradation over time, technological improvements in achievable efficiency since construction of the existing CFEGUs, or other causes. Additionally, the gap may indicate that there will be greater mitigation efficacy in upgrading the steam generators to ultra-supercritical (USC) steam generators rather than to SC steam generators or from CFEGU net heat rate improvement.

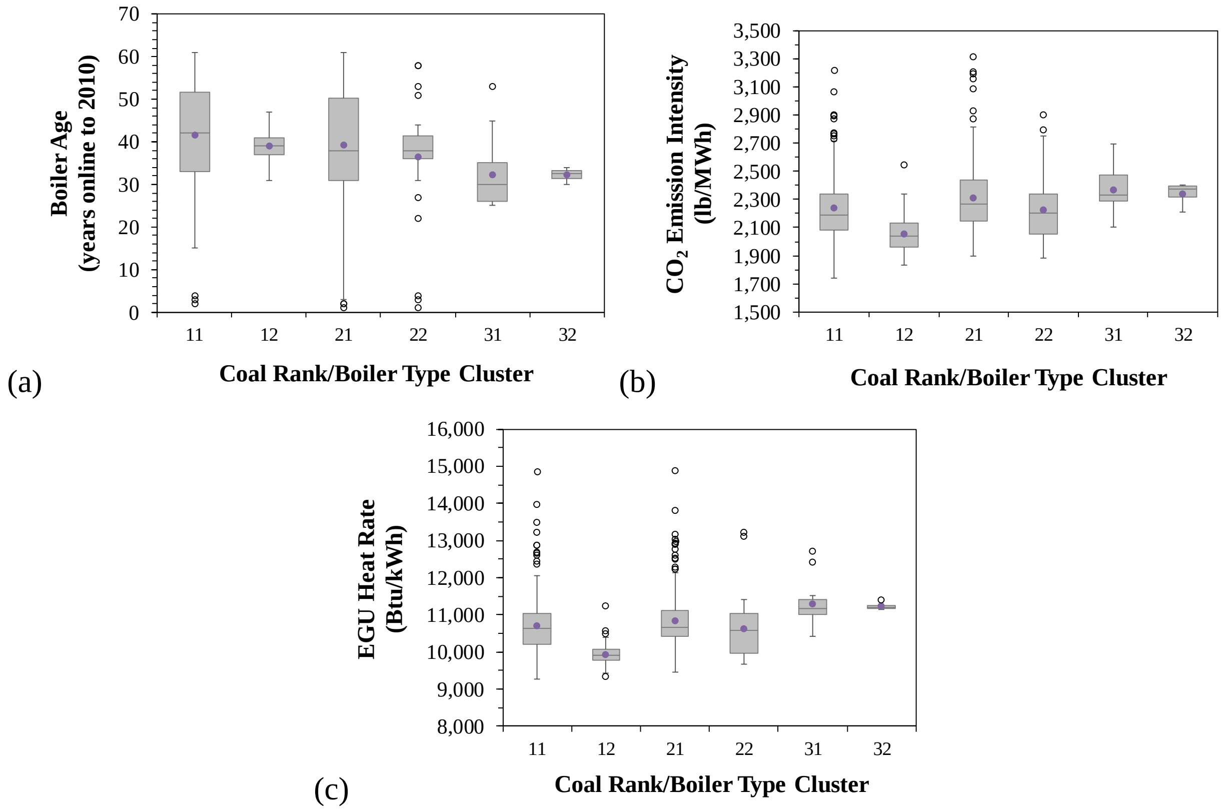

Figure B.3. CFEGU cluster characteristics: (a) EGU service age in 2010; (b) CO_2 net emission intensity (lbs/MWh); (c) EGU net heat rate (Btu/kWh). Clusters are defined by the coal rank and boiler type using a two-digit label in which the first digit signifies coal type (bituminous coal is rank 1, sub-bituminous coal is rank 2, lignite coal is rank 3) and the second-digit signifies boiler (subcritical boilers are designated type 1, SC boilers are designated type 2).

Table B.4. Cohen's d effect size matrix for difference in CO_2 net emission intensity for coal rank/boiler type clusters. Clusters are defined by the coal rank and boiler type using a two-digit label in which the first digit signifies coal type (bituminous coal is rank 1, sub-bituminous coal is rank 2, lignite coal is rank 3) and the second-digit signifies boiler (subcritical boilers are designated type 1, SC boilers are designated type 2).

Cluster	**11**	**12**	**21**	**22**	**31**	**32**
11	0	****	**	*	***	**
12	0.81	0	*****	****	******	******
21	0.29	1.16	0	**	**	*
22	0.04	0.99	0.34	0	***	*
31	0.54	2.40	0.37	0.65	0	**
32	0.41	2.23	0.13	0.48	0.24	0

* Very small, ** Small, *** Medium, **** Large, ***** Very large, ****** Huge

Table B.5. Box plot analysis of CFEGU net heat rate for coal rank/boiler type clusters. Simulations were done with proxy coal ranks on a 650 MW-gross, NSPS CFEGU without Hg emission control devices. Variation in heat rate with capacity for simulated CFEGU is less than one percent over existing capacity range. Clusters are defined by the coal rank and boiler type where bituminous coal is rank 1, sub-bituminous coal is rank 2, and lignite coal is rank 3. Subcritical boilers are designated type 1, while supercritical boilers are designated type 2.

Cluster	11	12	21	22	31	32
Minimum	9,260	9,338	9,445	9,660	10,432	11,157
Quartile 1	10,219	9,777	10,415	9,972	10,997	11,178
Mean	10,716	9,925	10,855	10,626	11,296	11,238
Quartile 3	11,026	10,061	11,119	11,025	11,418	11,245
Maximum	14,868	11,261	14,894	13,225	12,717	11,423
IECM	9,448	8,875	9,913	9,305	10,390	9,745
Quantity	254	63	264	35	15	4

B.7 Uncertainty

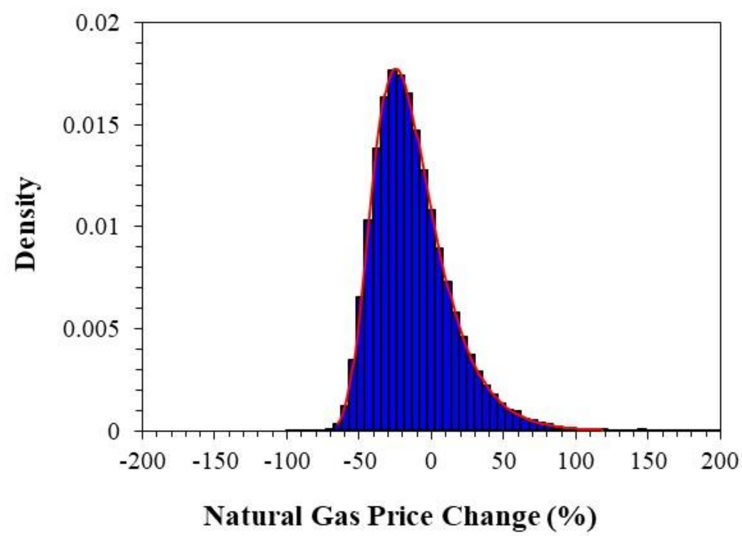

Figure B.4. Distribution for percent difference in projected natural gas price error based upon a simulation of 10,000 paired natural gas and coal price projection errors from fitted distributions and associated Spearman correlation coefficient. Negative values indicate underestimating projected price and positive values indicate overestimating projected price.

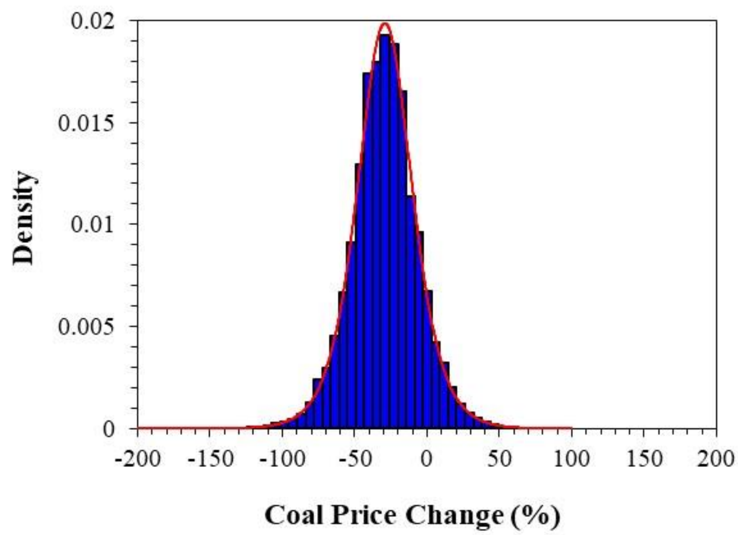

Figure B.5. Distribution for percent difference in projected coal price error based upon a simulation of 10,000 paired natural gas and coal price projection errors from fitted distributions and associated Spearman correlation coefficient. Negative values indicate underestimating projected price and positive values indicate overestimating projected price.

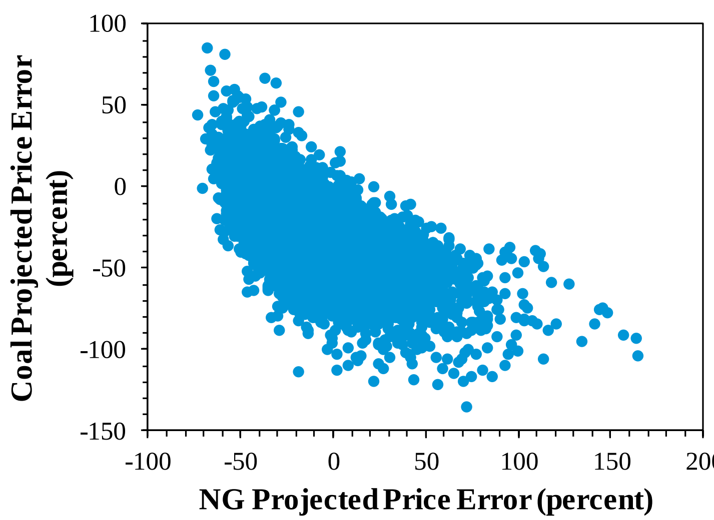

Figure B.6. Distribution of percent difference in projected natural gas and coal price errors, based upon a simulation of 10,000 paired natural gas and coal price projection errors from fitted distributions and associated Spearman correlation coefficient. Negative values indicate underestimating projected price and positive values indicate overestimating projected price.

Table B.6. Historical heat rate variation for Wisconsin CFEGU from EIA form 923 [43].

Year	Heat Rate (Btu/kWh)
2014	10,584
2013	10,335
2012	10,543
2011	10,509
2010	10,335
2009	10,261
2008	10,337
Mean	**10,418**
Standard Deviation	**125**

Table B.7. The AEO percent projected fuel price error for a 15-year horizon, as determined in the EIA Annual Energy Outlook Retrospective Review [44]. Negative values indicate projected price underestimated actual price.

AEO Report Year	Base Year for Projection	Projected Year	Natural Gas Price (%)	Coal Price (%)
1994	1992	2007	-26.9	39.9
1995	1993	2008	-45.0	-3.1
1996	1994	2009	-32.5	-21.5
1997	1995	2010	-39.4	-29.2
1998	1996	2011	-18.8	-39.5
1999	1997	2012	21.3	-41.7
2000	1998	2013	-1.9	-39.4
2001	1999	2014	-13.9	-41.5
2002	2000	2015	50.0	-38.8

Table B.8. Goodness of fit probabilities for distributions fitted to the AEO percent projected fuel price error for a 15-year horizon, as determined in the EIA Annual Energy Outlook Retrospective Review [44]. Bold values indicate the distribution and corresponding probability that best fits the projected price error data, using the maximum likelihood estimation method.

Distribution	Natural Gas p-value	Coal p-value
Fischer-Tippett Type II	**.997**	.290
GEV	.705	.039
Logistic	.981	**.451**
Normal	.828	.421
Normal (Standard)	<.0001	<.0001
Student	.016	.001

Table B.9. Spearman correlation matrix for projected natural gas and coal price error for a 15-year horizon, as determined in the EIA Annual Energy Outlook Retrospective Review [44].

Fuel Price	Natural Gas	Coal
Natural Gas	1	
Coal	-.667*	1

*Correlation is significant at .10 level.

Table B.10. Equation coefficient values for projected natural gas and coal price error for a 15-year horizon, as determined in the EIA Annual Energy Outlook Retrospective Review [44].

Fuel Price	**Beta**	**Mean**	**Standard. Deviation**
Natural Gas	20.754	-24.863	
Coal		-29.132	12.596

Table B.11. Simulation values for percent difference in projected natural gas and coal price error for a 15-year horizon, as determined in the EIA Annual Energy Outlook Retrospective Review [44]. Negative values indicate projected price underestimated actual price.

Fuel	**Mean**	**Standard. Deviation**
Natural Gas	-12.9%	26.7%
Coal	-29.1%	22.9%

Table B.12. The likelihood and expected values of the percent difference in projected natural gas and coal price errors derived by dividing the area defined by the minimum and maximum value projected error data points in Figure B.6 into nine, equally-sized regions. The centroid is the likelihood weighted-average expected values of the projected errors for all regions.

			Mean		**Median**	
Region	**Count**	**Likelihood**	**Coal**	**Natural Gas**	**Coal**	**Natural Gas**
1	641	6.4%	17.6%	-40.6%	13.8%	-41.1%
2	1	0.0%	5.7%	13.5%	5.7%	13.5%
3	0	0.0%	NA	NA	NA	NA
4	7,203	72.0%	-41.4%	-15.6%	-39.3%	-14.7%
5	1,863	18.6%	-45.6%	23.7%	-45.8%	18.9%
6	22	0.2%	-55.0%	102.8%	-58.8%	100.4%
7	45	0.5%	-89.9%	-9%	-79.2%	-8.1%
8	200	2.0%	-87.0%	39.6%	-83.4%	38.8%
9	25	0.2%	-83.3%	107.5%	-87.8%	103.3%
Centroid			**-39.3%**	**-8.6%**	**-37.9%**	**-8.9%**

Table B.13. LCOE model error components for the current Wisconsin CFEGU when made compliant for SO_x, NO_x, and Hg emission regulations. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

Compliant EGU Component	**LCOE ($/MWh)**	
	+	**-**
Hg capital cost	0.04	0.04
Hg O&M cost	0.56	0.56
NO_x combustion capital cost	0.22	0.22
NO_x combustion O&M cost	0.02	0.02
NO_x post combustion capital cost	0.48	0.48
NO_x post combustion O&M cost	0.10	0.10
SO_x capital cost	1.83	1.83
SO_x O&M cost	0.23	0.23
Base-plant ECD retrofit capital cost	2.20	2.20
Wet-cooling tower ECD retrofit capital cost	0.37	0.37
Percent increase LCOE for EGU with new ECDs	1.28	1.22
Initial heat rate	0.55	0.55
Heat rate improvement	2.80	0.50
Additional heat rate from ECDs	0.05	0.05
Capital cost adder Hg	0.01	0.00
Capital cost adder NO_x combustion	0.01	0.04
Capital cost adder NO_x post combustion	0.08	0.04
Capital cost adder SO_x	0.53	0.06
Coal price	17.34	3.86
Total estimated error without fuel error	**4.36**	**3.32**
Total estimated error with fuel error	**17.87**	**5.08**

Table B.14. LCOE model error components for compliant Wisconsin CFEGU with rank mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

Rank Mitigation Component	**LCOE ($/MWh)**	
	+	**-**
Hg capital cost	0.04	0.04
Hg O&M cost	0.56	0.56
NO_x combustion capital cost	0.22	0.22
NO_x combustion O&M cost	0.02	0.02
NO_x post combustion capital cost	0.48	0.48
NO_x post combustion O&M cost	0.10	0.10
SO_x capital cost	1.83	1.83
SO_x O&M cost	0.23	0.23
Base-plant ECD retrofit capital cost	2.20	2.20
Wet-cooling tower ECD retrofit capital cost	0.37	0.37
Percent increase LCOE for EGU with new ECDs	1.28	1.22
Rank capital cost	0.49	0.40
Rank O&M cost	0.07	0.07
Rank heat rate	0.95	0.95
Heat rate improvement	2.80	0.50
ECD heat rate variation for Rank	0.08	0.08
Capital cost adder Hg	0.00	0.00
Capital cost adder NO_x combustion	0.01	0.04
Capital cost adder NO_x post combustion	0.08	0.04
Capital cost adder SO_x	0.60	0.07
Capital cost adder Rank retrofit	0.01	0.00
Coal price	27.25	6.05
Total estimated error without fuel error	**4.47**	**3.44**
Total estimated error with fuel error	**27.62**	**6.96**

Table B.15. LCOE model error components for compliant Wisconsin CFEGU with natural gas co-fire mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

Co-fire Mitigation	**LCOE ($/MWh)**			
Co-fire Rate	**5%**		**25%**	
Component	**+**	**-**	**+**	**-**
Hg capital cost	0.04	0.04	0.04	0.04
Hg O&M cost	0.56	0.56	0.56	0.56
NO_x combustion capital cost	0.22	0.22	0.22	0.22
NO_x combustion O&M cost	0.02	0.02	0.02	0.02
NO_x post combustion capital cost	0.48	0.48	0.48	0.48
NO_x post combustion O&M cost	0.10	0.10	0.10	0.10
SO_x capital cost	1.83	1.83	1.83	1.83
SO_x O&M cost	0.23	0.23	0.23	0.23
Base-plant ECD retrofit capital cost	2.20	2.20	2.20	2.20
Wet-cooling tower ECD retrofit capital cost	0.37	0.37	0.37	0.37
Percent increase LCOE for EGU with new ECDs	1.28	1.22	1.28	1.22
Co-fire percent LCOE increase	0.01	0.01	0.01	0.01
NG pipeline capital cost	0.09	0.14	0.10	0.16
Co-fire heat rate	0.60	0.60	0.73	0.73
Heat rate improvement	2.80	0.50	2.80	0.50
ECD heat rate variation for Co-fire	0.06	0.06	0.07	0.07
Capital cost adder Hg	0.01	0.00	0.01	0.00
Capital cost adder NO_x gas reburn	0.39	0.42	0.39	0.42
Capital cost adder NO_x post combustion	0.09	0.05	0.07	0.04
Capital cost adder SO_x	0.53	0.06	0.52	0.06
Capital cost adder NG pipeline	0.06	0.01	0.07	0.01
Coal price	15.97	3.55	12.66	2.81
Natural gas price	1.61	0.98	8.09	4.94
Total estimated error without fuel error	**4.39**	**3.36**	**4.41**	**3.39**
Total estimated error with fuel error	**16.64**	**4.98**	**15.66**	**6.62**

Table B.16. LCOE model error components for compliant Wisconsin CFEGU with supercritical upgrade mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

Supercritical Upgrade Mitigation Component	**LCOE ($/MWh)** +	-
Hg capital cost	0.04	0.04
Hg O&M cost	0.56	0.56
NO_x combustion capital cost	0.22	0.22
NO_x combustion O&M cost	0.02	0.02
NO_x post combustion capital cost	0.48	0.48
NO_x post combustion O&M cost	0.10	0.10
SO_x capital cost	1.83	1.83
SO_x O&M cost	0.23	0.23
Base-plant ECD retrofit capital cost	2.20	2.20
Wet-cooling tower ECD retrofit capital cost	0.37	0.37
Percent increase LCOE for EGU with new ECDs	1.28	1.22
Demolition of steam island	0.45	0.44
Supercritical retrofit	1.87	1.87
Percent change in LCOE for SC upgrade	0.06	0.06
Supercritical heat rate	0.56	0.54
ECD heat rate variation for SC upgrade	0.05	0.05
Capital cost adder Hg	0.00	0.00
Capital cost adder NO_x combustion	0.01	0.04
Capital cost adder NO_x post combustion	0.08	-0.04
Capital cost adder SO_x	0.51	0.06
Capital cost adder demolition	0.16	0.16
Capital cost adder retrofit	3.04	3.04
Coal price	16.32	3.62
Total estimated error without fuel error	**4.91**	**4.87**
Total estimated error with fuel error	**17.05**	**6.07**

Table B.17. LCOE model error components for compliant Wisconsin CFEGU with ultra-supercritical upgrade mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

Ultra-supercritical Upgrade Mitigation Component	LCOE ($/MWh) +	LCOE ($/MWh) -
Hg capital cost	0.04	0.04
Hg O&M cost	0.56	0.56
NO_x combustion capital cost	0.22	0.22
NO_x combustion O&M cost	0.02	0.02
NO_x post combustion capital cost	0.48	0.48
NO_x post combustion O&M cost	0.10	0.10
SO_x capital cost	1.83	1.83
SO_x O&M cost	0.23	0.23
Base-plant ECD retrofit capital cost	2.20	2.20
Wet-cooling tower ECD retrofit capital cost	0.37	0.37
Percent increase LCOE for EGU with new ECDs	1.28	1.22
Demolition of steam island	0.45	0.44
Ultra-supercritical retrofit	2.07	2.07
Percent change in LCOE for USC upgrade	0.15	0.15
Ultra-supercritical heat rate	0.56	0.53
ECDs heat rate variation for USC upgrade	0.04	0.04
Capital cost adder Hg	0.00	0.00
Capital cost adder NO_x combustion	0.01	0.04
Capital cost adder NO_x post combustion	0.07	0.04
Capital cost adder SO_x	0.48	0.05
Capital cost adder demolition	0.16	0.16
Capital cost adder retrofit	3.35	3.35
Coal price	13.98	3.10
Total estimated error without fuel error	**5.19**	**5.15**
Total estimated error with fuel error	**14.91**	**6.01**

Table B.18. LCOE model error components for compliant Wisconsin CFEGU with CCS mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

CCS Mitigation	**LCOE ($/MWh)**					
Capture Rate	**10%**		**40%**		**90%**	
Component	+	-	+	-	+	-
Hg capital cost	0.04	0.04	0.04	0.04	0.04	0.04
Hg O&M cost	0.56	0.56	0.56	0.56	0.56	0.56
NO_x combustion capital cost	0.22	0.22	0.22	0.22	0.22	0.22
NO_x combustion O&M cost	0.02	0.02	0.02	0.02	0.02	0.02
NO_x post combustion capital cost	0.48	0.48	0.48	0.48	0.48	0.48
NO_x post combustion O&M cost	0.10	0.10	0.10	0.10	0.10	0.10
SO_x capital cost	1.83	1.83	1.83	1.83	1.83	1.83
SO_x O&M cost	0.23	0.23	0.23	0.23	0.23	0.23
Base-plant ECD retrofit capital cost	2.20	2.20	2.20	2.20	2.20	2.20
Wet-cooling tower ECD retrofit capital cost	0.37	0.37	0.37	0.37	0.37	0.37
Percent increase LCOE for EGU with new ECDs	1.28	1.22	1.28	1.22	1.28	1.22
Percent increase LCOE for adding CCS to CFEGU	2.33	2.12	2.57	2.34	2.97	2.73
CCS capital cost	0.43	0.43	0.43	0.43	0.41	0.40
CCS base-plant retrofit cost	0.28	0.23	0.34	0.23	0.40	0.36
CCS wet-cooling tower retrofit cost	0.29	0.18	0.34	0.18	0.27	0.30
CCS SO_x retrofit cost	0.03	0.03	0.03	0.03	0.02	0.02
CO_2 pipeline capital cost	1.36	2.21	1.45	2.21	1.47	2.20
Natural gas pipeline capital cost	0.09	0.14	0.09	0.14	0.09	0.14
CCS coal heat rate	0.55	0.55	0.48	0.47	0.41	0.40
Heat rate improvement	2.80	0.50	2.80	0.50	2.80	0.50
ECD heat rate variation for CCS	0.08	0.08	0.07	0.07	0.06	0.06
Capital cost adder Hg	0.00	0.00	0.00	0.00	0.01	0.00
Capital cost adder NO_x combustion	0.01	0.04	0.01	0.04	0.01	0.04
Capital cost adder NO_x post combustion	0.08	0.04	0.08	0.04	0.08	0.04
Capital cost adder SO_x	0.56	0.06	0.56	0.06	0.56	0.06
Capital cost adder PFC	1.45	0.11	3.89	0.32	9.18	0.69
Capital cost adder PCC	0.44	0.33	0.18	0.97	2.82	2.08
Capital Cost adder NG pipeline	0.06	0.01	0.06	0.01	0.06	0.01
Capital Cost adder CO_2 pipeline	0.92	0.92	0.98	0.96	0.94	0.93
CO_2 storage cost	0.33	0.01	1.15	0.86	2.17	0.06
Coal price	16.75	3.72	14.83	3.24	12.44	2.72
Natural gas price	2.00	1.20	7.07	4.25	13.35	8.04
Total estimated error without fuel error	**5.47**	**4.65**	**6.75**	**4.83**	**11.32**	**5.37**
Total estimated error with fuel error	**18.24**	**6.15**	**18.16**	**7.24**	**21.71**	**10.07**

Table B.19. LCOE model error components for compliant Wisconsin CFEGU with natural gas retrofit mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

NG Retrofit Mitigation Component	LCOE ($/MWh) +	LCOE ($/MWh) -
Natural gas pipeline	0.15	0.21
Change in NG retrofit fixed boiler O&M cost	0.52	0.52
Change in NG retrofit fixed wet-cooling tower O&M	0.12	0.12
Change in NG retrofit variable wet-cooling tower O&M	0.18	0.18
NG retrofit heat rate	1.19	1.19
Capital cost adder NG pipeline	0.09	0.01
Capital cost adder NG retrofit	0.18	0.17
Natural gas price	32.95	20.13
Total estimated error without fuel error	**1.34**	**1.34**
Total estimated error with fuel error	**32.98**	**20.17**

Table B.20. LCOE model error components for compliant Wisconsin CFEGU with NGCC mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

NGCC Mitigation Component	LCOE ($/MWh) +	LCOE ($/MWh) -
Demolition of turbine island	0.45	0.44
Natural gas pipeline	0.15	0.21
Heat rate penalty	0.22	0.22
Capital cost adder demolition	0.16	0.16
Capital cost adder NG pipeline	0.09	0.01
Capital cost adder NGCC PFC	2.84	2.84
Natural gas price	21.60	13.01
Total estimated error without fuel error	**2.89**	**2.89**
Total estimated error with fuel error	**21.79**	**13.33**

Table B.21. CO_2 emission intensity error components for current Wisconsin CFEGU when made compliant for SO_x, NO_x, and Hg emission regulations.

Compliant EGU Component	CO_2 Emission Intensity (lbs/MWh) +	CO_2 Emission Intensity (lbs/MWh) -
ECD heat rate variation	10.4	10.4
EGU heat rate variation	53.5	53.5
Total estimated error	**63.9**	**63.9**

Table B.22. CO_2 emission intensity error components for compliant Wisconsin CFEGU with rank mitigation technology for CO_2 emission intensity reduction.

Rank Mitigation	CO_2 Emission Intensity (lbs/MWh)	
Component	+	-
ECD heat rate variation	5	5
EGU heat rate variation	57.1	57.1
Percent reduction CO_2 intensity	5	5
Total estimated error	**57.6**	**57.6**

Table B.23. CO_2 emission intensity error components for compliant Wisconsin CFEGU with natural gas co-fire mitigation technology for CO_2 emission intensity reduction.

Co-fire Mitigation	CO_2 Emission Intensity (lbs/MWh)			
Co-fire Rate	5%		25%	
Component	+	-	+	-
ECD heat rate variation	5.1	5.1	4.6	4.6
EGU heat rate variation	54.4	54.4	49.3	49.3
Intensity regression residual	1.8	1.8	1.8	1.8
Total estimated error	**54.6**	**54.6**	**49.6**	**49.6**

Table B.24. CO_2 emission intensity error components for compliant Wisconsin CFEGU with supercritical upgrade mitigation technology for CO_2 emission intensity reduction.

Supercritical Upgrade Mitigation	CO_2 Emission Intensity (lbs/MWh)	
Component	+	-
ECD heat rate variation	4.9	4.9
CFEGU heat rate variation	54.4	54.4
Intensity regression residual	0.7	0.7
Total estimated error	**54.6**	**54.6**

Table B.25. CO_2 emission intensity error components for compliant Wisconsin CFEGU with ultra-supercritical upgrade mitigation technology for CO_2 emission intensity reduction.

Ultra-supercritical Upgrade Mitigation	CO_2 Emission Intensity (lbs/MWh)	
Component	+	-
ECD heat rate variation	4.2	4.2
EGU heat rate variation	54.7	54.7
Intensity regression residual	1.4	1.4
Total estimated error	**54.9**	**54.9**

Table B.26. CO_2 emission intensity error components for compliant Wisconsin CFEGU with ultra-supercritical upgrade mitigation technology for CO_2 emission intensity reduction.

Ultra-supercritical Upgrade Mitigation Component	CO_2 Emission Intensity (lbs/MWh) +	CO_2 Emission Intensity (lbs/MWh) -
ECD heat rate variation	4.2	4.2
CFEGU heat rate variation	54.7	54.7
Intensity regression residual	1.4	1.4
Total estimated error	**54.9**	**54.9**

Table B.27. CO_2 emission intensity error components for compliant Wisconsin CFEGU with CCS mitigation technology for CO_2 emission intensity reduction.

CCS Mitigation Capture Rate Component	CO_2 Emission Intensity (lbs/MWh) 10% +	10% -	40% +	40% -	90% +	90% -
ECD heat rate variation	4.7	4.7	3.1	3.1	0.5	0.5
CFEGU heat rate variation	48.2	48.2	32.1	32.1	5.4	5.4
Intensity regression residual	99	97	81	79	59	57
Total estimated error	**110.5**	**110.5**	**87.6**	**85.8**	**59.4**	**57.4**

Table B.28. CO_2 emission intensity error components for compliant Wisconsin CFEGU with NGCC mitigation technology for CO_2 emission intensity reduction.

NGCC Mitigation Component	CO_2 Emission Intensity (lbs/MWh) +	CO_2 Emission Intensity (lbs/MWh) -
Heat rate penalty regression residual	5.6	5.6
Total estimated error	**5.6**	**5.6**

Table B.29. Significance of the mitigation profile differences for the operational capacity with the base case and centroid fuel price expected value. Wilcoxon signed-rank paired test and Kolmogorov-Smirnov two-sample test are used to compare significance of differences by mitigation type.

Mitigation	Wilcoxon signed-rank paired test	Kolmogorov-Smirnov (two-sample test)
Compliant	**	
Coal Rank	****	
USC	****	****
NG Retrofit	****	
NG Co-fire		**
CCS Retrofit	****	****
NGCC	****	
Wind NGCC	**	
Solar NGCC		

Significance level: * 0.1, ** 0.05, ***0.01, **** ≤0.00

B.8 Materials and methods

B.8.1 Working database screening and characterization

The ESTEAM model analyzes the application of eight different CO_2 emission mitigation technologies on multiple EGUs. These CFEGUs are selected from the over 15,000 CFEGUs in the National Electric Energy Data System (NEEDS) [45] and the Emissions & Generation Resource Integrated Database (eGRID) [41] databases based on three key selection criteria: (i) All EGUs must be operating as of 2010 and have a capacity of at least 25 MW; (ii) The CFEGUs must not be designated as retiring before 2018; (iii) The CFEGUs must be non-combined heat and power, pulverized coal units with at least 95% of the fuel input coming from either bituminous, sub-bituminous, or lignite coal. Several additional criteria are used. (iv) The MWh of power generation produced by the CFEGU must be discernable from that produced by other EGUs at the same plant. (v) The CFEGU parasitic load (ω), calculated directly from the gross and net generation (Eq. B.1), is also restricted to be between 2% and 20%. (vi) Any parasitic load lower than 2% is better than a newly commissioned, NSPS plant. (vii) Any CFEGU with a parasitic load (ω) greater than 20% is likely one that is not yet operational, is undergoing repairs, or may have erroneous data. (vii) Similarly, the net CO_2 emission intensity must be physically possible for an CFEGU operating under normal operating conditions; (ix) the intensity cannot be lower than that for a new, 650 MW, supercritical bituminous coal plant (1,800 lbs/MWh), or greater than 3,330 lbs/MWh. These criteria result in 635 CFEGUs selected in the ESTEAM model.

$$\omega = \frac{(G_{gross} - G_{net})}{G_{gross}} \qquad \text{(B.1)}$$

where ω is the parasitic load (fraction), G_{gross} is the gross generation (MWh), and G_{net} is the net generation (MWh).

To estimate the change in net CO_2 emissions intensity due to retrofit of mitigation technologies, we require the database to contain the major parameters necessary to simulate the CFEGUs and the associated environmental control systems. These parameters include the net summertime nameplate capacity/plant size, annual operational hours, coal type, the gross and net power production, and the parasitic load. The aforementioned databases do not include the parasitic load, but this parameter can be estimated based on gross and net power outputs. However, 22 of the 635 CFEGUs lack the gross generation values for the calculation (Eq. B.1). To complete the dataset, a stepwise regression analysis[1] using 80% of the data was conducted to

[1] All econometric, statistic, and simulation operations are done with XLSTAT version 2018.5. All R^2 statistics are adjusted.

select two key explanatory variables from eleven possible variables: the resulting model (Eq. B.2, Table B.30) estimates gross generation based upon the CFEGU net generation and the presence of a wet or dry flue gas desulfurization (FGD) scrubber. The presence of the FGD scrubber as a dependent variable is relevant for this regression because this device has the largest associated parasitic load of any of the required emission control devices, Table B.31.

$$G_{gross} = \beta_0 + \beta_1 G_{net} + \beta_2 scrubber \tag{B.2}$$

where G_{gross} is the gross generation (MWh), G_{net} is the net generation (MWh), and *scrubber* is a dummy variable for the scrubber that is 1 if the CFEGU is equipped with a wet or dry FGD scrubber and is 0 otherwise.

Additional calculations include the device age and CO_2 emission intensity. The age of the steam generator or an emission control device is estimated to be equal to the referred year (2016) minus its on-line year. The CO_2 emission intensity (I_{net}) on a net basis is estimated as the annual CO_2 mass emission divided by the annual net electricity generation (Eq. B.3).

$$I_{net} = \frac{m_{CO_2}}{G_{net}} \tag{B.3}$$

where I_{net} is the net CO_2 emission intensity $\left(\frac{lbs}{MWh}\right)$, m_{CO_2} is the mass of the emitted CO_2 (lbs), and G_{net} is the electric power generation (MWh).

Table B.30. Coefficients from two-variable regression model for gross generation (MWh) analysis

β_0	β_1	β_2	R^2	RMSE
5479.44	1.06	56,025.45	.993	161,822

n = 488

Table B.31. Average (and standard deviation) parasitic load of environmental control device as a percent of gross power output.

Coal Rank	SO_x Wet Scrubber	NO_x Combustion	NO_x Post Combustion	Hg
Bituminous*	1.8% (0.06%)	0.0% (0.0%)	0.6% (0.03%)	0.0% (0.03%)
Sub-Bituminous†	1.9% (0.07%)	0.0% (0.0%)	0.6% (0.10%)	0.0% (0.02%)
Lignite‡	2.1% (0.01%)	0.0% (0.0%)	0.7% (0.03%)	0.0% (0.01%)

*n = 16; †n = 13; ‡n = 9

B.8.2 The Integrated Environmental Control Model

The IECM [42] is a publicly available computer-modeling tool developed by Carnegie Mellon University (CMU) for the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL). The model is based on mass and energy balances along with empirical data to estimate the plant-level performance, emissions, and costs of pulverized coal, NGCC, and integrated gasification combined cycle (IGCC) plants. In the model interface, the user can specify the plant configurations, fuel properties, CFEGU and generator characteristics, and emission control characteristics to simulate how the plant will perform under different configurations and operating conditions to estimate the associated plant capital and O&M costs used to determine the levelized cost of electricity (LCOE):

$$LCOE = \frac{CC \times FCF + FOM}{G_{net}} + VOM_{fuel} + VOM_{nonfuel} \quad \text{(B.4a)}$$

$$VOM_{fuel} = \frac{(C_{current})(hr)}{1000} \tag{B.4b}$$

where *LCOE* is the levelized cost of electricity $\left(\frac{\$}{MWh}\right)$, *CC* is the CFEGU capital cost ($), *FCF* is the fixed charge factor (fraction), *FOM* is the fixed operation and maintenance cost for the EGU($), G_{net} is the CFEGU net generation for the (MWh), VOM_{fuel} is the variable operation and maintenance cost related to fuel $\left(\frac{\$}{MWh}\right)$, $VOM_{nonfuel}$ is the non-fuel related variable operation and maintenance cost $\left(\frac{\$}{MWh}\right)$, $C_{current}$ is the fuel price for the given state ($/MMBtu), and *hr* is the CFEGU heat rate (Btu/kWh).

The O&M and capital costs can each be subdivided into two categories. The O&M cost is composed of the variable and fixed costs. These variable costs are consumable costs that are dependent upon CFEGU use, whereas the fixed costs are annual costs independent of use. For capital costs, the IECM categorizes the costs for the base plant, cooling system, and emission control devices as direct process area capital and other plant costs. Within each category, detail is given at the component-level that enables econometric analysis of the impact of changing performance and cost inputs, such as capacity and boiler type, on the cost of the various components. This component-level detail is useful to determine retrofit estimates, as one can observe the cost of the components before and after the retrofit. For the base plant, the process facilities capital components include the steam generator, the turbine island, coal handling, ash handling, water treatment, and auxiliary facilities, while the indirect capital costs include the general facilities capital, engineering and home office fees, project contingency cost, process contingency cost, interest charges, royalty fees, startup cost, and working capital. These details given for each category are also useful for econometric analysis of the impact of input changes on the components for these two costs.

Inputs required for this model to simulate performance and costs for the CFEGU include the capacity factor, gross capacity/plant size, net power generation, heat rate, and parasitic load. The plant configuration and financial parameters are other factors required to calculate the emissions and the LCOE in the IECM, respectively. We do not have direct information about all aspects of the power plants in which the study CFEGUs are situated: we do not know if in all cases the emission control devices and water treatment are shared by co-located CFEGUs or each is unique to an CFEGU. Therefore, default configurations are assumed, for simplicity, for the existing CFEGU and for the CFEGU when it is upgraded to be compliant with existing emission standards and the imposed CO_2 standard. For these default configurations, we apply the IECM configuration options in Table B.32(b) and use the associated default operational parameters for these devices for all CFEGUs in the dataset.

Table B.32. IECM and modeling assumptions and parameters for ESTEAM: (a) financial, (b) operational, (c) mitigation.

(a) Financial

Parameter	Value
Year costs reported	2010
Dollar costs basis	Constant
Indexes for inflation	CEPCI, CPI
Fossil-fuel EGU project book life (years)	30 years
Solar Generation book life (years)	30 years
Wind Generation book life (years)	30 years
Discount rate (fraction)	0.071
CFEGU default fixed charge factor (fraction)	0.113
Renewable generation fixed charge factor (fraction)	0.11
CFEGU applied project life for fixed charge factor	Minimum 30-year book life or remaining life
CFEGU remaining value calculation	Straight-line amortization
Construction costs	Overnight

Notes: CEPCI: Chemical Engineering Plant Cost Index; CPI: Consumer Price Index

(b) Operational

Parameter	Value
2030 CFEGU performance characteristics	2010
CFEGU retirement age	80 years
Transmission line loss (fraction)	0.075
Source coal and natural gas properties	IECM version 8.0.2
Source current and compliant CFEGU modeling and costing	IECM version 8.0.2
CFEGU current configuration	Pulverized coal, tangential wall, wastewater ash pond, no mixing fly ash disposal, wet-cooling tower, cold-side electrostatic precipitator
Year compliant with non-CO_2 air quality regulations	2016
NO_x compliance combustion controls	Low NO_x burner (LNB)
NO_x compliance post combustion controls	Hot-side selective catalytic reduction (SCR)
SO_x compliance post combustion controls	Wet flue-gas desulfurization (FGD)
Hg compliance post combustion controls	Carbon injection

(c) Mitigation

Parameter	Value
Regional construction adders	None
Source HRI improvement standard	IECM version 8.0.2
Maximum relative HRI (fraction)	0.5
Maximum absolute HRI (Btu)	1,205
HRI cost ($/kW-net)	100
Definition NG co-fire operation	Simultaneous firing coal and NG
NG co-fire performance calculation	Linear interpolation 5-25%
NG co-fire maintenance	None required for up to 25% co-fire
Steam generator upgrades	No CCS requirement
Baseline NG retrofit cost ($/kW)	62 (range: 50 to 75)
Baseline capacity for cited CFEGU retrofitted for NG (MW)	215
Power rule coefficient for economy of scale	0.6
Increase in heat rate due to NG retrofit (Btu)	200
Increase in net capacity due to NG retrofit (MW)	5
NGCC turbines type	GE 7FB
NGCC net generation constraint	Matches 2010 generation
CCS net generation constraint	Extra generation sold to grid
CCS performance calculation	Linear interpolation 10-90%
CCS capture method	Post combustion, Fluor, FG+ amine
CCS capture efficiency (fraction)	0.90
CCS flue bypass control type	Bypass
CCS power and steam source	Auxiliary gas-fired boiler
CCS thermal efficiency of auxiliary gas power system (fraction)	0.35
CCS SO_x polisher use	Yes
CCS CO_2 purity (fraction)	0.995
CCS CO_2 transportation method	Pipeline
CCS CO_2 storage method	Geological
CCS pipeline distance	Line-of-site to center of reservoir
NG and CO_2 pipeline O&M cost ($/mile/year)	5,000
NG pipeline distance source	Modified EPA estimates
Pipeline electric compressor station spacing (miles)	50
Modeled solar generation capacity (MW)	150
Modeled wind generation capacity (MW)	100
Solar generation capital cost ($/kW)	2,017
Wind generation capital cost ($/kW)	1,594
Solar generation O&M cost ($/kW/year)	7.1
Wind generation O&M cost ($/kW/year)	45.1
NG co-fire, coal rank upgrade, steam-generator upgrade, NGCC, CCS EGU mitigation modeling and costing source	IECM version 8.0.2

Note: kW: kilowatt

Fuel is also a key parameter to determine plant performance, emissions, and costs. The properties and costs of the three proxy coals for this study are shown in Table B.33, and the properties of NG are in Table B.34. We use \$4.5/MMBtu as the default NG cost [46].

Table B.33. As received properties and price of proxy coals used in the IECM [42].

Variable	**Illinois #6 bituminous**	**Wyoming Powder River Basin sub-bituminous**	**North Dakota lignite**
Heating value (Btu/lb)	11,670	8,340	6,020
Carbon (% wt.)	63.75	48.18	35.04
Hydrogen (% wt.)	4.5	3.31	2.68
Oxygen (% wt.)	6.88	11.87	11.31
Chlorine (% wt.)	0.29	0.01	0.09
Sulfur (% wt.)	2.51	0.37	1.16
Nitrogen (% wt.)	1.25	0.7	0.77
Ash (% wt.)	9.7	5.32	15.92
Moisture (% wt.)	11.12	30.24	33.03
Cost (\$/MMBtu)	1.64	0.53	1.27

Table B.34. As received properties of natural gas used in the IECM [42].

Variable	**Units**	**Natural gas**
Heating value	Btu/lb	22,480
Methane (CH_4)	vol. %	93.1
Ethane (C_2H_6)	vol. %	3.2
Propane (C_3H_8)	vol. %	1.1
Carbon Dioxide (CO_2)	vol. %	1.0
Oxygen (O_2)	vol. %	0.0
Nitrogen (N_2)	vol. %	1.6
Hydrogen Sulfide (H_2S)	vol. %	0.0
Density	lbs/cu ft	0.046

B.8.3 EGU-specific modeling

Once the IECM models for all proxy CFEGUs in a cluster are established, their emissions, and resulting LCOE from the associated costs are used to regress these metrics for other EGUs in the cluster and then determine the CFEGU performance and cost after the mitigation technology is implemented. The LCOE calculation ($LCOE_{current}$) entails the summation of the levelized annual O&M costs for the CFEGU, the unamortized capital cost for the emission control devices, and the unamortized capital costs for the basic elements of the CFEGU (referred to collectively as the basic CFEGU): the base plant, the wet-cooling tower (WT), and the total suspended particles management (TSP). The LCOE is first determined from a regression of the modeled cluster CFEGUs fitted completely with new emission control devices ($LCOE_{new}$) that are financed at the baseline FCF, while the basic EGU is fully amortized. The base plant, WT, and TSP are assumed to be fully amortized because the boiler age for more than 90% of the EGUs is at least 30 years (*Section B.5*). This levelized cost, inclusive of the associated O&M cost, can be expressed as a function of the coal rank and the annual net power generation for all steam generator types (Eq. B.5, Table B.35). $LCOE_{new}$ is used to determine $LCOE_{current}$. Here, the capital and O&M portions of the LCOE attributed to specific emission control devices ($LCOE_{emissions,k}$) that are not fitted to the existing CFEGU are subtracted from $LCOE_{new}$. The resulting LCOE is further adjusted for the amortization of the capital cost portion of any emission control device that is currently fitted ($LCOE_{CCfitted,k}$). These details are in *Section B.8.5.*

$$\ln(LCOE_{new}) = \beta_{0,i} + \beta_{1,i} ln(G_{net}) + \beta_{2,i} ln(G_{net})^2 + \beta_{3,i} ln(G_{net})^3 \qquad \text{(B.5)}$$

where $LCOE_{new}$ is the levelized cost of electricity for the database EGU at default fuel prices with all new emission controls and no capital cost for the basic EGU $\left(\frac{\$}{MWh}\right)$, G_{net} is the net generation for the CFEGU (MWh), and the subscript i indicates the coal/boiler cluster from which the coefficients come.

This technique can also be extended to the capital costs relating to the water tower and TSP systems (Eq. B.6, Table B.36 and Eq. B.7, Table B.37, respectively); the design capacity and heat rate are the significant variables used to define the costs for these subsystems. The capital cost for the base plant is dependent upon the steam generator type, as the cost of the generator is a major component of the overall cost; therefore, the econometric analysis finds that the variation in base-plant capital cost is best explained when both coal and generator type are considered. Here, parameters concerning the design and operation of the base plant are significant to calculate the base plant cost (Eq. B.8, Table B.38). To determine the LCOE adjustment for the basic CFEGU configuration ($LCOE_{basicadjust}$), the annual remaining capital costs for the base plant, wet-cooling tower, and TSP are taken as the product of the straight depreciation, based upon the CFEGU book life, and the FCF for the lessor of the remaining book life of the CFEGU and the default book life (Eq. B.9). The resulting equation for $LCOE_{current}$ is shown in Eq. B.10.

$$CC_{WT} = \beta_0 + \beta_1 Cap_{peak} + \beta_2\, hr + \beta_3 Cap_{peak} hr \quad \text{(B.6)}$$

where CC_{WT} is the capital cost for the wet-cooling tower (M\$), and Cap_{peak} is the net peak summertime capacity (MW), and hr is the net heat rate of the CFEGU $\left(\frac{Btu}{kWh}\right)$.

$$CC_{TSP} = \beta_{0,i} + \beta_{1,i}Cap_{peak} + \beta_{2,i}hrCap_{peak} \tag{B.7}$$

where CC_{TSP} is the capital cost for the TSP (M$), Cap_{peak} is the net peak summertime capacity (MW), hr is the net heat rate of the CFEGU $\left(\frac{Btu}{kWh}\right)$, and the subscript i indicates the coal/boiler cluster from which the coefficients come.

$$CC_{base} = \beta_{0,i} + \beta_{1,i}Cap_{peak} + \beta_{2,i}G_{net} + \beta_{3,i}Cap_{peak}^2 + \beta_{4,i}Cap_{peak}^3 \tag{B.8}$$

where CC_{base} is the modeled capital cost for the base plant (M$), Cap_{peak} is the net peak summertime capacity (MW), G_{net} is the CFEGU net generation (MWh), and the subscript i indicates the coal and boiler type.

$$LCOE_{basicadjust} = \frac{1\times10^6\left(CC_{base}\left(\max\left(0,1-\frac{Y_{base}}{amort}\right)\right)+CC_{WT}\left(\max\left(0,1-\frac{Y_{WT}}{amort}\right)\right)+CC_{TSP}\left(\max\left(0,1-\frac{Y_{TSP}}{amort}\right)\right)\right)FCF_{remain}}{G_{net}} \tag{B.9}$$

where $LCOE_{basicadjust}$ is the LCOE adjustment for the basic CFEGU from the database $\left(\frac{\$}{MWh}\right)$, CC_{base} is the capital cost of the base plant (M$), Y_{base} is the age of the base plant (years), *amort* is the amortization period based on the CFEGU book life (years), Y_{WT} is the age of the wet-cooling tower (years), Y_{TSP} is the age of the TSP (years), CC_{WT} is the capital cost of the wet-cooling tower (M$), CC_{TSP} is the capital cost of the TSP (M$), G_{net} is the EGU net generation (MWh), FCF_{remain} is the fixed charge factor for the remaining life of the CFEGU (fraction), and $1\text{x}10^6$ is the conversion factor from millions of dollars to dollars.

$$LCOE_{current} = LCOE_{new} + LCOE_{basicadjust} + \sum \delta_{fit,k} LCOE_{CCfit,k} - \sum \delta_{new,k} LCOE_{emission,k} \tag{B.10}$$

where $LCOE_{current}$ is the modeled LCOE for the currently configured CFEGU from the database $\left(\frac{\$}{MWh}\right)$, $LCOE_{new}$ is the modeled LCOE for the currently configured CFEGU with all new emission control devices and no capital costs from the base plant configuration $\left(\frac{\$}{MWh}\right)$, $LCOE_{basicadjust}$ is the modeled remaining capital cost portion of the LCOE for the basic CFEGU from the database $\left(\frac{\$}{MWh}\right)$, $\delta_{fit,k}$ has a value of one if the emission control device is currently fitted and a value of zero if the device is not, $LCOE_{CCfit,k}$ is the modeled LCOE adjustment for the remaining capital cost of the current fitted emission control devices $\left(\frac{\$}{MWh}\right)$, $\delta_{new,k}$ has a value of one if the emission control device is new and a value of zero if the device is currently fitted, $LCOE_{emission,k}$ is the modeled LCOE for the new emission control devices $\left(\frac{\$}{MWh}\right)$ given in Eq. B.19, the subscript k indicates the emission control device, and $1\text{x}10^6$ is the conversion factor from millions of dollars to dollars.

The output from these and subsequent regressions can be modified for non-default fuel prices with a levelized adder based upon the difference in the fuel prices and the EGU-specific heat rate and net generation, Eq. B.11. In addition to the default IECM fuel prices, EIA 2012 data on region and state-specific delivered coal costs to the electric power sector [47] are used in ESTEAM. When these values are used, and the state-specific historical data are not available, the regional or national average is used as a proxy for the missing state data. These 2012 prices are brought forward to 2030 with the percent increase in US average electric power sector, steam coal prices based on the EIA historical 2012 price and the projected 2030 price from the AEO 2017 reference case without the CPP [48]. Similarly, the 2030 natural gas prices are based upon the 2012, state-specific delivered gas prices to the electric power sector [49]. The 2012 prices are brought forward to 2030 with the percent increase in the regional average electric power sector, natural prices based on the EIA historical 2012 price [50] and the projected 2030 price from the AEO 2017 reference case without the CPP [48]. With these prices, the fuel price adder is then defined as

$$\Delta_{fuelprice} = \frac{1000(C_{current} - C_{default})hr}{1 \times 10^6} \tag{B.11}$$

where $\Delta_{fuelprice}$ is the change in variable O&M due a difference in fuel price between the IECM default price and the current price of the fuel type for a given state $\left(\frac{\$}{MWh}\right)$, $C_{current}$ is the fuel price for the given state ($/MMBtu), $C_{default}$ is the IECM default fuel price ($/MMBtu), hr is the CFEGU heat rate (Btu/kWh), 1000 is the conversion from MWh to kWh, and $1 \text{x} 10^6$ is a conversion for millions.

Table B.35. Coefficients of CFEGU LCOE regression model as a function of net power generation (MWh) for fully amortized base plant, water tower, and particulate materials stack. CFEGU equipped with all required emission control devices that are unamortized.

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	R²	RMSE
Bituminous/ Subcritical*	26.808	-3.073	0.199	-1.2×10^{-3}	.997	0.038
Bituminous/ Supercritical*	26.808	-3.073	0.199	-1.2×10^{-3}	.997	0.038
Sub-bituminous/ Subcritical†	36.664	-5.073	0.254	-4.4×10^{-3}	.999	0.025
Sub-bituminous/ Supercritical†	36.664	-5.073	0.254	-4.4×10^{-3}	.999	0.025
Lignite/Subcritical‡	332.349	-67.779	4.668	-0.107	1.000	0.007
Lignite/Supercritical§	-6486.894	1267.966	-82.530	1.79	1.000	0

*n = 16; †n = 13; ‡n = 5; §n = 4

Table B.36. Coefficients of capital cost regression model for wet-cooling tower subsystem (M$) as a function of peak summertime capacity (MW).

Coal/Boiler type	β_0	β_1	β_2	β_3	R²	RMSE
Bituminous*	21.375	6.3×10^{-2}	-1.6×10^{-3}	0	.980	4.291
Sub-bituminous†	-18.263	-0.195	-1.7×10^{-3}	2.6×10^{-5}	.988	3.731
Lignite‡	2.6×10^{-2}	0	0	7.6×10^{-6}	.981	3.275

*n = 23; †n = 13; ‡n = 9

Table B.37. Coefficients of capital cost regression model for TSP subsystem (M$).

Coal/Boiler type	β_0	β_1	β_2	R²	RMSE
Bituminous*	7.321	0.23	-2.0×10^{-5}	.823	8.572
Sub-bituminous†	2.324	0	5.7×10^{-6}	.997	1.408
Lignite‡	3.467	0.048	0	.970	2.372

*n = 23; †n = 13; ‡n = 9

Table B.38. Coefficients of capital cost regression model for base plant (M$).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	R^2	RMSE
Bituminous/ Subcritical*	80.130	0	1.5×10^{-4}	0	0	.978	20.977
Bituminous/ Supercritical†	-647.328	4.703	0	-5.5×10^{-3}	2.4×10^{-6}	.990	55.884
Sub-bituminous/ Subcritical‡	79.616	0.414	0	2×10^{-3}	-1.6×10^{-6}	.998	23.611
Sub-bituminous/ Supercritical§	9.418	1.377	0	-3.6×10^{-4}	$9. \times 10^{-8}$	1	5.869
Lignite/Subcritical¶	85.085	0	1.5×10^{-4}	0	0	.991	32.696
Lignite/ Supercritical#	10207.734	-28.452	0	2.1×10^{-2}	0	1	

*n = 9; †n = 6; ‡n = 6; §n = 5; ¶n = 5; #n = 4

B.8.4 Financial calculations

The FCF for calculating the LCOE (Eq. B.4) is estimated based upon the financial schedule outlined in the IECM [51] and other defaults shown in Table B.32(a). All past construction uses the default 11.28% FCF, which is based upon an CFEGU book life of 30 years, and a 20-year depreciation schedule. Current and future fossil fuel projects use the same book life and depreciation schedule and consider 80 years to be the expected retirement age for the coal-fired EGU. The project FCF results from whichever of the book life or remaining age to retirement results in the shortest horizon. Wind and solar construction projects use 11% as a default FCF and have an assumed 20-year and 30-year book life, respectively. Since the duration of past and future EGU-specific projects are site-specific, all construction costs are assumed to be overnight.

As the characteristics concerning CO_2 emissions (operating hours, net power generated, emissions estimate) derive from 2010 data, all fiscal calculations are in 2010 dollars. For instances where construction and related material costs are estimated external to the IECM, the Chemical Engineering Plant Cost Index (CEPCI) [19] is used to convert the costs to 2010 dollars. The Consumer Price Index (CPI) [2] is used to convert other costs to constant 2010 dollars.

B.8.5 Emission compliance

One must also account for the increase in LCOE from the addition of other emission control devices that are required to meet traditional air quality standards. Any EGU without all necessary ECDs is first upgraded to include the absent devices—before the CO_2 mitigation technologies are retrofitted to the CFEGU. This is true for all cases except for NG retrofit and NGCC conversions, where these devices are not required. The type of emission control device that could be added is highly dependent upon the capital planning for the owning entity; therefore, the model assumes default choices for these new devices, Table B.32(b). For simplicity, this model assumes that all necessary upgrades were done in 2016.

The individual EGU capital and O&M costs associated with the existing and required NOx, SO_x, and Hg controls are calculated from regressions on the proxy clusters. In these regressions, capital costs are typically power functions (consistent with economies of scale) of EGU capacity and O&M costs are a function of net electricity generation (Eq. B.12 and Eqs. B.13-B.17). While the general form of the equations is the same for each device and each cluster, except for the SO_x O&M regressions (Eqs. B.14-B.17), the associated coefficients are not (Tables B.39-B.46).

$$CC_{emission,k} = \beta_{0,i}(Cap_{peak})^{\beta_{1,i}} \tag{B.12}$$

where $CC_{emission,k}$ is the capital cost associated with the specific emission control device (M$), Cap_{peak} is the peak summertime capacity for the CFEGU (MW), the subscript k indicates the emission control device type, and the subscript i indicates the coal/boiler cluster from which the coefficients come.

$$OM_{emission,k} = \beta_{0,i}(G_{net})^{\beta_{1,i}} \tag{B.13}$$

where $OM_{emission,k}$ is the annual O&M costs associated with the specific emission control device (M$), G_{net} is the net generation for the CFEGU (MWh), the subscript k indicates the emission control device type, and the subscript i indicates the coal/boiler cluster from which the coefficients come.

$$OM_{SOx,BIT} = \beta_0 + \beta_1 ophrs + \beta_2 cap + \beta_3(ophrs \times cap) \tag{B.14}$$

where $OM_{SOx,BIT}$ is the annual O&M costs associated with the SO_x emission control device for all bituminous-fired EGUs (M$), *ophrs* is the operating hours for the CFEGU (hrs), and *cap* is the CFEGU peak summertime capacity (MW).

$$OM_{SOx,SUB} = \beta_0 + \beta_1 cap + \beta_2 hr + \beta_3(cap \times hr) \tag{B.15}$$

where $OM_{SOx,SUB}$ is the annual O&M costs associated with the SO_x emission control device for all sub-bituminous-fired EGUs (M$), *cap* is the EGU peak summertime capacity (MW), and *hr* is the heat rate for the CFEGU in the current configuration prior to any heat rate improvement $\left(\frac{Btu}{kWh}\right)$.

$$OM_{SOx,LIG1} = \beta_0 + \beta_1 cap + \beta_2 hr + \beta_3 (hr \times ophrs) \tag{B.16}$$

where $OM_{SOx,LIG1}$ is the annual O&M costs associated with the SO_x emission control device for subcritical lignite-fired EGUs (M$), *cap* is the CFEGU peak summertime capacity (MW), *hr* is the heat rate for the CFEGU in the current configuration prior to any heat rate improvement $\left(\frac{Btu}{kWh}\right)$, and *ophrs* is the operating hours for the CFEGU (hrs).

$$OM_{SOx,LIG2} = \beta_0 + \beta_1 ophrs + \beta_2 hr + \beta_3 (ophrs \times hr), \tag{B.17}$$

where $OM_{SOx,LIG2}$ is the annual O&M costs associated with the SO_x emission control device for supercritical lignite-fired EGUs (M$), *hr* is the heat rate for the CFEGU in the current configuration prior to any heat rate improvement $\left(\frac{Btu}{kWh}\right)$, and *ophrs* is the operating hours for the CFEGU (hrs).

To calculate the capital cost component of the LCOE associated with each device (Eq B.18), age related adjustments are made to the capital cost and to the FCF, as described in *Section B.8.4*. The resulting capital cost ($LCOE_{CCfit,k}$) is then added to the levelized O&M cost for the device to determine the emission control LCOE ($LCOE_{emission,k}$), Eq. B.19.

$$LCOE_{CCfit,k} = 1 \times 10^{6} \left(\frac{CC_{emission,i,k}\left(\max\left(0,1-\frac{Y_k}{amort}\right)\right)FCF_{remain}}{G_{net}} \right) \tag{B.18}$$

where $LCOE_{CCfit,k}$ is the remaining capital cost portion of the LCOE for the specific emission control device $\left(\frac{\$}{MWh}\right)$, $CC_{emission}$ is the capital cost for emission control device, Y_k is the age of the emission control device (years), *amort* is the amortization period based on the subsystem book life (years), FCF_{remain} is the fixed charge factor based on the lesser of the book life and the remaining years before EGU retirement, and G_{net} is the CFEGU net generation (MWh), the subscript k indicates the emission control device type, and 1×10^6 is a conversion for millions.

$$LCOE_{emission,k} = LCOE_{CCfit,k} + 1 \times 10^{6} \left(\frac{OM_{emission,k}}{G_{net}} \right) \tag{B.19}$$

where $LCOE_{emission,k}$ is the LCOE for the specific emission control device $\left(\frac{\$}{MWh}\right)$, $LCOE_{CCfit,k}$ is the remaining capital cost portion of the LCOE for the emission control device $\left(\frac{\$}{MWh}\right)$, $OM_{emission,k}$ is the annual O&M cost for the emission control device (M$), G_{net} is the CFEGU net generation (MWh), the subscript k indicates the emission control device type, and 1×10^6 is a conversion for millions.

The addition of these necessary ECDs to the CFEGU will result in retrofitting costs for some of the existing subsystems: the base plant, the wet-cooling tower, and the NO_x combustion ECD. To model these costs, the percent increase in total capital requirement for each of these subsystems is determined from regressions on the IECM simulated results for the cluster CFEGUs without and with all required emission control devices. Here, all baseline CFEGUs are modeled with the NOx combustion ECD and the lignite units are fitted with wet FGDs, as all lignite EGUs are already fitted with SO_x ECDs. The resulting increases, Table B.47, are independent of CFEGU capacity and boiler type. The retrofit costs for the TSP from the additional ECDs are not considered to be significant and are ignored.

The emission control devices will also increase the parasitic load on the system. Retrofits of additional environmental control devices thereby increase the CFEGU heat rate and the CO_2 emission intensity, which are insensitive to boiler type but do vary with coal rank and the emission control type. The heat rate of an existing CFEGU increases by 2% from the addition of a SO_x scrubber and by approximately 0.6% for NO_x post combustion, while the other devices show negligible increases, Table B.48. Increases in parasitic load and CO_2 emission intensity are shown in Tables B.31 and B.49, respectively.

The compliant LCOE ($LCOE_{comply}$), heat rate (hr_{comply}) and emission intensity (I_{comply}) from the addition of the emission control device to make the EGU compliant are then given as (Eq. B.20-22, respectively)

$$LCOE_{comply} = LCOE_{current} + \sum \delta_{new,k} LCOE_{emission,k} + \frac{(C_{current})\left(hr_{current}\left(1+\sum \delta_{new,k} hr_{emission,i,k}\right)\right)}{1000} + 1 \times 10^{6}\left(\frac{\left(CC_j \sum\left(\delta_{new,k} CRetro_{emission,i,j,k}\right)\right) FCF_{remain}}{G_{net}}\right) \tag{B.20}$$

where $LCOE_{comply}$ is the LCOE for the compliant CFEGU $\left(\frac{\$}{MWh}\right)$, $LCOE_{current}$ is the modeled LCOE for the currently configured CFEGU from the database $\left(\frac{\$}{MWh}\right)$, $\delta_{new,k}$ has a value of one if the emission control device is new and a value of zero if the device is currently fitted, $LCOE_{emission,k}$ is the modeled LCOE for the new emission control devices $\left(\frac{\$}{MWh}\right)$, $C_{current}$ is the fuel price for the given state (\$/MMBtu), $hr_{current}$ is the current CFEGU heat rate (Btu/kWh), $hr_{emission,,i,k}$ is the relative increase in heat rate for the emission control device (fraction), CC_j is the capital cost of the CFEGU component (M\$), $CRetro_{emission,i,j,k}$ is the relative increase in cost for the CFEGU component from the addition of the ECD (fraction), FCF_{remain} is the fixed charge factor for the remaining life of the CFEGU (fraction), G_{net} is the CFEGU net generation (MWh), the subscript *i* indicates the coal type, the subscript *j* indicates the CFEGU component upgraded (base plant, NOx combustor, or water tower), the subscript *k* indicates the emission control device, and $1\text{x}10^6$ is the conversion factor from millions of dollars to dollars.

$$hr_{comply} = hr_{current}\left(1 + \sum \delta_{new,k} hr_{emission,i,k}\right) \tag{B.21}$$

where hr_{comply} is the compliant CFEGU heat rate (Btu/kWh), $hr_{current}$ is the current CFEGU heat rate (Btu/kWh), $\delta_{new,k}$ has a value of one if the emission control device is new and a value of zero if the device is currently fitted, $hr_{emission,,i,k}$ is the relative increase in emission intensity for the emission control device from (fraction), the subscript i indicates the coal type, and the subscript k indicates the emission control device.

$$I_{comply} = I_{current}\left(1 + \sum \delta_{new,k} I_{emission,i,k}\right) \quad \text{(B.22)}$$

where I_{comply} is the emission intensity for the compliant CFEGU $\left(\frac{lbs}{MWh}\right)$, $I_{current}$ is the emission intensity for the current CFEGU $\left(\frac{lbs}{MWh}\right)$, $\delta_{new,k}$ has a value of one if the emission control device is new and a value of zero if the device is currently fitted, $I_{emission,,i,k}$ is the relative increase in emission intensity for the emission control device from (fraction), the subscript i indicates the coal type, the subscript j indicates the CFEGU component upgraded (base plant, NOx combustor, or water tower), the subscript k indicates the emission control device, and $1x10^6$ is the conversion factor from millions of dollars to dollars.

Table B.39. Coefficients of SO_x capital cost (M$) regression model as a function of peak summer capacity (MW).

Coal/Boiler type	$\boldsymbol{\beta_{0,i}}$	$\boldsymbol{\beta_{1,i}}$	R^2	RMSE
Bituminous/Subcritical*	10.641	0.368	.930	5.873
Bituminous/Supercritical†	5.523	0.486	.964	7.41
Sub-bituminous/Subcritical‡	4.295	0.510	.998	2.246
Sub-bituminous/Supercritical‡	4.295	0.510	.998	2.246
Lignite/Subcritical§	7.163	0.457	.982	6.771
Lignite/Supercritical¶	2.93	0.591	.995	1.156

*n = 9; †n = 6; ‡n = 11; §n = 5; ¶n = 4

Table B.40. Coefficients of NO_x combustion capital cost (M$) regression model as a function of peak summer capacity (MW).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	R^2	RMSE
Bituminous/Subcritical*	0.004	1.153	.977	0.808
Bituminous/Supercritical*	0.004	1.153	.977	0.808
Sub-bituminous/Subcritical†	0.007	1.100	.998	0.268
Sub-bituminous/Supercritical†	0.007	1.100	.998	0.268
Lignite/Subcritical‡	0.006	1.111	.986	0.470
Lignite/Supercritical‡	0.006	1.111	.986	0.470

*n = 15; †n = 11; ‡n = 9

Table B.41. Coefficients of NO_x post combustion capital cost (M$) regression model as a function of peak summer capacity (MW).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	R^2	RMSE
Bituminous/Subcritical*	0.62	0.545	.918	1.451
Bituminous/Supercritical†	0.196	0.747	.964	2.300
Sub-bituminous/Subcritical‡	0.162	0.797	.998	0.584
Sub-bituminous/Supercritical§	0.277	0.716	1.000	0.415
Lignite/Subcritical¶	0.239	0.737	.983	1.452
Lignite/Supercritical¶	0.239	0.737	.983	1.452

*n = 9; †n = 6; ‡n = 6; §n = 5; ¶n = 9

Table B.42. Coefficients of Hg capital cost (M$) regression model as a function of peak summer capacity (MW).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	R^2	RMSE
Bituminous/Subcritical*	0.085	0.611	.920	0.316
Bituminous/Supercritical†	0.023	0.833	.949	0.642
Sub-bituminous/Subcritical‡	0.012	0.849	.999	0.049
Sub-bituminous/Supercritical§	0.025	0.738	1.000	0.047
Lignite/Subcritical¶	0.025	0.747	.981	0.217
Lignite/Supercritical#	0.013	0.849	0.992	0.138

*n = 9; †n = 6; ‡n = 6; §n = 5; ¶n = 5; #n = 4

Table B.43. Coefficients of SO_x O&M cost (M$) regression model as a function of net power generation (MWh).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	R^2	RMSE
Bituminous/Subcritical*	10.847	-0.008	-0.001	$3.3\text{x}10^{-6}$	.980	0.955
Bituminous/Supercritical*	10.847	-0.008	-0.001	$3.3\text{x}10^{-6}$	.980	0.955
Sub-bituminous/Subcritical†	9.392	-0.013	$-3.9\text{x}10^{-4}$	$2.1\text{x}10^{-6}$	.995	0.281
Sub-bituminous/ Supercritical†	9.392	-0.013	$-3.9\text{x}10^{-4}$	$2.1\text{x}10^{-6}$	.995	0.281
Lignite/Subcritical‡	-75.984	0.044	-0.005	$1.4\text{x}10^{-6}$	1.000	0.106
Lignite/Supercritical§	13.783	0	0.022	$-1.9\text{x}10^{-6}$	1.000	0.006

*n = 15; †n = 11; ‡n = 5; §n = 4

Table B.44. Coefficients of NO_x combustion O&M cost (M$) regression model as a function of net power generation (MWh).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	R^2	RMSE
Bituminous/Subcritical*	$1.82\text{x}10^{-6}$	0.714	.985	0.005
Bituminous/Supercritical†	$5.54\text{x}10^{-6}$	0.664	.965	0.020
Sub-bituminous/Subcritical‡	$1.29\text{x}10^{-6}$	0.756	.972	0.022
Sub-bituminous/Supercritical‡	$1.29\text{x}10^{-6}$	0.756	.972	0.022
Lignite/Subcritical§	$3.02\text{x}10^{-7}$	0.845	.971	0.010
Lignite/Supercritical§	$3.02\text{x}10^{-7}$	0.845	.971	0.010

*n = 9; †n = 6; ‡n = 11; §n = 9

Table B.45. Coefficients of NO_x post combustion O&M cost (M$) regression model as a function of net power generation (MWh).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	R^2	RMSE
Bituminous/Subcritical*	$5.29\text{x}10^{-5}$	0.7004	.991	0.113
Bituminous/Supercritical*	$5.29\text{x}10^{-5}$	0.7004	.991	0.113
Sub-bituminous/Subcritical†	$8.67\text{x}10^{-5}$	0.665	.991	0.117
Sub-bituminous/Supercritical†	$8.67\text{x}10^{-5}$	0.665	.991	0.117
Lignite/Subcritical‡	$7.36\text{x}10^{-5}$	0.678	.992	0.087
Lignite/Supercritical‡	$7.36\text{x}10^{-5}$	0.678	.992	0.087

*n = 15; †n = 11; ‡n = 9

Table B.46. Coefficients of Hg O&M cost (M$) regression model as a function of net power generation (MWh).

Coal/Boiler type	$\boldsymbol{\beta_{0,i}}$	$\boldsymbol{\beta_{1,i}}$	R^2	RMSE
Bituminous/Subcritical*	$7.00\text{x}10^{-5}$	0.788	.994	0.382
Bituminous/Supercritical†	$1.45\text{x}10^{-3}$	0.605	.983	3.426
Sub-bituminous/Subcritical‡	$1.16\text{x}10^{-4}$	0.707	.988	0.688
Sub-bituminous/Supercritical§	$3.99\text{x}10^{-5}$	0.78	.997	0.482
Lignite/Subcritical¶	$7.01\text{x}10^{-5}$	0.743	.992	0.492
Lignite/Supercritical#	$1.86\text{x}10^{-4}$	0.685	1.000	0.610

*n = 9; †n = 6; ‡n = 6; §n = 5; ¶n = 5; #n = 4

Table B.47. Relative increase in total cost for CFEGU components due to installation of emission control devices to make CFEGU fully compliant. These increases are relative to a base plant fitted with only a NOx combustion emission control device to bituminous and sub-bituminous EGUs. Lignite EGUs additionally have a wet SOx emission control device fitted. The lower percent increase for the lignite EGU in all cases is related to the presence of the SOx emission control device.

	Coal Rank	Base Plant	NO_x Combustion	Water Tower
Capacity-weighted Average	Bituminous	2.0%	2.1%	2.3%
	Sub-bituminous	2.2%	2.7%	1.9%
	Lignite	0.5%	0.7%	0.5%
Standard Deviation	Bituminous	0.1%	0.2%	0.6%
	Sub-bituminous	0.1%	0.2%	0.8%
	Lignite	0.2%	0.2%	0.2%

Table B.48. Relative average increase (and standard deviation) in heat rate due to installation of emission control device.

Coal Rank	SO_x Wet Scrubber	NO_x Post Combustion	Hg
Bituminous	1.9% (0.08%)	0.6% (0.02%)	0.04% (0.03%)
Sub-bituminous	2.10% (0.09%)	0.7% (0.20%)	0.02% (0.04%)
Lignite	2.3% (0.05%)	0.7% (0.046%)	0.0% (0.05%)

Table B.49. Relative average increase (and standard deviation) in CO_2 emission intensity due to installation of emission control device.

Coal Rank	SO_x Wet Scrubber	NO_x Combustion	NO_x Post Combustion	Hg
Bituminous	3.2% (0.08%)	0.0% (0.0%)	0.6% (0.05%)	0.0% (0.12%)
Sub-bituminous	2.2% (0.08%)	0.0% (0.0%)	0.7% (0.21%)	0.0% (0.03%)
Lignite	3.1% (0.03%)	0.0% (0.0%)	0.7% (0.04%)	0.0% (0.03%)

B.8.6 Mitigation technologies

B.8.6.1 Improving Plant Heat Rate

For the model, this incremental improvement is relative to a "gold standard" based upon the net heat rate for a newly constructed plant at IECM default conditions. Rather than using the operational parameters, the standards include the CFEGU equipped with a wet-cooling tower and configured according to a matrix of unit attributes that creates 24 classifications, Table B.50: EGU type, coal rank, wet or dry SO_x mitigation, and bag filter or electrostatic particulate (ESP) devices. The difference between the "gold standard" and database net heat rate thus represents the maximum improvement that may be theoretically achieved when equipment upgrades and best practices are applied to a similarly configured CFEGU built decades ago. The EPA presents several best practices and mechanical upgrades (nine no-cost or low-cost improvements and four more costly improvements) that may be useful in realizing a portion of the difference, up to a maximum improvement of 1,205 Btu for the mechanical upgrades [42]. As these improvements are not additive and are truncated by the Btu limit, it may not be possible to improve the heat rate to the extent of making the aged CFEGU as efficient as one that is newly built. The EPA determined that heat rate gains as great as 30% might be achieved through process improvements, with an overall improvement of approximately 50% [52]. Therefore, a maximum heat rate improvement of 50% of the gap between the current heat rate and the “gold standard” heat rate, or the lesser of that and the maximum Btu improvement, is realized in the model (Eq. B.23) at an improvement cost of $100/kW-net [52]. The subsequent improvement in emission intensity is proportional to the heat rate improvement (Eq. B.24). Any savings from decreased fuel costs is subtracted from the annualized cost of the improvement to determine the EGU LCOE after the heat rate improvement (Eq. B.25).

$$hr_{HRI} = \left(hr_{comply} - \min\left[\left(\frac{hr_{gold,i} - hr_{comply}}{2}\right), 1205\right]\right) \quad \text{(B.23)}$$

where hr_{HRI} is the heat rate for the CFEGU after the heat rate improvement $\left(\frac{Btu}{kWh}\right)$, $hr_{gold,i}$ is the “gold standard” heat rate associated with the compliant EGU configuration $\left(\frac{Btu}{kWh}\right)$, hr_{comply} is the heat rate for the compliant CFEGU $\left(\frac{Btu}{kWh}\right)$, 2 limits the possible heat rate improvement to 50% of the difference between the “gold standard” heat rate and the compliant heat rate, 1205 is the limit for heat rate improvement $\left(\frac{Btu}{kWh}\right)$, and the subscript i indicates the “gold standard” EGU configuration cluster from which the heat rate comes.

$$I_{HRI} = I_{comply}\left(1 + \frac{hr_{HRI} - hr_{comply}}{hr_{comply}}\right) \quad \text{(B.24)}$$

where I_{HRI} is the emission intensity for the CFEGU with the HRI mitigation $\left(\frac{lbs}{MWh}\right)$, I_{comply} is the emission intensity for the compliant CFEGU $\left(\frac{lbs}{MWh}\right)$, hr_{HRI} is the heat rate for the CFEGU after the heat rate improvement $\left(\frac{Btu}{kWh}\right)$, and hr_{comply} is the heat rate for the compliant CFEGU $\left(\frac{Btu}{kWh}\right)$.

$$LCOE_{HRI} = LCOE_{comply} + \frac{1000(C_{HRI})(Cap_{peak})FCF_{remain}}{G_{net}} - \frac{1000(C_{current})\left(\min\left[\left(\frac{hr_{gold,i}-hr_{comply}}{2}\right),1205\right]\right)}{1\times10^{6}(G_{net})} \tag{B.25}$$

where $LCOE_{HRI}$ is the LCOE related to the heat rate improvement $\left(\frac{\$}{MWh}\right)$, $LCOE_{comply}$ is the LCOE for the compliant CFEGU $\left(\frac{\$}{MWh}\right)$, C_{HRI} is the capital cost for the heat rate improvement $\left(\frac{\$}{kWh}\right)$, Cap_{peak} is the EGU summertime peak capacity (MW), FCF_{remain} is the fixed charge factor for the remaining life (fraction), G_{net} is the CFEGU net generation (MWh), $C_{current}$ is the price of the current coal for the given state (\$/MMBtu), $hr_{gold,i}$ is the “gold standard” heat rate associated with the compliant CFEGU configuration $\left(\frac{Btu}{kWh}\right)$, hr_{comply} is the heat rate for the compliant CFEGU $\left(\frac{Btu}{kWh}\right)$, 1205 is the limit for heat rate improvement $\left(\frac{Btu}{kWh}\right)$, 1000 is the conversion from kW to MW, $1\text{x}10^6$ is a conversion for millions, and the subscript i indicates the “gold standard” CFEGU configuration cluster from which the heat rate comes.

Table B.50. CFEGU configurations for "gold standard" heat rates, as constructed in the IECM.

Coal type	SO_x scrubber type	PM type	Boiler type	Heat rate (Btu/kWh)
Bituminous	Wet	ESP	Subcritical	9.450
Bituminous	Wet	ESP	Supercritical	8,876
Bituminous	Wet	Bag filter	Subcritical	9,470
Bituminous	Wet	Bag filter	Supercritical	8.893
Bituminous	Dry	ESP	Subcritical	9,349
Bituminous	Dry	ESP	Supercritical	8,795
Bituminous	Dry	Bag filter	Subcritical	9,359
Bituminous	Dry	Bag filter	Supercritical	8,787
Sub-bituminous	Wet	ESP	Subcritical	9,915
Sub-bituminous	Wet	ESP	Supercritical	9,747
Sub-bituminous	Wet	Bag filter	Subcritical	9,941
Sub-bituminous	Wet	Bag filter	Supercritical	9,329
Sub-bituminous	Dry	ESP	Subcritical	9,791
Sub-bituminous	Dry	ESP	Supercritical	9,198
Sub-bituminous	Dry	Bag filter	Subcritical	9,809
Sub-bituminous	Dry	Bag filter	Supercritical	9,212
Lignite	Wet	ESP	Subcritical	10,390
Lignite	Wet	ESP	Supercritical	9,747
Lignite	Wet	Bag filter	Subcritical	10,420
Lignite	Wet	Bag filter	Supercritical	9,769
Lignite	Dry	ESP	Subcritical	10,260
Lignite	Dry	ESP	Supercritical	9,625
Lignite	Dry	Bag filter	Subcritical	10,270
Lignite	Dry	Bag filter	Supercritical	9,638

B.8.6.2 Upgrading coal rank

These decreases in CO_2 emission intensity from the decrease in net plant heat rate and an absolute decrease in parasitic load, Table B.51, come at the additional expense (Eq. B.25) of increased capital costs for retrofitting the CFEGU to use bituminous coal and additional non-fuel and fuel O&M charges due to the bituminous coal properties and higher price per MMBtu than the other coals, Table B.33. An econometric analysis of the cluster dataset CFEGUs (Eq. B.26, Table B.52) shows that retrofitting an CFEGU to use bituminous coal is well characterized by the annual net power generation, as is the change in non-fuel O&M costs (Eq. B.27, Table B.53).

The change in LCOE due to fuel O&M cost can be characterized by the difference in price between the two coals and the net heat rates associated with these coals (Eq. B.28).

$$LCOE_{coalupgrade} = LCOE_{comply} + \Delta CC_{rank} + \Delta OM_{non-fuel} + \Delta OM_{fuel} \tag{B.25}$$

where $LCOE_{coalupgrade}$ is the LCOE from upgrading the coal rank to bituminous $\left(\frac{\$}{MWh}\right)$, $LCOE_{comply}$ is the compliant LCOE for the CFEGU prior to the rank upgrade $\left(\frac{\$}{MWh}\right)$, ΔCC_{rank} is the capital cost change in LCOE $\left(\frac{\$}{MWh}\right)$, $\Delta OM_{non-fuel}$ is the non-fuel related change in O&M $\left(\frac{\$}{MWh}\right)$, and ΔOM_{fuel} is the change in O&M related to the difference in fuel price for the coals $\left(\frac{\$}{MWh}\right)$.

$$\Delta CC_{rank} = \frac{1\times10^{6}\left(\beta_{0,i} G_{net}^{\beta_{1,i}}\right)(FCF_{remain})}{G_{net}(FCF_{0})} \tag{B.26}$$

where ΔCC_{rank} is the capital cost change in LCOE $\left(\frac{\$}{MWh}\right)$, G_{net} is the CFEGU net generation (MWh), FCF_0 is the initial fixed charge factor (fraction), FCF_{remain} is the fixed charge factor for the remaining life (fraction), $1\text{x}10^6$ is a conversion for millions, and the subscript i indicates the coal/boiler cluster from which the coefficients come.

$$\Delta OM_{non-fuel} = \frac{1\times10^{6}\left(\beta_{0,i}+\beta_{1,i}G_{net}+\beta_{2,i}G_{net}^{2}\right)}{G_{net}} \tag{B.27}$$

where $\Delta OM_{non-fuel}$is the non-fuel related change in O&M $\left(\frac{\$}{MWh}\right)$, G_{net} is the CFEGU net generation (MWh), 1x10^6 is a conversion for millions, and the subscript *i* indicates the coal/boiler cluster from which the coefficients come.

$$\Delta OM_{fuel} = \frac{1000\left((1-\delta_i)C_{bituminous}-C_{default}\right)hr_{HRI}}{1\times10^{6}} \tag{B.28}$$

where ΔOM_{fuel} is the change in O&M related to the difference in fuel price for the coals $\left(\frac{\$}{MWh}\right)$, δ is the change in CFEGU heat rate due to the upgrade that is given in Table B.51 (fraction), $C_{bituminous}$ is the bituminous fuel price for the given state (\$/MMBtu), $C_{current}$ is the price of the current coal for the given state (\$/MMBtu), hr_{HRI} is the EGU heat rate prior to rank upgrade (Btu/kWh), 1000 is the conversion from kWh to MWh, 1x10^6 is a conversion for millions, and the subscript *i* indicates the coal type for which the heat rate change coefficient comes.

Table B.51. Change in CFEGU characteristics from upgrading coal rank to bituminous coal.

	Benchmark Coal	**Net CO_2 emission intensity**	**Parasitic Load**	**Net Plant Heat Rate**
Capacity-weighted Average	Sub-bituminous	-8.2%	-0.3%	-3.9%
	Lignite	-12.4%	-0.5%	-7.2%
Standard Deviation	Sub-bituminous	0.1%	0.1%	0.1%
	Lignite	0.1%	0.2%	0.2%

Note: The change to net CO_2 emission intensity and net plant heat rate are relative changes, while that to the parasitic load is an absolute change.

Table B.52. Coefficients of regression model for estimating increase in capital cost (M$/year) from upgrading coal rank to bituminous coal as a function of net power generation (MWh).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	R^2	RMSE
Sub-bituminous/Subcritical*	4.48×10^{-2}	0.225	.962	0.085
Sub-bituminous/Supercritical†	6.13×10^{-2}	0.023	.965	0.055
Lignite/Subcritical‡	-1.86×10^{-5}	0.692	.970	0.056
Lignite/Supercritical‡	-1.86×10^{-5}	0.692	.970	0.056

*n = 6; †n = 11; ‡n = 9

Table B.53. Coefficients of regression model for estimating increase in non-fuel O&M cost (M$/year) from upgrading coal rank to bituminous coal as a function of net power generation (MWh).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	R^2	RMSE
Sub-bituminous/Subcritical*	0.412	5.74×10^{-7}	1.56×10^{-14}	.998	0.058
Sub-bituminous/ Supercritical†	0.237	7.96×10^{-7}	2.41×10^{-14}	.966	0.380
Lignite/Subcritical‡	-0.724	-1.98×10^{-6}	0	.994	0.349
Lignite/Supercritical‡	-0.724	-1.98×10^{-6}	0	.994	0.349

*n = 6; †n = 11; ‡n = 9

B.8.6.3 Upgrading steam generator

While upgrading the existing steam cycle with new supercritical or ultra-supercritical boilers and turbines can substantially improve the CFEGU heat rate and lower the CO_2 emission intensity (Tables B.54 and B.55), there are many associated costs with demolition of the existing steam generator and turbine, the capital costs for the upgraded components, and the related change in O&M. The CFEGU demolition cost (CC_{dem}) is empirically estimated from the current CFEGU capacity with a power function regression (Eq. B.29, Table B.56) on data from case studies presented in the Electric Power Research Institute handbook for decommissioning coal-fired plants [53]. These costs are inclusive of hazardous waste cleanup and disposal that can account for 25% to more than 50% of the demolition cost [53]: almost 50% of this waste cost is associated with steam generation and almost 50% is associated with the waste-water ash pond.

The resulting total demolition cost is then apportioned to subsystems. Here, we assume that the ratio of demolition cost for the steam generator and turbine island to the demolition cost of the CFEGU without emission control devices is equal to the ratio of the cost for the original steam generator and turbine island to the total cost for the CFEGU without emission control devices. This ratio is determined with regressions on IECM simulations of the cluster EGUs (Eq. B.30, Table B.57).

$$CC_{dem} = \beta_0(Cap_{peak})^{\beta_1} \tag{B.29}$$

where CC_{dem} is the demolition capital cost ($), and Cap_{peak} is the CFEGU summertime peak capacity (MW).

$$PCC_{steam} = \beta_{0,i}(G_{net})^{\beta_{1,i}} \tag{B.30}$$

where PCC_{steam} is the percent of demolition cost associated with the current steam-generator subsystem and turbine (fraction), G_{net} is the CFEGU net generation (MWh), and the subscript i indicates the coal/boiler cluster from which the coefficients come.

The capital cost for retrofitting the steam-generator upgrade into an existing base plant may be greater than that for installing the system in a new base plant. As a surrogate for site-specific retrofit costs into the existing base plant, this total retrofit capital cost ($CC_{sgsupgrade}$) comprises the cost and installation of the upgraded steam generator and turbine (C_{sg}) for a new CFEGU and an estimate of the additional retrofit capital costs for installation into the existing base plant. This supplemental cost is the represented as the difference between the total capital requirements (TCR) for a new base plant and the process facility capital (PFC) for that new base plant, and is derated by the ratio of the steam generator and turbine costs to the new base-plant total capital requirements (Eq. B.31). Here, the new steam-generator subsystem-cluster simulations used to model the upgrade are done with the required ECDs fitted: this can increase the capital cost for the new steam generators and base plant by up to 2% over the same steam generators and base plants without the devices. The resulting capital cost regression coefficients are a function of annual net power generation and vary with coal and boiler type. For clusters other than lignite/supercritical, the regression follows a power function (Eq. B.32, Table B.58). The regression for the supplemental boiler upgrade retrofit cost for a supercritical boiler further depends upon whether the boiler is replaced with a newer supercritical steam generator (Eq. B.33, Table B.59), or if it is replaced with an ultra-supercritical steam generator (Eq. B.34, Table B.60).

$$CC_{sgsupgrade} = \frac{C_{sg}(TCR - PFC)}{TCR} + C_{sg} \tag{B.31}$$

where $CC_{sgsupgrade}$ is the total retrofit cost for upgraded steam cycle (M$), C_{sg} is the capital cost for the upgraded steam generator and turbine (M$), *TCR* is the total capital requirements (M$), *PFC* is the process facility capital costs (M$).

$$CC_{sgsupgrade\ i,k} = \beta_{0,i,k}(G_{net})^{\beta_{1,i,k}} \tag{B.32}$$

where $CC_{sgsupgrade}$ is the capital cost associated with retrofitting the current steam-generator subsystem with an upgraded subsystem (M$), G_{net} is the CFEGU net generation (MWh), the subscript k indicates the upgraded steam generator type, and the subscript i indicates the coal/boiler cluster from which the coefficients come.

$$CC_{sgsupgrade1\ i} = \beta_0 + \beta_1 G_{net} \tag{B.33}$$

where $CC_{sgsupgrade1}$ is the capital cost associated with retrofitting the current lignite supercritical steam-generator subsystem with a new supercritical subsystem (M$), G_{net} is the CFEGU net generation (MWh), and the subscript i indicates the coal/boiler cluster from which the coefficients come.

$$CC_{sgsupgrade2\ i} = \beta_0 + \beta_1 G_{net} + \beta_2 G_{net}^2 \tag{B.34}$$

where $CC_{sgsupgrade2}$ is the capital cost associated with retrofitting the current lignite supercritical steam generator subsystem with an ultra-supercritical subsystem (M$), G_{net} is the CFEGU net generation (MWh), and the subscript i indicates the coal/boiler cluster from which the coefficients come.

Upgrading the steam-generator system to a more efficient one does not mean that the retrofitted system will have the steam-cycle heat rate of one fitted in a new plant—the inefficiencies in the old plant may remain. As such, the steam-cycle heat rates for the cluster boilers must be adjusted from the boiler type default settings before IECM simulations concerning changes in these parameters are run to produce the regression data. This adjustment is made by applying the theoretical percent improvement in heat rate for the upgrade to the heat rate of the current boiler. Therefore, the heat rate for the upgraded boiler type ($hr_{upgrade}$) will decrease relative to the performance of the current boiler system ($hr_{current}$) by the ratio of the IECM default values of the new boiler type (IECM$hr_{upgrade}$) and the current boiler type (IECM$hr_{current}$), Eq. B.35. When this adjustment is made in the upgraded cluster boilers, the operating hours, base-plant parasitic load, and net generation of the current CFEGU are held constant; therefore, the gross capacity of the upgraded CFEGU is adjusted to maintain these parameters.

$$hr_{upgrade} = hr_{current} \frac{IECMhr_{upgrade}}{IECMhr_{current}} \tag{B.35}$$

The lower steam-cycle heat rate for the upgraded boiler will decrease the VOM cost of the CFEGU. This heat rate improvement will also cause a fractional change in the LCOE of the current CFEGU, in absence of the capital costs associated with the upgrade. To model this LCOE change, regressions on the fractional difference in the LCOE of the cluster CFEGUs with and without upgrades are run for cases with the steam generator subsystems fully amortized to avoid any LCOE differences related to these capital costs. The resulting model is a decrease in

LCOE that is a function of the annual power generation and varies according to coal and steam generator type, (Eq. B.36, Table B.61).

$$\varepsilon_{sgsupgrade\ i,k} = \beta_{0,i,k}(G_{net})^{\beta_{1,i,k}} \qquad \text{(B.36)}$$

where $\varepsilon_{sgsupgrade}$ is the change in the current CFEGU LCOE associated with the change in O&M costs from retrofitting the compliant steam-generator subsystem with an upgraded subsystem (fraction), G_{net} is the CFEGU net generation (MWh), the subscript k indicates the upgraded steam generator type, and the subscript i indicates the coal/boiler cluster from which the coefficients come.

Since the change in LCOE (Eq. B.36) is calculated with the fully amortized steam-generator subsystem, a correction must be made for the cases when the regression is applied to a subsystem that is not projected to be fully amortized when the upgrade is undertaken. This is accomplished by calculating the capital cost of the current base plant and determining the remaining amortization. In this equation, Eq. B.37, the capital cost of the base plant is modeled with a power function based on the net generation of the CFEGU and dependent upon the coal rank and boiler type, Table B.62. The remaining capital cost ($CC_{base\ i}$) uses a straight-line amortization that is assumed in the model to be 30 years. As the remaining capital cost cannot be less than zero, the maximum of zero or the ratio of the age of the base plant to the amortization period is considered. The LCOE for the base plant ($LCOE_{base}$) can then be calculated by annualizing the cost with the FCF, based on the life remaining without an upgrade, and levelizing the cost with the net generation, Eq. B.38. This LCOE can then be subtracted from the current LCOE of the CFEGU to offset any remaining capital cost for the steam generator subsystem. Furthermore, any remaining capital cost can be added back to the upgrade LCOE to account for the stranded value of the removed asset.

$$CC_{base\ i} = \left(\beta_{0,i}(G_{net})^{\beta_{1,i}}\right)\left(\max\left(0{,}1 - \frac{Y}{amort}\right)\right) \tag{B.37}$$

where $CC_{base\ i}$ is the remaining capital cost for the existing base plant (M$), G_{net} is the CFEGU net generation (MWh), Y is the age of the base plant (years), amort is the amortization period (years), and the subscript i indicates the coal/boiler cluster from which the coefficients come.

$$LCOE_{base} \ = 1 \times 10^{6}\,\frac{CC_{base\ i}FCF_{remain}}{G_{net}} \tag{B.38}$$

where CC_{base} is the remaining capital cost for the current base plant (M$), FCF_{remain} is the fixed charge factor for the remaining life of the CFEGU without a steam-generator upgrade (fraction), G_{net} is the CFEGU net generation (MWh), and the subscript i indicates the coal/boiler cluster from which the coefficients come.

To estimate the total LCOE for the upgraded CFEGU, Eq. B.39, the capital costs for the demolition (CC_{dem}) apportioned to the current steam generator subsystem and the retrofitting of the upgrade subsystem ($CC_{sgsupgradex\ i,k}$) are added to the remaining capital cost of the replaced subsystem ($CC_{base\ i}$), and annualized with the FCF. The remaining LCOE related to capital costs of the emission controls and cooling tower, and the CFEGU O&M costs are accounted for with the change in LCOE for the upgraded CFEGU relative to the compliant CFEGU ($\varepsilon_{sgsupgrade}$) that is compensated for any remaining capital cost in the replaced steam-generator subsystem. The total LCOE for an existing CFEGU with an upgraded steam generation subsystem ($LCOE_{sgsupgrade}$) is then defined as

$$LCOE_{sgsupgrade} = \left(\frac{\left(CC_{dem}PCC_{steam}+CC_{sgsupgradex\ i,k}+CC_{base\ i}\right)FCF_{default}}{G_{net}}\right) + \left(1 - \epsilon_{sgsupgrade\ i,k}\right)\left(LCOE_{comply} - LCOE_{base}\right) \qquad \text{(B.39)}$$

where CC_{dem} is the capital cost for demolishing the entire CFEGU (M\$), PPC_{steam} is the percent of the capital cost for the current CFEGU that is attributed to the steam generator subsystem (fraction), $CC_{sgsupgradex\ i,k}$ is the capital cost of the steam-generator subsystem upgrade that is dependent upon the upgrade type and current coal rank and boiler type (M\$), $CC_{base\ i}$ is the remaining capital cost of the current base plant (M\$), $FCF_{default}$ is the default FCF (11.28%), G_{net} is the CFEGU net generation (MWh), $\varepsilon_{sgsupgrade\ i,k}$ is the fraction change in the compliant CFEGU LCOE due to the upgrade (excluding capital costs related to the upgrade and any base-plant capital costs), $LCOE_{comply}$ is the LCOE for the compliant CFEGU before the upgrade, $LCOE_{base}$ is the LCOE for the compliant CFEGU that is related to the base plant before the upgrade, the subscript *k* indicates the upgraded steam generator type, and the subscript *i* indicates the coal/boiler cluster from which the coefficients come.

Table B.54. Reductions in compliant heat rate and CO_2 emission intensity from upgrading existing steam generator to supercritical steam generators for coal/boiler clusters.

	Heat Rate		CO_2 Intensity	
Coal/Boiler type	**Capacity-weighted Average**	**Standard Deviation**	**Capacity-weighted Average**	**Standard Deviation**
Bituminous/ Subcritical	5.9%	0.04%	5.8%	0.06%
Bituminous/ Supercritical	5.7%	0.01%	5.6%	0.04%
Sub-bituminous/ Subcritical	5.9%	0.02%	5.8%	0.02%
Sub-bituminous/ Supercritical	5.7%	0.02%	5.7%	0.03%
Lignite/Subcritical	5.9%	0.04%	5.8%	0.03%
Lignite/Supercritical	5.7%	0.05%	5.7%	0.02%

Table B.55. Reductions in compliant heat rate and CO_2 emission intensity from upgrading existing steam generator to ultra-supercritical steam generators for coal/boiler clusters.

	Heat Rate		CO_2 Intensity	
Coal/Boiler type	**Capacity-weighted Average**	**Standard Deviation**	**Capacity-weighted Average**	**Standard Deviation**
Bituminous/ Subcritical	19.3%	0.04%	19.3%	0.05%
Bituminous/ Supercritical	19.2%	0.04%	19.1%	0.05%
Sub-bituminous/ Subcritical	19.4%	0.03%	19.3%	0.03%
Sub-bituminous/ Supercritical	19.2%	0.04%	19.2%	0.06%
Lignite/Subcritical	19.4%	0.02%	19.3%	0.03%
Lignite/Supercritical	19.2%	0.02%	19.2%	0.02%

Table B.56. Coefficients of plant demolition capital cost ($) regression model as a function of summertime peak capacity (MW).*

Model Coefficient	β_0	β_1	R^2	**RMSE**
	7.17×10^6	-0.753	0.832	21,139

*n = 3

Table B.57. Coefficients of allocation percentage regression model of steam generator and turbine in base-plant demolition cost as a function of annual net power generation (MWh).

Coal/Boiler type	$\boldsymbol{\beta_{0,i}}$	$\boldsymbol{\beta_{1,i}}$	R^2	**RMSE**
Bituminous/ Subcritical*	0.336	0.0395	.831	0.009
Bituminous/ Supercritical†	0.428	0.0248	.947	0.003
Sub-bituminous/ Subcritical‡	0.421	0.0197	.929	0.003
Sub-bituminous/ Supercritical§	0.342	0.0365	.998	0.001
Lignite/Subcritical¶	0.283	0.0419	.971	0.005
Lignite/Supercritical#	0.455	0.0142	.890	0.001

*n = 9; †n = 6; ‡n = 6; §n = 5; ¶n = 5; #n = 4

Table B.58. Coefficients of supplemental retrofitting capital cost (millions of dollars) regression model for upgrading steam generator as a function of annual net power generation (MWh).

	Supercritical Upgrade				**Ultra-supercritical Upgrade**			
(Coal/Boiler type)	$\boldsymbol{\beta_{0,i}}$	$\boldsymbol{\beta_{1,i}}$	R^2	**RMSE**	$\boldsymbol{\beta_{0,i}}$	$\boldsymbol{\beta_{1,i}}$	R^2	**RMSE**
Bituminous/ Subcritical*	0.021	0.652	0.987	13.108	0.023	0.654	.987	14.468
Bituminous/ Supercritical†	0.018	0.676	0.971	64.935	0.021	0.674	.972	70.088
Sub-bituminous/ Subcritical‡	0.018	0.666	0.997	20.355	0.020	0.667	.997	22.557
Sub-bituminous/ Supercritical§	0.014	0.69	0.944	54.535	0.016	0.688	.942	60.559
Lignite/ Subcritical¶	0.008	0.719	0.996	24.736	0.008	0.725	.997	27.032

*n = 9; †n = 6; ‡n = 6; §n = 5; ¶n = 5

Table B.59. Coefficients of supplemental retrofitting capital cost (M$) regression model for upgrading steam generator from a lignite, supercritical boiler to a new supercritical boiler, as a function of annual net power generation (MWh).*

(Coal/Boiler type)	β_0	β_1	R^2	RSME
Lignite/Supercritical	134.072	7.94×10^{-5}	.997	18.958

*n = 4

Table B.60. Coefficients of supplemental retrofitting capital cost (M$) regression model for upgrading steam generator from a lignite, supercritical boiler to a new ultra-supercritical boiler, as a function of annual net power generation (MWh).*

(Coal/Boiler type)	β_0	β_1	R^2	RMSE
Lignite/Supercritical	0.0485	0.6074	.984	71.046

*n = 4

Table B.61. Coefficients of regression model of LCOE percentage change associated with upgrading steam generator as a function of annual net power generation (MWh).

EGU parameter	Relative change in LCOE due to supercritical upgrade				Relative change in LCOE due to ultra-supercritical upgrade			
Model Coefficient Coal/Boiler type	β_0	β_1	R^2	**RMSE**	β_0	β_1	R^2	**RMSE**
Bituminous/ Subcritical*	$3.9x10^{-4}$	0.305	.981	0.001	$1.6x10^{-3}$	0.292	.983	0.003
Bituminous/ Supercritical†	$3x10^{-3}$	0.170	.971	0.001	$7.8x10^{-3}$	0.184	.973	0.004
Sub-bituminous/ Subcritical‡	$1.9x10^{-4}$	0.313	.996	0.001	$1.1x10^{-3}$	0.3	.996	0.002
Sub-bituminous/ Supercritical§	$8.3x10^{-4}$	0.236	.969	0.002	$2.8x10^{-3}$	0.232	.966	0.006
Lignite/Subcritical¶,‖	$9.8x10^{-4}$	0.234	.953	0.002	$3.06x10^{-3}$	0.245	.961	0.005
Lignite/Supercritical#,‖	$7.3x10^{-4}$	0.265	.535	0.005	$3.06x10^{-3}$	0.245	.961	0.005

*n = 9; †n = 6; ‡n = 8; §n = 5; ¶n = 5; #n = 4; ‖n = 9 for USC upgrade

Table B.62. Coefficients of capital cost regression model for determining total capital cost of base plant (M$) for amortization purposes when upgrading steam generator, as a function of annual net power generation (MWh).

Coal/Boiler type	β_0	β_1	R^2	RMSE
Bituminous/Subcritical*	0.012	0.715	.998	15.983
Bituminous/Supercritical†	0.044	0.640	.972	68.016
Sub-bituminous/Subcritical‡	0.012	0.715	.998	15.983
Sub-bituminous/Supercritical§	0.015	0.715	.996	49.797
Lignite/Subcritical¶	0.016	0.706	.998	27.032
Lignite/Supercritical#	4.983	0.338	.939	49.448

*n = 13; †n = 6; ‡n = 13; §n = 5; ¶n = 5; #n = 4

B.8.6.4 Co-firing with natural gas

The costs associated with this co-firing are site-specific. If NG is already on-site, ESTEAM uses the IECM default values for gas reburn retrofitting costs ($19.67/kilowatt-gross) as a proxy for co-fire capital retrofit costs [42]. If NG is not available at the site, the additional cost of bringing the gas to the site must also be added to the current plant LCOE. This additional cost for co-firing at any given rate is the summation of the annualized and levelized pipeline and compressor station costs, and the associated O&M costs for NG transportation and use at the plant. The associated pipeline costs (*Section B.8.7 Natural gas pipeline cost*) are determined in part by the increase in EGU heat rate, hr_1 (Eq. B.40, Table B.63) as a function of percent co-fire, and the associated NG flow rate, (Eq. B.75).

$$hr_1 = \beta_0 + \beta_1 NG + \beta_2 R_{lig} + \beta_3 G_{net} hr_{HRI} + \beta_4 G_{net} NG + \beta_5 R_{lig} hr_{HRI} + \beta_6 R_{bit} NG + \beta_7 R_{lig} NG \qquad \text{(B.40)}$$

where hr_1 is the new CFEGU heat rate $\left(\frac{Btu}{kWh}\right)$, NG is the co-fire level (fraction), G_{net} is the CFEGU net generation (MWh), hr_{HRI} is the heat rate for the compliant boiler after the heat rate improvement $\left(\frac{Btu}{kWh}\right)$, R_{lig} is a dummy variable for the lignite coal rank that is 1 if the EGU uses lignite coal and is 0 otherwise, and R_{bit} is a dummy variable for the bituminous coal rank that is 1 if the EGU uses bituminous coal and is 0 otherwise.

The incurred CFEGU NG co-fire fixed O&M component is considered to be 1.5% of the total plant cost and is determined in aggregate with the related non-fuel VOM cost, which is a nonlinear function of the net generation and the co-fire rate. This nonlinearity is related to the effect of co-firing on the CFEGU heat rate and parasitic load, and on the variable costs of the emission control devices to treat the effluent. Increasing the consumption of NG also changes the CFEGU VOM expenditures that are related to the coal and NG quantity and price, which are calculated separately. As such, the variable portion is dependent upon the coal properties and on the steam generator type, and the equations for the change in LCOE (ε_{cf}) are defined by these attributes. Equation B.41a (Table B.64) is applied to bituminous-fired EGUs at 5%, 20-25%, and 40% co-fire rates, while Eq. B.41b (Table B.65) is applied to non-bituminous-fired EGUs at any co-fire rate.

$$\epsilon_{\mathrm{cf}} = \beta_0 + \beta_1 G_{net} + \beta_2 G_{net}^2 + \beta_3 NG \tag{B.41a}$$

$$\epsilon_{\mathrm{cf}} = \beta_0 + \beta_1 G_{net} + \beta_2 NG + \beta_3 NG^2 \tag{B.41b}$$

where ε_{cf} is the change in LCOE due to co-firing (fraction), G_{net} is the CFEGU net generation (MWh), and NG is the co-fire level (fraction).

Therefore, the LCOE for the co-firing with natural gas is given by

$$LCOE_{cf} = (1+\varepsilon_{cf})LCOE_{nonfuel} + \frac{1000C_{cf}Cap_{peak}(1+\omega)(FCF_{remain}-FCF_{init})}{G_{net}} + VOM_{fuelcf} + LCOE_{ngpipe} \quad \text{(B.42)}$$

where $LCOE_{cf}$ is the LCOE of the CFEGU with co-fire $\left(\frac{\$}{MWh}\right)$, ε_{cf} is the change in the LCOE of the CFEGU due to co-firing (fraction), $LCOE_{nonfuel}$ is the LCOE of the compliant EGU (excluding fuel cost) without co-fire $\left(\frac{\$}{MWh}\right)$, C_{cf} is the capital cost of the gas reburn retrofit ($/kW-net), Cap_{peak} is the peak, net summertime capacity of the CFEGU prior to conversion (MW), ω is the parasitic load (fraction), FCF_{remain} is the fixed charge factor for the remaining life of the CFEGU (fraction), FCF_{init} is the default fixed charge factor (fraction), VOM_{fuelcf} is the variable operation and maintenance cost related to fuel for co-firing $\left(\frac{\$}{MWh}\right)$, $LCOE_{ngpipe}$ is the LCOE for the natural gas pipeline $\left(\frac{\$}{MWh}\right)$, G_{net} is the EGU net generation (MWh), and 1000 is the conversion factor from kW to MW.

$$LCOE_{nonfuel} = LCOE_{HRI} - VOM_{fuel} \quad \text{(B.43)}$$

where $LCOE_{nonfuel}$ is the LCOE of the compliant CFEGU (excluding fuel cost) without co-fire $\left(\frac{\$}{MWh}\right)$, $LCOE_{HRI}$ is the LCOE of the compliant CFEGU with the HRI mitigation $\left(\frac{\$}{MWh}\right)$, and VOM_{fuel} is the variable operation and maintenance cost related to fuel without co-firing $\left(\frac{\$}{MWh}\right)$.

$$VOM_{fuelcf} = \frac{hr_1\left(C_{coal}(1-NG)+NG\left(C_{gas}\right)\right)}{1000} \tag{B.44}$$

where VOM_{fuelcf} is the variable operation and maintenance cost related to fuel for co-firing $\left(\frac{\$}{MWh}\right)$, hr_1 is the new CFEGU heat rate $\left(\frac{Btu}{kWh}\right)$, C_{coal} is the current coal price for the given state (\$/MMBtu), NG is the co-fire level (fraction), and C_{gas} is the current natural gas price for the given state (\$/MMBtu).

The relative change in LCOE is associated with a relative change in CO_2 emission intensity. This intensity change (Eq. B.45, Table B.66) is expressed as

$$\Delta \mathrm{I_{cf}} = \beta_0 + \beta_1 NG + \beta_2 R_{lig} + \boldsymbol{\beta_3} G_{net} NG + \beta_4 R_{bit} G_{net} + \beta_5 G_{net} hr_{HRI} + \beta_6 R_{lig} hr_{HRI} + \beta_7 R_{bit} NG + \beta_8 R_{lig} NG \tag{B.45}$$

where $\Delta \mathrm{I_{cf}}$ is the relative change in CO_2 emission intensity (fraction), NG is the co-fire level (fraction), hr_{HRI} is the heat rate for the compliant boiler after the heat rate improvement, R_{lig} is a dummy variable for the lignite coal rank that is 1 if the EGU uses lignite coal and is 0 otherwise, and R_{bit} is a dummy variable for the bituminous coal rank that is 1 if the EGU uses bituminous coal and is 0 otherwise.

Therefore, the emission intensity for the CFEGU at a given percent co-fire is given by

$$I_{cf,i} = (1 + \Delta I_{cf}) I_{HRI,i} \tag{B.46}$$

where $I_{cf,i}$ is the CFEGU CO_2 emission intensity with co-fire $\left(\frac{lbs}{MWh}\right)$, $I_{HRI,i}$ is the CO_2 emission intensity of the compliant CFEGU after the HRI mitigation and without co-fire $\left(\frac{lbs}{MWh}\right)$, and the subscript *i* refers to the measure based upon net or gross generation.

Table B.63. Coefficients of regression model of new EGU heat rate $\left(\frac{\mathbf{Btu}}{\mathbf{kWh}}\right)$ associated with the level of nature gas co-fire (fraction).*

β_0	β_1	β_2	β_3	β_4	β_5	β_6	β_7	R^2	RMSE
-2.0×10^{-5}	-2.9×10^{-9}	0.04	0.006	-1.9×10^{-6}	-6.2×10^{-7}	0.037	-0.034	.997	4.6×10^{-4}

*n = 16

Table B.64. Coefficients of regression model of percent LCOE change (fraction) associated with specific levels of nature gas co-fire (fraction) for bituminous coal-fired generators.

Coal/Boiler type	Percent Co-fire	β_0	β_1	β_2	β_3	R^2	RSME
Bituminous/ Subcritical*	5	$1.3x10^{-3}$	$1.1x10^{-8}$	$-2.0x10^{-15}$	0	.966	$1.1x10^{-3}$
Bituminous/ Supercritical†		$-1.4x10^{-2}$	$2.8x10^{-9}$	$-1.1x10^{-16}$	0	.856	$2.7x10^{-3}$
Bituminous/ Subcritical‡	20-25	0.018	$-1.7x10^{-9}$	0	-0.144	.892	$1.8x10^{-3}$
Bituminous/ Supercritical§		$4.1x10^{-2}$	$-3.6x10^{-9}$	0	-0.217	.856	$3.9x10^{-3}$
Bituminous/ Subcritical¶	40	$-3.0x10^{-2}$	$-1.3x10^{-8}$	$8.5x10^{-16}$	0	.952	$2.3x10^{-3}$
Bituminous/ Supercritical#		$-2.8x10^{-2}$	$-8.9x10^{-9}$	$4.1x10^{-16}$	0	.928	$5.1x10^{-3}$

*n = 9; †n = 6; ‡n = 18; §n = 12; ¶n = 9; #n = 6

Table B.65. Coefficients of regression model of percent LCOE change (fraction) associated with all levels of nature gas co-fire (fraction) for subbituminous and lignite coal-fired generators.

Coal/Boiler type	β_0	β_1	β_2	β_3	R^2	RSME
Sub-bituminous/ Subcritical	0.061	$4.8x10^{-10}$	0.020	$-1.01x10^{-4}$	.983	$3.8x10^{-4}$
Sub-bituminous/ Supercritical	$3.5x10^{-2}$	$6.1x10^{-9}$	-0.25	0.151	.932	$7.6x10^{-3}$
Lignite/Subcritical	$4.4x10^{-2}$	$-1.3x10^{-8}$	-0.36	0.17	.895	$1.4x10^{-2}$
Lignite/Supercritical	0.137	$-3. 7x10^{-8}$	-0.526	0.379	.858	$2x10^{-2}$

*n = 24; †n = 20; ‡n = 6; §n = 20

Table B.66. Coefficients of regression model of relative CO_2 emission intensity change (fraction) associated with the level of natural gas co-fire (fraction).*

β_0	β_1	β_2	β_3	β_4	β_5	β_6	β_7	β_8	R^2	RSME
5.26×10^{-4}	-0.426	-6.14×10^{-3}	3.75×10^{-10}	2.38×10^{-10}	-5.97×10^{-7}	-5.92×10^{-7}	0.0567	-0.0357	1	4.14×10^{-4}

*n = 60

B.8.6.5 Conversion from coal to 100% natural gas

To obtain this emission-intensity improvement, several aspects of the physical structure of the CFEGU must change. These changes include retrofitting control systems, forced draft fans, the air heater, and super and reheat surface modifications [54]. The cost for these changes for the NG retrofit is between \$50 to \$75 per kW for a 215 MW CFEGU [55]. In the model, this cost ($C_{ngretro}$) is sized with the power rule to determine the retrofit cost for any CFEGU with the equation

$$C_{ngretro} = C_{base}\left(\frac{Cap_{base}}{Cap_{peak}}\right)^{\beta} \tag{B.47}$$

where $C_{ngretro}$ is the capacity-normalized capital cost for the conversion of the CFEGU to 100% natural gas boiler $\left(\frac{\$}{kW}\right)$, C_{base} is the baseline retrofit cost taken as the average of the retrofit cost range[22] $\left(\frac{\$}{kW}\right)$, Cap_{base} is the capacity of the baseline CFEGU (MW), Cap_{peak} is the CFEGU summertime, net peak capacity from the NEEDS database (MW), and β is the coefficient for the power rule, Table B.32(c).

The VOM for the base plant is dominated by the fuel cost; therefore, the model only considers the fuel energy requirements for the retrofitted CFEGU to determine the VOM. Here, adjustments are made to the CFEGU heat rate and capacity to calculate the new fuel use. Firing with natural gas instead of coal will increase the CFEGU heat rate by 200 Btu/kWh [55], while the net heat rate will be reduced from the elimination of fitted emission control devices (Eq.

B.48). Additionally, the CFEGU net output will increase by 5 MW [55], which is compensated for with a reduction in operating hours to maintain constant net generation. The new energy requirement is given in Eq. B.48.

$$hr_{ngretro} = hr_{current}(1 - \sum \Delta hr_{emission}) + \Delta hr_{NG} \tag{B.48}$$

where the $hr_{ngretro}$ is the net heat rate for the NG retrofitted CFEGU (Btu/kWh), $hr_{current}$ is the net heat rate for the current CFEGU prior to retrofit (Btu/kWh), $\Delta hr_{emission}$ is the fractional change in CFEGU when the existing emission control devices are decommissioned (fraction), and Δhr_{NG} is the increase in CFEGU net heat rate when natural gas is used instead of coal (Btu/kWh).

$$Btu_{ngretro} = 1000 G_{net} hr_{ngretro} \tag{B.49}$$

where $Btu_{ngretro}$ is the annual energy requirement for the CFEGU to produce the specified net generation quantity (Btu), G_{net} is the net generation (MWh), the $hr_{ngretro}$ is the net heat rate for the NG retrofitted CFEGU (Btu/kWh), and 1000 is the conversion from MWh to kWh.

Three components of the reduced O&M costs for the gas-fired EGU reflect reductions in the boiler fixed O&M, and the cooling water tower fixed and variable O&M (Eq. B.50). The fixed O&M reductions relate to a lower labor requirement for operating the EGU, as well as less maintenance material, while the variable component is directly related to a reduction in water and electricity use. These changes are based upon the assumption that the expenses for a NG retrofitted CFEGU will begin to resemble those for a NGCC plant at the same net power output. In this case, the coal-fired base plant related component of the O&M for the gas-fired EGU is estimated as the O&M cost of the base plant less the cost of the coal and one-half of the associated labor. The O&M expenses of the boiler and water tower for the retrofitted CFEGU is taken as the product of the regressed O&M component for the coal-fired cluster EGUs, sorted by coal rank, and the ratio of the O&M for that component in a NGCC plant to that for the component in a coal-fired EGU at the same net generation, Table B.67. The variable fuel cost is the product of the price of the fuel and the required Btu.

$$OM_{retro} = \frac{1\times10^6\left(\beta_{2,i}\left(\beta_{0,i}+\beta_{1,i}Cap_{peak}\right)+\beta_{5,i}\left(\beta_{3,i}+\beta_{4,i}Cap_{peak}\right)+\beta_{8,i}\left(\beta_{6,i}+\beta_{7,i}G_{net}\right)\right)+C_{NG}\frac{Btu_{ngretro}}{1\times10^6}}{G_{net}} \qquad \text{(B.50)}$$

where OM_{retro} is the fixed and variable O&M of the natural gas retrofitted CFEGU $\left(\frac{\$}{MWh}\right)$, Cap_{peak} is the CFEGU summertime, net peak capacity from the NEEDS database (MW), G_{net} is the net generation (MWh), C_{NG} is the price of the natural gas ($/MMBtu), $Btu_{ngretro}$ is the annual natural gas consumption for the retrofitted CFEGU (Btu), $1\text{x}10^6$ is a conversion for millions, and the subscript *i* indicates the coal rank from which the coefficients come.

Combining the result from Eq. B.50 with those from Eq B.37 and the capital and O&M costs associated with the natural gas pipeline (*Section B.8.7*). results in the LCOE for the conversion to a 100% natural gas generator equation:

$$LCOE_{ng\ conv} = \left(\frac{\left(1000C_{ngretro}Cap_{peak}+CC_{base}\right)FCF_{remain}}{G_{net}}\right) + OM_{retro} + LCOE_{ngpipe} \qquad \text{(B.51)}$$

where $LCOE_{ng\ conv}$ is the LCOE for the conversion of the CFEGU to a 100% natural gas boiler $\left(\frac{\$}{MWh}\right)$, $C_{ngretro}$ is the cost for converting the CFEGU $\left(\frac{\$}{kW}\right)$, Cap_{peak} is the peak, net summertime capacity of the CFEGU prior to conversion (MW), CC_{base} is the capital cost for the remaining CFEGU inclusive of the capital cost for the existing emission control devices (M\$), FCF_{remain} is the fixed charge factor for the remaining life of the CFEGU (fraction), $OM_{ngretro}$ is the levelized O&M cost for the converted CFEGU $\left(\frac{\$}{MWh}\right)$, $LCOE_{ngpipe}$ is the LCOE for the natural gas pipeline $\left(\frac{\$}{MWh}\right)$, and 1000 is the conversion factor from MW to kW.

The EGU CO_2 emission intensity for the conversion (I_{ngconv}) is calculated from the ratio of the molecular weight of CO_2 relative to carbon, the mass of carbon per Btu of NG, and the Btu requirement from Eq. B.49. The intensity equation is expressed as

$$I_{ngconv} = \left[Btu_{ngretro}\left(\frac{lbs\ C}{Btu_{NG}}\right)\left(\frac{lbs\ CO_2}{lbs\ C}\right)\right]/G_{net} \qquad \text{(B.52)}$$

where I_{ngconv} is the EGU net CO_2 emission intensity $\left(\frac{lbs}{MWh}\right)$, $Btu_{ngretro}$ is the annual Btu requirement for the EGU to produce the specified net generation quantity, G_{net} is the net generation (MWh), there are $3.19\text{x}10^{-5}\ \frac{lbs\ C}{Btu_{NG}}$, and there are $3.667\ \frac{lbs\ CO_2}{lb\ C}$ for NG.

Table B.67. Coefficients of regression model of the O&M costs $\left(\frac{\$}{\mathbf{MWh}}\right)$ related to CO_2 mitigation by retrofitting boiler for 100% NG conversion, as a function of annual net power generation (MWh). Coefficients $\beta_{2,i}$, $\beta_{5,i}$, and $\beta_{8,i}$ are the ratio of the O&M for that component in a NGCC plant to that for the component in a coal-fired EGU at the same net generation.

	Boiler fixed O&M					Water Tower Fixed O&M					Cooling Tower Variable O&M				
Coal type	$\beta_{0,i}$	$\beta_{1,i}$	R^2	RMSE	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	R^2	RMSE	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	R^2	RMSE	$\beta_{8,i}$
Bituminous*	9.028	0.018	.975	1.163	0.419	0.562	$1.4\text{x}10^{-3}$	.971	0.098	0.806	0.133	$9.5\text{x}10^{-7}$	.916	0.814	0.659
Sub-bituminous†	9.217	0.02	.994	0.639	0.419	0.62	$1.4\text{x}10^{-3}$	.943	0.151	0.758	0.349	$8.1\text{x}10^{-7}$	.993	0.220	0.803
Lignite‡	9.519	0.022	.988	0.709	0.386	0.523	$1.8\text{x}10^{-3}$	.973	0.087	0.797	0.324	$1.02\text{x}10^{-6}$	.991	0.205	0.655

*n = 16; †n = 11; ‡n = 9

B.8.6.6 Conversion from coal-fired EGUs to NGCC plant

For demolition cost and allocation, the same methods outlined for upgrading the steam generator are followed. The capital costs for the new subsystems come directly from the IECM defaults, with the minimum number of turbine stages required to meet the net generation of the existing coal-fired EGU. Therefore, only enough turbine stages are installed to meet the net generation of the original plant. Additional capital costs are added to the NGCC conversion to account for modifications to the existing structure for this brownfield conversion, as was done for the upgraded steam-generator mitigation. Operation and maintenance costs, excluding fuel, are determined with regressions on the cluster CFEGUs as a function of the number of turbine stages. The fuel costs are taken directly from the IECM for fuel flow rates for the different turbine configures and the required operation hours. As in the case for 100% conversion to NG, we use the procedures described earlier to add the remaining capital costs of the coal-fired EGU and the new costs for the NG pipeline (*Section B.8.7*). The overall LCOE is then the summation of these levelized and annualized costs, where these costs are levelized with the new net generation.

Since these are new NGCC plants, the heat rates and CO_2 emission intensities for each plant in the model are identical to those for NSPS NGCC plants in the IECM; as such, all current and proposed CO_2 emission regulations are met. Each EGU may have a unique LCOE and emission intensity that are greatly dependent upon the net generation of the EGU, as this determines the minimum number of gas turbines and the related capacity factor. The turbine requirement is derived by matching the net electricity output from different combinations of turbine stages operated at capacity factors between 0-87% to the net generation of the current configuration of the EGU, Table B.68. As only the minimum number of turbines operated at an adjusted capacity factor is chosen to meet this net generation, the NGCC plant is correctly sized to replicate the existing CFEGU and to minimize overgeneration.

This constraint to meet and not exceed the net generation of the coal-fired EGU may necessitate the new NGCC plant to operate at a load factor that is below the maximum achievable load, thereby incurring an increase in the design heat rate and the associated fuel consumption costs and emission intensity [56-60]. This heat rate penalty can be characterized as a cubic function, Eq. B.52, that is applied to an average heat rate to calculate the change in heat rate during startup and at maximum load [56]. When the coefficients from [56] are compensated such that the 100% load has no penalty[1](Figure B.7, Table B.69), the heat rate penalty at 50% load is 13%, which will cause a corresponding increase in CO_2 emission intensity of 13%. As this emission increase is closer to the corresponding 9% increase in emission intensity for NGCC plants cited in [60] than is the 18% increase empirically determined in [57] and used for comparison in [56], the cubic structure and coefficients based upon [58] are used to determine the percent heat rate penalty and increase in CO_2 emission intensity for the NGCC mitigation, as function of the capacity factor. The resulting percent penalty is then applied to the theoretical emission intensity to determine the adjusted emission intensity, Eq. B.54, and to the fuel flow rate to determine the resulting increase in fuel cost, Eq. B.56.

$$HR_{penalty} = \beta_0 + \beta_1 CF + \beta_2 CF^2 + \beta_3 CF^{-1} \tag{B.55}$$

[1] Coefficients for the heat rate penalty curve are determined from a nonlinear regression using data points measured from the curve generated in [56].

where $HR_{penalty}$ is the heat rate penalty for the NGCC plant (fraction) and CF is the adjusted capacity factor required for the NGCC mitigated CFEGU to match the net generation of the current EGU.

$$I_{NGCC} = I_0\left(1 + HR_{penalty}\right) \tag{B.54}$$

where I_{NGCC} is the adjusted CO_2 emission intensity for the NGCC mitigation (lbs/MWh), I_0 is the default emission intensity for the NGCC plant at maximum load as modeled in the IECM (lbs/MWh), and $HR_{penalty}$ is the heat rate penalty for the NGCC plant due to the adjusted capacity factor required for the NGCC mitigated CFEGU to match the net generation of the current CFEGU (fraction).

The capital cost for the NGCC plant is a function of the number of turbines. This cost entails the new equipment for the power block process area and the non-processes facility costs for the plant power block, which also come directly from the IECM defaults. Here, the power block new equipment includes GE 7FB gas turbines, the heat recovery steam generator (HRSG), the steam turbine, and the HRSG feedwater system, while the non-process facilities cost includes the general facility required to house the new equipment, Table B.70. As some of the existing general facilities are reused, double counting when calculating the total capital cost for a given turbine configuration is avoided by subtracting the product of a portion of the general facilities cost and the ratio of the steam and gas turbine costs to the base-plant general-facility cost (Eq.

B.55) from the summation of the equipment costs (Eq. B.56). This portion of the general facilities cost is the general facilities capital for one gas turbine and the associated steam turbine and HRSG, and as such is held constant at $18 million.

$$CC_{NGCC} = C_{plantpb} - \frac{C_{gf}(C_{gt}+C_{st})}{C_{plantpb}} \tag{B.55}$$

where CC_{NGCC} is the capital cost for the conversion that excludes demolition (M$), $CC_{plantpb}$ is the capital cost for the for the new plant facilities and equipment (M$), CC_{gf} is the capital cost constant for the general facilities (18 M$), CC_{gt} is the capital cost for the new gas turbines (M$), and CC_{st} is the capital cost for the new steam turbines (M$).

$$CC_{plantpb} = C_{gt} + C_{st} + C_{HRSG} + C_{feedwater} + C_{pb} \tag{B.56}$$

where $CC_{plantpb}$ is the capital cost for the new plant facilities and equipment (M$), CC_{gt} is the capital cost for the new gas turbines (M$), CC_{st} is the capital cost for the new steam turbines (M$), CC_{HRSG} is the capital cost for the new HRSG subsystem (M$), $CC_{feedwater}$ is the capital cost for the new HRSG feedwater subsystem (M$), and CC_{pb} are the remaining non-process facilities capital cost (M$).

The remaining contributions to the LCOE are the estimated cost to demolish the boiler and steam turbine, the remaining capital costs of the current coal-fired EGU, the costs for the NG pipeline and compressor stations and the O&M costs. For the demolition cost, the same methods outlined for upgrading the steam generator are followed. Similarly, the same procedure is used to determine the new costs for the NG pipeline, based upon the pipeline diameters required for the new energy flux.

The number of gas turbines will also influence the O&M costs for the plant—fuel, power block, and water tower. The fuel cost is estimated as the product of the fuel price, the plant operating hours, and the plant energy requirement, which is a function of the number of required turbines (Eq. B.57 Table B.70). The remaining power block O&M expense comprises the variable, internal electricity needs and the fixed labor and material costs (Eq. B.58, Table B.71). While the fixed components only vary with the number of turbines, regressions on the variable cost component indicate a linear relationship with operating hours that varies with the number of turbines, Table B.70. The slope for this cost is negative, as this is an internal transfer that offsets the cost of the subsystems that requiring the electricity, such as the water tower that also consumes water. These variable components for the water tower O&M can be modeled as a linear regression with operating hours, while the fixed component varies only with the number of turbines and are modeled as such in Eq. B.57.

$$VOM_{NG} = \dot{m}_\iota\left(1 + HR_{penalty}\right)(ophrs)C_{NG} \tag{B.57}$$

where VOM_{NG} is the fuel related variable operations and maintenance cost for the plant ($), $\dot{m}$ is the plant energy requirement (MMBtu/hr), $HR_{penalty}$ is the heat rate penalty for the NGCC plant due to the adjusted capacity factor required for the NGCC mitigated CFEGU to match the net generation of the current CFEGU (fraction), *ophrs* is the annual operating hours for the CFEGU,

C_{NG} is the price of the natural gas (\$/MMBtu), and the subscript i refers to the number of turbines for the converted CFEGU.

$$OM_{NGCC} = 1 \times 10^{6}\left(\beta_{0.i} + \beta_{2,i} + (\beta_{1,i} + \beta_{3,i})ophrs + \beta_{4,i} + \beta_{5,i}\right) \tag{B.58}$$

where OM_{NGCC} is the fixed O&M cost of the NGCC plant (\$), *ophrs* is the annual operating hours for the CFEGU, $1\text{x}10^{6}$ is a conversion for millions, and the subscript i refers to the number of turbines for the converted CFEGU.

The overall LCOE (Eq. B.59) is then the summation of these capital cost annualized and levelized with the new net generation.

$$LCOE_{NGCC} = \left(\frac{\left(CC_{dem}PCC_{steam} + CC_{NGCC} + CC_{base}\right)FCF_{default}}{G_{net1}}\right) + \frac{OM_{NGCC} + VOM_{NG}}{G_{net1}} + LCOE_{ngpipe} \tag{B.59}$$

where $LCOE_{NGCC}$ is the LCOE for the NGCC plant $\left(\frac{\$}{MWh}\right)$, CC_{dem} is the capital cost for demolishing the entire CFEGU (M\$), PPC_{steam} is the percent of the capital cost for the current CFEGU that is attributed to the steam-generator subsystem (fraction), CC_{NGCC} is the capital cost for the conversion that excludes demolition (M\$), CC_{base} is the remaining capital cost for CFEGU inclusive of the capital cost for the compliant emission control devices (M\$), $FCF_{default}$

is the default fixed charge factor (11.28%), G_{net1} is the net generation of the converted CFEGU (MWh), OM_{NGCC} is the fixed O&M cost for the converted CFEGU ($),$VOM_{NG}$ is the fuel related variable O&M cost for the plant ($), and $LCOE_{ngpipe}$ is the LCOE for the natural gas pipeline$\left(\frac{\$}{MWh}\right)$.

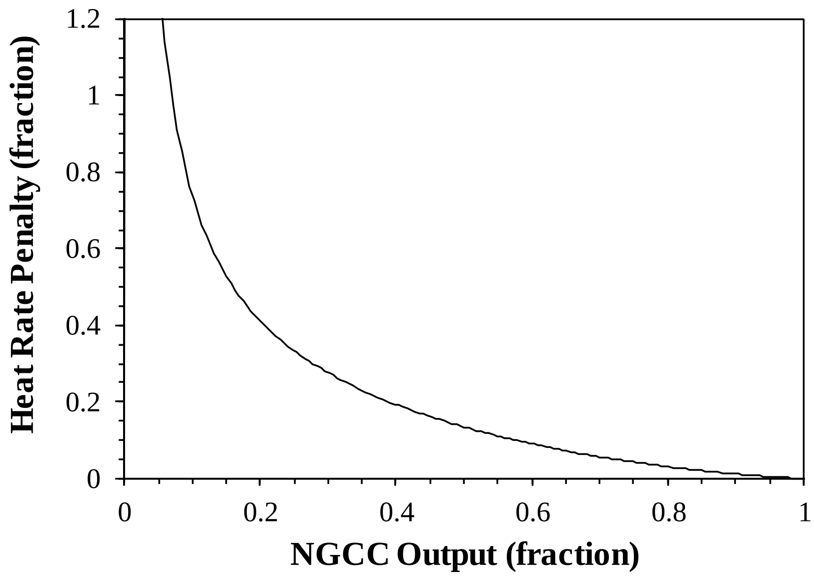

Figure B.7. Heat rate penalty applied to NGCC plants in ESTEAM.

Table B.68. NGCC plant characteristics for various gas turbine configurations, based upon default NSPS, NGCC plant modeled in the IECM with GE 7FB gas turbines.

Number gas turbines	Gross plant capacity (MW_g)	Net plant capacity (MW)	Net heat rate (Btu/kWh)	Energy Flux (MMBtu/hr)	Net CO_2 intensity (lbs/MWh)
1	270	263	6,575	1,797	803
2	541	527	6,575	3,594	803
3	811	790	6,575	5,391	803
4	1,082	1,053	6,575	7,188	803
5	1,352	1,316	6,575	8,985	803

Table B.69. Coefficients for the cubic function describing the fractional heat rate penalty associated with load factors less than the maximum load for the NGCC plant as modeled in the IECM.*

β_0	β_1	β_2	β_3	R^2	RMSE
0.217	-0.516	0.241	0.057	1.000	0.003

*n = 9

Table B.70. Capital cost (M$) for power block process area and plant costs, based upon default NSPS, NGCC plant modeled in the IECM with GE 7FB gas turbines.

Number gas turbines	Gas turbine	Heat recovery steam generator	Steam turbine	HRSG feedwater system	Non-process facilities	Total capital cost
1	55	29	19	17	64	269
2	110	58	39	28	121	540
3	175	87	58	37	180	809
4	220	116	77	46	239	1,077
5	275	144	96	55	297	1,344

Table B.71. Coefficients of regression model of related O&M cost (M$) for NGCC mitigation as a function of annual operating hours (hours).*

Number of gas turbines	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$
1	-0.193	-5.41×10^{-5}	0.193	1.00×10^{-4}	6.118	0.788
2	-0.358	-1.08×10^{-4}	0.358	2.80×10^{-4}	9.127	1.058
3	-0.521	-1.62×10^{-4}	0.521	4.20×10^{-4}	12.1	1.327
4	-0.683	-2.16×10^{-4}	0.683	5.60×10^{-4}	15.05	1.589
5	-0.845	-2.70×10^{-4}	0.845	7.00×10^{-4}	17.99	1.836

Note: The correlation coefficient for all variable cost regressions is $R^2 = 1$. *n = 9

B.8.6.7 Conversion from coal-fired EGUs to NGCC plant with co-located renewable source

The LCOE for the co-located generation is a generation-weighted average of the two sources. For the NGCC plant, the annualized capital costs are identical to those without the renewable generation, but the O&M costs may increase with the reduced generation requirement, according to the equations in the previous section (Eqs. B.56 and B.52). Here, the reduced generation, from the reduced operating hours, will result in an increase in the NGCC LCOE, when the capital and O&M costs are levelized, Eq. B.59.

The capital and O&M costs for the renewable sources are constant for the given source type, and the required generation is reached by replicating the source at a standard capacity, with the associated state-specific capacity factor. As these sources are theoretically co-located, and actual resource availability and additional transmission costs for the renewable sources are site-specific, renewable transmission costs are not included here. The capital and fixed O&M costs for future utility solar PV and onshore wind capacity are given in the 2019 National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) for service in 2030 [3]. The overnight capital cost for a utility solar PV facility is $825/kW, while that for an onshore wind farm is costed at $1,189/kW, in 2010 dollars. To each, an 11% FCF is applied. The annual fixed O&M cost for the solar farm is $9.9/kW and is $39/kW for the wind farm. Solar costs are taken from the NREL mid-technology cost scenario for a mid-range solar irradiance equating to a 20% capacity factor for a collector located in Kansas City, Missouri. Wind costs are representative of techno-resource group 4 wind turbine in the mid-technology cost scenario. All costs are converted from 2017 dollars to 2010 dollars with CEPCI [19].

The capacity factors for each renewable technology are necessary to determine the LCOEs for these sources. These state-specific capacity factors are calculated with net generation and capacity data provided by the NREL for future generation scenarios with high renewable generation mixes [61]. Utility solar PV capacity factors are calculated from the 30% renewable energy penetration and incremental technology improvements (30% RE-ITI) scenario. As only eight states are projected to have utility solar generation in 2030, the utility solar capacity factors for all states are based upon the state-specific rooftop solar capacity factors. These values are increased by a factor of 1.45 to determine the utility solar proxy capacity factor: 1.45 is the average, relative increase in capacity factor between rooftop and utility solar PV for those eight states. The onshore wind capacity factor also uses the state-specific capacity factor for the 30% RE-ITI scenario. For states that do not have wind capacity in 2030 at this renewable level, the capacity factor from the 80% RE-ITI scenario is used.

B.8.6.8 Retrofitting CCS.

This mitigation option, for the CCS subsystem described in Table B.32(c), will incur capital and O&M costs for the CCS and auxiliary power systems, the required retrofits to current subsystems, the CO_2 transport and saline sequestration costs, and the NG costs associated with the auxiliary power system. The LCOE contribution from the CCS plant and auxiliary boiler capital and O&M costs are calculated with parameters from a series of linear and nonlinear regressions based upon simulations of the cluster CFEGUs in the IECM. For retrofitting costs, we use information from the IECM regarding the impact of the CCS on the CFEGU base plant, SO_x subsystem, and the cooling water subsystem. These costs derive from the difference in the capital cost of these subsystems for the cluster CFEGUs with and without the CCS and auxiliary boiler. The model also accounts for the variations in sequestration expenditures associated with transportation and storage of the CO_2 product at variable capture rates. The NETL storage reservoir database [62] lists 228 CO_2 sequester sites within the U.S., which the model uses to determine the lowest overall cost from the combination of transportation and storage costs from the CFEGU to the line-of-sight center of the ten nearest sites, *Section B.8.8*. The resulting LCOE at the required capture rate to meet the intensity target is calculated from a linear interpolation of the LCOE for the CFEGU at a 10% and 90% capture rate.

The NG pipeline length, capital and O&M costs are determined using the methods from *Section B.8.7*. To levelize these costs for the LCOE calculation, a new net generation for the plant is determined to account for the surplus electricity produced by the auxiliary boiler that is sold on the grid. This supplemental electricity is a linear function of the coal-fired EGU heat rate, the coal type, the percent capture, and the original net generation.

The model employs a CCS subsystem that is powered by an NG auxiliary boiler for which the CO_2 is not captured. The CO_2 emission intensity for the plant also includes the additional emissions from the auxiliary boiler. This new total emission is a nonlinear function of the coal-fired EGU heat rate, the coal type, the percent capture, the original CO_2 intensity, and the new parasitic load. The parasitic load results from the supplemental load on the base-plant subsystems from the addition of the CCS system; and is a linear function of the coal-fired EGU heat rate, the coal type, the percent capture, and the original parasitic load.

The calculation for the CFEGU overall CO_2 emission intensity requires determining the relative percent intensity reduction due to CCS, the increased net generation from the auxiliary boiler, and the increase in parasitic load from the CCS. The regression for the relative percent reduction in CO_2 emission intensity is dependent upon the CCS capture rate, the coal type, the compliant heat rate and the new net generation (Eq. B.60, Table B.72). The regression describing this increase is dependent upon the coal type, the compliant CFEGU heat rate, and the original net generation of the EGU (Eq. B.61, Table B.73).

$$I_{CCS} = I_{HRI}\left(1 + \left(\beta_0 + \beta_1 G_{net} + \beta_2 hr_{HRI} + \beta_3 ccs + \beta_4 R_{bit} + \beta_5 R_{lig} + \beta_6 hr_{HRI}^2 + \beta_7 ccs^2\right)\right) \quad \text{(B.60)}$$

where I_{CCS} is the CFEGU emission intensity with the addition of the CCS subsystem $\left(\frac{lbs}{MWh}\right)$, I_{HRI} is the compliant CFEGU emission intensity after the HRI mitigation, G_{net} is the net generation of the compliant CFEGU (MWh), hr_{HRI} is the net heat rate of the compliant CFEGU with the HRI mitigation $\left(\frac{Btu}{MWh}\right)$, ccs is the capture rate for the CCS subsystem (fraction), R_{bit} is a dummy variable for the bituminous coal rank that is 1 if the EGU uses bituminous coal and is 0 otherwise, and R_{lig} is a dummy variable for the lignite coal rank that is 1 if the EGU uses lignite coal and is 0 otherwise.

$$G_{net1} = G_{net}\left(1 + (\beta_0 + \beta_1 ccs + \beta_2 hr_{HRI} ccs + \beta_3 R_{bit} ccs)\right) \quad \text{(B.61)}$$

where G_{net1} is the net generation of the retrofitted CFEGU with the addition of the generation from the auxiliary NG boiler (MWh), G_{net} is the net generation of the compliant CFEGU (MWh), ccs is the capture rate for the CCS subsystem (fraction), hr_{HRI} is the net heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, and R_{bit} is a dummy variable for the bituminous coal rank that is 1 if the EGU uses bituminous coal and is 0 otherwise.

Econometric analysis of the capital cost for the subsystem indicates that the cost can be predicted for each coal type from the CO_2 emission rate of the compliant CFEGU and the percent of capture (Eq. B.62 and Table B.74). The associated retrofitting percent capital cost for the CFEGU is composed of two parts. The first is the variable percent increase in component capital cost that increases with increasing percent capture; this is observed for the base-plant capital cost (Table B.75) and the wet-cooling tower capital (Table B.76). Each of these is determined by regressions on the percent difference in total capital cost for these subsystems at capture percentages between 10% and 90% relative to the CFEGU without capture. The base-plant retrofit cost percentage is a simple, linear fit from increasing of capture percentages (Eq. B.63), while those for the water tower are best predicted from the capture percentages, and the compliant CFEGU heat rate and net generation (Eq. B.64). The other component is the fixed percent increase in capital cost, Table B.77. This is the observed percent difference in total capital cost for these subsystems at 10% capture relative to the fully compliant case without capture. The fixed component is an additional offset to the variable component of the retrofitting cost for the base plant and the water tower (Eq. B.65), as without the fixed component the retrofit cost for each subsystem might be underestimated. For the SO_x wet scrubber, the fixed component (Eq. B.66) is the total retrofitting cost, as the capital cost does not increase as the percent capture increases. No significant increase in the capital cost for other subsystems is noted with the addition of CCS. The additional capital cost for the base and water tower are then defined with Eq. B.67 and Eq. B.68, respectively.

$$CC_{ccs} = \beta_{0,i} + \beta_{1,i} tons_{hr} + \beta_{2,i} ccs + \beta_{3,i} tons_{hr} ccs \tag{B.62}$$

where CC_{ccs} is the capital cost for the CCS subsystem (M$), $tons_{hr}$ is the emission rate of the CO_2 for the compliant CFEGU after the HRI mitigation $\left(\frac{tons}{hour}\right)$, *ccs* is the capture rate for the CCS subsystem (fraction), and the subscript *i* indicates the coal rank from which the coefficients come.

$$\Delta CC_{ccsbase} = \beta_{0,i} + \beta_{1,i}ccs, \tag{B.63}$$

where $\Delta CC_{ccsbase}$ is the additional capital cost for the base plant due to the capture rate of the CCS subsystem (M$), *ccs* is the capture rate for the CCS subsystem (fraction), and the subscript *i* indicates the coal rank from which the coefficients come.

$$\Delta CC_{ccsWT} = \beta_{0,i} + \beta_{1,i}hr + \beta_{2,i}G_{net} + \beta_{3,i}ccs + \beta_{4,i}hr_{HRI}G_{net} + \beta_{5,i}hrccs + \beta_{6,i}hr_{HRI}ccsG_{net} \tag{B.64}$$

where ΔCC_{ccsWT} is the additional capital cost for the wet-cooling tower due to the capture rate of the CCS subsystem (M$), G_{net} is the net generation of the compliant EGU (MWh), *ccs* is the capture rate for the CCS subsystem (fraction), and hr_{HRI} is the net heat rate of the compliant CFEGU $\left(\frac{Btu}{kWh}\right)$, and the subscript *i* indicates the coal rank from which the coefficients come.

$$\Delta CC_{ccsfix\,k} = \beta_{0,i,k} \tag{B.65}$$

where $\Delta CC_{ccsfix\,k}$ is the additional fixed capital cost for the base plant (fraction), WT, or SO_x emission control device due to the addition of a CCS subsystem, the subscript *i* indicates the coal rank from which the coefficient comes, and the subscript *k* indicates the CFEGU component.

$$CC_{CCSSOx} = \Delta CC_{ccsfixSOx} CC_{SOx} \tag{B.66}$$

where CC_{CCSSOx} is the total additional capital cost for the SO_x emission control device from retrofitting the CCS subsystem (M$), $\Delta CC_{ccsfixSOx}$ is the additional capital cost for the SO_x emission control device to add the CCS subsystem (fraction).

$$CC_{CCSbase} = CC_{base}\left(\left(1 + \Delta CC_{ccsbase}\right)\left(1 + \Delta CC_{ccsfix\,base}\right) - 1\right) \tag{B.67}$$

where $CC_{CCSbase}$ is the total additional capital cost for the base plant to retrofitting the CCS subsystem (M$), $\Delta CC_{ccsbase}$ is the additional capital cost for the base plant due to the capture rate of the CCS subsystem (fraction), CC_{base} is the capital cost for the compliant CFEGU base plant (M$), and $\Delta CC_{ccsfix\,base}$ is the additional capital cost for the base plant to add the CCS subsystem (fraction).

$$CC_{CCSWT} = CC_{WT}\left((1+\Delta CC_{ccsWT})(1+\Delta CC_{ccsfix\,WT})-1\right) \tag{B.68}$$

where CC_{CCSWT} is the total additional capital cost for the wet-cooling tower from retrofitting the CCS subsystem (M$), ΔCC_{ccsWT} is the additional cost for the wet-cooling tower due to the capture rate of the CCS subsystem (fraction), CC_{WT} is the wet-cooling tower capital cost for the compliant EGU (M$), $\Delta CC_{ccsfix\,WT}$ is the additional capital cost for the wet-cooling tower to add the CCS subsystem (fraction).

The addition of the CCS subsystem will increase the CFEGU LCOE due to the new capital and O&M costs, as well as upgrades or modifications to the existing plant. These costs are simulated with the proxy CFEGUs, with the capital costs for all components (except the NOx, SOx, and Hg ECDs) completely amortized before the addition of the fully amortized CCS subsystem that has no CO_2 transportation or storage costs. Regressions are then applied to determine the percent change in LCOE due to the CCS addition. The capital costs for the emission control devices are included in the simulations as a supplemental retrofit cost. Some of the variable material components of this cost include the NG for the auxiliary boiler, the reagent for the SO_x polisher, and the water and amines sorbent for the capture system. The relative percent increase in LCOE for each coal type is dependent upon the compliant CFEGU heat rate, the new net generation, the tons of CO_2 emitted per hour, and the capture rate (Eq. B.69 and Table B.78).

$$\varepsilon_{ccs} = \beta_{0,i} + \beta_{1,i}ccs + \beta_{2,i}ophrs + \beta_{3,i}I_{HRI} + \beta_{4,i}cap_{peak} + \beta_{5,i}ophrs(ccs) + \beta_{6,i}cap_{peak}(ccs) + \beta_{7,i}I_{HRI}(Iccs) + \beta_{8,i}ccs(ophrs)cap_{peak} + \beta_{9,i}ophrs(I_{HRI}) + \beta_{10,i}ophrs(I_{HRI})ccs \quad \text{(B.69)}$$

where ε_{ccs} is the relative increase in LCOE from the addition of a CCS subsystem (fraction), *ccs* is the capture rate for the CCS subsystem (fraction), *ophrs* is the annual operating hours for the EGU (hours), I_{HRI} is the EGU emission intensity for the CFEGU after the HRI mitigation $\left(\frac{lbs}{MWh}\right)$, cap_{peak} is the CFEGU capacity (MW), and the subscript *i* indicates the coal rank from which the coefficients come.

The LCOE related to the CO_2 and NG pipelines are other components of the CFEGU cost for CCS mitigation. The models for capital and O&M costs for the CO_2 transportation and storage are discussed in *Section B.8.8*. The calculation for the costs for the NG pipeline and compressor stations (*Section B.8.7*), are dependent upon the NG flow rate required to support the designed CO_2 capture rate. To determine the flow rate, the model predicts the percent increase in total plant fuel input over the case with no capture. As the NG auxiliary boiler provides the CCS subsystem energy, any increase in total fuel input is due to the NG consumption. Therefore, the NG fuel flow rate (Btu/hour) is determined by multiplying the percent increase in fuel by the CFEGU net heat rate before the CCS installation, and the original annual net generation, and then dividing this product by the operating hours. Econometric analysis of the flow rate independent variables shows that the capture rate has the greatest effect on NG consumption, and that the flow rate is dependent upon the coal type, CFEGU heat rate, and net generation (Eq. B.70 and Table B.79).

$$\dot{m}_{aux} = \frac{1000hr_{comply}G_{net}}{ophrs} \times \left(\beta_0 + \beta_1 G_{net} + \beta_2 hr_{HRI} + \beta_3 ccs + \beta_4 R_{bit} + \beta_5 R_{lig} + \beta_6 hr_{HRI}^2 + \beta_7 ccs^2\right) \quad \text{(B.70)}$$

where $\dot{m}_{aux}$ is the natural gas mass flow for the auxiliary NG boiler for the CCS subsystem $\left(\frac{Btu}{hour}\right)$, G_{net} is the net generation of the compliant CFEGU (MWh), *ophrs* is the annual operating hours,), hr_{HRI} is the net heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, *ccs* is the capture rate for the CCS subsystem (fraction), R_{bit} is a dummy variable for the bituminous coal rank that is 1 if the EGU uses bituminous coal and is 0 otherwise, R_{lig} is a dummy variable for the lignite coal rank that is 1 if the EGU uses lignite coal and is 0 otherwise, and 1,000 is the conversion from kWh to MWh.

The EGU LCOE for CCS mitigation is the sum of the aforementioned costs, Eq. B.71. Here the capital costs are annualized with the FCF based upon the lessor between the remaining years of operation and the book life for the CFEGU. Additionally, the net generation inclusive of that produced by the auxiliary natural gas boiler is used to levelize these costs.

$$LCOE_{CCS} = LCOE_{comply} + LCOE_{new} \times \varepsilon_{ccs} + \left(\frac{1\times10^{6}\left(CC_{ccs} + CC_{CCSbase} + CC_{CCSWT} + CC_{CCSSOx}\right)FCF_{remain}}{G_{net1}}\right) + LCOE_{CO_2pipe} + LCOE_{ngpipe} \quad \text{(B.71)}$$

where $LCOE_{CCS}$ is the total CFEGU LCOE from the addition of the CCS addition $\left(\frac{\$}{MWh}\right)$, $LCOE_{comply}$ is the LCOE for the compliant CFEGU $\left(\frac{\$}{MWh}\right)$, $LCOE_{new}$ is the LCOE for the compliant CFEGU equipped with new all new emission control devices $\left(\frac{\$}{MWh}\right)$, ε_{ccs} is the change in the compliant CFEGU LCOE due to the addition of the CCS subsystem (fraction), CC_{ccs} is the capital cost for CCS subsystem (M\$), $CC_{CCSbase}$ is the retrofit capital cost for the base plant (M\$), CC_{CCSWT} is the retrofit capital cost for the wet-cooling tower (M\$), CC_{CCSSOx} is the retrofit capital cost for the SO_x emission control device (M\$), FCF_{remain} is the fixed charge factor for the remaining life of the EGU (fraction), $LCOE_{CO_2pipe}$ is the levelized and annualized LCOE for the CO_2 transportation pipeline $\left(\frac{\$}{MWh}\right)$, $LCOE_{ngpipe}$ is the LCOE for the auxiliary boiler natural gas pipeline $\left(\frac{\$}{MWh}\right)$, and $1x10^6$ is a conversion for millions.

Table B.72. Coefficients of the regression model for estimating relative CO_2 emission intensity change associated with a percentage of CO_2 capture by CCS.*

β_0	β_1	β_2	β_3	β_4	β_5	β_6	β_7	R^2	RMSE
0.0423	$5.13x10^{-10}$	$2.41x10^{-6}$	-1.086	$6.05x10^{-3}$	0.00156	$-3.6x10^{-10}$	0.3	1	0.001

*n = 135

Table B.73. Coefficients of the regression model for estimating relative change in net generation from addition of auxiliary boiler employed for CCS.*

β_0	β_1	β_2	β_3	R^2	RMSE
-0.0309	0.0491	-0.0425	3.64×10^{-5}	.999	0.005

*n = 123

Table B.74. Coefficients of the regression model for capital cost for CCS subsystem (M$).

Coal type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	R^2	RMSE
Bituminous*	15.575	1.1×10^{-2}	11.415	1.287	.999	12.227
Sub-bituminous†	14.541	8.1×10^{-3}	6.622	1.318	1.000	4.443
Lignite‡	13.1	1.6×10^{-2}	17.115	1.283	1.000	5.779

*n = 69; †n = 41; ‡n = 27

Table B.75. Coefficients of the regression model for estimating fractional change in capital cost related to retrofits from addition of CCS subsystem as a function of CCS capture rate from 10% to 90%.

System Retrofit		Base Plant (increasing CCS)		
Coal/boiler type	$\beta_{0,i}$	$\beta_{1,i}$	R^2	**RMSE**
Bituminous*	5.5×10^{-4}	0.130	.972	0.007
Sub-bituminous†	6.2×10^{-4}	0.141	.985	0.005
Lignite/Subcritical‡	5.3×10^{-4}	0.15	.992	0.004
Lignite/Supercritical§	6.7×10^{-4}	0.144	1.000	0.001

*n = 92; †n = 52; ‡n = 20; §n = 16

Table B.76. Coefficients of the regression model for estimating fractional change in water tower capital cost from retrofits associated with CCS subsystem.

Coal/boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	R^2	RSME
Bituminous*	1.2×10^{-2}	0	0	0.235	0	2.8×10^{-5}	-4.4×10^{-7}	4.7×10^{-11}	.904	0.061
Sub-bituminous†	0.153	-1.2×10^{-5}	0	0.773	0	0	-1.0×10^{-6}	-1.0×10^{-10}	.926	0.061
Lignite/Subcritical‡	1.8×10^{-2}	0	-8×10^{-8}	2.99	7.4×10^{-12}	-1.8×10^{-4}	0	-1.1×10^{-11}	.979	0.030
Lignite/Supercritical§	-4.242	3.8×10^{-4}	0	0	0	4.2×10^{-5}	0	0	.927	0.041

*n = 92; †n = 52; ‡n = 20; §n = 16

Table B.77. Coefficients of the regression model for estimating fractional change in capital cost related to retrofits from addition of CCS subsystem.

System Retrofit	**SO_x (initial offset)**		**Base Plant (initial offset)**		**WT (initial offset)**	
Coal/boiler type	**$\beta_{0,i}$**	**St. Dev.**	**$\beta_{0,i}$**	**St. Dev.**	**$\beta_{0,i}$**	**St. Dev.**
Bituminous*	0.071	0.005	0.005	0.018	0.015	0.018
Sub-bituminous†	0.053	0.002	0.000	0.000	0.016	0.003
Lignite/Subcritical‡	0.065	0.002	0.000	0.000	0.018	0.003
Lignite/Supercritical§	0.065	0.002	0.000	0.000	0.015	0.002

*n = 23; †n = 13; ‡n = 5; §n = 4

Table B.78. Coefficients of the regression model for estimating relative fractional change in LCOE related to addition of CCS subsystem.

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	$\beta_{9,i}$	$\beta_{10,i}$	R^2	RMSE
Bituminous/ Subcritical*	0.095	0	0	0	0	2.0×10^{-4}	1.8×10^{-3}	0	-1.8×10^{-7}	0	0	.949	0.040
Bituminous/ Supercritical†	0.104	0	0	0	0	0	0	1.9×10^{-4}	0	0	0	.989	0.028
Sub-bituminous/ Subcritical‡	0.319	0	0	-8.6×10^{-5}	0	0	4.1×10^{-3}	-2.1×10^{-4}	0	0	0	.987	0.040
Sub-bituminous/ Supercritical§	0.086	7.979	0	0	0	0	0	-3.5×10^{-3}	0	0	0	.991	0.053
Lignite/Subcritical¶	0.168	0	2.1×10^{-3}	7.0×10^{-3}	0	2.0×10^{-4}	4.5×10^{-4}	0	0	-8.8×10^{-7}	0	.967	0.032
Lignite/Supercritical#	0.086	0	0	0	6.5×10^{-5}	0	0	$-3.5. \times 10^{-3}$	0	0	8.4×10^{-8}	.991	0.053

*n = 51; †n = 18; ‡n = 27; §n = 15; ¶n = 15; #n = 12

Table B.79. Coefficients of the regression model for estimating NG consumption (Btu/hour) of auxiliary boiler due to addition of CCS subsystem.*

β_0	β_1	β_2	β_3	β_4	β_5	β_6	β_7	R^2	RMSE
-1.3×10^{-2}	1.3×10^{-10}	$3. 3 \times 10^{-6}$	0.059	-0.012	8.7×10^{-4}	-1.5×10^{-10}	2.3×10^{-4}	.999	0.005

*n = 135

B.8.6.9 CCS energy-supply configurations.

In the IECM, there are three possible energy configurations to supply the steam necessary for the amine system to process the CO_2 effluent from an CFEGU retrofitted with CCS, Table B.80. In one configuration the subsystem uses some of the steam produced from the coal boiler for the amine processing. In this case, the net generation for the CFEGU decreases by 13% for a 90% capture rate, leading to a corresponding increase in the CFEGU heat rate. Another configuration uses the steam from an auxiliary NG boiler solely for the CO_2 process. Here, the net generation from the CFEGU remains at that for the compliant CFEGU. The third configuration, the one used in this model, steam from the auxiliary NG boiler is used in the amine process and to generate additional electricity (55% more than the no auxiliary boiler case, at 90% capture). Each of these configurations also has an impact on the emission intensity, as the CO_2 emissions from the auxiliary boiler are not captured, as such the LCOE for each will be impacted differently when a CO_2 tax is applied. This is not the case for the application of a CCS tax credit because the same quantity of CO_2 is captured for each configuration.

Wisconsin EGU ORIS Unique ID 4050_B_5 will have been in service for 45 years in 2030. Given an 80-year operational life, the FCF for the CCS mitigation is 11.28%. The LCOE for the CCS energy configuration without an auxiliary NG boiler is then \$63.6/MWh, inclusive of the CO_2 sequestration infrastructure and cost (Table B.81). This is more than \$8/MWh less expensive than the configuration used in the model and almost \$1/MWh less that for the NGCC mitigation for this CFEGU. Therefore, the energy configuration for CCS can have an impact on the frontier due to intensity and LCOE, though there are also the added impacts of reduced generation and possible change in dispatch order due to the increased heat rate.

Application of the \$50/tonne CCS tax credit can decrease the LCOE, but this relief is limited to 12 years [65]. When the credit is derated over the 30-year period for the LCOE calculation, the LCOE for the "no auxiliary boiler" configuration is then \$9/MWh less than that for the modeled CFEGU and \$3/MWh less than the alternative mitigation. This preference is reversed if the FCF is increased to reflect a shorter operational life for the CFEGU, or to match the duration of the tax credit. For a duration of 12 years, the FCF increases to 16.61%, Table B.82. Here, the "no auxiliary boiler" configuration is now \$11/MWh less expensive than the modeled configuration but \$6/MWh more expensive than the alternative mitigation, which still uses a 11.28% FCF because the book life of the mitigation is not impaired. Therefore, the remaining life of the CFEGU can affect the mitigation decision for a given energy configuration.

The net generation for each case is an additional consideration. While net generation is increased by 56% with the addition of the auxiliary boiler for steam and power, the net generation for the NGCC mitigation is not increased. Here, the capacity factor is limited to match the net generation of the existing CFEGU. When this restriction is removed and the capacity factor is limited to 87%, the net generation increases to 4,016,000 MWh and the LCOE decreases to \$50.5/MWh. This LCOE is lower than any in the previous scenarios. Furthermore, the CO_2 tax would need to be greater than \$41/tonne for cost parity with CCS without an auxiliary boiler and with the 45Q tax credit. Therefore, it may still be preferable to mitigate with NGCC than CCS for this CFEGU under some circumstances.

Table B.80. EGU-specific performance metrics for Wisconsin EGU ORIS Unique ID 4050_B_5 in different CCS energy configurations for a 90% capture rate.

EGU Metric	Units	Compliant	No NG Aux	NG Aux Steam	NG Aux Steam and Power
Net generation	GWh	2,457	2,149	2,457	3,334
Net heat rate	Btu/kWh	10,570	12,090	16,350	12,020
Net efficiency	fraction	.327	.282	.209	.284
Net CO_2 intensity	lbs/MWh	2,235	257	758	662

Table B.81. LCOE comparison for 11.28% FCF and 30-year life. CCS tax credit set at $50/tonne for 12 years. Units are $/MWh.

LCOE Component	Compliant	No NG Aux	NG Aux Steam	NG Aux Steam and Power	NGCC Conversion
Base	31.0	53.1	74.3	61.8	66.4
CCS transport	0	11.8	11.8	7.6	0
CO_2 storage	0	0.7	0.7	0.5	0
NG pipeline	0	0	6.3	4.1	0
Total LCOE	31.0	65.6	93.1	74.0	66.4
CCS tax credit	0	2.0	2.0	1.3	0
Overall LCOE	**31.0**	**63.6**	**91.1**	**72.7**	**66.4**

Table B.82. LCOE comparison for 16.61% FCF and 12-year life. CCS tax credit set at $50/tonne for 12 years.

LCOE Component	Compliant	No NG Aux.	NG Aux. Steam	NG Aux. Steam and Power	NGCC Conversion
Base	32.2	60.3	82.1	69.6	66.4
CCS transport	0	16.3	16.3	10.5	0
CO_2 storage	0	0.7	0.7	0.5	0
NG pipeline	0	0	9.1	5.9	0
Total LCOE	32.2	77.3	108.2	86.5	66.4
CCS tax credit	0	5.0	5.0	3.2	0
Overall LCOE	**32.2**	**72.3**	**103.2**	**83.2**	**66.4**

B.8.7 Natural gas pipeline cost

Co-firing with NG, converting to a 100% NG boiler or combined cycle power plants, and adding CCS with NG auxiliary boilers all depend upon the availability of NG at the CFEGU. The cost to bring NG to the individual CFEGUs is estimated in the model and is considered an expense added to the cost of the NG for the book life of the required pipeline. In the IPM v.5.13 [45], the EPA determines the pipeline length, in part, with line-of-sight from the EGU to the nearest main line. If the required mass flow to convert the CFEGU to 100% NG use is more than 10% of the mass flow for that main line, the EPA finds the next nearest line and taps up to 10% more NG from that line. This process continues until the mass flow for the conversion is met. The diameter for each of these lateral pipes is calculated from the maximum mass flow that the main line can supply with the 10% limit, if the CFEGU required mass flow, or the remaining required mass flow, is greater than that which the main line can supply, Eq B.72. The cost for each lateral (Eq. B.73) is then calculated and summed to get the total cost and the total pipeline miles is the summation of the laterals. These values are used to determine the average lateral length.

$$D = (14.83Q)^{0.37495} \tag{B.72}$$

where D is the diameter of the NG lateral pipeline (inches), Q is the mass flow (million cubic feet per day), and 14,83 and 0.37495 are EPA derived constants from application of the Weymouth Equation.

$$C = 90{,}000(D)(miles) \tag{B.73}$$

where C is the cost of the lateral pipeline of the NG lateral pipe (dollars), D is the pipeline diameter (inches), *miles* is the lateral length (miles), and 90,000 is the total cost per diameter-mile of the pipeline ($/in-mile).

The above equations and the IPM values for cost and miles are used to back-calculate for the average diameter and mass flow, to determine the estimated pipeline costs for ESTEAM. Given the number of laterals, we can also calculate the average length for each lateral. With these numbers, we can then use the ESTEAM mass flows and determine the average lateral flow by dividing the ESTEAM mass flow by the number of laterals. The number of laterals required is found by dividing the total required ESTEAM mass flow for the CFEGU by the average mass flow for that CFEGU from the IPM model, Eq. B.74.

$$Lat = \left\lfloor {}^{Q_{Esteam}}\!/_{Q_{IPM}} \right\rfloor + 1 \tag{B.74}$$

where Lat is the number of required lateral pipelines, Q_{ESTEAM} is the required NG mass flow for the CFEGU for the given mitigation (million cubic feet per day), and Q_{IPM} is the average NG mass flow for the EGU found in IPM (million cubic feet per day).

The pipeline construction cost (CC_{pipe}) is estimated with national average costs for the right of way, materials, labor and miscellaneous charges as a function of the length and diameter of the pipeline and have a 42% average percent error, as outlined in [64]: cost projections that tend to be higher than costs quotations by industry experts [65]. As there are large variations in the dataset for CFEGU-specific pipeline distances and mass flows (Eq. B.75) necessary for the mitigation options studied, this study does not use a fixed dollar per mile pipeline cost: the cost is estimated from the CFEGU-specific mass flow, $\dot{m}_{NG}$, with the Panhandle A equation for pipeline diameter and utilized natural gas transportation pressure ranges [66] from 200 to 1,500 lbs per square inch gauge (psig).

$$\dot{m}_{NG} = 24\left[\left(\frac{1000(hr_{NG})(G_{net})(NG)}{1028(ophrs)}\right)\Big/\left(\left(\frac{P_{std}}{P_{act}}\right)\left(\frac{T_{act}}{T_{std}}\right)\right)\right] \quad \text{(B.75)}$$

where $\dot{m}_{NG}$ is the mass flow $\left(\frac{scft}{day}\right)$, hr_{NG} is the CFEGU heat rate adjusted for NG use, *ophrs* is the annual operating hours, P_{std} is the standard pressure (14.7 lbs per square inch absolute), P_{act} is the actual pressure (14.7 lbs per square inch absolute, IECM default), T_{act} is the actual temperature (537 °R, IECM default), T_{std} is the standard temperature (520 °R), 1000 is the conversion from kWh to MWh, 1028 is the EIA reported [67] average heat content (Btu/cubic foot) of consumer delivered NG from 2003 to 2016, and 24 is the number of hours in a day.

An additional pipeline construction cost is the compressor stations that are often installed at 40 to 100-mile intervals, depending upon terrain, to boost the line pressure [66]. For the model, we assume that the stations are installed every 50 miles and the number of stations is rounded down to the nearest 50 miles. To approximate the capital cost for each station, the model uses the cost estimation for CO_2 booster stations in the IECM [68] that is based on a regression derived by the International Energy Agency for reciprocating compressors capital costs. This cost is expressed as

$$CC_{comp} = 8.35P + 0.49 \tag{B.76}$$

where CC_{comp} is the capital cost for the compressor station, (2004 M$), P is the power (MW) of the compressor station. The power (W) required by the adiabatic compressor to maintain the pressure is expressed in Eq. B.77:

$$W = \frac{1}{\eta}\left(\frac{\dot{m}_{NG}RT}{M}\right)\left(\frac{\gamma}{\gamma-1}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1\right] \tag{B.77}$$

where W is the required power (W), η is the efficiency factor of compressor (fraction); $\dot{m}_{NG}$ is the gas flow rate (kg/sec); R is the gas constant; T is the compressor temperature (°K); M is the molecular weight (kg/mole); P_1 is the pump inlet pressure (Pascal); P_2 is the pump outlet pressure (Pascal); and γ is the gas expansion factor (dimensionless), Table B.83.

The capital cost portion of the LCOE for the required pipeline and compressor station then becomes the levelized product of the capital cost for these additions and the FCF that is levelized by the net generation for the CFEGU:

$$CC_{ngpipe} = \frac{1\times10^{6}(CC_{pipe}+CC_{comp})FCF_{remain}}{G_{netx}} \tag{B.78}$$

where CC_{ngpipe} is the annualized and levelized capital cost component of the NG pipeline LCOE ($\frac{\$}{MWh}$), CC_{pipe} is the capital cost of the natural gas pipeline (M$), CC_{comp} is the capital cost of natural gas compressor stations (M$), FCF_{remain} is the fixed charge factor for the remaining life of the EGU (fraction), G_{netx} is the EGU net generation that is appropriate for the mitigation (MWh), and $1\text{x}10^6$ is the conversion factor from millions of dollars to dollars.

The O&M portion of the LCOE for the pipeline, includes the levelized operating cost for the power for the compressor stations and the levelized maintenance cost for the pipeline. For simplicity, we assume that the electric grid powers the compressor station at the U.S. average industrial price of electricity in 2010 [69], and that the pipeline cost is fixed at $5,000 per mile, which is assumed to include any maintenance cost for a required compressor station [67]. The levelized, annual O&M cost for the NG pipeline is then expressed as

$$OM_{ngpipe} = \left(5000L + n\frac{EWh}{1000}\right)/G_{netx} \tag{B.79}$$

where OM_{ngpipe} is the O&M cost for the NG pipeline ($\frac{\$}{MWh}$), L is the pipeline length (miles), E is the average industrial price for electricity ($0.067/kWh) [69], n is the number of compressor stations, W is the power required for the compressor (Watts), h is the EGU annual hours of operation, G_{netx} is the EGU net generation that is appropriate for the mitigation (MWh), 5000 is the maintenance cost per mile of pipeline length ($/mile), and 1000 is the conversion factor for kWh to MWh.

The NG pipeline LCOE is then the summation of the capital and O&M components, Eq. B.80.

$$LCOE_{ngpipe} = CC_{ngpipe} + OM_{ngpipe} \tag{B.80}$$

where $LCOE_{ngpipe}$ is the LCOE of the NG pipeline ($\frac{\$}{MWh}$), CC_{ngpipe} is the annualized and levelized capital cost component of the NG pipeline LCOE ($\frac{\$}{MWh}$), and OM_{ngpipe} is the O&M cost for the NG pipeline ($\frac{\$}{MWh}$).

Table B.83. Constants used in NG compressor housing calculations.

Parameter	Symbol	Units	Value
Expansion factor for NG	γ	none	1.3
Compressor station temperature	T	°R	563.67
Compressor overall efficiency	η	fraction	.792
NG inlet pressure	P_1	Psi	1,200
NG outlet pressure	P_2	Pa	1,500
Molecular weight NG	M	lbs/mole	0.035
NG energy content per pound fuel	None	Btu/lb	22,480
Electricity price	None	$/kWh	0.067

B.8.8 CO_2 transportation and storage costs

The calculations for the capital cost for the CO_2 transportation is based upon an energy balance equation, as derived in [68], with the inlet and outlet pressures held constant over pipe segment lengths that is of 50 miles. To determine the capital cost for the pipeline, a similar process is followed as in the NG pipeline cost estimation, with CO_2 properties used in lieu of NG properties (Tables B.84 and B.85). The length of the pipeline for this calculation is conservatively approximated as the line-of-sight distance between the CFEGU and the center of the sequestration site; therefore, the model does not compensate for details such as the pipe thickness, nor use the nearest standard pipe size that is greater than the iterated pipe diameter. These details would be more important if one considered optimizing the pipeline route for the terrain [65,71,72], or for a network that gathered effluent from various power plants and transported it to a common set of injection wells located at the sequestration site [72-75].

The capital cost for the CO_2 compressor stations is calculated in the same manner as for the NG compressor stations. As with the natural gas pipeline cost, the capital cost portion of the LCOE for the required CO_2 pipeline is annualized with the FCF and levelized with the CFEGU net generation, Eq. B.81.

$$CC_{CO_2pipe} = \frac{1\times10^6(CC_{pipe}+CC_{comp})FCF_{remain}}{G_{net1}} \tag{B.81}$$

where CC_{CO_2pipe} is the annualized and levelized capital cost component of the CO_2 pipeline LCOE ($\frac{\$}{MWh}$), CC_{pipe} is the capital cost of the natural gas pipeline (M\$), CC_{comp} is the capital cost of natural gas compressor stations (M\$), FCF_{remain} is the fixed charge factor for the remaining life of the CFEGU (fraction), G_{net1} is the CFEGU net generation (MWh) including generation from the CCS auxiliary NG boiler, and 1×10^6 is the conversion factor from millions of dollars to dollars.

The CCS O&M costs related to transport and storage are those for the pipeline, the compressor station and the sequestration site. The pipeline O&M cost is taken as the same as that for the NG pipeline at $5,000 per mile. Similarly, the cost for the compressor station is based upon the amount of work done by the compressor (Eq. B.77) and uses the same power assumptions as for the NG case. The additional cost of sequestration is added and levelized to obtain the full O&M cost:

$$OM_{CO_2\,pipe} = \left(5000L + n\frac{EWh}{1000} + \frac{I_{HRI} G_{net} \dot{C} S}{2000}\right) / G_{net1} \qquad \text{(B.82)}$$

where $OM_{CO_2\,pipe}$ is the O&M cost for the CO_2 pipeline ($\frac{\$}{MWh}$), L is the CO_2 pipeline length (miles), E is the cost of electricity ($0.067/kWh),[63] n is the number of compressor stations, W is the power required for the compressor (Watts), h is the CFEGU annual hours of operation, I_{HRI} is the net emission intensity of the compliant CFEGU after the HRI mitigation and before CCS mitigation (lbs/MWh), G_{net} is the CFEGU net generation (MWh) excluding generation from the CCS auxiliary NG boiler, $\dot{C}$ is the CO_2 capture rate (fraction), S is the CO_2 storage cost ($/ton), G_{net1} is the CFEGU net generation (MWh) including generation from the CCS auxiliary NG boiler, 5000 is the maintenance cost of the pipeline ($/mile), 1000 is the conversion factor for kWh to MWh, and 2000 is the conversion factor for pounds to tons.

The CO_2 transportation and storage LCOE is then the summation of the capital and O&M components, Eq. B.83.

$$LCOE_{CO_2\,pipe} = CC_{CO_2 pipe} + \ OM_{CO_2\,pipe} \tag{B.83}$$

where $LCOE_{CO_2\,pipe}$is the LCOE of the CO_2 pipeline and storage ($\frac{\$}{MWh}$), $CC_{CO_2 pipe}$ is the annualized and levelized capital cost component of the CO_2 pipeline LCOE ($\frac{\$}{MWh}$), and $OM_{CO_2\,pipe}$ is the O&M cost for the CO_2 pipeline and storage ($\frac{\$}{MWh}$).

As the model is EGU-specific, the pipeline length to the sequestration site and the associated storage cost used in the calculations are site-specific and capture rate-specific. This is necessary because while transportation and storage costs vary between sites, a site with a low transportation cost but high storage cost may be economical for low capture rates but costly at a high capture rate [75-77]. Therefore, the total transport and storage cost for the ten nearest line-of-site storage areas, which are of adequate capacity, to each CFEGU are calculated at multiple capture rates (10%, 40%, and 90%) to determine the site for each CFEGU with the lowest overall increase in LCOE at the desired capture rate. Data from the NETL saline storage reservoir database [62,78] concerning location, storage cost, and storage volume for 228 sequestration sites are used for these calculations.

Table B.84. Constants used in CO_2 pipeline diameter calculations.

Parameter	Symbol	Units	Value
Average compressibility	Z_{ave}	none	0.22
Average Temperature (ground temperature)	T_{ave}	°R	501.75
Molecular weight CO_2	M	lbs/mole	0.097
CO_2 inlet pressure	p_1	Psi	1,500
CO_2 outlet pressure	p_2	Psi	1,200
CO_2 average pressure	P_{ave}	Psi	1,761.9
Elevation difference between pipe inlet and outlet	Δh	ft	0
Pipe roughness	ε	in	1.80×10^{-3}
Supercritical CO_2 viscosity	μ	lbs/(ft-s)	7.46×10^{-8}
Supercritical CO_2 density	ρ	lbs/ft^3	59.93
Initial flow velocity for diameter iteration	V_0	ft/s	4.46

Table B.85. Constants used in CO_2 compressor housing calculations.

Parameter	Symbol	Units	Value
Expansion factor for CO_2	γ	none	1.4
Compressor station temperature	T	°R	563.67
Compressor overall efficiency	η	fraction	.792
CO_2 inlet pressure	P_1	Psi	1,500
CO_2 outlet pressure	P_2	Psi	1,200
Molecular weight CO_2	M	lbs/mole	0.097
Electricity price	None	$/kWh	0.067

B.8.9 State mitigation calculation

Table B.86. 2012 historical state-specific coal and natural gas prices, and 2030 base case scenario natural gas increase. 2012 coal prices are decreased 3% for 2030 base case scenario. Omitted states had no coal-fired power plants in 2012.

State	Bituminous ($/MMBtu)	Sub-bituminous ($/MMBtu)	Lignite ($/MMBtu)	NG ($/MMBtu)	Increase NG Price, 2030 (fraction)
Alabama	$3.45	$2.16	$1.87*	$2.89	0.62
Arizona	$1.92	$2.06	$1.65*	$3.27	0.33
Arkansas	$2.11*	$2.20	$1.99*	$2.96	0.55
Colorado	$2.21	$1.73	$1.65*	$3.81	0.33
Connecticut	$3.61*	$4.56	$1.84†	$3.68	0.30
Delaware	$4.12	$2.35*	$1.84†	$3.14	0.41
Florida	$3.41	$3.42*	$1.84†	$4.49	0.41
Georgia	$4.34	$2.30	$1.84†	$3.18	0.41
Illinois	$1.55	$1.93	$1.84†	$3.09	0.55
Indiana	$2.36	$2.56	$1.84†	$2.86	0.55
Iowa	$2.56*	$1.44	$1.51*	$3.99	0.55
Kansas	$2.20	$1.79	$1.51*	$3.06	0.55
Kentucky	$2.27	$2.20	$1.87*	$3.34	0.62
Louisiana	$2.97	$2.26	$3.22	$2.79	0.55
Maryland	$3.73	$4.08	$1.84†	$3.00	0.41
Massachusetts	$3.08	$4.56*	$1.84†	$3.37	0.30
Michigan	$3.52	$2.73	$1.84†	$3.00	0.55
Minnesota	$3.34	$2.00	$1.51*	$3.52	0.55
Mississippi	$3.86	$3.21	$1.87	$2.76	0.62
Missouri	$2.66	$1.83	$1.51*	$3.29	0.55
Montana	$1.90*	$1.33	$1.65	$3.86	0.33
Nebraska	$2.56*	$1.50	$1.51*	$3.66	0.55
Nevada	$2.32	$2.72	$1.65*	$3.23	0.33
New Hampshire	$4.31	$4.56*	$1.84†	$5.26	0.38
New Mexico	$2.00	$1.90	$1.65*	$3.18	0.33
New York	$3.15	$3.14	$1.84†	$3.65	0.21
North Carolina	$3.78	$2.35*	$1.84†	$4.14	0.41
North Dakota	$2.56*	$1.79	$1.51*	$5.42	0.55
Ohio	$2.43	$3.24	$1.84†	$2.83	0.55
Oklahoma	$1.49*	$1.95	$1.99	$2.81	0.55
Oregon	$3.22*	$1.80	$1.84†	$2.93	0.33
Pennsylvania	$2.55	$3.15*	$1.84†	$2.90	0.21
South Carolina	$4.03	$2.35*	$1.84†	$3.44	0.41
Tennessee	$2.59	$2.56	$1.87*	$2.73	0.62
Texas	$2.11*	$1.87	$1.88	$2.78	0.55
Utah	$1.73	$2.48	$1.65*	$2.79	0.33

Notes: *: Regional default price; †: U.S. default price.

Table B.86. Continued… 2012 historical state-specific coal and natural gas prices, and 2030 base case scenario natural gas increase. 2012 coal prices are increased 3% for 2030 base case scenario. Omitted states had no coal-fired power plants in 2012.

State	Bituminous ($/MMBtu)	Sub-bituminous ($/MMBtu)	Lignite ($/MMBtu)	NG ($/MMBtu)	Increase NG Price, 2030 (fraction)
Virginia	$3.53	$2.35	$1.84†	$3.11	0.41
Washington	$3.22*	$2.11*	$1.84†	$4.13	0.33
West Virginia	$2.54	$3.75	$1.84†	$3.04	0.41
Wisconsin	$3.51	$2.25	$1.84*	$3.06	0.55
Wyoming	$1.90*	$1.43	$1.65	$5.57	0.33

Notes: *: Regional default price; †: U.S. default price.

B.9 Validation

Many of the underlying equations to determine the LCOE or emission intensity of the current, compliant, and mitigated CFEGU states are derived from regressions based upon simulations of CFEGUs in the IECM or from similar analyses. These regressions are implemented piecewise into the model such that there is no one equation based upon one regression that can solely describe the LCOE or intensity of an CFEGU for these states. Therefore, the accuracy of the model equations for these metrics, relative to the simulations upon which these piecewise regressions are based, can be demonstrated by assessing the difference in these metrics as obtained with the two methods. To determine the accuracy, nine CFEGUs that span the capacity and net generation range for the sub-bituminous subcritical cluster are modeled and simulated in the IECM. The CFEGU baseline operating parameters are used for inputs in the comparison, as are default IECM coal and natural gas prices. Since the IECM simulation does not address all options in ESTEAM and uses different equations and values to determine some costs, some of these ESTEAM costs are calculated external to the IECM component-level simulation results.

When the IECM simulated LCOE is subtracted from the modeled LCOE, Figure B.8, the difference for the compliant and mitigated CFEGUs tends to be within ± $4/MWh. In all but one case, this difference falls between the 95% tolerance limits for the metric, which are established with the uncertainty analysis for Wisconsin CFEGU ORIS Unique ID 4050_B_5 at the low and high1 uncertainty levels; the one LCOE point, Figure B.8(h), that is not within the 95% confidence bounds is within 10% of the $61/MWh IECM value. Furthermore, the difference tends to be unbiased with regard to capacity for all mitigations—except for the supercritical and ultra-supercritical boiler retrofits, Figures B.8(e) and B.8(f). Here, the LCOE overestimation of the regressed model decreases with increasing capacity. This initial bias relates to overestimating the capital cost of the power plant components used to determine the retrofitting cost, for the smaller capacity CFEGUs. Therefore, any bias that is added to compliant or mitigated configurations to derive the LCOE component of the least-cost frontier may be associated with lower capacity CFEGUs that have costly LCOEs and may not be on the least-cost frontier at the associated state-level aggregation.

In calculating the intensity metric, there is an initial difference between regressed and simulated complaint intensity values that will subsequently affect the comparison for the mitigated intensities, Figure B.9. This difference is large enough for four CFEGUs in the compliant state that the differences in intensity exceed the 95% tolerance limits established in the uncertainty analysis, with absolute differences between 70-300 lbs/MWh, Figure B.9(a). The percent differences relative to the simulated intensity range from 3% for the differences near 70 lbs/MWh to 13% for the 300 lbs/MWh difference. However, the percent difference for the mitigations is the same as that for the compliant case, which indicates that there is not additional model error. Therefore, the initial offset does not affect the relative change in compliant emission intensity because of the mitigation measures nor the least-cost frontier for an individual CFEGU.

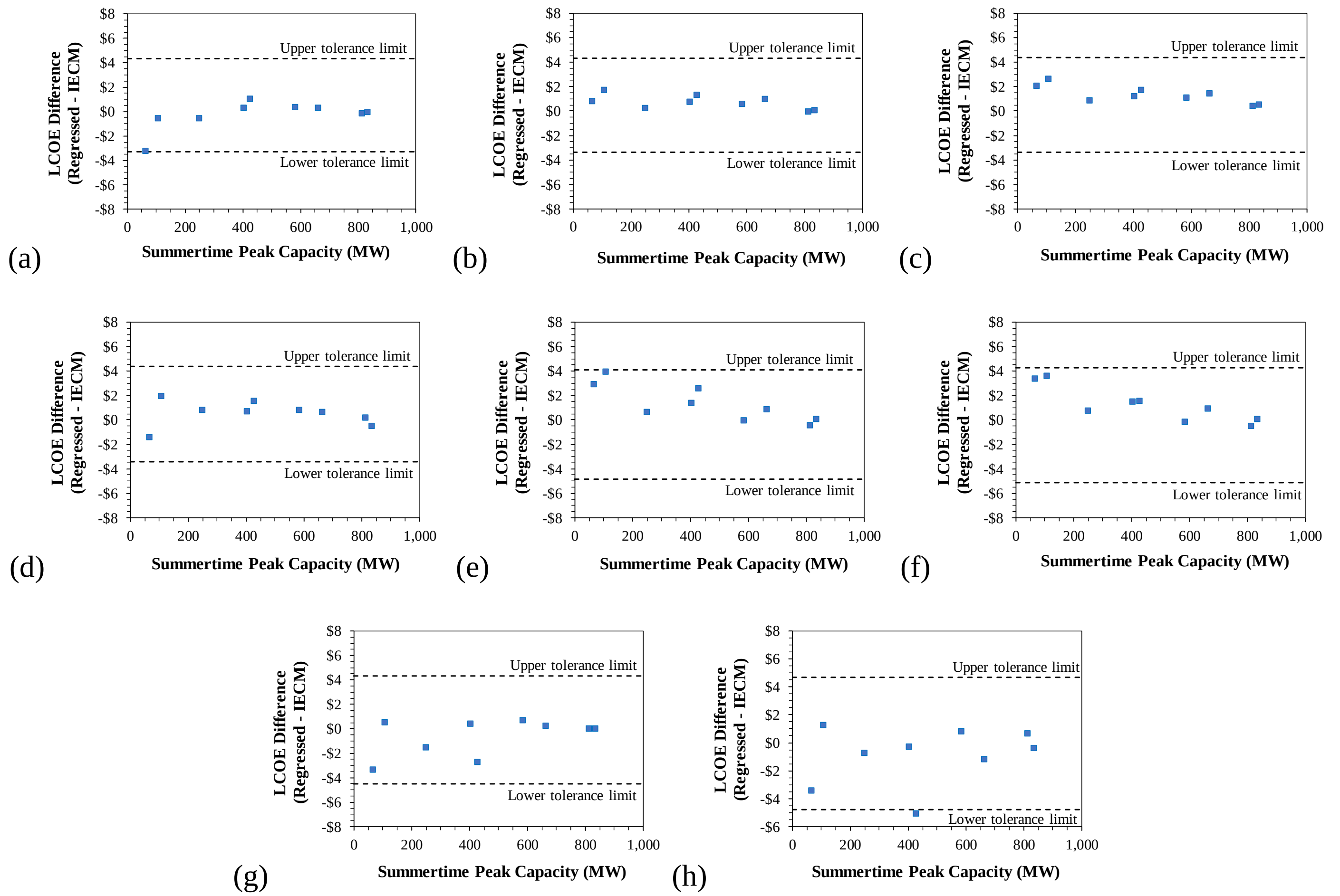

Figure B.8. LCOE validation for compliant (a), subbituminous subcritical EGUs with the various mitigation measures: (b) 5% natural gas co-fire, (c) 20% natural gas co-fire, (d) coal rank upgrade, (e) supercritical upgrade, (f) ultra-supercritical upgrade, (g) CCS with a 10% capture rate, and (h) CCS with a 90% capture rate. These validations are the difference between the LCOE of the CFEGUs as simulated in the IECM and those as determined with the model equations for the default operating conditions and commodity prices. The nine CFEGUs were selected to span the capacity range for this cluster. The dashed horizontal lines represent the 95% tolerance limits for the metric, as determined in the uncertainty analysis for Wisconsin CFEGU ORIS Unique ID 4050_B_5 at the low and high1 uncertainty levels, without cost adders in Tables B.14-B.21. One LCOE point is not within the tolerance limits; this point is within 10% of the IECM value.

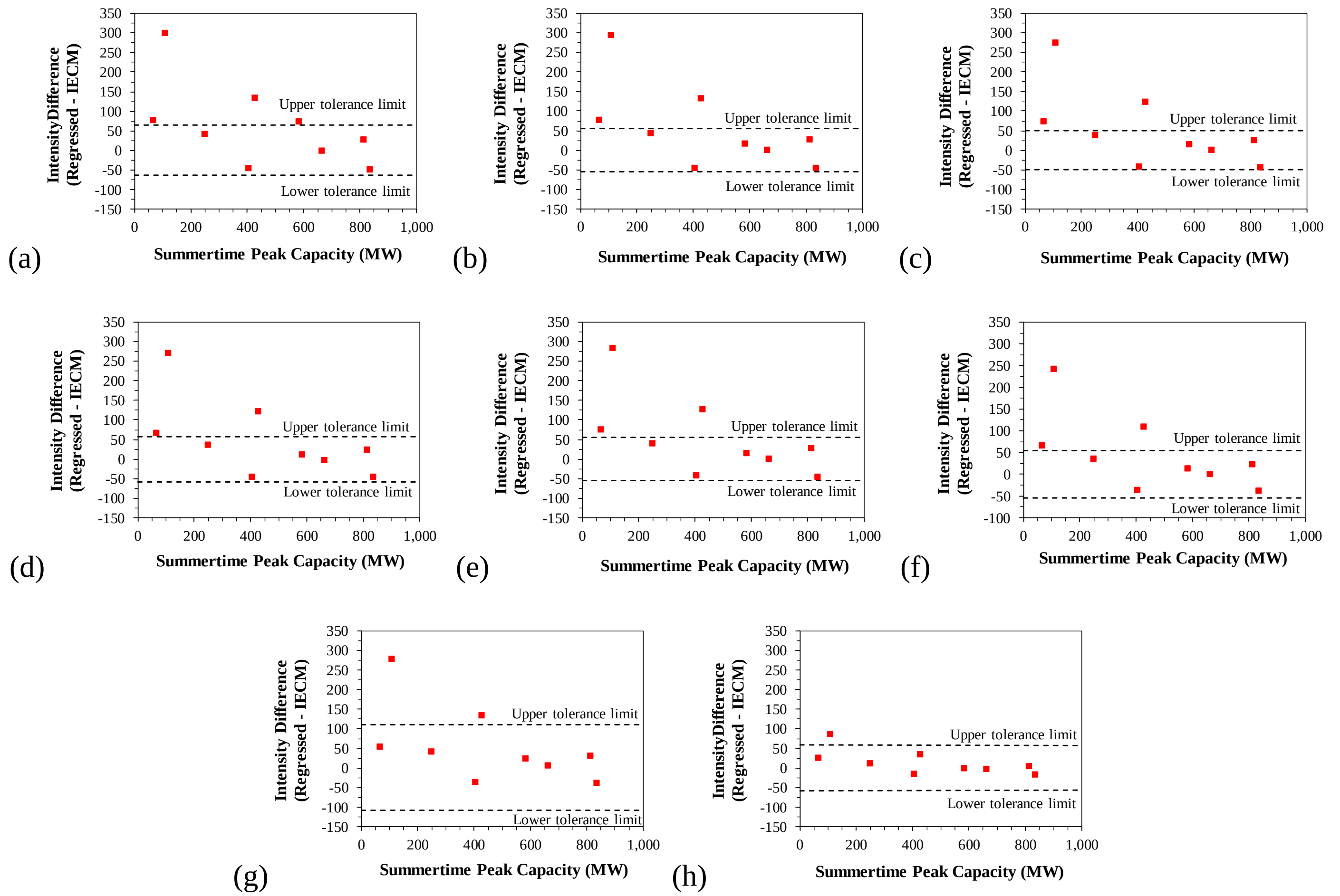

Figure B.9. Carbon dioxide emission intensity validation for compliant (a), sub-bituminous subcritical EGUs with the various mitigation measures: (b) 5% natural gas co-fire, (c) 20% natural gas co-fire, (d) coal rank upgrade, (e) supercritical upgrade, (f) ultra-supercritical upgrade, (g) CCS with a 10% capture rate, and (h) CCS with a 90% capture rate. These validations are the difference between the intensity of the CFEGUs as simulated in the IECM and those as determined with the model equations for the default operating conditions and commodity prices. The nine CFEGUs were selected to span the capacity range for this cluster. The dashed horizontal lines represent the 95% tolerance limits for the metric, as determined in the uncertainty analysis for Wisconsin CFEGU ORIS Unique ID 4050_B_5 at the low and high1 uncertainty levels, Tables B.22-B.29. For each validation, at least one intensity point is not within the tolerance limits; these points are within 3-13% of the IECM values.

B.10 Sensitivity analysis

Two observations can be drawn from analysis of these least-cost frontier examples (See *Section B.5* and *B.6* for dataset observations). First, NG co-fire and CCS mitigations, for which the reduction intensity depends upon the rate at which the mitigation is applied, may be on the frontier for only a portion of the overall range of applicable rates. The economic viability of these effective rates will vary for different CFEGUs and under different constraints, necessitating an EGU-level analysis of the options. For example, if changing coal rank is not an option because of CFEGU design, coal availability, existing coal contracts, or state and site-specific considerations, then the rates for which NG co-fire will be the least-cost option may expand, Figure 3.4(d). Similarly, if upgrading steam generators without CCS is not permitted by regulators, then the CCS capture rates may expand, because the steam-generator upgrade would no longer be an option in this model (Figures 3.3, 3.4). For CCS, higher retrofitting costs and shorter amortization periods may reduce the economically viable capture rates, *ceteris paribus*.

Second, CFEGU-specific characteristics can alter the frontier, as not all mitigations are equally affected by variations in specific characteristics of the physical plant or the related requirements of the mitigation. Two mitigation requirements related to the physical location of the CFEGU are the distances to the sequestration site and the NG source. Decreasing the CO_2 pipeline cost by decreasing the required pipeline length by 20%, Table 3.4, affects only the CCS mitigation, resulting in CCS at a 22-27% capture rate now being on the frontier for an intensity range of 1,684-1,771 lbs/MWh, Figure B.10(b). Similarly, increasing the NG pipeline length by 20% increases the cost for any mitigation using NG, though it does not affect them all equally because the pipe diameter differs for each mitigation. At this variation level, the cost increases are insufficient to change the mitigations on the frontier but the costs for these NG mitigations increase, Figure B.10(c).

The physical properties of the boiler will also affect the mitigation cost. If the heat rate is greater because the boiler or plant efficiency has degraded due to cycling, maintenance, or age, this will affect the emission intensity and LCOE for all mitigations that retain the characteristics of the boiler or plant, Figure B.10(d). For a 20% increase in heat rate, the only mitigation that remains on the frontier is the NGCC conversion, because the power island is replaced. CCS mitigation at a 14-23% capture rate is now on the frontier for an intensity range of 1,960-2,125 lbs/MWh. This mitigation now dominates NG retrofit within this range because the lowered efficiency for NG retrofit increases the VOM.

The boiler age may also affect the FCF for mitigations due to expected retirement, which can be a proxy for restricting the operation of any fossil-fuel mitigation solution beyond 2030. If the boiler is only able to operate until 2050, because of age or regulatory requirement, the CFEGU FCF increases to 13%. This increase does not change the mitigations on the frontier, Figure B.10(e), but does asymmetrically increase the LCOEs for all mitigations, according to capital costs from Figure 5. Restricting the operation further to 2040 increases the FCF to 18% and increases the mitigations with high capital costs further from the original frontier, Figure B.10(f). Here, the low capital cost of NG retrofit as a moderate emission-reduction mitigation is less affected by the higher financial premiums that may come with possible stranding.

The configuration of the CFEGU prior to mitigation can also affect the frontier. If the ECDs are not added until 2030, the LCOE for all coal-fired mitigation will increase over the default case, Figure B.10(g). For the Wisconsin EGU, the later addition increases the mitigated LCOEs by approximately $2/MWh.

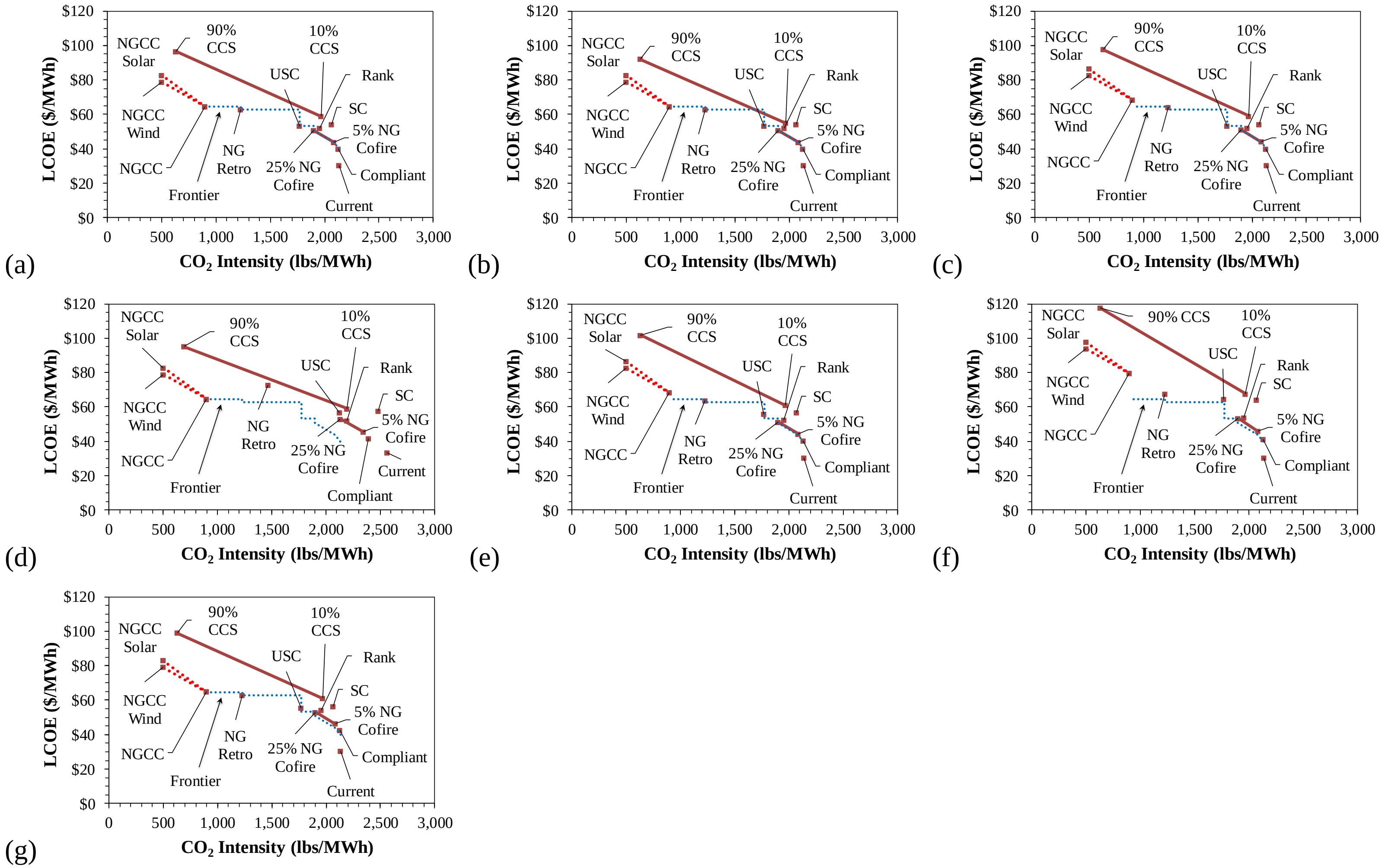

Figure B.10. Sensitivity of the Wisconsin CFEGU to EGU-specific characteristics: (a) default, (b) 20% CO_2 pipeline length decrease, (c) 20% NG pipeline length increase, (d) 20% heat rate increase, (e) 20-year book life, (f) 10-year book life, and (g) ECDs added in 2030.

B.11 Conversion table.

Table B.87. Conversion table from U.S. Customary units to Standard International units

U.S. Customary Unit	Equivalent	SI Unit
1 Btu	1,055.06	Joules
1 Mile	1.6093	kilometers
1 pound (mass)	0.454	kilograms
1 ton (short)	0.9072	metric tons

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Appendix C: Rate-based emission reduction at the EGU-, state-, and national-level

The work in this appendix was rejected by the *Proceedings of the National Academy of Sciences* and by *Environmental Science & Technology*.

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C.1 Background

In 2009, CO_2 emissions comprised almost 82% of total energy-related GHG emissions in the U.S., of which 40% were produced by the power sector [1]. In the same year, the U.S. Environmental Protection Agency determined that well-mixed GHG emissions from new motor vehicles threaten current and future public health and welfare related to climate change [2]. As a result and motivated by the U.S. Supreme Court’s decision in *Massachusetts v Environmental Protection Agency* [3], the EPA began to treat CO_2 as a pollutant and sought to regulate it under Section 111(b) and Section 111(d) of the Clean Air Act. These efforts have taken many forms over the years, including the Clean Power Plan [4] and the Affordable Clean Energy rule [5].

The policy uncertainty created by political volatility regarding reducing CO_2 emissions in power-sector (and the indeterminacy in the promulgated methods, limits, and timing of future regulations), may require more focus on mitigating existing coal-fired sources. The potential of mitigations to achieve specific CO_2 emission intensity targets for these power sources can be derived through a bottom-up modeling approach of EGU-specific, least-cost mitigation-technology frontiers. Utilizing these frontiers to determine the set of economically feasible mitigations can lead to insights such as lower LCOE for the state-level and national power fleet through greater utilization of existing coal-fired generation, while achieving a deeper emission-intensity reduction than those accorded in previous policies. Such an approach may be increasingly useful to formulate and analyze future policies requiring greater dependence on variable renewable-energy; as these policies may necessitate mid-term reliance on existing coal-based power-sector infrastructure, while the development and deployment of the requisite technology, operation, and market transformations necessary to ensure grid resilience are underway [46-52]. Furthermore, disaggregation and expanding the mitigation-technology set to include both early-development and mature-stage options with variable ranges can facilitate comparison to other policy options to understand better the least-cost feasible mitigation strategy.

To look at the EGU-level mitigation options available to meet a national rate-based target applied at the state-level with the ESTEAM model, we first calculate the unique least-cost mitigation frontiers for each coal-fired EGU in a given state, with U.S. Energy Information Administration projected 2030 fuel prices, as discussed in Chapter 3. Agnostic to any policy mechanism, ESTEAM then identifies the fleet-wide, minimum-

LCOE solution that satisfies a CO_2 emission intensity target for each state coal-fleet to meet a desired reduction in net power-sector emission intensity from 2005 levels, given both expected net generation from non-coal sources and total electricity demand. These solutions are in turn aggregated at the national level to create a mitigation-technology profile that illustrates the fleet mitigation-capacity preferences and LCOE for various emission intensity targets. From this, we evaluate the importance of fuel prices for mitigation decisions at the CFEGU, state, and national level. We further examine the impact and limitations of heat rate improvement (HRI) in the presence of fungible mitigations, the possible role of ultra-supercritical (USC) steam-generator upgrades for mitigation, the usage of carbon capture and storage (CCS) at various emission intensity reduction levels, and the impact of the CCS tax credit [53] on this usage.

C.2 Materials and methods

In this work, additional databases are used, and methods developed to those discussed in Chapter 3.2 and *Appendix B, Section B.8*. With CO_2 intensity targets and the exogenous additions of the state-level demand and available non-coal generation (determined with user inputs or dispatch models discussed in Chapter 3 and *Appendix B, Section B.1*), the EGU-specific frontiers for the coal fleet can be used to minimize LCOE, while meeting generation and CO_2 emission-intensity constraints at the state-level (Figure .3.1). The mitigation-technology profile for intensity reductions at the national level is achieved through aggregation of the state-level profiles (See *Section C.5.8*).

State-level power generation statistics for 2002 to 2011 come from the EIA [59]. Carbon dioxide emissions and power generation for 2005 come from the sixth edition of eGRID2007 version 1.1 database [57] and a compilation of EIA Forms 860 [60] and 923 [63]. Historical 2012 and projected 2030 data for generation, emissions, generation classification, and energy efficiency savings are from the EPA technical documentation supporting the Clean Power Plan Proposal [62-65].

Such solutions are comparable to those from the dispatch models. While ESTEAM and the aforementioned dispatch-based models (*Appendix B*, *Section B.8*) each determine least-cost solutions for CO_2 mitigation, ESTEAM adds richness to the mitigation solutions available to each unique coal-fired EGUs, whereas the other models add by permitting integrated dispatch of all EGU types in order to accommodate detailed planning for future operations. Yet for this objective, given the uncertainty in mid-to-long-term planning (and the limitations associated with the model-specific algorithms, inputs, and constraints), each of these models is best-suited for policy comparison and to explore mitigation compliance strategies [55].

C.3 Results

C.3.1 EGU-level reduction

As an example of the construction of the least-cost mitigation technology frontier, consider a sub-bituminous EGU in Indiana, with HRI, at the 2030 state-specific, base case fuel prices, shown in Figure C.1 (*Section C.5.1*). Here, the least-cost frontier (defined by the blue dotted line) extends from the compliant position to employ coal rank and high rates of NG co-fire mitigation that achieve emission intensities that exceed those needed by the coal fleet to achieve a 30% emission-intensity reduction (defined by the black dashed line) for the state power-sector. To meet a hypothetical 30% reduction target, the USC upgrade mitigation is the least-cost option.

Further intensity reductions (up to 59%) are achieved with NGCC conversion, while deeper reductions are achieved by supplanting some of the NGCC generation with that from wind.

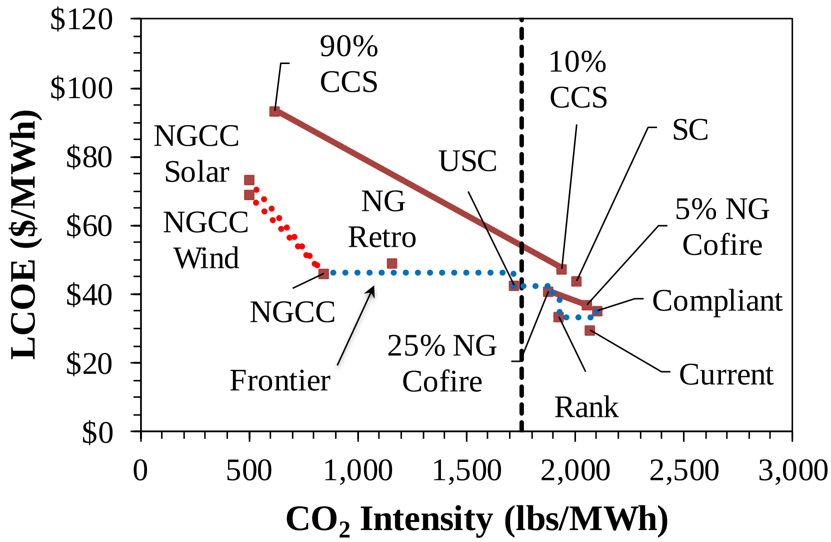


Figure C.1. Least-cost frontier (dotted blue line) for a sub-bituminous-fired EGU in Indiana. The dashed, black line represents the target CO_2 emission intensity (net) for the EGU. Solid red lines represent the loci of solutions for different levels of NG co-fire and CCS capture rates. The dotted red lines illustrate the two paths for further CO_2 emission-intensity reductions with renewable energy for the NGCC mitigation. The HRI employed in the compliant state is limited to 50% of the difference between the net heat rate for the "gold standard" and existing EGU up to the maximum improvement of 1,205 Btu. Improvement cost is set at $100/kW.

Alternative mitigation profiles can result from different commodity prices. For an EGU in Iowa without and with HRI (Figure C.2), the higher price of bituminous coal relative to both sub-bituminous coal and NG prices, results in NG co-fire dominating rank change for co-fire rates up to 19%, at which point the least-cost mitigation is again USC. However, a higher NG price delays introduction of the NGCC conversion but also encourages deployment of CCS for partial capture rates between 18% and 43%.

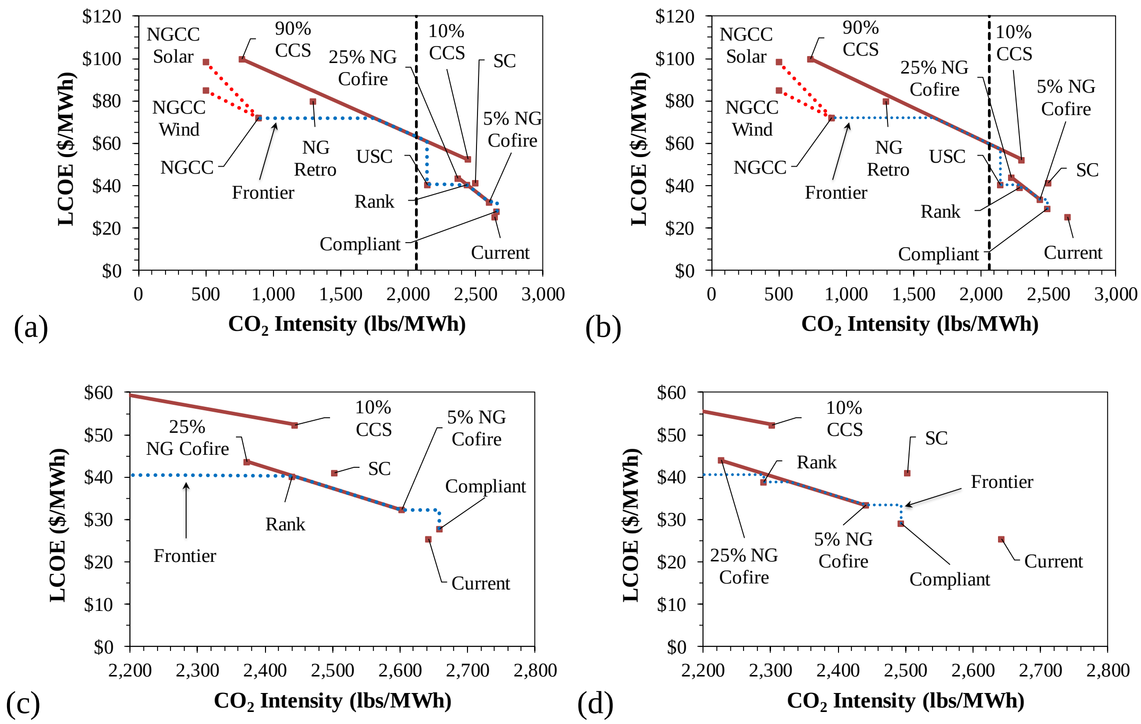


Figure C.2. Least-cost frontier for a sub-bituminous-fired EGUs in Iowa. Panels (a, c) show the mitigation measures with the heat rate improvement. Panels (b, d) show the mitigation measures without the heat rate improvement. Application of the HRI increases the LCOE for the mitigation and decreases the associate emission intensity for all mitigation measures that retain the original steam generator and continue to use coal. These shifts can be seen in greater detail in Panels (c) and (d).

Several observations can be drawn from analysis of these least-cost frontier examples. First, NG co-fire and CCS mitigations, for which the reduction intensity depends upon the rate at which the mitigation is applied, may be viable solutions only over a portion of the possible range of feasible rates. The economic viability of these effective rates varies for different CFEGUs and under different constraints. For example, if changing coal rank is not an option because of availability, existing coal contracts, or state and site-specific considerations, then the rates for which NG co-fire will be the least-cost option may expand. Similarly, if upgrading steam generators without CCS is not permitted by regulators, then the CCS capture rates may expand, because the steam-generator upgrade would no longer be an option in this model. For CCS, higher retrofitting costs and shorter amortization periods may further affect the economically viable capture rates, *ceteris paribus*. Furthermore, the relative change in fuel prices can affect the viable rates for CCS and NG co-fire. A higher NG price relative to the coal prices may decrease the variable operation and maintenance costs for CCS and NG co-fire mitigations relative to that for mitigation options with full NG conversion, thereby expanding the viable CCS and NG co-fire rates. However, the higher NG price may also decrease the viable rates relative to exclusively coal-based mitigation options.

Second, HRI can have a diverse impact on the frontier. For the Indiana CFEGU, the HRI-modeled intensity reduction is almost indiscernible, occurring at a LCOE increase greater than that for the coal rank mitigation (Figure C.5). In contrast, for the Iowa CFEGU, a modeled 6.2% HRI decreases the intensity to approximately the same level as that for a SC steam-generator upgrade, Figure C.2(d). It is unlikely that such a large HRI improvement can be achieved through the low-cost improvements outlined [68, 69], given that the SC upgrade entails modifying the entire steam cycle. Therefore, such EGU-specific modeling can provide insight for the relative economic and technological feasibility of HRI that would otherwise be missed through application of an average HRI, or dismissal of other mitigation alternatives.

A third observation is that the least-cost mitigation technology may result in a reduction that exceeds the intensity requirement. This often occurs for reductions of less than 50%, when the least-cost mitigation for a CFEGU is to convert to a gas-fired boiler or combined cycle unit. When one considers the fleet of coal-fired EGUs in a state meeting the state reduction requirement as a group, rather than individually, the over-reduction for one CFEGU is an opportunity for another CFEGU to use a mitigation option that results in an under-reduction thereby yielding a lower overall LCOE for the state fleet. Therefore, the mitigation option chosen for a specific CFEGU may differ for these two contexts.

C.3.2 State-level mitigation demonstrated for Indiana

The EGU-level solutions are driven by the site-specific parameters and the interaction of the mitigation technologies used by each CFEGU to reach the sought intensity reduction. As an example of this process aggregated at the state-level, consider the solution set for 41 Indiana CFEGUs. The frontier for the 15.5 GW of capacity employs all mitigation technology categories, Figure C.3(a), illustrating the importance of having each mitigation technology as an option to achieve the least-cost LCOE for a fleet emission-intensity target (*Section C.5.2*). Here, most capacity only requires HRI for intensities near the 2010 emission level and capacity conversion to NGCC increases as the targeted intensity decreases (Table C.1). When the coal-fleet intensity requirement is above 2,000 lbs/MWh-net, 70% of the operational capacity does not require mitigation other than HRI; the remaining 30% is mitigated with upgraded coal rank. However, this mitigation is adopted for an economic reason: it is more economical in the model for these plants to change coal rank than to operate with the current coal (absent supply contracts and other factors). As the emission-intensity target is reduced to 1,750 lbs/MWh (the 30% reduction target), 60% of the operational capacity still retains the original steam generator (Table C.1). However, most of the compliant and rank-change capacity is replaced by NG co-fire mitigation at a generation-weighted average level of 17%. Mitigation of the remaining operating capacity replaces the original steam generator primarily with an USC boiler or a NGCC plant—a trend that continues for further emission-intensity reduction.

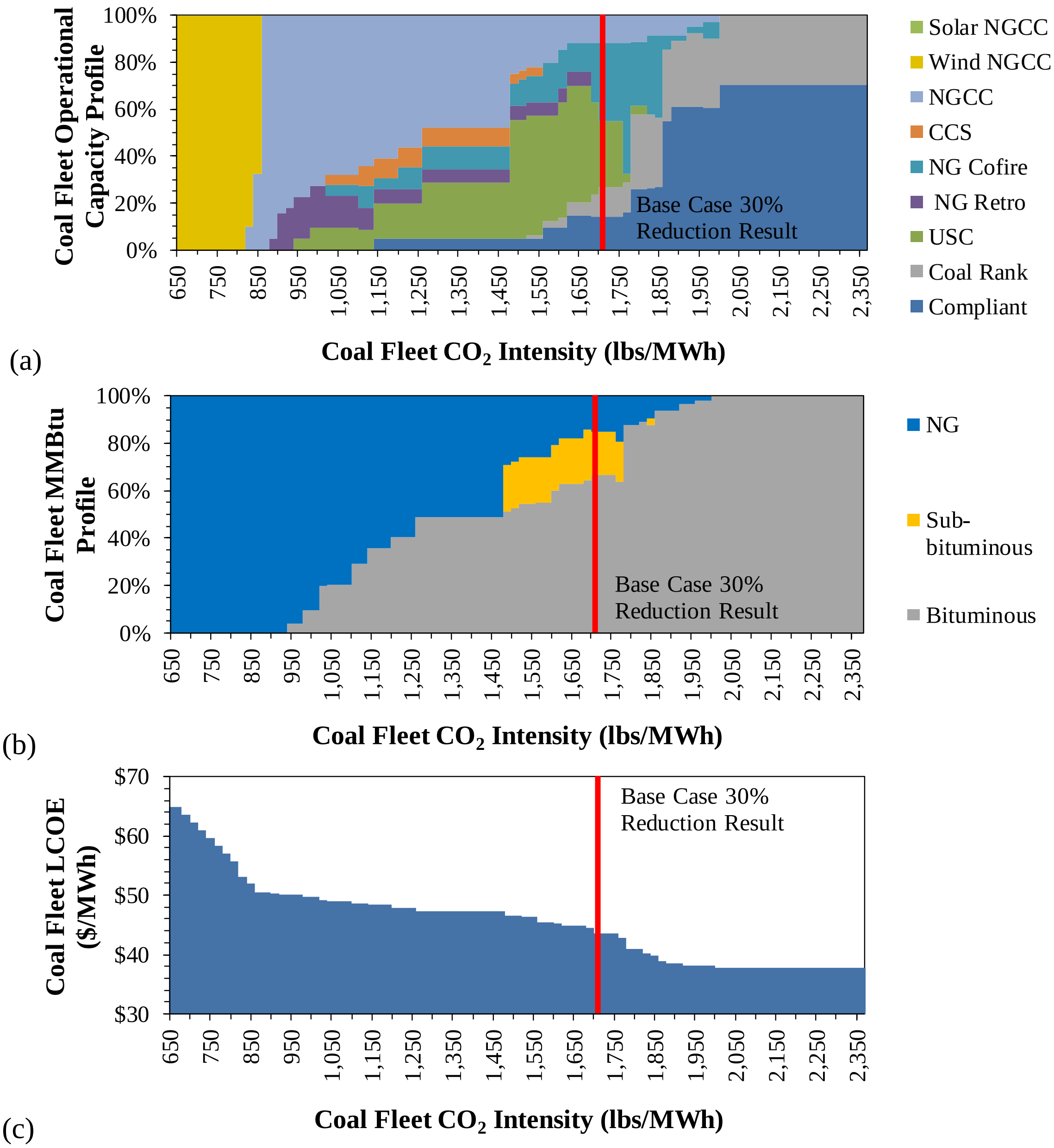


Figure C.3. Mitigation technology capacity profiles with HRI to achieve various emission intensities for Indiana. Operational capacity is defined as capacity in operation at the specified intensity levels. The solid red line denotes the actual coal-fired fleet emission intensity resulting from a 30% reduction in overall state emission intensity from 2005. Because of the addition of renewable NGCC generation, this 30% reduction requires only a 19% reduction in the coal-fired fleet intensity, from the 2005 level. The HRI is limited to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btu. Improvement cost is set at $100/kW. The coal fleet profiles for (a) mitigation, (b) fuel type used by the operational capacity, and (c) resulting LCOE are shown as a function of the achieved coal fleet intensity through mitigation.

As the required emission intensity of the coal fleet decreases, both the fleet LCOE and the reliance on NG increase, Figure C.3(b-c). The current Indiana coal fleet has a $35.6/MWh generation-weighted average LCOE, prior to compliance. The addition of the required ECDs and the implementation of the HRI increases this cost to $41.2/MWh. When the fleet is regulated for the 30% CO_2 emission-intensity reduction requirement, the addition of EGU-specific mitigations technologies increases the LCOE by 11.9% to $46.1/MWh. However, the LCOE can also decrease through the retirement of unneeded CFEGU capacity. For Indiana, 16% of the coal-fired capacity is retired because enough new capacity is available from NGCC and renewable sources in 2030. These retired CFEGUs have higher LCOEs, thereby relieving some of the increased cost of mitigations. The combined effect of the actions increases the CO_2 regulated fleet LCOE, but only to $43.5/MWh, Figure C.3(c). Beyond this intensity, the fleet LCOE increases as more expensive mitigation technologies are deployed.

The deeper reduction from these mitigation measures increasingly requires fuel-switching, Figure C.3(b). Without any mitigation required, the heat input from coal in the dataset is 8.2×10^8 MMBtu—30% less than that required in 2010. For coal fleet intensities below 2,010 lbs/MWh, NG consumption from NG co-fire and NGCC mitigation replace some of the bituminous coal. At a 30% overall intensity reduction, coal use decreases 21% further from the no mitigation level, while NG use increases to 1.1×10^8 MMBtu—an increase almost equal to the Indiana power sector NG use in 2010 [56]. Bituminous coal use continues to diminish, while intensity decreases as some coal-rank mitigation is supplanted with USC upgrade for two sub-bituminous EGUs at 1,750 lbs/MWh. Natural gas use continues to increase, up to this intensity, with more direct coal replacement with additional NGCC and NG co-fire capacity. At 1,490 lbs/MWh, there is a large decrease in sub-bituminous coal consumption, when these CFEGUs are replaced with NGCC mitigation. For deeper reductions, existing coal capacity is also converted to NGCC plants.

C.3.3 U.S.-level mitigation

National patterns mirror, in many ways, the trends seen for Indiana, Figure C.4(a-c). As we have seen before, ESTEAM applies HRI and economic retirements to achieve a reduction in the coal-fleet intensity of 6% (using 2030 fuel prices) from 2,138 lbs/MWh in 2005 (57) to 2,015 lbs/MWh in 2030 (excluding interactions between states). At this lower intensity achieved in the absence of a formal limit, the original steam generator and the use of coal is retained for 95% of the operating capacity, while the remaining capacity is converted for economic reasons to use solely NG (Table C.2). This results in a \$37.5/MWh regulated LCOE. The 30% reduction target reduces the coal fleet intensity to 1,837 lbs/MWh, which is achieved without further retirement (Table C.3). To achieve this, 56% of the capacity retains the original steam generator and continues to use coal, while NG conversions increases from 5% to 13% of the operational capacity, with 1.3 billion MMBtu of NG heat input supplanting that from coal. This increases the LCOE to \$41.3/MWh.

The profile contours in Figure C.4 suggest that the marginal changes for these parameters may be seen as linear approximations that vary across intensity regions, Figure C.7. From 1,980-1,790 lbs/MWh, the marginal cost to achieve the 30% reduction is 2.6¢ per unit of intensity reduction (lbs/MWh), (Table C.4(a)). This is due to the rapid replacement of compliant capacity primarily with NG co-fire, coal rank, and USC-mitigated capacity (Table C.4(b-e)). For deeper reductions to 850 lbs/MWh, the marginal cost reduction decreases to 1.1¢ for each additional unit of intensity reduction. These deeper reductions at a lower marginal cost result primarily from an increase in NGCC capacity at a marginal rate of 0.13-0.28 GW per unit of intensity reduction (Table C.4(f)). Such marginal relationships suggest that the policymaker should pursue nonuniform intensity reductions across states by targeting larger reductions for states with lower marginal reduction costs in union with smaller reductions for states where such costs are higher. As such, the mitigation cost for the coal fleet, and the marginal impact on fuel use (*Section C.5.3*), should be considered in addition to the availability and cost of introducing new renewable and low-carbon generation sources.

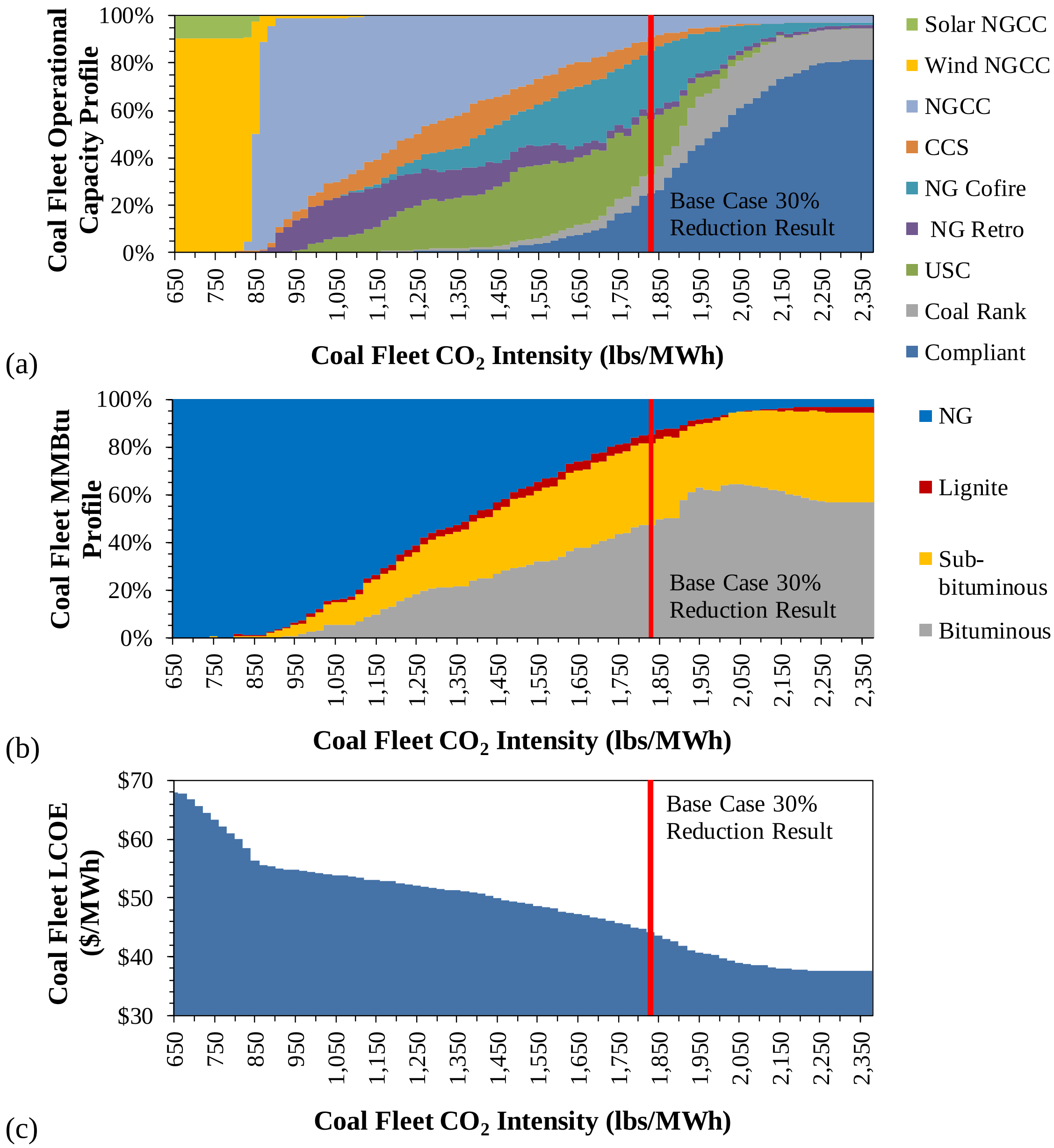


Figure C.4. Mitigation technology capacity profiles with HRI to achieve various emission intensities for the U.S. coal fleet. Supercritical steam-generator upgrade is the only mitigation technology option that is dominated by another mitigation option for every emission intensity target. Operational capacity is defined as capacity in operation at the specified intensity levels. The solid red line denotes the actual coal-fired fleet emission intensity resulting from a 30% reduction in overall state emission intensity from 2005. The HRI is limited to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btu. Improvement cost is set at $100/kW. The coal fleet profiles for (a) mitigation, (b) fuel type profile, and (c) LCOE are shown as a function of the achieved coal fleet intensity through mitigation.

C.4 Mitigation profile

C.4.1 Mitigation profile

The foundation of future coal-fleet mitigation is the EPA projection of the non-coal generation in 2030 [70], primarily from renewable and NGCC capacities, that reduces the need for coal-fired generation and results in the elimination of approximately 480 Mtons of CO_2 emissions through the retirement of 30% of the 2010 existing coal summertime peak capacity (*Section C.5.4*). This decrease accounts for almost half of the overall 34% U.S. power-sector emission reduction, for an intensity target based upon a uniformly applied 30% reduction in the 2005 state-level emission intensities. Furthermore, the low NG price, which is the impetus for the EPA's [51] and the EIA's [71] projected increase in NGCC generation in 2030, can lead to a reduction in emission intensity and emissions of more than 30%—with and without HRI—for predominately economic reasons for the remaining coal-fired EGUs (Table C.8). Therefore, the combination of retirement as a mitigation tool and low NG price that allows for low-cost mitigation solutions indicates that achieving the 30% reduction in the U.S. power-sector emission intensity or emissions, while involving some fuel-price risk, appears to be quite viable. Deeper reductions are possible from the existing coal fleet but require the increased use of NG: the modeled increase in NGCC conversion mitigation with and without renewable generation can be a proxy for the otherwise exogenous addition of these capacities to the model.

This example highlights that NG pricing is another economic mechanism that can be used for near-term emission reductions in the power sector [72]. As such, policies could be put in place at the federal and state-level to encourage low, future NG prices. Such policies could include increasing funding of NG research, development and deployment (RD&D) for improved unconventional extraction with a decreased environmental footprint [73], continuing tax incentives and subsidies [73, 74], and improving and expanding the distribution infrastructure to deflate state-level price variations and reduce methane leaks [75]. Even so, price volatility at the user-level can still occur to make NG power-generation less desirable to regulators, merchant operators, and end-users. This volatility could be reduced through financial instruments for the near-term, and with price-stable power purchase agreements from renewable generation for the longer-term [76-78]. Such a reliance on renewable energy might further the progress towards deeper reductions in the longer-term.

Even with these measures, uncertainty in the NG and coal prices can affect the mitigation decisions [79-81]. This uncertainty is greater than that from the cost modeling of the CFEGUs, and the mitigation measures, and can lead to significantly different mitigation profiles (*Appendix B. 7*). Correlated simulations of the error in the EIA's 15-year fuel-price projections show that the likelihood of fuel price scenarios that can lead to substantially different mitigation profiles, is more likely to lead to wider use of NG (18.6% likelihood), than to greater coal use (6.4% likelihood) (Figure 3.2). These scenarios increase the use of NG retrofit, and USC upgrades and CCS retrofit mitigations, respectively (Figure C.13).

C.4.2 HRI

Implementation of the HRI methods can be effective in decreasing CO_2 emission intensity, and as such is integral to both the CPP [4] and the ACE rule [5], but the impact of this mitigation is limited (*Section C.5.6*). The application of the HRI model to the entire coal fleet dataset in the 2010 configuration results in a generation weighted-average 4% heat rate improvement, similar to that found by the EIA [82]; however, this gain is partially offset by additional parasitic loads from requisite ECDs. When all CFEGUs are made compliant with the existing emission standards, the parasitic load from any additional ECDs increases the pre-HRI fleet intensity by 1%. Therefore, the generation weighted-average intensity of the compliant coal-fleet after the HRI is approximately 2,100 lbs/MWh, which is a 3% intensity reduction from the 2010 configuration.

The relevance of HRI as a mitigation tool is further diminished in the presence of other mitigation technologies and favorable fuel prices (*Section C.5.6.2.*). When the intensity target is no more stringent than to maintain the 2005 state-level intensities in 2030, the results for mitigations with and without HRI are similar (Table C.10). In both cases, meeting the coal-fleet intensity targets yields a reduction in the national CO_2 intensity and emissions of approximately 33% and 30%, respectively, from 2005 levels. This is because economic mitigation dominates HRI for smaller reduction levels, while more substantive mitigation approaches are necessary for larger reduction targets. For example, a targeted 30% reduction in 2005 state-level intensities, which results in a reduction in the national CO_2 intensity and emissions of approximately 37% and 34%, respectively, may require more than 75% of the operational coal-fleet to mitigate for CO_2 compliance, with and without HRI (Tables C.8 and C.10).

One implication is that it may be more effective to achieve CO_2 emission intensity and emission reductions by setting a specific target, such as done in the CPP, rather than mandating a specific mitigation method that may be waived [5]. This may be of importance, when policy mechanisms, as implemented in the ACE rule, are dependent upon an uncertain market forces to drive reductions [83]. Not only may the expected HRIs be difficult, costly, or uncertain to obtain [69, 84-86]; but the uncertainty in the realization of expected fuel prices can lead to regret (*Appendix B*, *Section B.7*), and technology and carbon lock-in for individual EGUs, and consequently for the mitigated fleet [87-89]. The latter issues can lead to higher electricity prices, and to the inability of the mitigated fleet to meet future reduction requirements because of committed CO_2 emissions from existing capacity [90] that require further asset abandonment through an unlocking mechanism for these energy investments [91] or a competitive market.

A further implication of HRI is that CFEGUs with poor heat rates are likely to be those that are not economical to use in the carbon-restricted future. Rather than pursuing HRI on these CFEGUs, it may be less costly to retire them and produce generation from EGUs with lower initial heat rates [92]. However, determining the disposition of the CFEGU *a priori*, based upon the initial heat rate and possible improvement, may not be simple. The complexity of the “retire or mitigate” decision for a 30% reduction can be seen in the *a posteriori* analysis, regarding mitigation outcomes as a function of heat rate, by grouping these dispositions into five classifications: remain, refuel, CCS retrofit, repower, and retire (*Section C.5.6.3*). In such a representation for a 30% intensity reduction, the proportion of CFEGUs mitigating solely with HRI does diminish with increasing heat rate and the proportion of retirements increases. However, there is no operational heat rate level above which all CFEGUs are retired or for which an HRI is not a viable solution (as a sole or coupled mitigation). Similarly, retirement or repowering are the mitigation solutions for approximately two-thirds of the CFEGUs at the mode for the initial heat rate. This diversity in classifications across heat rates illustrates the leverage that the emission-intensity reduction targets and 2030 fuel prices may have in the mitigation decision (Figure C.16), and the risk that a policymaker and operator assume when assumptions about either parameter are made to formulate a possible policy and solution set.

C.4.3 USC

For the midrange of the intensity targets, an increasing share of the mitigated capacity is derived from upgrading the steam generator to USC, though doing so is likely to invoke a review under the NSPS for new, modified and reconstructed CFEGUs. Under the current EPA regulation, such a mitigation would not be permitted unless the CFEGU is retrofitted with CCS to meet the new emission standard [93]. However, the dominance or parity of this option relative to mitigation using CCS and NGCC for much of the midrange intensity targets indicates that significant reductions in emissions could be met with existing coal technology [94] and done so with a lower LCOE than for a new NGCC plant. As such, policymakers could allow NSPS waivers only for CO_2 emissions from USC upgrades for which USC upgrades is the least-cost mitigation option. Furthermore, policymakers could consider increasing RD&D funding on advanced USC steam generators, which may achieve efficiencies greater than 45% [94], and on programs that promote advanced coal-generation technologies, such as the National Energy Technology Laboratory's COAL FIRST [95].

Recently, the EPA proposed relaxing the emission-intensity requirements to set SC steam-generator technology, without CCS, as the best system of emission reductions for the NSPS emission-intensity threshold [96]. Yet for purposes of mitigating existing EGUs, SC upgrade is never used as a mitigation-technology option for the state-solution sets, when faced with fungible amitigations, Figure C.4(a). Furthermore, SC upgrade is not on the least-cost frontier for any EGU, under the modeled conditions. The SC upgrade is dominated by USC upgrades for 93% of the frontiers (Figure C.17), as in Figure C.1, or by other mitigation options (as in Figure C.2 and Figure C.4). Therefore, while the proposal sets a maximum emission-intensity limit for reviewing steam-generator upgrades that permits the USC upgrades, one should not infer that the

SC upgrade is on the least-cost mitigation frontier and that deeper intensity reductions are possible at a lower LCOE.

C.4.4 CCS Retrofit

CCS mitigation for existing CFEGUs has limited competitiveness in the presence of fungible mitigations. With a 30% reduction in 2005 state-level intensities, CCS retrofit, which is highly dependent on coal and NG fuel prices, is the least-cost solution for only six out of the 354 CFEGUs projected to be operational in 2030 and would annually store less than two million tons of CO_2 (*Section C.5.8.*). A reduction of 40% would achieve a more than ten-fold increase in CCS generation capacity and storage. Even so, much of this added capacity is limited to two states with the highest NG price and the lowest coal prices—North Dakota and Wyoming. For these EGUs, only one (located in Wyoming) uses CCS for each of the three modeled intensity reduction levels: eight additional CFEGUs use CCS at 40% reduction levels. Therefore, without economic or policy incentives, the use of CCS is unlikely to be a viable mitigation option for an CFEGU across the discussed reduction and projected 2030 fuel price scenarios, and its use is further diminished with more homogenous state-level NG prices.

The modeled coal-fired CCS generation capacity can be increased with an incentive to permanently sequester the pollutant, such as the $50/tonne tax credit for qualifying EGUs in the Amendments to 26 U.S. Code 45Q in the Bipartisan Budget Act of 2018 concerning CCS [53]. For the power sector, the tax credit does not increase CCS mitigation capacity as much as does requiring intensity reductions greater than 30%, under the model constraints (Table C.11). In the absence of cost minimization, the credit does increase the CCS generating capacity and storage for a 30% reduction by almost a factor of three, but the increase still falls short of that achieved with a 40% reduction target without a credit. As the targeted intensity decreases, the further increase in CCS generating capacity and associated coal use, relative to the non-credit case, supplants some of the NGCC and USC-upgrade mitigation capacity. These increases are also evident for coal-fleet intensities below 850 lbs/MWh, where CCS mitigation supplants some NGCC with renewable generation capacity. Yet even with the tax credit, coal-fired CCS dominates NGCC with renewables for only 53 out of the 599 feasible CFEGUs to meet a 750 lbs/MWh EGU intensity target (Figure C.25).

As the amendment is also intended to promote CCS for CO_2 reduction in fuel and industrial applications to lower the overall U.S. emissions, the tax credit may be expected to cover some of the associated marginal costs to make CCS financially feasible. International Energy Agency analysis for these applications shows that the $50/tonne credit may offset these costs sufficiently to make as much as 140 million tonnes of CO_2 available annually for capture [97]. However, ESTEAM indicates that the applicable CCS tax credit value for the power sector may be insufficient to compensate for the additional CCS mitigation costs at the 30% reduction level, due in part to the limited duration of the credit, and only makes an additional 8.9 million tonnes of CO_2 annually available (Table C.11). In comparison to the wind production tax credit, the CCS tax credit for the modeled EGUs would cover a smaller percentage of the CCS-associated capital and operation and maintenance (O&M) costs, (Figure C.23). Furthermore, if we consider EGU-specific cost minimization by comparing the economic competitiveness of CCS with the tax credit directly to that for a brownfield NGCC conversion, NGCC dominates CCS with 90% capture for all but 33 out of 635 EGUs—of which 16 are in

North Dakota and Wyoming, where the high NG price and low coal price favors coal-fired CCS (Figure C.26). These examples imply that the tax credit is insufficient to make CCS cost competitive to alternative investments in NG generation and steam-generator upgrade alternatives. As such, the credit level would need to be increased, the threshold lowered, or the applicable duration extended to promote further power sector CCS use for existing CFEGUs in scenarios where policymakers are only considering operators cooperatively meeting reduction targets in the presence of fungible mitigations, and when operators may seek lower costs through greater reduction in the absence of trading mechanism.

C.5 Supplemental information for rate-based analysis

C.5.1 EGU-level mitigation-technology frontiers.

A sub-bituminous EGU in Indiana is used to illustrate the least-cost mitigation frontier. For this example (Figure C.5(a)), the CFEGU without heat rate improvement (HRI) and in the 2010 configuration does not meet the CO_2 emission intensity target of 1,760 lbs/MWh for the coal fleet, as shown by the dashed line, to achieve a 30% state-level reduction (i.e., the "Current" point is to the right of the dashed line). Additionally, the CO_2 emission intensity and the LCOE may both increase because of the possible addition of emission control devices to make the EGU comply with other emission standards. This point is labeled "Compliant." In this case, the compliant CFEGU does not meet the CO_2 emission intensity target, so mitigation is required for the CFEGU to be regulated for CO_2 emissions.

If the target is lower than 2,100 lbs/MWh, upgrading coal rank to bituminous coal (labeled "Rank") is the least-cost measure, at a LCOE of $32/MWh, and the intensity is decreased to

1,950 lbs/MWh. Further reductions along the frontier require switching to natural gas (NG) co-fire at 19%, with an associated LCOE of $38/MWh. NG co-fire at 19% to 25% levels remains the most cost-effective solution for target intensities between 1,950 lbs/MWh and 1,900 lbs/MWh. Below this, the frontier must move to another singular point associated with the ultra-supercritical steam-generator upgrade (labeled "USC") for intensity targets between 1,890 to 1,717 lbs/MWh, as using CCS will incur greater costs. If reductions are required beyond this point, a brownfield conversion to an NGCC plant is needed (labeled "NGCC"). This mitigation will further reduce the emission intensity to 840 lbs/MWh, with an associated LCOE of $46.2/MWh. The least-cost mitigation options to achieve greater intensity reductions involve replacing the NGCC generation with that from co-located wind.

Mitigation from improving the compliant net heat rate will alter this frontier, Figure C.5(b), depending upon the heat rate of the existing CFEGU. Prior to improvement, the modeled compliant CFEGU in Indiana has a net heat rate of 9,987 British thermal units per kilowatt-hour (Btu/kWh) and a CO_2 emission intensity of 2,126 lbs/MWh; by comparison, the corresponding "gold standard" EGU (*Section C.5.6.1*) has a net heat rate of 9,747 Btu/kWh. Therefore, the achieved net HRI is 1.2%, when the HRI rules are applied (*Section C.5.6.1*). This improvement decreases the emission intensity of the CFEGU by 25 lbs/MWh at a net cost of $1.5/MWh; thereby shifting the cost-effective frontier (Figure C.5(d)), as the compliant EGU, NG co-fire and CCS mitigations will now have smaller emission rates and greater LCOEs than those for the corresponding states without the improvement, Figure C.5(c). Other mitigation transition points on the frontier are not altered, as these are defined by the mitigation options for which the HRI is not implemented.

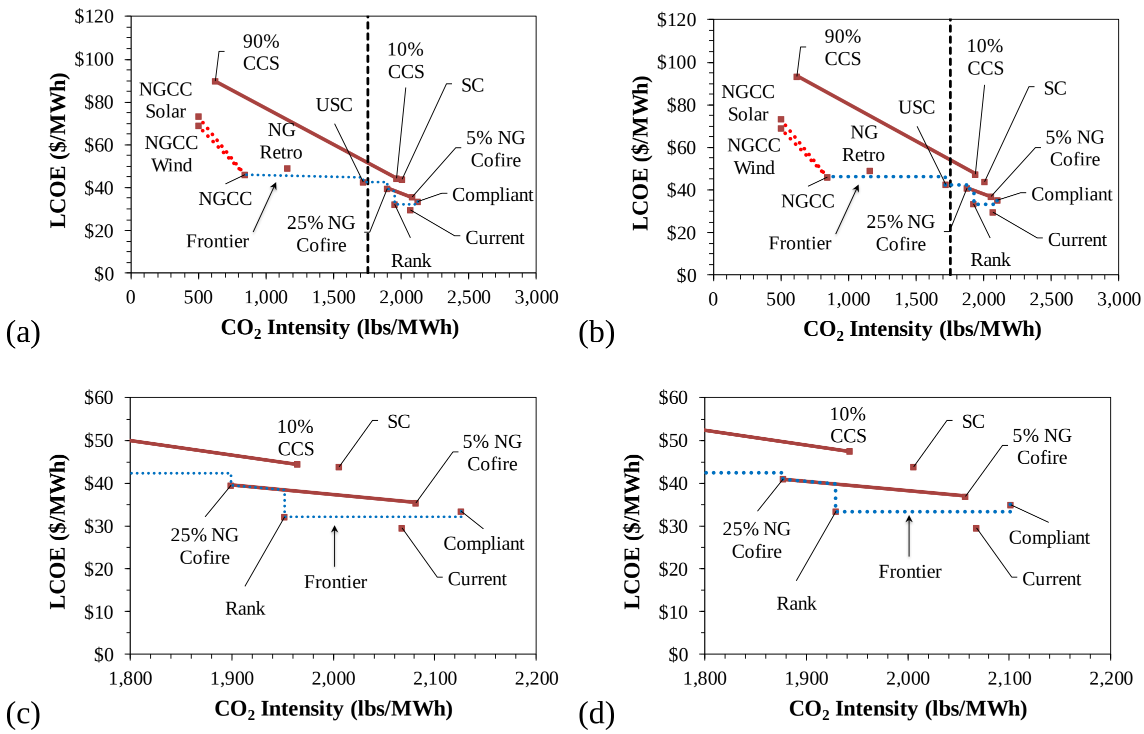


Figure C.5. CO_2 emission intensity-mitigation measures least-cost frontier for a sub-bituminous-fired EGUs in Indiana. Panels (a, c) show the mitigation measures without the heat rate improvement. Panels (b, d) show the mitigation measures with the heat rate improvement. Application of the HRI increases the LCOE for the mitigation and decreases the associate emission intensity for all mitigation measures that retain the original steam generator and continue to use coal. For this CFEGU, the shift is $1.5/MWh and 25 lbs/MWh, which is difficult to discern, (c) and (d).

C.5.2 State-level mitigation

The emission intensity of the Indiana coal fleet was 2,150 lbs/MWh in 2005 (25). By 2010, the coal-fired fleet intensity reduced to 2,120 lbs/MWh for the dataset, due in part to the exclusion of some EGUs operating in 2005 and to yearly fluctuations in operation parameters. When these EGUs are brought into compliance, this intensity increases to 2,140 lbs/MWh. This intensity is reduced to 2,050 lbs/MWh, at a cost of $1.1/MWh, with the application of the described HRI that improves the generation-weighted average of the dataset fleet net heat rate by 4.3%. Therefore, the coal-fired fleet has a 5% reduction in intensity from constraining the 2005 fleet and the implementation of the HRI. Further reductions will require other mitigation options.

While some CO_2 mitigation models include NG co-fire, conversion to 100% NG steam generator, and fixed CCS retrofit as viable technologies to reduce CO_2 emissions in the coal fleet, these mitigation models omit coal rank, variable CCS retrofit, USC steam-generator upgrades without CCS, and NGCC conversion as viable options, Table 3.1. The importance of having each of the mitigation technologies as an option to achieve the least-cost LCOE for an emission-intensity target can be observed with the counterfactual. For the Indiana coal fleet operating with the base case fuel prices, Figure C.6(b), the difference in LCOE from a scenario that has all other mitigation options but omits NGCC conversion and one that includes it is greater than that from omitting either CCS retrofit, USC steam-generator upgrade, or coal rank mitigations. This condition is true when the coal price, Figure C.6(a), or the NG price, Figure C.6(g), is 30% lower than the base case fuel prices, and when the coal price, Figure C.6(c), or NG price, Figure C.6(i), is 30% greater than the base prices. However, omission of these other mitigation options also increases the LCOE. When the coal price increase from 70% to 130% of the base case, Figure C.6(d-f), the difference in LCOE diminishes from $1-4 to $0-1. Conversely, when the NG price increase from 70% to 130% of the base case, Figure C.6(j-l), the difference in LCOE increases from $0-1 to $2-5.

Comparing the sets of coal and NG variations shows that the impact from omitting mitigation options is not uniform across the emission-intensity range. Omitting NGCC conversion as a mitigation option has the largest impact on LCOE for mitigation targets that require lower intensity targets. USC is more sensitive to NG price than to coal price and has an impact for mid-range intensity targets. CCS is an important option for mid to low-range intensity targets and at high-range targets when coal is inexpensive. For all cases, the rank mitigation-option has impact for high-intensity targets. Therefore, the omission of any mitigation option can result in a greater target-intensity LCOE and is dependent upon the target intensity and the fuel prices. For some states, this dependency can lead to unique mitigation solutions, due to the complex interaction of the CFEGU-specific mitigations, where the least-cost LCOE to achieve a specific actual intensity is one for which a mitigation technology is omitted.

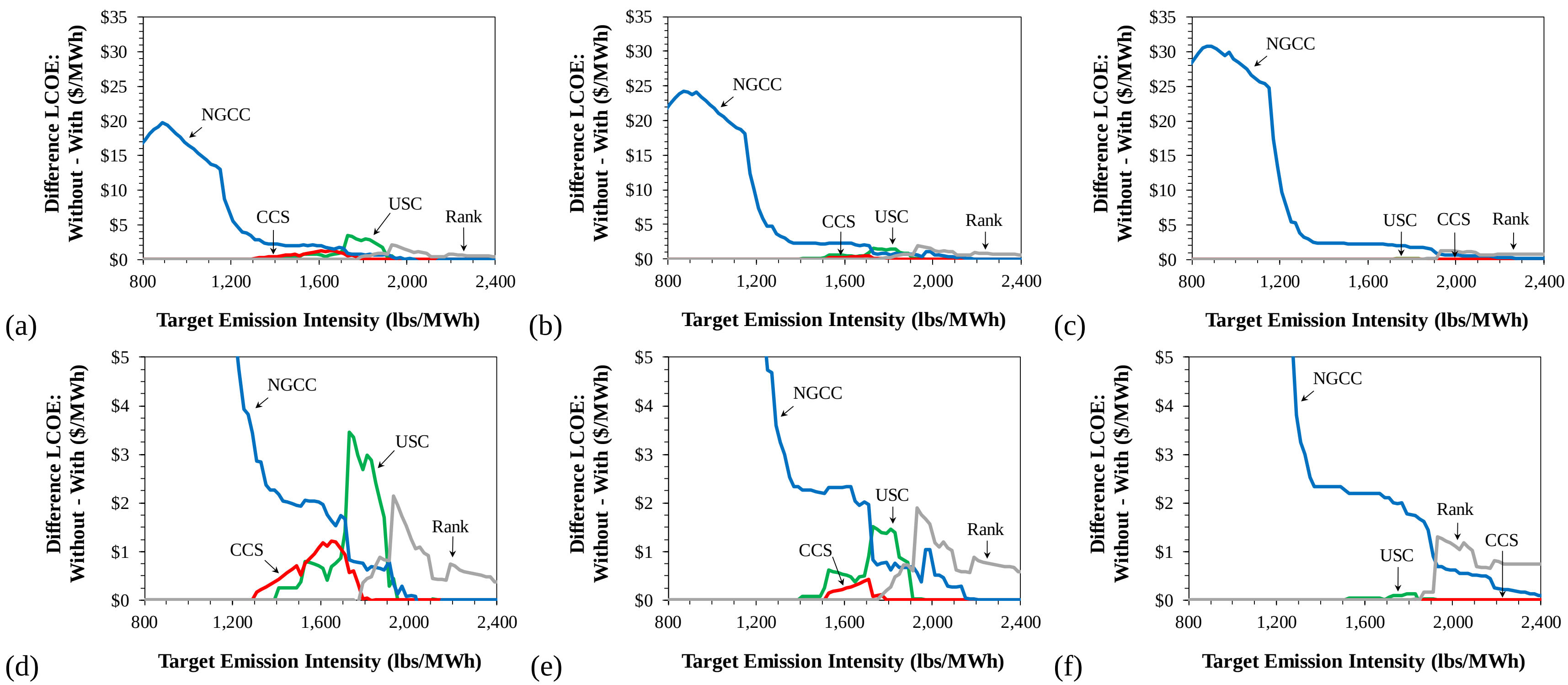


Figure C.6. Difference in emission intensity target LCOE for Indiana from omission of mitigation option for variations in coal (a-f) and natural gas (g-l) prices at +/- 30% from base case prices. As coal price increases from -30% of the base case price (a and d)), to the base case (b and e), to +30% of the base case price (c and f), the importance of having CCS and USC options decreases and that for NGCC increases. As natural gas price increases from -30% of the base case price (g and j), to the base case (h and k), to +30% of the base case price (i and l), the importance of having NGCC decreases and that for CCS and USC options increases.

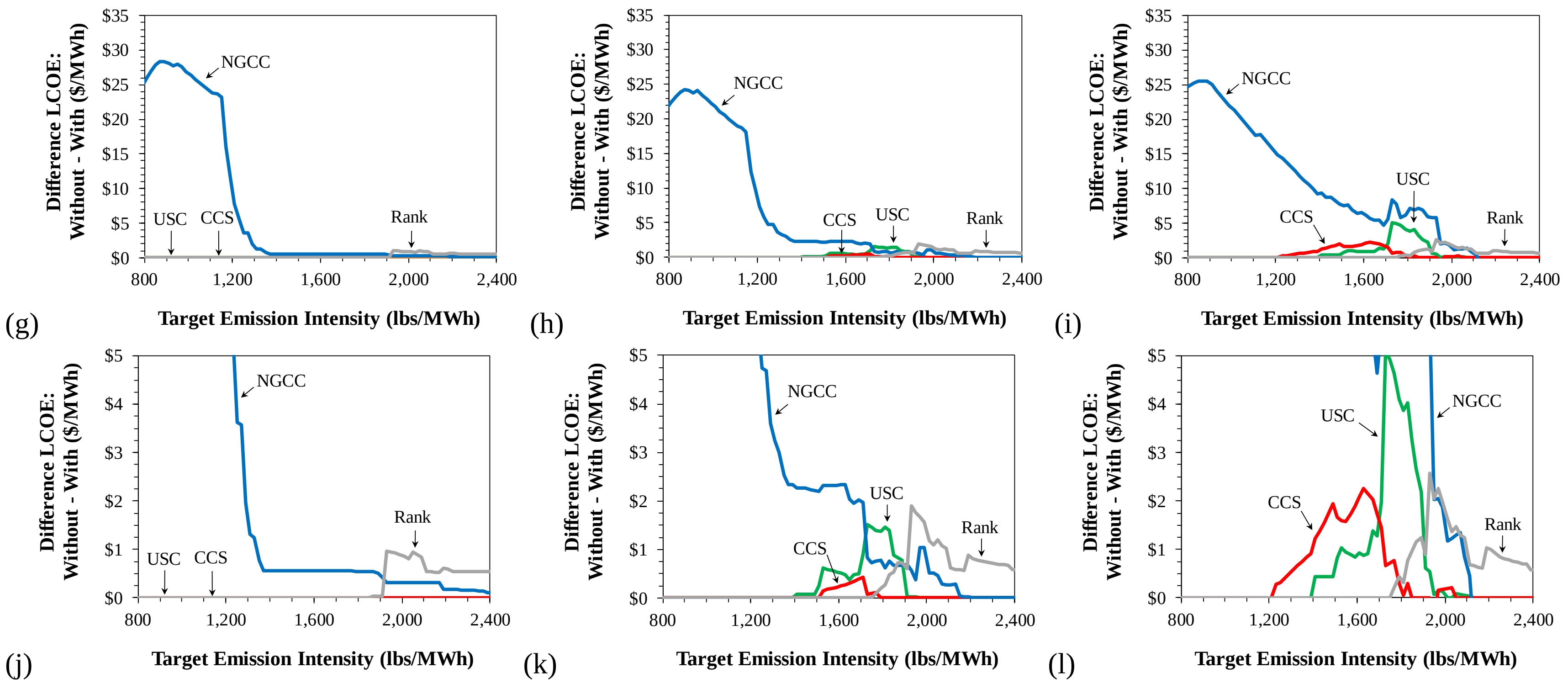


Figure C.6. Continued…Difference in emission intensity target LCOE for Indiana from omission of mitigation option for variations in coal (a-f) and natural gas (g-l) prices at +/- 30% from base case prices. As coal price increases from -30% of the base case price (a and d)), to the base case (b and e), to +30% of the base case price (c and f), the importance of having CCS and USC options decreases and that for NGCC increases. As natural gas price increases from -30% of the base case price (g and j), to the base case (h and k), to +30% of the base case price (i and l), the importance of having NGCC decreases and that for CCS and USC options increases.

Table C.1. Mitigation technology capacity profiles with HRI to achieve the 19% reduction in the coal-fired fleet intensity necessary to meet a 30% overall emission intensity reduction, from the 2005 level, for the state fleet in Indiana. The improvement is limited to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btus. Improvement cost is set at $100/kW. Level of NG co-fire and CCS capture rate is based upon the generation-weighted average.

Mitigation	Number of EGUs	Capacity (MW)	Level (fraction)
Compliant (HRI only)	3	1,871	NA
Coal Rank	7	1,645	NA
NG Co-fire	9	4,376	0.17
SC	0	0	NA
USC	4	3,645	NA
CCS	0	0	0
NG Retrofit	0	0	NA
NGCC	4	1,534	NA
Retired	14	2,425	NA

C.5.3 U.S.-level mitigation.

Restructuring the power sector changes fuel-type consumption. The coal-fired EGUs in the ESTEAM dataset represent 84% of the coal Btus consumed by the electric power-sector fleet in 2010 and 102% of the 2012 consumption, as NG consumption increased and the total use of these fuels diminished (26), Figure C.7. By 2030, market and policy forces of projected fuel prices and additional renewable and NGCC sources in the model will continue the trend in reduced coal consumption to 10.3 billion, million Btus (MMBtus) without the need for CO_2 regulated mitigation (other than HRI after retrofitting necessary ECDs), Figure C.4(c). This 50% reduction in coal use from 2005 levels reduces the US coal-fired fleet emission intensity to 1,980 lbs/MWh—a 7% reduction. With regulated mitigation to reach the 30% power-sector reduction, coal use decreases to 9.3 billion MMBtus (an additional 5% reduction) and the coal-fired fleet intensity decreases to 1,840 lbs/MWh. Correspondingly, fuel-switching causes the NG consumption in the existing coal fleet to increase to 1.3 billion MMBtus, an increase that is equivalent to 23% of the 2005 power sector use. Therefore, to achieve the 30% intensity reduction the marginal increase in NG consumption (or reduction in coal consumption) to achieve the 30% intensity reduction is 0.004 billion MMBtus per unit of intensity reduction, Table C.5. Deeper reductions to 910 lbs/MWh, double this marginal rate (Table C.5).

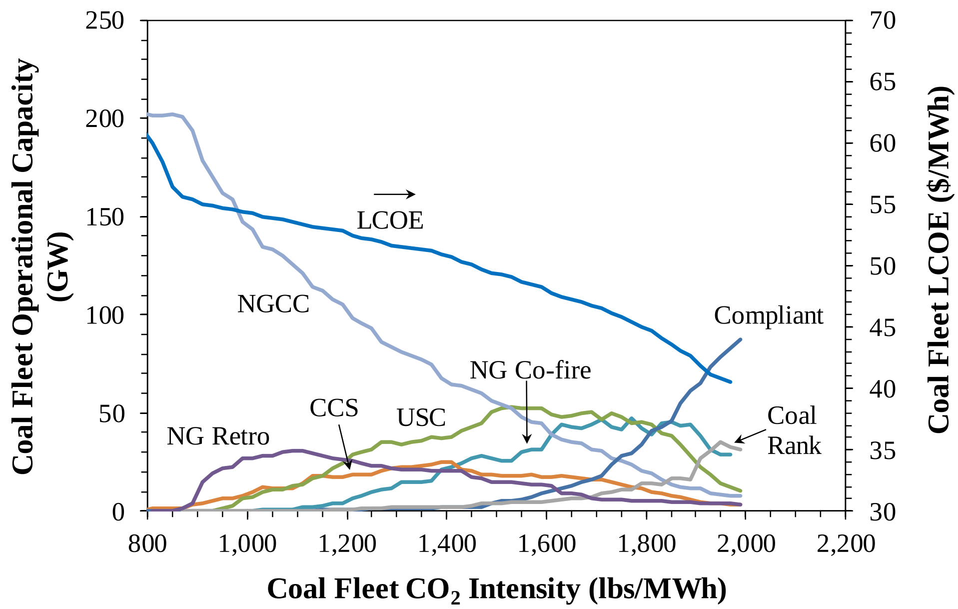


Figure C.7. Mitigation capacity and associated LCOE to achieve a range of U.S. coal-fleet emission intensities for the 2030 base-case scenario with HRI.

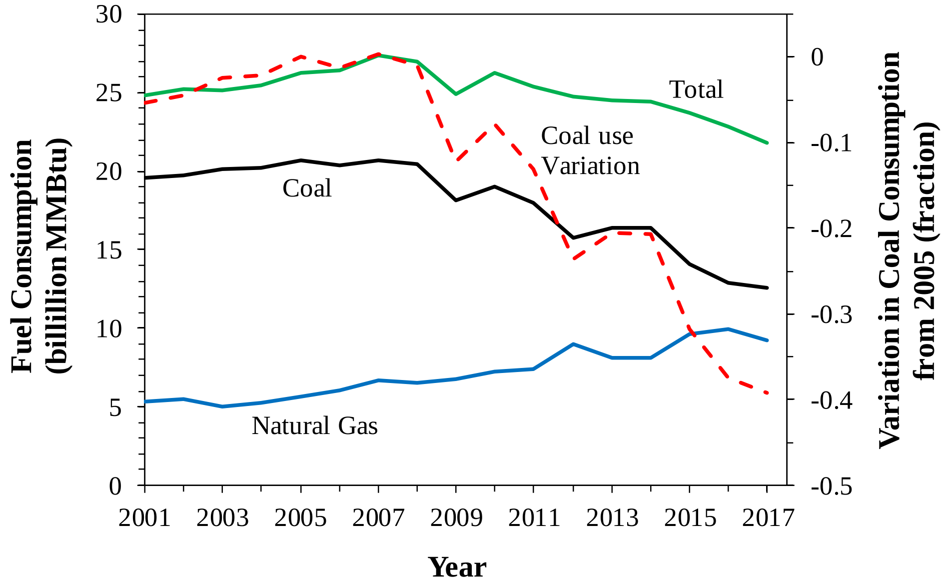


Figure C.8. Historical coal and natural gas fuel consumption in the U.S. electric power sector (5).

Table C.2. Mitigation technology capacity profiles with HRI when 2030 fuel prices and additional NGCC and renewable generation are modeled without a required emission intensity reduction, from the 2005 level, for the U.S. coal-fired fleet. The HRI is limited to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btus. Improvement cost is set at $100/kW. Level of NG co-fire and CCS capture rate is based upon the generation-weighted average.

Mitigation	Number of EGUs	Capacity (GW)	Level (fraction)
Compliant (HRI only)	273	140	NA
Coal Rank	44	23.4	NA
NG Co-fire	7	2.4	0.07
SC	0	0	NA
USC	1	0.1	NA
CCS	0	0	NA
NG Retrofit	16	2.4	NA
NGCC	12	5.5	NA
Retired	282	75.6	NA

Table C.3. Mitigation technology capacity profiles with HRI to achieve a 30% overall emission intensity reduction, from the 2005 level, for the U.S. coal-fired fleet. The HRI is limited to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btus. Improvement cost is set at $100/kW. Level of NG co-fire and CCS capture rate is based upon the generation-weighted average.

Mitigation	Number of EGUs	Capacity (GW)	Level (fraction)
Compliant (HRI only)	112	67.4	NA
Rank	64	28.6	NA
NG Co-fire	47	26.8	0.12
SC	0	0	NA
USC	43	26.3	NA
CCS	6	1.5	0.23
NG Retrofit	43	6.4	NA
NGCC	41	15.5	NA
Retired	279	75.8	NA

Table C.4. Linear approximations of different parameters in 2030 as a function of intensity over specific intensity ranges. Equation takes the form of $y=ax+b$, where x is the emission intensity and y is the parameter.

(a) LCOE ($/MWh)

Intensity Range	a	b	R^2	RMSE
1,990-1,790	-0.026	91.21	.990	0.182
1,790-850	-0.011	65.662	.985	0.379

(b) Compliant capacity (GW).

Intensity Range	a	b	R^2	RMSE
1,990-1,790	0.276	-461.57	.990	1.827
1,790-1,410	0.079	-114.662	.892	3.245

(c) NG co-fire capacity (GW).

Intensity Range	a	b	R^2	RMSE
1,990-1,850	-0.203	412.38	.898	3.586
1,850-1,630	-3.05×10^{-4}	44.02	-.010	2.410
1,630-1,010	0.066	-71.69	.954	2.716

(d) USC upgrade capacity (GW).

Intensity Range	a	b	R^2	RMSE
1,990-1,790	-0.195	397.31	.981	1.812
1,790-1,510	-0.026	92.65	.719	1.442
1,090-1,510	0.083	-75.27	.940	2.729
850-1,090	0.062	-55.35	.901	1.598

(e) Coal rank capacity (GW).

Intensity Range	a	b	R^2	RMSE
1,990-1,890	0.142	-246.93	.514	4.741
1,890-1,690	0.047	-70.82	.935	0.813
1,690-1,090	0.012	-13.46	.937	0.548

(f) NGCC conversion capacity (GW).

Intensity Range	a	b	R^2	RMSE
1,990-1,790	-0.063	131.99	.920	1.228
1,790-1,250	-0.130	250.48	.993	1.842
1,250-850	-0.275	428.54	.968	6.406

(g) Natural gas conversion capacity (GW).

Intensity Range	a	b	R^2	RMSE
1,990-1,790	-0.086	180.56	.944	1.383
1,790-850	-0.200	375.62	.990	5.521

(h) CCS retrofit capacity (GW).

Intensity Range	a	b	R^2	RMSE
1,990-1,630	-0.042	86.22	.939	0.713
1,630-1,470	-0.007	28.76	.430	0.402
1,470-1,410	-0.093	154.66	.839	1.013
1,410-850	0.049	-39.84	.963	1.176

(i) NG retrofit capacity (GW).

Intensity Range	a	b	R^2	RMSE
1,990-1,790	-0.010	23.68	.959	0.139
1,790-1,090	-0.037	71.01	.982	1.051
1,090-850	0.134	-110.43	.866	4.084

Table C.5. Linear equation approximations for 2030 natural gas heat input from mitigated coal-fired EGUs in the U.S. coal fleet for CO_2 emission intensities ranges. Equation takes the form of $y=ax+b$, where x is the emission intensity and y is the heat input (billion MMBtu).

Intensity Range	a	b	R^2	RMSE
1,990-1,790	-0.004	9.73	.979	0.044
1,790-910	-0.008	15.92	.996	0.138

C.5.4 Intensity reduction targets.

An alternative method to reducing emission intensity is to have each state meet the same intensity target, rather than a uniform percent reduction. In 2005, the emission intensity for the U.S. power sector was 1,353 lbs/MWh and that for the coal-fired fleet was 2,138 lbs/MWh (25, 27- 29). Maintaining this power-sector fleet intensity with a state target of 1,353 lbs/MWh, considering the additional 2030 renewable and NGCC generation (Table C.6), implies that the U.S. coal-fired intensity must be no greater than 3,972 lbs/MWh for the required 1,200 TWh generation. As this intensity is greater than the 2005 coal-fleet intensity, and the 2010 intensity in the dataset, no mitigations are required on average. However, the resulting mitigation profile shows that the coal-fleet intensity is reduced to 1,832 lbs/MWh and mitigation technologies are employed, Figure C.9(a) and Table C.7. This decrease is because in some states the 2030 fuel price makes it economically advantageous to switch fuels or to repower the CFEGU as an NGCC plant. For other states, mitigation is required because the continued reliance on coal-fired generation without an adequate increase in low/no carbon generation results in an intensity above the target.

Coincidently, a 30% reduction from the 2005 state-level intensities results in a similar coal-fleet emission intensity as the aforenoted case—1,838 lbs/MWh. Comparing the mitigation profiles for the two cases shows that different mitigated capacities are required, though the resulting LCOE and fuel consumption is similar, Table C.7. Therefore, different approaches to setting the state-level intensity targets can achieve similar results, in some circumstances.

Maintaining the 2005 state-level intensities, rather than the national intensity, can also require some coal-fleet mitigation in coordination with the addition of the new 2030 generation, Figure C.9(b), Table C.7. While more compliant capacity is maintained for no reduction at the state-level than at the national-level, approximately 22% of the operational capacity is still mitigated, Table C.8. However, 94% of this mitigated capacity is done for economic reasons, rather than regulatory compliance. The resulting decrease in U.S. emission intensity and CO_2 emissions of more than 30% is similar to that for the "30% reduction" target in state-level emissions, but the coal-fleet LCOE is $4/MWh lower for the "no reduction" target, Figure C.10. Therefore, a reduction in national emission intensity and emissions of approximately 30% from 2005 levels can be obtained through setting state-level intensity targets at 2005 levels, *ceteris paribus*. These reductions are driven primarily by the additional 2030 generation from non-coal capacity that eliminates approximately 480 Mtons of CO_2 through coal-capacity retirement, which accounts for 57% of the U.S. power-sector emission reduction from 2005, and through 2030 fuel prices that enable emission reduction for economic reasons. The combination of these factors indicates that achieving the 2005 state-level reduction target, while involving some risk, appears quite viable.

(a)

(b)

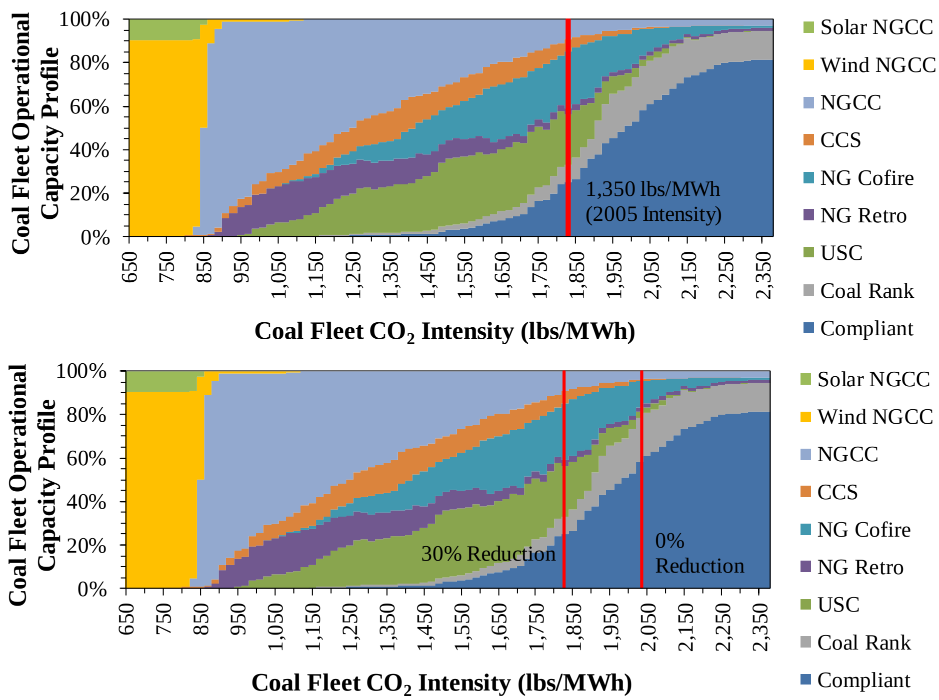


Figure C.9. Mitigation profiles for U.S. coal fleet from meeting emission-intensity targets based upon 2005 (a) U.S. power-sector intensity and (b) state-specific intensities. U.S. power-sector intensity in 2005 was 1,353 lbs/MWh. A 30% reduction in this intensity yields a target for each state of 950 lbs/MWh. Mitigations are inclusive of an HRI to 50% of the difference between the net heat rate for the “gold standard” and existing CFEGU up to the maximum improvement of 1,205 Btu.

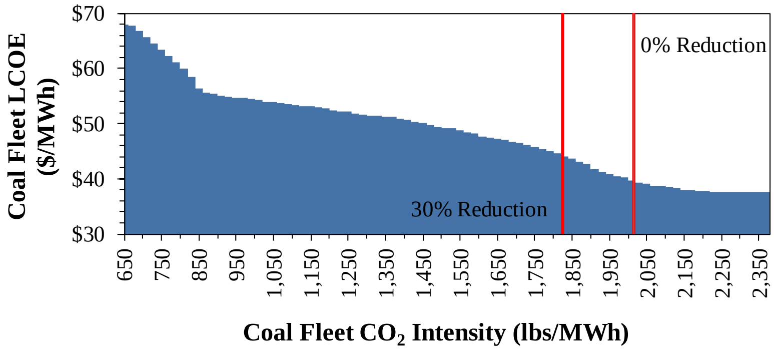


Figure C.10. LCOE profile for U.S. coal fleet from meeting emission-intensity targets based upon 2005 state-specific intensities. A 30% reduction in these intensities yields a coal-fleet generation weighted-average intensity of 1,840 lbs/MWh to achieve a 34% reduction in national CO_2 emissions at a cost of $41.3/MWh. No reduction in the state-level intensities produces a 2,015 lbs/MWh coal-fleet intensity to achieve a 31% reduction in national CO_2 emissions at a cost of $37.5/MWh. Mitigations are inclusive of an HRI to 50% of the difference between the net heat rate for the “gold standard” and existing CFEGU up to the maximum improvement of 1,205 Btu.

Table C.6. Historical and future generation profiles and intensities for U.S. power sector. 2005 data are derived from EIA sources (25, 27-29). 2012 and 2030 data are based upon EPA estimates (30). 2005 "N.A." generation and intensity values are not differentiated from same source values. 2030 "T.B.D." need intensity target to determine. Twenty-three TWh of coal-fired generation from EGUs that do not fit the selection criteria and are labeled as "excluded" by the EPA (30) are omitted from the table categories but are included in the generation total. This generation is supplied by the dataset coal fleet in the model.

	2005			2012			2030		
Source	**Generation (TWh)**	**% Mix**	**Intensity (lbs/MWh)**	**Generation (TWh)**	**% Mix**	**Intensity (lbs/MWh)**	**Generation (TWh)**	**Mix**	**Intensity (lbs/MWh)**
Nuclear	782	19.3%	0	769	19.0%	0	805	18.2%	0
Renewable	87	2.1%	0	218	5.4%	0	525	11.8%	0
Hydropower	270	6.7%	0	276	6.8%	0	273	6.1%	0
NGCC	570	14.0%	862	959	23.7%	875	1,400	31.6%	875
NGCC (excluded)	N.A.	0.0%	N.A.	63	1.6%	872	63	1.4%	872
OGST	195	4.8%	1,802	100	2.5%	1,460	36	0.8%	1,460
OGST (excluded)	N.A.	0.0%	N.A.	9	0.2%	1,609	9	0.2%	1,609
Other Fossil	121	3.0%	2,463	67	1.7%	1,261	129	2.9%	1,261
Other Fossil (excluded)	N.A.	0.0%	N.A.	49	1.2%	915	49	1.1%	915
Tribal NGCC (excluded)	N.A.	0.0%	N.A.	1	0.0%	858	1	0.0%	858
Tribal Coal	N.A.	0.0%	N.A.	32	0.8%	2,123	24	0.5%	2,123
Coal	2,035	50.1%	2,138	1,474	36.3%	2,214	1,098	24.8%	T.B.D.
Total	**4,061**	**100%**	**1,353**	**4,043**	**100%**	**1,124**	**4,435**	**100%**	**T.B.D.**
Mtons		**2,746**			**2,276**			**T.B.D.**	

Table C.7. Coal-fleet mitigation profile and metric details for various state emission-intensity targets, based upon meeting a percent reduction in the 2005 U.S. power-sector intensity and a percent reduction in the 2005 state-specific intensity, with HRI. U.S. power-sector intensity was 1,353 lbs/MWh in 2005. When each state meets this intensity target, the generation capacities and metrics are similar to those for meeting a 30% reduction in the state-specific 2005 intensities. Targeting no reduction in the state-level intensities results in a similar U.S. power-sector intensity and emission reductions as in the 30% reduction case. This is due in part to the added NGCC and renewable generation in 2030. The change in fuel prices and HRI also contribute to these reductions. Mitigations shown are inclusive of an HRI to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btu.

Mitigation/Metric	Units	1,350 lbs/MWh Target	State 0% Reduction	State 30% Reduction
Compliant Capacity	GW	82.5	139.9	67.4
Coal-Rank Capacity	GW	23.1	23.4	28.6
USC Capacity	GW	19	0.1	26.3
NG Retrofit Capacity	GW	6.5	2.4	6.4
NG Co-fire Capacity	GW	14	1.4	26.8
CCS Retrofit Capacity	GW	11.3	0	1.5
NGCC Capacity	GW	15.6	5.5	15.5
Retired Capacity	GW	76.3	75.6	75.8
U.S. Power-Sector Intensity	lbs/MWh	849	898	850
Coal-Fleet Intensity	lbs/MWh	1,832	2,015	1,838
Coal-Fleet Intensity Target	lbs/MWh	2,174	2,518	2,009
Coal-Fleet Net Generation	TWh	1,121	1,116	1,116
Coal-Fleet LCOE	$/MWh	42.1	37.5	41.3
Coal Consumption	Million MMBtu	9,389	10,616	9,267
NG Consumption	Million MMBtu	1,331	345	1,268

Table C.7. Continued…Coal-fleet mitigation profile and metric details for various state emission-intensity targets, based upon meeting a percent reduction in the 2005 U.S. power-sector intensity and a percent reduction in the 2005 state-specific intensity, with HRI. U.S. power-sector intensity was 1,353 lbs/MWh in 2005. When each state meets this intensity target, the generation capacities and metrics are similar to those for meeting a 30% reduction in the state-specific 2005 intensities. Targeting no reduction in the state-level intensities results in a similar U.S. power-sector intensity and emission reductions as in the 30% reduction case. This is due in part to the added NGCC and renewable generation in 2030. The change in fuel prices and HRI also contribute to these reductions. Mitigations shown are inclusive of an HRI to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btu.

Mitigation/Metric	Units	1,350 lbs/MWh Target	State 0% Reduction	State 30% Reduction
U.S. Power-Sector Emissions	CO_2 Mtons	1,803	1,908	1,807
Coal-Fleet Emissions	CO_2 Mtons	1,026	1,125	1,026
U.S. Emission-intensity reduction from 2005	fraction	0.37	0.34	0.37
Coal-Fleet Emission-intensity Reduction from 2005	fraction	0.16	0.06	0.14
U.S. CO_2 Mass-reduction from 2005	fraction	0.35	0.31	0.34
Coal-Fleet CO_2 Mass-reduction from 2005	fraction	0.53	0.48	0.53

Table C.8. Coal-fleet total capacity and designated mitigation capacity from meeting a percent reduction in the 2005 state-specific emission intensity. Mitigated capacity fractions do not include compliant CFEGU capacity. Non-economic mitigated capacity is defined as the capacity for which a compliant CFEGU is not a possible solution. Mitigations are inclusive of an HRI to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btu, unless otherwise indicated.

State-level Intensity Reduction	0%		30%	
HRI Condition	Without	With	Without	With
Total Capacity (GW)	172.3	172.2	171.7	172.1
Total Mitigated Capacity (fraction)	0.235	0.224	0.669	0.644
Non-economic Mitigated Capacity (fraction)	0.272	0.060	0.87	0.796

C.5.5 Likelihood mitigation profiles.

The simulation of the EIA projected fuel price errors indicates that there is a greater likelihood that both fuel prices will be underestimated, Figure B.6, with the underestimation for coal being greater than that for NG. The resulting national mitigation profile with the inclusion of this underestimation, based on the centroid of the regions (Table B.12), indicates that a lower emission intensity will be achieved for a 30% reduction, Figure C.11, because more capacity will be switched to 100% NG mitigation rather than be mitigated with NG co-fire and steam-generator upgrades, Figure C.12. This increased reliance on NG conversion is seen over the intensity range, such that the associated intensity over-reduction enables significantly more EGUs to remain compliant or be mitigated with coal rank upgrade. In doing so, the fundamental distribution profiles for the mitigation options are often significantly changed, Table B.29.

Therefore, the error in the EIA projection can have a significant impact on the shape of the mitigation distribution and the expected capacity for the mitigations.

These variations are particularly evident when examining the mitigation profiles for the likelihood regions, Figure C.13. In general, when the EIA projection overestimates a fuel price, the capacity for mitigations that use that fuel increases relative to the base case. As there is an asymmetry in the distribution for projected errors, there is a greater likelihood that each fuel price increase will be underestimated, region 4. This will result in a mitigation profiles that look similar to the centroid and base case. As the NG price increase is overestimated, relative to the coal price increase, regions 5 and 6, the use of NG retrofit mitigation increases. The likelihood of this occurring is 18%. Similarly, if there is an underestimation of NG price increase and the coal price increase is overestimated, mitigations that permit coal use (USC and CCS mitigations) increase. However, there is only a 6.4% likelihood that this will occur.

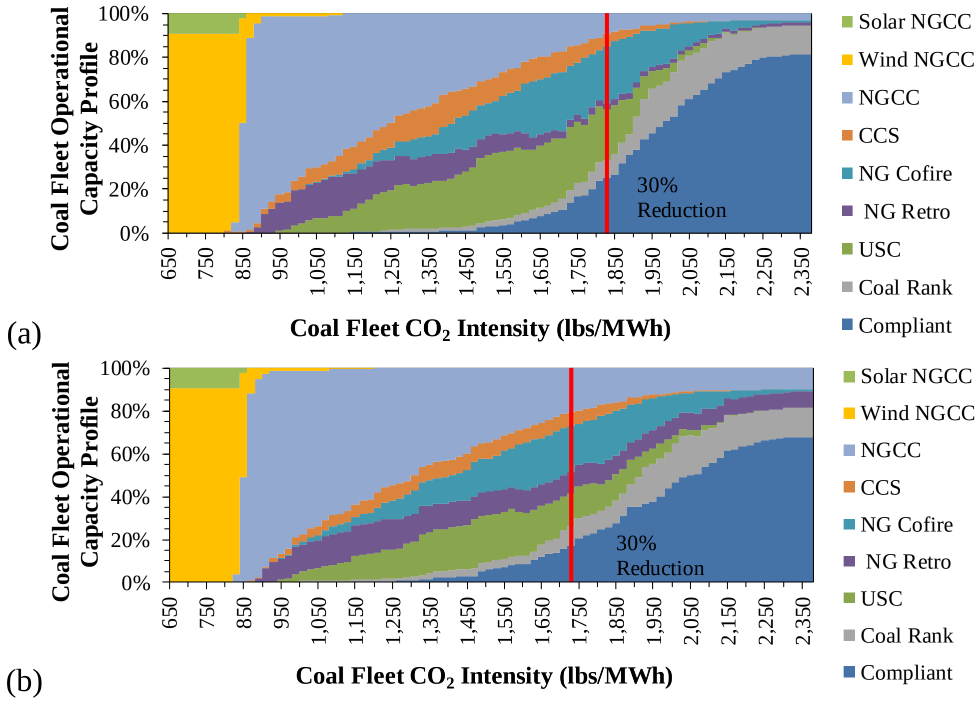


Figure C.11. The mitigation profiles for the US coal fleet mitigated for a 30% state-level emission intensity reduction in 2030 with the base case (a) and centroid of the expected value regions (b) fuel prices.

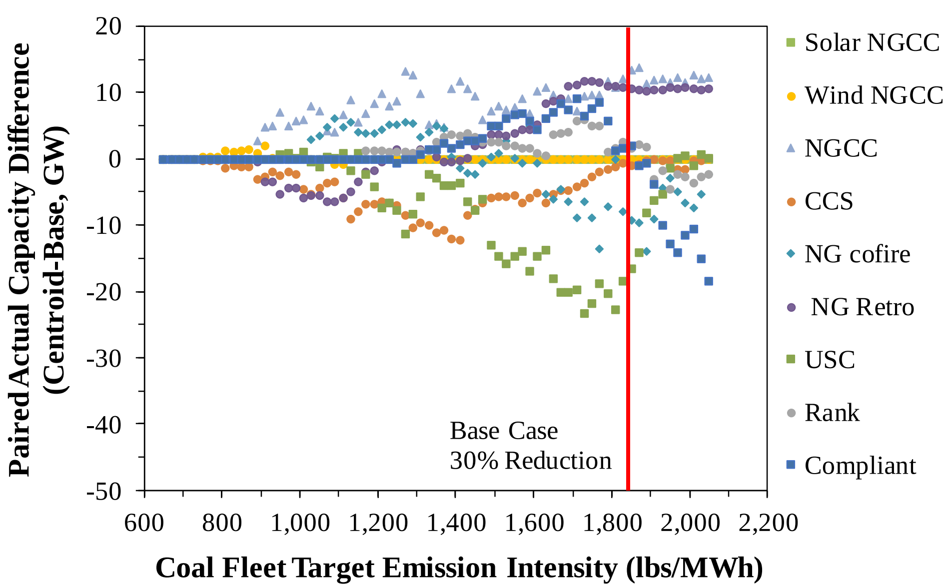


Figure C.12. The difference in operation capacity as a function of coal-fleet emission intensity for different mitigation options due to fuel price variations for the centroid of the expected value regions and the base case.

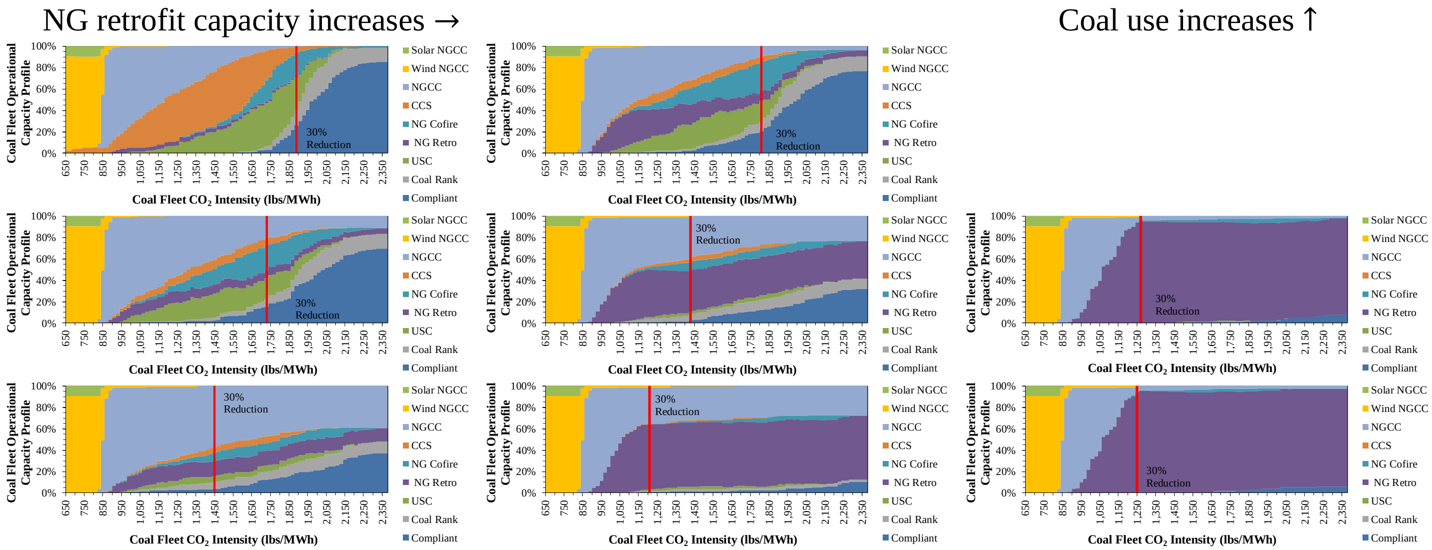


Figure C.13. The mitigation profiles for the nine expected value regions described in Figure 4 for the U.S. coal fleet mitigated for a 30% emission intensity reduction in 2030. Profiles are arranged according to Figure 3.2 orientation. Region 3 is a null set and has no profile. Natural gas use through NG retrofit mitigation increases from left to right, as the projected price increase for natural gas is overestimated. Coal use increases from bottom to top, as the projected coal price increase is overestimated.

C.5.6 Improving EGU heat rate.

C.5.6.1 "Gold standard."

When no constraints are placed on the extent of the HRI in the ESTEAM model, Figure C.14(a), these improvements form monotonic loci associated with the "gold standard" classifications. In some cases, these improvements are negative and indicate the heat rate for the CFEGU is better than that for the "gold standard." While this is not possible within the context of the model, this is possible in application because not all CFEGU-specific parameters (e.g. coal rank and atmospheric temperature and humidity) are modeled in the "gold standard." Positive improvements are made to the CFEGU heat rates such that the CFEGUs with the greatest heat rate may be improved upwards of 35%. The resulting generation weighted-average fleet HRI is 8%. Inclusion of the model constraints, Figure C.14(b), sets a floor at 0% improvement, truncates the improvements near 11%, and diminishes gains as the heat rate increases above 12,000 Btu/kWh, thereby preventing the heat rate from being better than those for the "gold standards" or from improving beyond what might be possible for $100/kW (34, 48). These constraints reduce the HRI to 4%, at a cost of $2.2/MWh ($1.2/MWh inclusive of fuel savings).

These heat rate gains are partially offset by additional parasitic loads from requisite emission control devices. The 4% HRI equates to a generation weighted-average intensity reduction of 87 lbs/MWh from the 2,166 lbs/MWh intensity of the dataset coal fleet in the 2010 configuration. When all EGUs are made compliant with the emission standards for SOx, NOx, and Hg, the parasitic load from these additional devices increases the pre HRI fleet intensity to 2,188 lbs/MWh. Therefore, the intensity of the compliant coal fleet after the HRI is approximately 2,100 lbs/MWh, which is only a 3% intensity reduction from the 2010 configuration.

While constraining the possible HRI can impact the average heat rate gains in the coal fleet, the impact of both constraints is not equal. A sensitivity analysis of both constraints, the maximum heat-rate improvement achieved and of the percent of the difference between the heat rate for the CFEGU and the "gold standard" that can be recovered, shows that the HRI is more sensitive to the percent recovered constraint, Table C.9(a). Allowing the maximum percent improvement constraint to be relaxed from 50% to 70% increases the HRI average improvement from 4% to 5.5%, while there is no change in improvement when the maximum allowed constraint is relaxed to 2,000 Btu/MWh. Putting this in context of the CFEGUs for which the HRI is an effective mitigation measure to achieve a 30% reduction, modifying the constraints only increases the HRI by an additional maximum of 0.2%, Table C.9(b). Therefore, the HRI constraints have a limited impact on the resulting mitigation measures for reduction targets that require more than an HRI.

C.5.6.2 HRI with fungible mitigations.

The possibility of using other mitigation technologies may decrease the relevance of the HRI as a mitigation tool in the presence of favorable fuel prices. Eliminating the *de facto* HRI mitigation, while maintaining the state-level intensity, decreases the overreduction in the coal-fleet emission intensity and results in an increase in the U.S.-level emission intensity and total emissions by approximately 2.5%. These increases are small because the mitigated capacities are similar for each case, Tables C.8 and C.10, but the non-economic mitigated capacity increases to 27% for the no HRI case. Without the additional HRI cost, the coal-fleet LCOE decreases by almost $1/MWh. When the reduction target is increased to 30% of the 2005 state-level intensity, the absence of the HRI also diminishes the reduction in intensity and emissions for the U.S. power sector by 1%, but without a cost savings. For this reduction level, mitigation for economic gain reduces from 20% with HRI to 13% without HRI.

These examples suggest that in the absence of a required HRI mitigation, the abandoned intensity reduction may be compensated with fungible mitigations that result in almost equal intensity and emission reductions, and at a coal-fleet LCOE that is similar to that achieved with the HRI. One implication is that in some cases, the least-cost solution for a state coal fleet or an individual CFEGU to meet a required improvement in intensity reduction may be a mitigation other than an HRI. Therefore, it may be more effective to achieve CO_2 emission intensity and emission reductions by setting a specific target (43) rather than mandating a specific mitigation method to use (43, 44).

The mitigation profile capacities are stable for intensities above 2,300 lbs/MWh. At this point, approximately 25% of the capacity uses a non-compliant mitigation because it is more economical to switch fuels or to convert to a NGCC plant, despite any additional capital costs associated with the VOM savings for these measures. There are two reasons for the economic gain. One reason is the additional cost of the HRI. An example of this gain is the least-cost frontier for an CFEGU in Pennsylvania, Figure C.15(a). Here, the cost of compliance with the HRI is $2/MWh more expensive than switching fuels to NG. However, if the HRI is not employed because the intensity target can be met without it, the resulting increase in LCOE due to compliance comparable to that for mitigating with NG, Figure C.15(b). This implies that without a state-wide intensity target, the presence of a mandated mitigation option concerning improving business as usual intensities can drive greater emission reductions. Removing this requirement through a site-specific waiver can limit realized gains, however.

The second reason is that the additional cost of emission compliance for coal is high enough that it is cost-effective to use a mitigation that does not require the additional emission control devices. For example, the LCOE for a compliant CFEGU in Tennessee, with the HRI, is $12/MWh higher than that for the currently configured EGU, Figure C.15(c). The compliant LCOE is also almost $2/MWh more expensive than converting the CFEGU to an NGCC plant; therefore, the least-cost option is to convert the CFEGU, rather than to make it compliant with traditional emission regulations. If the CFEGU is not required to be complaint with these regulations, the current LCOE for the CFEGU is less than that for the NGCC conversion: the current configuration is the dominant technology on the least-cost frontier. This implies that waiving traditional emission compliance for some CFEGUs can reduce possible gains in CO_2 emission reduction, even in the absence of an intensity target.

Both examples illustrate that the absence of waivers (44) can allow market mechanisms to work in reducing CO_2 emission intensity, even when the associated requirements are not seen as being constraining for CO_2. Further, the presence of a known intensity reduction requirement that only nudges the historical emissions can realize even greater reductions than the requirement suggests. However, this requires effective market mechanisms that rely on specific fuel price scenarios. In the absence of these scenarios, actualizing intensity reductions are not realized without deeper targets to drive mitigation. Here too, the realized intensity reduction may be greater than the requirement because of the market mechanisms.

C.5.6.3 Retire or mitigate decision.

An implication of the HRI constraints is that CFEGUs with severely degraded heat rates are likely to be those that are not economical to use in the carbon-restricted future. Rather than pursuing HRI on these CFEGUs, it may be less costly to retire these boilers and produce generation from CFEGUs with lower initial heat rates. Determining the disposition of the CFEGU *a priori*, based upon the initial heat rate and possible improvement, may not be so simple. The complexity of the retire or mitigate decision for a 30% reduction can be seen in the *a posteriori* analysis, regarding mitigation outcomes as a function of the compliant heat rate, by grouping these dispositions into five classifications: remain, refuel, retrofit, repower, and retire. The remain classification includes all CFEGUs for which only the HRI is necessary, whereas the refuel classification includes all CFEGUs for which the original coal rank is supplemented or replaced with natural gas or bituminous coal. If the CFEGU requires CCS retrofitting, then the classification is retrofit. HRI is also used for all of the previously described mitigations. Replacing the steam generator, such as with SC and USC upgrades and NGCC plant conversions, is a repower classification. The final classification, retire, includes all CFEGUs that are not generating electricity to meet state demand. HRI is not used for these mitigations.

In such a representation with base case fuel prices, Figure C.16, the proportion of CFEGUs mitigating solely with HRI does diminish with increasing heat rate and the proportion of retirements increases; however, there is no operational heat rate level above which all CFEGUs are retired or for which an HRI is not a viable solution, as a sole or coupled mitigation. Similarly, retirement or repowering are the mitigation solutions for approximately two-thirds of the CFEGUs at the initial heat rate mode. This diversity in classifications across heat rates is often a result of evaluating CFEGU reductions at a state-level. Some states have excess generation from other sources so that coal-fired capacity from CFEGUs with low heat rates can be retired; other states need the coal-fired capacity, even if the heat rate is above the national average. The state-specific intensity targets and 2030 fuel prices are additional factors contributing to the diversity.

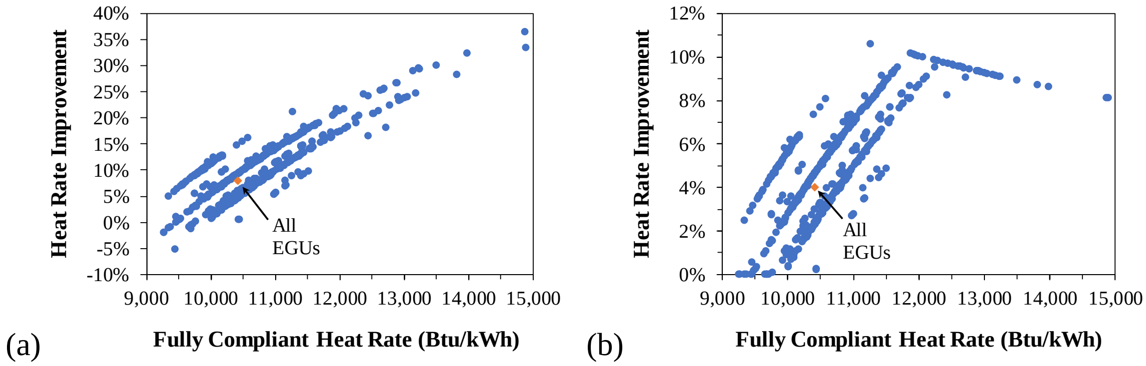


Figure C.14. Heat rate improvement for U.S. coal-fleet dataset (a) without and (b) with HRI limited to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btu. Inclusion of limits prevents the heat rate for some CFEGUs from being better than those for the "gold standards" and other CFEGUs from improving beyond what might be possible for $100/kW (45, 46). With limitations, the generation weighted average HRI is decreased to 4% from 8%. Stratification in data relate to CFEGU "gold standard" classifications.

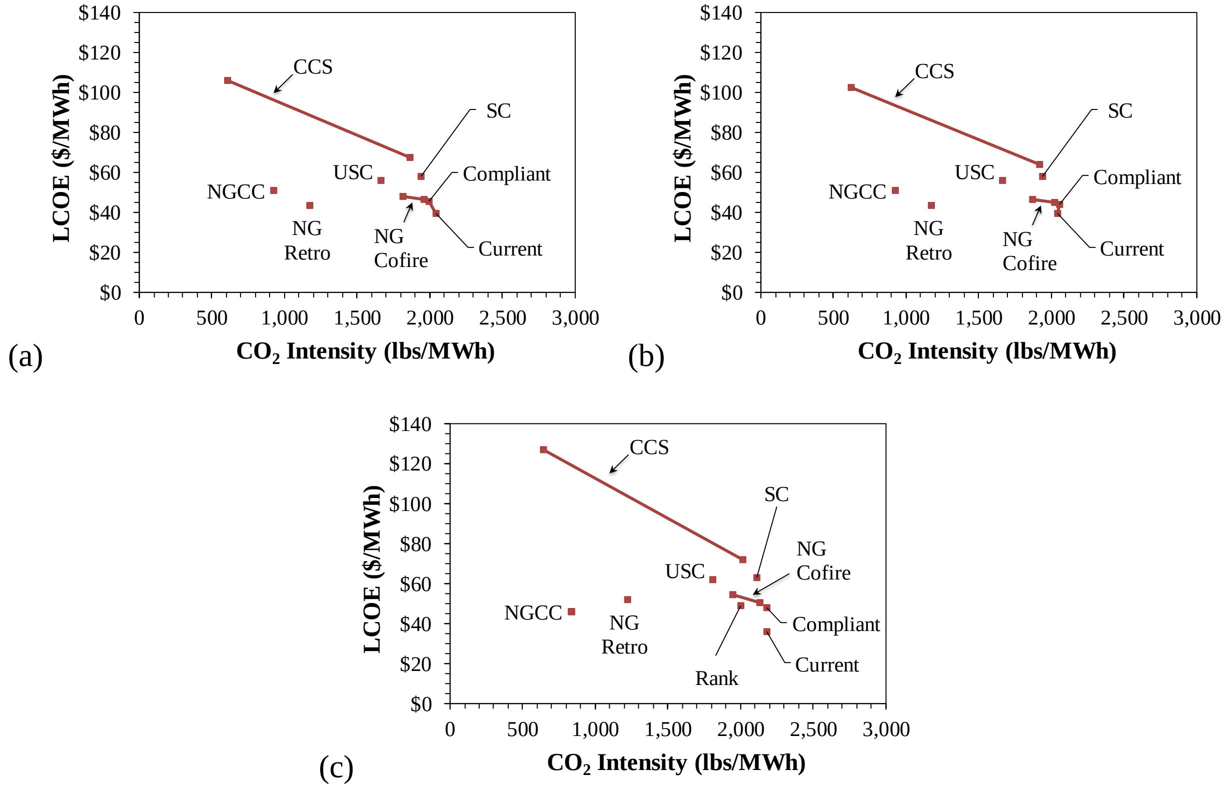


Figure C.15. Least-cost mitigation frontiers for CFEGUs in (a, b) Pennsylvania and (c) Tennessee. Panel(a) shows the frontier with HRI and base case fuel prices at a cost of $2.63/MWh. In the absence of a mitigation target, NG retrofit is the mitigation choice. Eliminating the HRI lowers the compliant LCOE to below that of the NG retrofit mitigation, Panel(b), making the compliant CFEGU the least-cost mitigation. For the Tennessee CFEGU, the least cost CFEGU operation is to convert the CFEGU to an NGCC plant, Panel(c). Removing the compliance constraint makes the least-cost operation of the CFEGU the current configuration, in the absence of an intensity target.

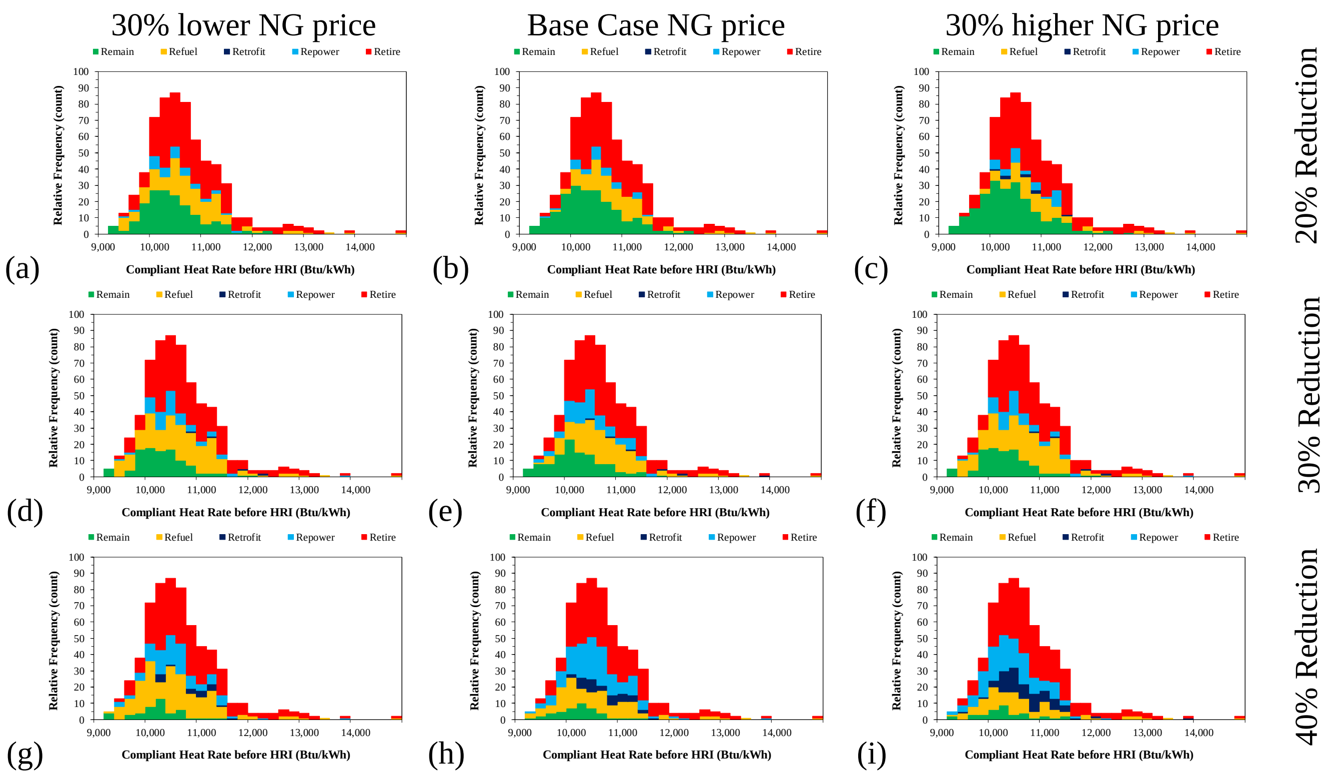


Figure C.16. Disposition of U.S. coal fleet for various CO_2 emission-intensity reductions at the state-level, as a function of compliant heat rate for different NG price scenarios. State-level intensity-reduction targets are 20%, 30%, and 40%. Natural gas price is varied ± 30% relative to the base case. Remain classification includes all CFEGUs for which only the HRI is necessary. Refuel classification includes all CFEGUs for which the original coal rank is supplemented or replaced with natural gas or bituminous coal. Retrofit classification includes all EGUs for which CCS retrofitting is required. Repower classification includes all CFEGUs for which the steam generator is replaced (SC and USC upgrades, and NGCC plant conversion). Retire classification includes all CFEGUs that are not generating electricity to meet state demand. This graphic includes an HRI that is limited to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btu. Improvement cost is set at \$100/kW. For each scenario, the retirement is constant. Within each NG price scenario, the CFEGU disposition for the remain category decreases as the reduction target increases. The trend to mitigate for economic reasons is observed in the increase in the remain category for the 30% reduction target, as the NG price increases. The retrofit category (CCS) increases as coal becomes less expensive relative to NG, for the 40% reduction scenarios.

Table C.9. Two-way sensitivity analysis of generation weighted-average percent HRI from variable maximum heat-rate reduction and allowable percent recovery for (a) the entire EGU dataset and (b) only those post-mitigation operational EGUs that retain the original steam generator and are fueled primarily with coal. Limiting dataset does not indicate HRI bias to post-mitigation outcome. For each case, achieved reduction is more sensitive to allowable recovery than to maximum heat-rate reduction.

(a)

		Maximum Heat Rate Reduction (Btu/MWh)															
		500	600	700	800	900	1,000	1,100	1,200	1,300	1,400	1,500	1,600	1,700	1,800	1,900	2,000
Allowable Recovery	30%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
	40%	3.0%	3.1%	3.1%	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%
	50%	3.5%	3.7%	3.8%	3.9%	3.9%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
	60%	3.8%	4.1%	4.4%	4.6%	4.7%	4.7%	4.7%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
	70%	4.0%	4.5%	4.8%	5.1%	5.3%	5.4%	5.5%	5.5%	5.5%	5.5%	5.6%	5.6%	5.6%	5.6%	5.6%	5.6%
	80%	4.1%	4.7%	5.2%	5.5%	5.8%	6.0%	6.1%	6.2%	6.3%	6.3%	6.3%	6.3%	6.4%	6.4%	6.4%	6.4%
	90%	4.2%	4.9%	5.4%	5.9%	6.2%	6.5%	6.7%	6.8%	6.9%	7.0%	7.1%	7.1%	7.1%	7.1%	7.1%	7.2%
	100%	4.3%	5.0%	5.6%	6.1%	6.6%	6.9%	7.2%	7.4%	7.6%	7.7%	7.8%	7.8%	7.9%	7.9%	7.9%	7.9%

(b)

		Maximum Heat Rate Reduction (Btu/MWh)															
		500	600	700	800	900	1,000	1,100	1,200	1,300	1,400	1,500	1,600	1,700	1,800	1,900	2,000
Allowable Recovery	30%	2.4%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
	40%	3.1%	3.2%	3.2%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%
	50%	3.6%	3.9%	4.0%	4.0%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%
	60%	3.9%	4.3%	4.6%	4.7%	4.8%	4.9%	4.9%	4.9%	4.9%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
	70%	4.0%	4.5%	4.8%	5.1%	5.3%	5.4%	5.5%	5.5%	5.5%	5.5%	5.6%	5.6%	5.6%	5.6%	5.6%	5.6%
	80%	4.1%	4.7%	5.2%	5.5%	5.8%	6.0%	6.1%	6.2%	6.3%	6.3%	6.3%	6.3%	6.4%	6.4%	6.4%	6.4%
	90%	4.2%	4.9%	5.4%	5.9%	6.2%	6.5%	6.7%	6.8%	6.9%	7.0%	7.1%	7.1%	7.1%	7.1%	7.1%	7.2%
	100%	4.3%	5.0%	5.6%	6.1%	6.6%	6.9%	7.2%	7.4%	7.6%	7.7%	7.8%	7.8%	7.9%	7.9%	7.9%	7.9%

Table C.10. Coal-fleet mitigation profile and metric details for various state emission-intensity targets, based upon meeting a percent reduction in the 2005 state-specific intensity with and without HRI. When each state meets this intensity target, the generation capacities and metrics are similar to those for meeting a 30% reduction in the state-specific 2005 intensities. Targeting no reduction in the state-level intensities results in a similar U.S. power-sector intensity and emission reductions as in the 30% reduction case. This is due in part to the added NGCC and renewable generation in 2030. The change in fuel prices and HRI also contribute to these reductions. Mitigations shown are inclusive of an HRI to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btu.

Mitigation/Metric	Units	State 0% Reduction no HRI	State 0% Reduction with HRI	State 30% Reduction no HRI	State 30% Reduction with HRI
Compliant Capacity	GW	137.1	139.9	62	67.4
Coal-Rank Capacity	GW	23.5	23.4	28.5	28.6
USC Capacity	GW	0.5	0.1	27	26.3
NG Retrofit Capacity	GW	2.5	2.4	7.0	6.4
NG Co-fire Capacity	GW	5.4	1.4	31.3	26.8
CCS Retrofit Capacity	GW	0.1	0	3.3	1.5
NGCC Capacity	GW	3.9	5.5	13.9	15.5
Retired Capacity	GW	75.2	75.6	75.3	75.8
U.S. Power-Sector Intensity	lbs/MWh	921	898	865	850
Coal Fleet Intensity	lbs/MWh	2,099	2,015	1,891	1,838
Coal-Fleet Intensity Target	lbs/MWh	2,628	2,518	2,035	2,009
Coal-Fleet Net Generation	TWh	1,117	1,116	1,120	1,116
Coal Fleet LCOE	$/MWh	36.9	37.5	41.2	41.3
Coal Consumption	Million MMBtu	11,098	10,616	9,556	9,267
NG Consumption	Million MMBtu	311	345	1,345	1,268

Table C.10. Continued…Coal-fleet mitigation profile and metric details for various state emission-intensity targets, based upon meeting a percent reduction in the 2005 state-specific intensity with and without HRI. When each state meets this intensity target, the generation capacities and metrics are similar to those for meeting a 30% reduction in the state-specific 2005 intensities. Targeting no reduction in the state-level intensities results in a similar U.S. power-sector intensity and emission reductions as in the 30% reduction case. This is due in part to the added NGCC and renewable generation in 2030. The change in fuel prices and HRI also contribute to these reductions. Mitigations shown are inclusive of an HRI to 50% of the difference between the net heat rate for the "gold standard" and existing CFEGU up to the maximum improvement of 1,205 Btu.

Mitigation/Metric	Units	State 0% Reduction no HRI	State 0% Reduction with HRI	State 30% Reduction no HRI	State 30% Reduction with HRI
U.S. Power-Sector Emissions	CO_2 Mtons	1,955	1,908	1,836	1,807
Coal Fleet Emissions	CO_2 Mtons	1,173	1,125	1,059	1,026
U.S. Emission-intensity Reduction from 2005	fraction	0.32	0.34	0.36	0.37
Coal Fleet Emission-intensity Reduction from 2005	fraction	0.02	0.06	0.12	0.14
U.S. CO_2 Mass-Reduction from 2005	fraction	0.29	0.31	0.33	0.34
Coal-Fleet CO_2 Mass-Reduction from 2005	fraction	0.46	0.48	0.51	0.53

C.5.7 USC Upgrade.

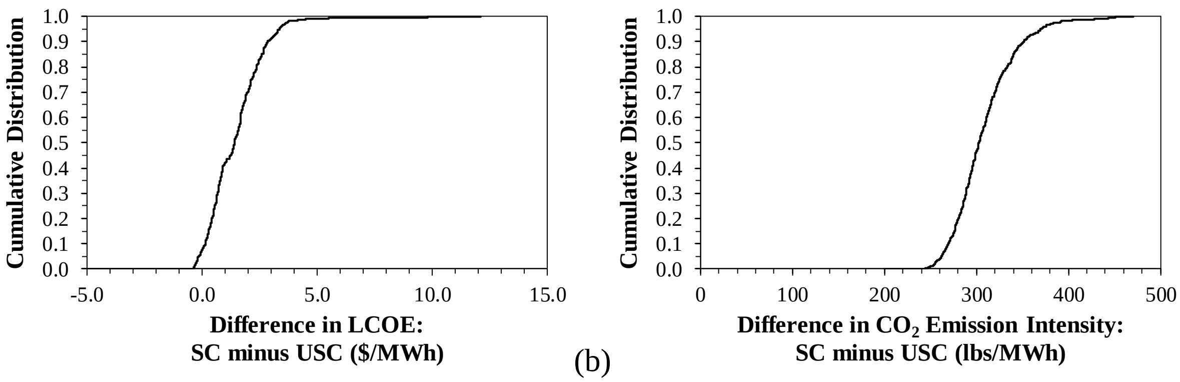


Figure C.17. Comparison of difference in (a) LCOE and (b) emission intensity for SC and USC steam-generator upgrades mitigations for dataset coal-fleet. USC upgrades dominate SC upgrades of all but 43 of the 635 CFEGUs, when using state-specific fuel prices and retaining original EGU net generation. USC LCOE is greater than that for SC by as much as $0.4/MWh. Difference in LCOE and emission intensity values between ESTEAM model and SC and USC cited in (47) is due in part to assumptions about higher heating value efficiencies for steam generators.

C.5.8 CCS Retrofit.

With a nation-wide 30% reduction in CO_2 emission intensity implemented uniformly at the state-level, CCS-retrofit mitigation is the least-cost solution for only six CFEGUs and would annually store less than three million tons of CO_2, assuming the default commodity prices and an absence of CO_2 taxes, tax credits, or subsidies, Table C.11. Increasing the reduction 40-50% greatly increases the total-fleet CCS capacity to upwards of 19 GW, with 38-41 CFEGUs annually capturing more than 40 Mtons of CO_2. This is accomplished not only by increasing the number of EGUs using CCS, but by increasing the capture rate of these CFEGUs, Figure C.18(a). Even so, the required capture rate remains below 90% capture; the median capture rate only increases from 18% for a 30% reduction to 40% for a 50% reduction and no CFEGU exceeds a 60% capture rate. The number of CCS retrofits increases the number of sequestration sites from five to fourteen, yet the capture rates are low enough that all but two of these sites will be filled to more than 45% capacity for the remaining service life of the CFEGUs, Figure C.18(b). Two unique sites are oversubscribed for the lifetime of the CFEGUs at the capture rates for the 40% and 50% reductions; however, alternative sites are available at additional the transportation and storage costs (T&S) costs of $2.5/MWh and $5/MWh, respectively.

Fungible mitigations with lower LCOE drive the limited number of CFEGUs using CCS. When aggregating the CFEGU mitigation frontiers at the national-level, there is a rapid increase in natural gas related and steam-generator upgrade mitigation capacity that supplants that which could be CCS capacity, as the required intensity reduction increases, Figure C.19(a). This trend tapers the increase in CCS capacity over the same reduction range and extensively limits much of the capacity to two states, Table C.12, with the highest natural gas price and the lowest coal prices—North Dakota and Wyoming (Table B.86). In addition to the fuel price disparity, the use of CCS increases for other CFEGUs because of the additional net generation from the auxiliary NG boiler at the greater capture rates associated with the deeper reductions decreases the CCS LCOE, Figure C.19(c). However, only one CFEGU (located in Wyoming) uses CCS for all intensity levels: 23 additional CFEGUs use CCS for two intensity levels. Therefore, CCS may not be a stable mitigation option for an CFEGU across all reduction and fuel price scenarios.

The CCS LCOE can also be decreased through tax credits related to sequestering the captured CO_2. Amendments to 26 US Code 45Q in the Bipartisan Budget Act of 2018 concerning CCS (48) allow for a 12-year, $50/tonne tax credit for qualifying EGUs that permanently sequester the pollutant. In the absence of cost minimization, this credit[1] ($39/ton in

[1] While the tax credit is applicable for only 12 years after commencement of the operation of the CCS subsystem, for which construction must start by 2027 (48), we assume for simplicity that this operation begins in 2030. If the service life of the CFEGU is greater than 12 years, the 12-year credit is averaged over the EGU …continued

2010 dollars) increases the use of CCS for a 30% reduction, but the increase falls short of that achieved with a 40% reduction target without a credit, Table C.11: the annual, generation weighted-average worth of the credit being only $1.5/MWh for the 8.9 Mtons of sequestered CO_2. The increase in the number of CFEGUs and capacity is most dramatic in Kentucky and Indiana, Table C.12, where the projected coal prices are low in comparison to the natural gas prices. For lower intensity targets, the CCS capacity and associated coal use increases further in lieu of NGCC and USC upgrade mitigations, Figures C.19(b) and C.20. These increases are also evident for coal fleet intensities below 850 lbs/MWh, where CCS mitigation supplants some NGCC with renewable generation capacity.

In addition to increasing the number of CFEGUs mitigating with CCS, the credit also impacts other CCS attributes. With the credit, more sequestration sites are used and filled to greater capacity than for the 30% reduction case, Figure C.18 (b) and Table C.13. The credit also decreases the LCOE for theses CFEGUs; the median credited LCOE is $59/MWh. Further reductions in the coal fleet intensity lead to increased CCS utilization at higher average capture rates, *ceteris paribus*, Figure C.21(a). The subsequent increase in sequestered CO_2, Figure C.21(a), increases the total cost of the credit, Figure C.21(b), to a maximum at 1,210 lbs/MWh, which is approximately a 50% reduction in coal-fleet intensity. In comparison to the use of CCS without the tax credit, Figure C.21(c), the presence of the credit increases the amount of CO_2 captured; but does not alter the generation weighted-average capture rate until lower intensities, when NGCC with renewable generation is replaced by CCS. The increased CCS utilization with the credit does not increase the fleet LCOE; rather, the difference between the without and with credit LCOE is less than $1/MWh throughout the range of mitigated coal fleet intensities, Figure

service life to a maximum of 30 years. The worth of the credit ($/MWh) is inclusive of the generation from the natural gas auxiliary boiler.

C.22, and within the 95% confidence bounds for the CCS LCOE, Table B.18. The taxpayer cost for this subsidized LCOE difference is approximately $57 million.

One possible consideration in assessing the tax credit is how much of the cost associated with CCS is compensated for with the credit. For wind, the production tax credit (PTC) worth[2] is approximately equal to the estimate for the annual O&M cost for a 2.16 MW onshore wind turbine and is at least 23% of the estimate $52/MWh LCOE (50). However, without another policy mechanism, the CCS tax credit value may be insufficient to fully compensate for many of the additional CCS mitigation costs at the 30% reduction level. In particular, the CCS tax credit compensates for at most 60% of the additional CO_2 T&S cost,[3] Figure C.23. Furthermore, the median credit offset is approximately 6% of the total CCS retrofit costs. This breakeven cost can be higher than that in the literature (51, 52) due in part to the added EGU-specific costs of the auxiliary boiler, the presence of fungible mitigations for CO_2 reduction, and the ineligibility of five of the fifteen CFEGUs for credits.

Another possible consideration in assessing the CCS tax credit level, and the related functional and financial impacts, is the technology neutrality of the credit (53), for which a comparison to the wind production tax credit is appropriate. The generation weighted-average emission intensity of the U.S. coal fleet in the dataset is 2,166 lbs/MWh; therefore, each MWh of electricity provided by wind instead of coal-fired generation eliminates 1.08 tons of CO_2. As the maximum wind PTC is $21/MWh (in 2010 dollars) (54), the technology neutral CCS tax credit should be almost $23/ton; this is substantially less than the $39/ton CCS credit. However, on

[2] The PTC has a face value of $24/MWh ($21/MWh in 2010 dollars) for a 10-year period. As this is pretax and of limited duration, the face value is derated over the 20-year life of the wind turbine to be worth at least $15/MWh (49).

[3] The T&S cost includes the sequestration costs, O&M costs, and the capital cost for the CO_2 pipeline and any required compressor stations. These capital costs are annualized over the book life of the CFEGU—up to 30 years.

average this credit is never worth more than $4/MWh, Figure C.21(b). Furthermore, the resulting maximum expenditure for the credit is only $550 million, which is below the estimated $4.8 billion ($4.2 billion in 2010 dollars) average, annual expenditure for the wind PTC from 2018-2022 (55). In ESTEAM, this low expenditure is because EGUs ineligible for credits will still mitigate with CCS because of the advantageous fuel prices, in some scenarios; and the credit worth is diluted, because more than 70% of the CFEGUs have a possible service life that is greater than the duration of the credit, Figure B.2(c). Furthermore, in some instances the maximum credit value may be realized, but the remaining life of the CFEGU is short enough that the FCF for the CCS retrofit increases the cost of the project beyond the value of the credit. Therefore, in most instances the credit is inadequate to offset the mitigations costs to be competitive with natural gas and steam generator upgrade alternatives. The credit level may need to be increased, the threshold lowered, or the applicable duration extended to promote further power-sector CCS use in scenarios where policy makers are only considering operators cooperatively meeting reduction targets in the presence of fungible mitigations, and when operators may seek lower costs through greater reduction in the absence of trading mechanism.

The impact of low natural gas prices is also observed, when directly comparing CCS retrofit and NGCC mitigations to meet a possible deeper regulatory intensity target. For this deeper reduction target, the comparison can be made to NGCC conversion generation augmented with co-located renewable generation from the least-cost of solar and wind sources. In such a scenario to meet a required intensity target of 750 lbs/MWh, with both the CCS capture rate and augmented renewable generation limited to 90%, only 53 out of the 599 possible operational EGUs[4] operate with CCS capture rates from 71% to 90% and renewable augmentation rates from

[4] Thirty-six EGUs require capture rates greater than 90% to meet the emission intensity target: these CFEGUs are omitted.

10% to 90%, Figure C.24 (a, c). For the operational units, the CCS tax credits are worth up to \$33/MWh, Figure C.24(b); yet only 40 credits are large enough to decrease the LCOE for a CCS retrofit to below that for the augmented NGCC conversion, Figure C.25. Therefore, the possibility of NGCC and renewable co-location, given projected low natural gas prices and the availability of renewable generation, may be a less expensive alternative to retrofitting CCS for coal-fired EGUs, unless the CCS tax credits are increased.

In the absence of any emission intensity regulation, one can further compare the EGU-specific economic competitiveness of CCS with the tax credit directly to that for the brownfield NGCC conversion, Figure C.26. For this case, converting the CFEGU to a NGCC plant dominates CCS with 90% capture for all but 33 of the 635 EGUs—of which 16 are in North Dakota and Wyoming, where the high natural gas price and low coal price favors coal-fired CCS. This preference for NGCC implies that the tax credit is also insufficient to make CCS viable to alternative generation investments.

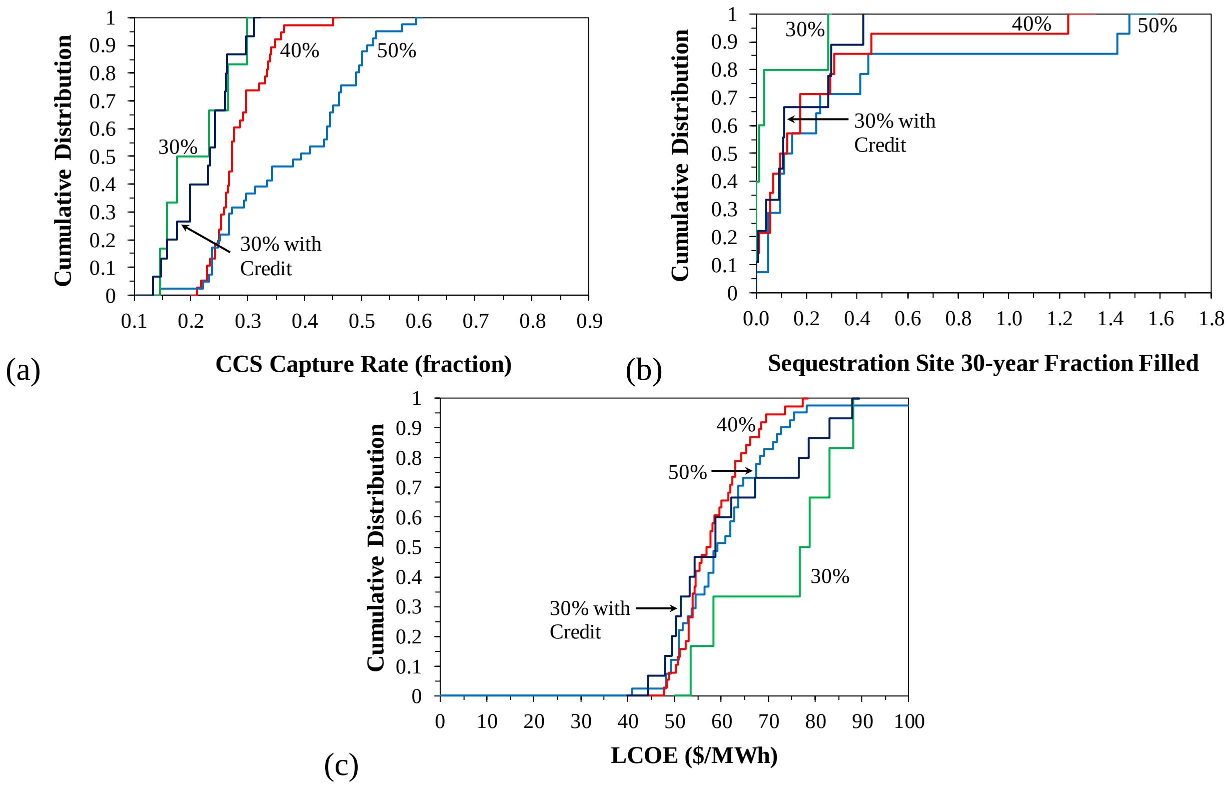


Figure C.18. Impact of intensity reduction and $50/tonne CCS tax credit on CCS (a) capture rate, (b) sequestration site subscription, and (c) CFEGU LCOE. Capture rates increase with increasing reduction target and with tax credit, Panel (a), yet maximum capture rates remain below 60%, even with 50% reduction. As the number of CCS retrofitted EGUs and capture rates increase the number of sequestration sites used and the subscription at the sites increases. Over 80% of the sites are filled to less than 30% capacity for reductions for all cases. Two sites for CFEGUs in Montana and Wyoming are oversubscribed for the 40% and 50% reductions. Alternative sites are available in Montana for $5/MWh and in Wyoming for $2-5/MWh. The median LCOE is less than $80/MWh for the reduction levels studied and decreases significantly for reductions of at least 40%, Panel (c). The addition of the tax credit to the 30% reduction case reduces the median LCOE to be similar to that for the 50% reduction case.

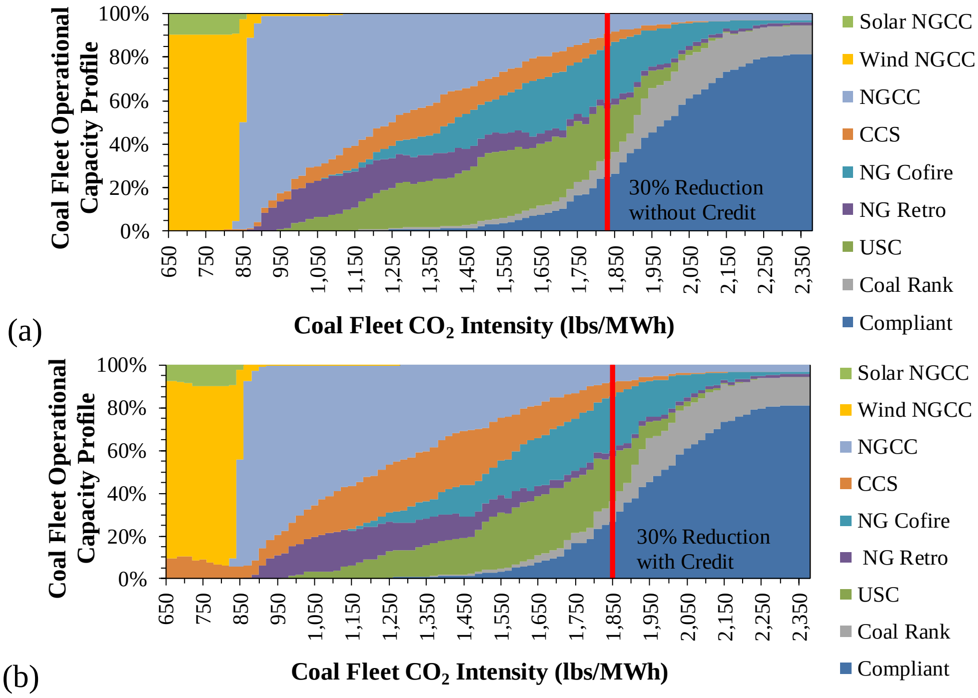


Figure C.19. Mitigation profiles for different reduction targets without (a) and with (b) \$50/tonne CCS tax credit. The CCS capacity increases with increasing intensity reductions without the credit but is dominated by increasing NGCC capacity. The addition of the credit significantly increases the operational CCS capacity at all intensity reduction levels.

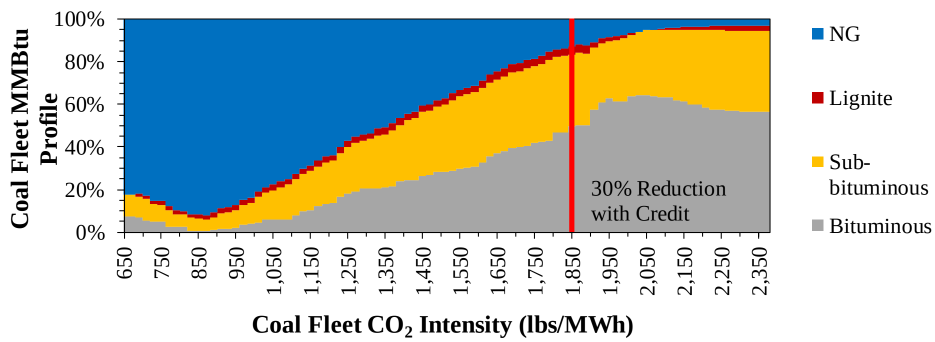


Figure C.20. Fuel-use profiles for fleet capacity with the \$50/tonne CCS tax credit. The credit increases coal use, relative to the non-credit case, over the entire intensity range.

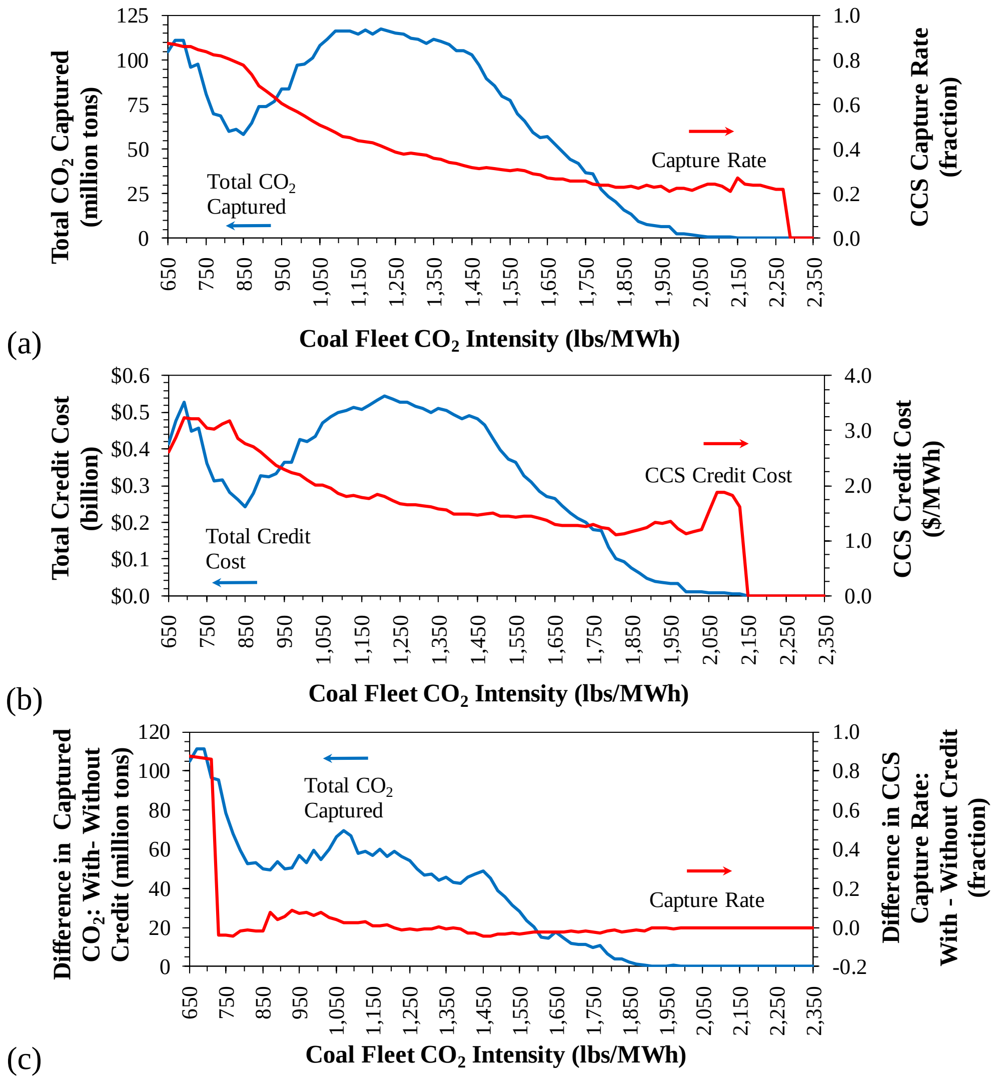


Figure C.21. CO_2 captured and generation weighted-average capture rate, Panel (a), and total CCS tax credit cost and worth ($/MWh), Panel (b), as a function of U.S. coal-fleet emission intensity with the $50/tonne CCS tax credit. The instability at high intensities is caused by the limited number of CFEGUs mitigating with CCS, while that at the lower intensities is caused by the replacement of NGCC plants with CCS retrofitted coal-fired EGUs. In comparison to the use of CCS without the tax credit, Panel (c), the presence of the credit increases the amount of CO_2 captured; but does not alter the generation weighted-average capture rate until lower intensities, when NGCC with renewable generation is replaced by CCS.

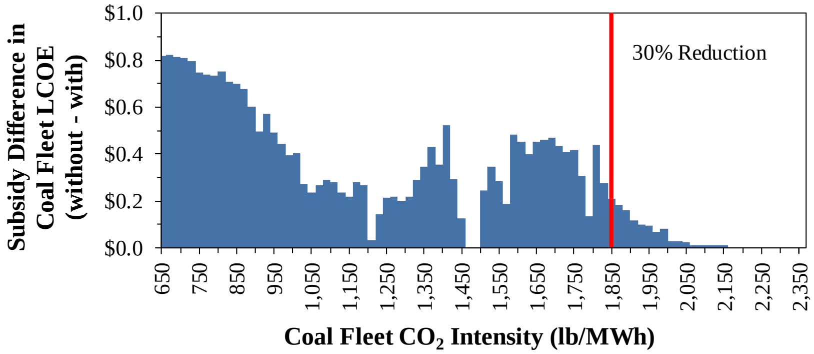


Figure C.22. Difference in mitigated coal-fleet LCOE without and with the \$50/tonne CCS tax credit. At a 30% reduction target, the LCOE with the credit is less than \$1/MWh lower than that without the credit.

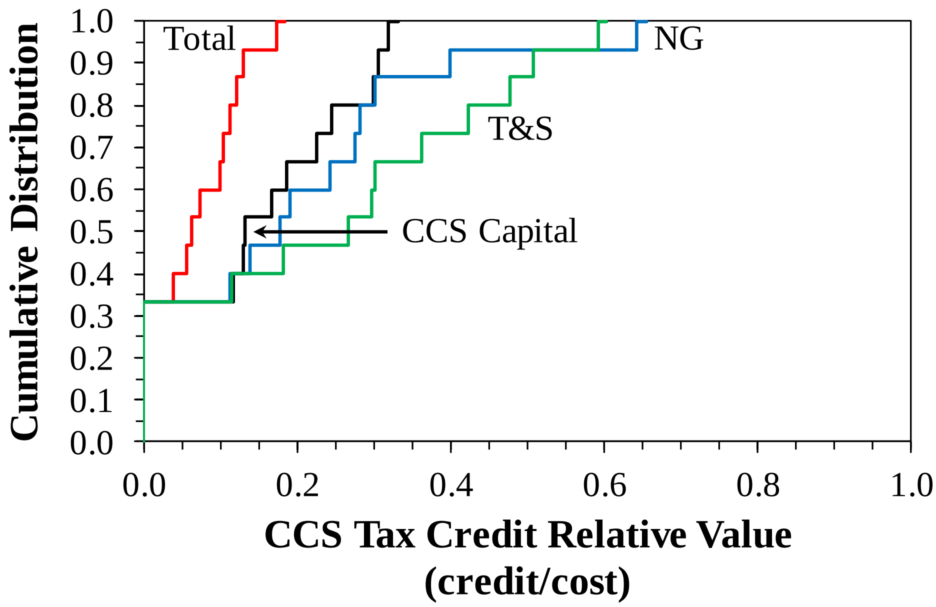


Figure C.23. The relative value of the \$50/tonne CCS tax credit for the 13 CFEGUs that use CCS mitigation to achieve a 30% reduction in state-level emission intensity to other costs associated with CCS retrofitting. The relative value is the \$/MWh equivalent of the fully monetized credit for the sequestered CO_2, at the net generation inclusive of the surplus generation from the natural gas auxiliary boiler, divided by the \$/MWh value for the specified metric. Unique metrics graphed are the capital cost for the CCS subsystem and natural gas pipeline, the natural gas VOM cost for the auxiliary boiler, and the transportation and storage costs (T&S) cost for the CO_2 sequestration (capital and O&M), and the total of these three costs.

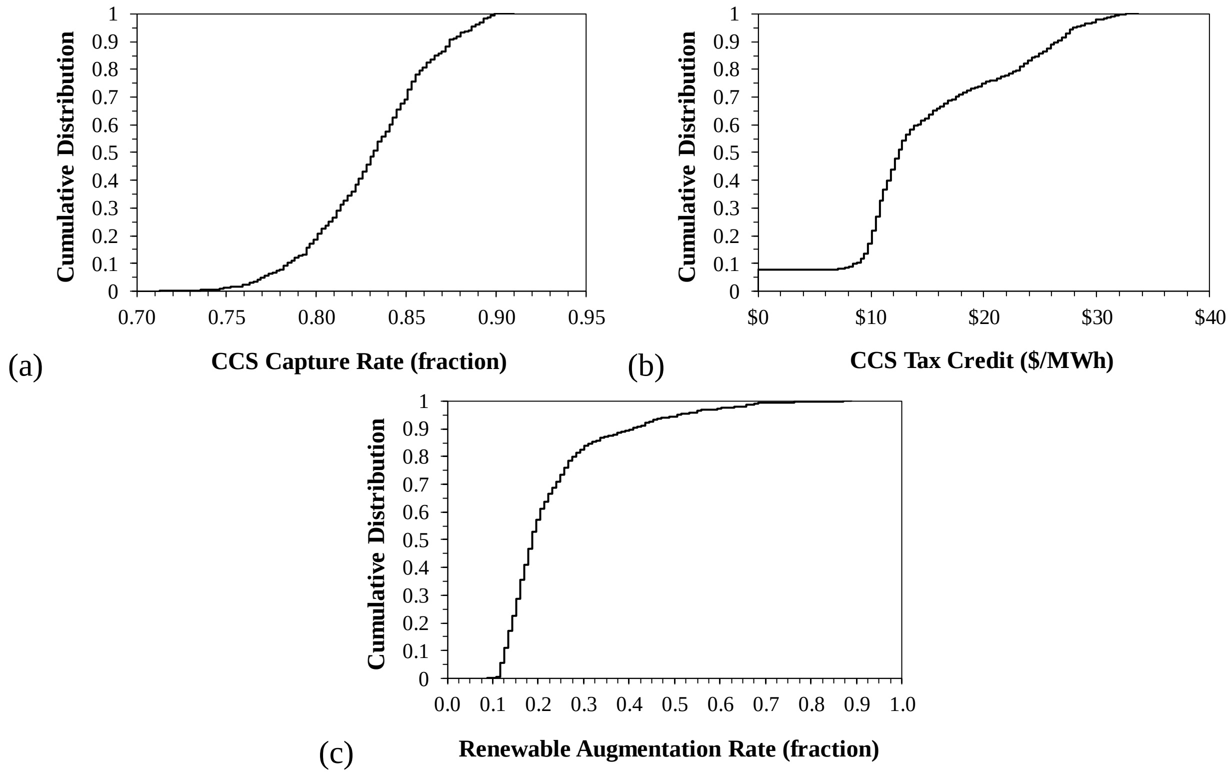


Figure C.24. Comparison of EGU-specific mitigation attributes for CCS retrofit and NGCC conversion co-located with renewable generation to meet 750 lbs/MWh CO_2 emission intensity. CCS mitigation (a) limits the capture rate to 90% and (b) includes a $50/tonne tax credit. Even with the high capture rate, 53 CFEGUs do not capture enough CO_2 to qualify for the credit. NGCC related LCOE is the least-cost renewable generation, solar or wind, for which the renewable contribution is limited to 90%, (c). For these criteria, 599 of the 635 EGUs are operational. Of these operational CFEGUs, 20% of the CFEGUs require a CCS capture rate of at least 86%, while 20% of the CFEGUs require NGCC conversion augmented with at least 28% renewable generation to meet the intensity target.

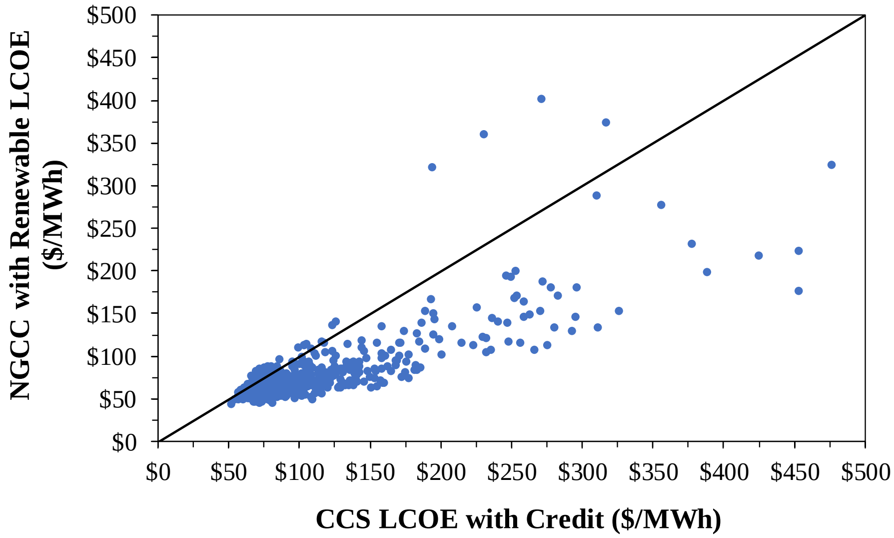


Figure C.25. Comparison of EGU-specific LCOE to meet 750 lbs/MWh CO_2 emission intensity with CCS retrofit and NGCC conversion with co-located renewable generation. CCS mitigation limits the capture rate to 90% and includes a $50/tonne tax credit. NGCC related LCOE is the least-cost renewable generation, solar or wind, for which the renewable contribution, is limited to 90%. Data points that fall to the left of the diagonal line indicate that CCS retrofit is the least-cost alternative to NGCC with co-located renewable generation. CCS retrofit is the least-cost alternative for 53 of 599 CFEGUs meeting these criteria. The remaining 36 CFEGUs in the dataset require capture rates greater than 90% and are omitted.

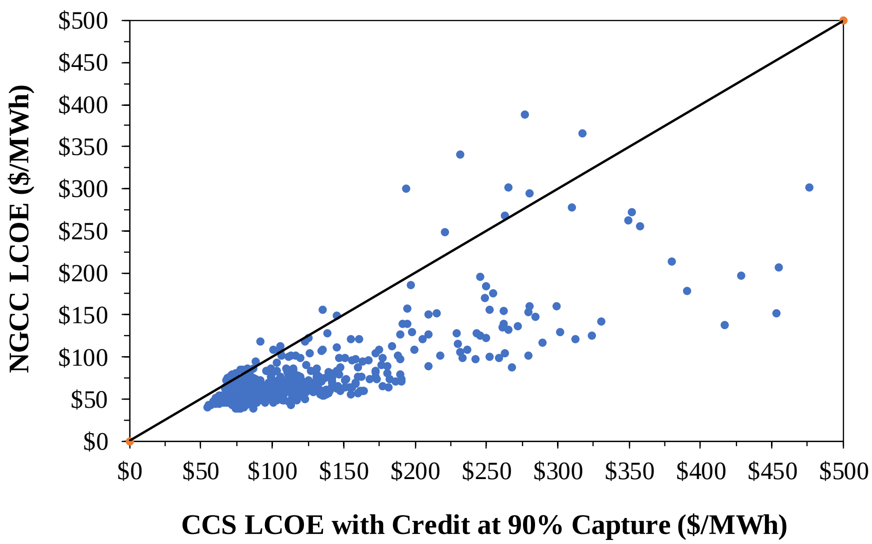


Figure C.26. Comparison of EGU-specific LCOE for CCS retrofit and NGCC conversion, in the absence of an emission intensity target. CCS mitigation capture rate is 90% and LCOE includes a $50/tonne tax credit. Data points that fall to the left of the diagonal line indicate that CCS retrofit is the least-cost alternative to NGCC conversion. CCS retrofit is the least-cost alternative for only 33 of the 635 CFEGUs.

Table C.11. National coal fleet statistics for CCS mitigation at various intensity-reduction targets without and with $50/tonne CCS tax credit. Introducing a CCS tax credit with a 30% intensity-reduction targets promotes CCS use and CO_2 capture less than that from increasing the reduction target to 40%.

State Fleet Intensity Reduction	U.S. Coal Fleet Intensity (lbs/MWh)	EGUs with CCS (number)	Aggregate Summertime Peak Capacity (MW)	Coal Use (billions MMBtu)	NG Use (billions MMBtu)	CO_2 Captured Annually (Mtons)	Unique Storage Sites (number)
0%	1,981	0	0	10.3	0.6	0	0
30%	1,838	6	1,498	9.3	1.3	2.7	5
40%	1,576	38	18,051	7.1	3.2	39.5	13
50%	1,217	41	19,250	4.0	5.5	57.5	14
30% with credit	1,843	15	5,423	9.4	1.2	8.9	8
2005 Reference	**2,138**	**0**	**0**	**20.3***	**NA**	**0**	**0**
2012 Reference	**2,214**	**0**	**0**	**16***	**NA**	**0**	**0**

*Total includes all consumption from all electric utilities and independent power producers (101).

Table C.12. State-level statistics for number of EGUs using CCS at various intensity-reduction targets, without and with $50/tonne CCS credit. North Dakota and Wyoming CFEGUs account for more than 50% of the CFEGUs that use CCS mitigation without the credit. This relates to the projected high natural gas and low coal prices in these states that limit other mitigation options. Introduction of the CCS tax credit greatly increases the number of CFEGUs using CCS mitigation in Kentucky, Indiana, and Missouri.

	State Intensity Reduction			
State	**30%**	**40%**	**50%**	**30% with subsidy**
Colorado	0	0	4	0
Illinois	0	0	4	0
Indiana	0	2	2	2
Iowa	1	1	2	1
Kentucky	0	7	4	5
Missouri	0	3	2	2
Montana	0	2	3	0
Nebraska	1	2	1	1
North Dakota	1	9	8	1
Texas	0	0	1	0
Wyoming	3	12	10	3

Table C.13. Quantity of CO_2 stored at unique sequestration sites with implementation of the $50/tonne CCS tax credit and 30% intensity-reduction target. Total captured emissions are limited to the remaining service life of the CFEGU to a maximum of 30 years.

Site	Yearly storage (Mton)	Lifetime storage (Mton)	Yearly fill (fraction)	Lifetime fill (fraction)
Entrada 7	1.18	35.36	0.01	0.29
Frio 7b	1.10	14.33	0.02	0.3
Knox 1	0.61	6.67	0.00	0.04
Minnelusa 1	1.05	24.4	0.00	0.1
Mount Simon 2	1.80	30.21	0.00	0.11
Mount Simon 3	0.8	23.90	0.00	0.01
Mount Simon 5	0.94	25.54	0.00	0.11
Mount Simon 11	1.80	42.20	0.02	0.43
Red River 1	0.29	4.9	0.00	0.00

C.5.9 State mitigation calculation.

In order to calculate the least-cost mitigation technologies for the state coal fleet to meet a required reduction in the overall emission intensity for the state, the net generation by fuel type and the total demand must first be determined. The state demand in 2030 is the product of the 2012 demand and the projected incremental percent increase in demand from 2012 minus the EPA projection for the state incremental increase in energy efficiency from 2017, Eq. C.1 (30). The EPA determines the incremental increase in demand as the average, annual regional increase in total electricity sales (MWh) between 2012 and 2040, which is estimated for each electricity market module (EMM) region by the EIA (96). In the model, the increased demand percentage allocated from each EMM region to a state is based upon an estimation of the region and the intersection of the population concentration for the state (Table C.14), if a state is in multiple regions.

Alaska and Hawaii are not included in the EMM projections, so the weighted average incremental increase for the regions, based upon demand, is used as a proxy.

$$G_{2030,s} = G_{2012,s}(1 + r_s)^t - E_{2029,s}G_{2012,s} \tag{C.1}$$

where $G_{2030,s}$ is the state net generation demand in 2030 (MWh), $G_{2012,s}$ is the state net generation in 2012 (MWh), r_s is the annual increase in demand for the state (fractional), t is the number of years over which the demand increases, $E_{2030,s}$ is the state cumulative energy efficiency increase by 2030 (fractional), $G_{2012,s}$ is the state net generation in 2030, and the subscript *s* indicates the state.

With the demand determined inclusive of the energy efficiency savings, the amount of generation available for export, or the required amount to be imported, for a state is calculated as the difference of the demand and the summation of the generation from the endogenous sources derated for a nationwide 7.51% transmission and distribution loss (97). This endogenous generation is equal to the total amount given by the EPA in the CPP proposal for regulated sources for 2029 (98) and includes that from other fossil fuel and zero carbon sources that are otherwise excluded from the proposed regulation calculations (99). The necessary coal-fired EGU emission intensity to meet the required emission intensity reduction is then determined by solving Eq. C.2 for coal-fired emissions.

$$I_{coal} = \left(I_{2005}(1 - r_{2030}) - \sum I_i \, G_i \;\right)/G_{coal} \tag{C.2}$$

where I_{coal} is the emission intensity for the regulated coal-fired EGUs ($\frac{lbs}{MWh}$), I_{2005} is the state emission intensity in 2005 inclusive of all electric power sector generating sources ($\frac{lbs}{MWh}$), r_{2030} is the sought reduction in emission intensity for the state (fractional), I_i is the emission intensity for a generation sources other then the regulated coal sources, G_i is the net generation from the generation sources other then the regulated coal sources (MWh), G_{coal} is the net generation from the regulated coal-fired generation sources, and the subscript i indicates the type of generation source of which there are 11 in addition to the regulated coal: nuclear, renewable, hydroelectric, NGCC, NGCC excluded, oil gas steam turbine (OGST), OGST excluded, other fossil, other fossil excluded, tribal coal, and tribal natural gas.

The coal-fired fleet for the state is regulated with regard to the CO_2 emission-intensity goal by selecting the mitigation technology that is required for the individual coal-fired EGUs to meet or surpass I_{coal}. To do so for each EGU, the achievable emission intensity for each technology is compared to I_{coal}, where the level of co-fire or capture required for this emission intensity is linearly interpolated. The EGU-specific LCOEs for those technologies that are less than or equal to I_{coal} are then compared to establish the least-cost mitigation on the frontier for each CFEGU. In some instances, the resulting intensity may be lower than that required because the mitigation with the lowest LCOE is chosen, rather than the mitigation that yields the intensity nearest to the required intensity. As there is a limit to the required generation from coal, the regulated CFEGUs are then ranked according to the lowest LCOE. To achieve the lowest overall generation-weighted average LCOE, the generation is summed from the lowest LCOE to the highest LCOE until the required generation is achieved. All CFEGUs that are not part of this summation are retired and contribute no generation and emissions. The emission intensity for the state from the coal-fired EGUs is thus the generation-weighted average of the CFEGU intensities for those EGUs that continue to operate.

This EGU-specific mitigation choice can result in the coal-fired fleet generation-weighted average emission intensity, or “actual” intensity, being lower than the emission target and the corresponding LCOE being greater than otherwise necessary. As these EGU-specific discontinuities result in a monotonically increasing fleet LCOE with decreasing fleet intensity, this inefficiency is circumvented by calculating the coal fleet frontier for emission-intensity targets between 650 to 2,500 lbs/MWh, at a resolution of 20 lbs/MWh, and selecting the lowest fleet LCOE from those targets that results in an actual intensity that is less than or equal to I_{coal}. Eq. C.2 can then be solved for the 2030 emission intensity with the new generation-weighted average for the coal-fired EGUs emission intensity determine the updated state emission-intensity goal. The goal may still be surpassed because the most mitigation technologies are optimally selected on a discrete basis. It should be noted that this method does not allow one or more CFEGUs to use CCS at a 90% capture rate so that other CFEGUs will require no mitigation. Rather, all EGUs much meet some intermediate intensity target, which precludes this “on/off” behavior.

While this method is applied to individual states, it can also be applied to neighboring states or regions. This is done by forming a “superstate” through reallocating the appropriate individual coal-fired EGUs and non-coal generation sources to the superstate and then applying the aforementioned methods.

Table C.14. State projected incremental percentage increase in sales, based upon allocation of the EMM average annual percentage increase in total electricity sales from 2012 to 2040. Data are from EIA projections in the Annual Energy Outlook 2013 (96).

State	Average annual percentage demand increase	State	Average annual percentage demand increase
Alabama	1.03%	Nebraska	0.41%
Alaska	0.78%	Nevada	1.00%
Arizona	1.29%	New Hampshire	0.31%
Arkansas	0.86%	New Jersey	0.51%
California	0.86%	New Mexico	1.29%
Colorado	1.28%	New York	0.15%
Connecticut	0.31%	North Carolina	1.10%
Delaware	0.51%	North Dakota	0.41%
Florida	0.98%	Ohio	0.57%
Georgia	1.03%	Oklahoma	0.88%
Hawaii	0.78%	Oregon	1.00%
Idaho	1.00%	Pennsylvania	0.52%
Illinois	0.55%	Rhode Island	0.31%
Indiana	0.57%	South Carolina	1.10%
Iowa	0.41%	South Dakota	0.41%
Kansas	0.59%	Tennessee	0.88%
Louisiana	0.86%	Texas	0.89%
Maine	0.31%	Utah	1.00%
Maryland	0.51%	Vermont	0.31%
Massachusetts	0.31%	Virginia	1.10%
Michigan	0.33%	Washington	1.00%
Mississippi	0.86%	West Virginia	0.57%
Missouri	0.54%	Wisconsin	0.56%
Montana	1.00%	Wyoming	1.00%

C.5.10 Fuel Equilibrium Prices.

In ESTEAM, the 2012 state-specific fuel prices are brought forward to 2030 with the percent increase in U.S. average electric-power sector fuel prices, based on the EIA historical 2012 price and the projected 2030 price from the Annual Energy Outlook 2017 reference case without the CPP (15, 32). These future prices are applied uniformly across the intensity targets to determine the mitigation profiles; however, the fuel prices may vary across intensity targets as the mitigation technologies employed change the demand for each fuel. The strength of the uniform assumption can be validated against the AEO 2017 projected price data as a function of fuel consumption in the power sector, with and without the CPP, Figure C.26.

Figure C.26(a) illustrates the equilibrium price for the two fuels, based upon the EIA projections of equilibrium prices from the supply and demand without and with the CPP regulation. Without the CPP, the coal price fluctuates but there is little change in demand. For natural gas, the equilibrium price decreases with demand and is similar for both scenarios. The relevance of these relationships can be put in perspective with the addition of the fuel use from the modeled cases. Adding ESTEAM results for the 30% reduction targets, with and without CCS tax credits, reduces coal use by approximately 35%, relative to the without CPP demand, to levels that are at the lower extreme of the EIA projected coal use with the CPP. Therefore, observations concerning equilibrium pricing in the mitigation scenarios should use the equilibrium response of the EIA with CPP projection. For natural gas, the increased use from coal-fired mitigation can add 1.25 quads to the overall use, or approximately 13% more consumption to the EIA 2030 projection. Therefore, the additional natural gas use may affect the fuel price. As both equilibrium price curves are similar, the no CPP curve can be used to be consistent with the model assumptions.

The expected marginal change in fuel price from the change in consumption due to mitigation is relative to the EIA 2030 prices and consumptions. Transforming the projections to be relative to 2030 and fitting OLS regressions to the data between 2020 and 2050, Table C.15, shows that the coal price increase may be increased upwards of 3% and the natural gas price by upwards of 5%, Figure C.26(b) and Table C.16. This represents a maximum increase in coal price of \$0.06/MMBtu and a \$0.24/MMBtu increase for natural gas in the model. These increases are less than the projected fuel price error (*Appendix B, Section B.7*) and the range in fuel prices for the AEO projected cases and scenarios (15, 32); therefore, the assumption of uniformity is maintained for these mitigation ranges. Reductions of up to 50%, Table C.17, do increase fuel prices for coal and natural gas up to 5% and 31%, respectively, but are still within the fuel price error and the price range for the AEO projected cases and scenarios.

The greater sensitivity of natural gas price to demand and the upward pressure on the fuel price for deeper reductions means that the mitigation capacity profile for these deeper reductions may alter when the equilibrium price is accounted for: The natural gas mitigation capacities may initially be overestimated. This possible overestimation for different reduction scenarios can be determined by using the model results for the fuel consumption and generation-weighted average fuel prices in the equilibrium price sensitivity regression and iterating to an equilibrium price that is within 0.01% of the required base-case fuel price increase. Doing so for the discussed scenarios determines the equilibrium prices in less than six iterations (Table C.18), with the coal and natural gas price increasing upwards of 5% and 25% from the base case prices, respectively. While meaningful capacity changes are not observed for the 30% reduction changes (Tables C.19 and C.20 and Figure C.27(a, b, e, f)), significant capacity are observed for deeper reductions—changes in which the coal related USC upgrade, CCS retrofit mitigation capacities increase and the natural gas related NG retrofit, NG co-fire and NGCC conversion mitigations decrease, Table C.19 and Figure C.27(a, c, d). These capacity profile changes are less than those from the fuel price error and the price range for the AEO projected cases and scenarios. Therefore, other macroeconomic and technical mechanisms may affect the mitigation fuel prices more than the equilibrium fuel price.

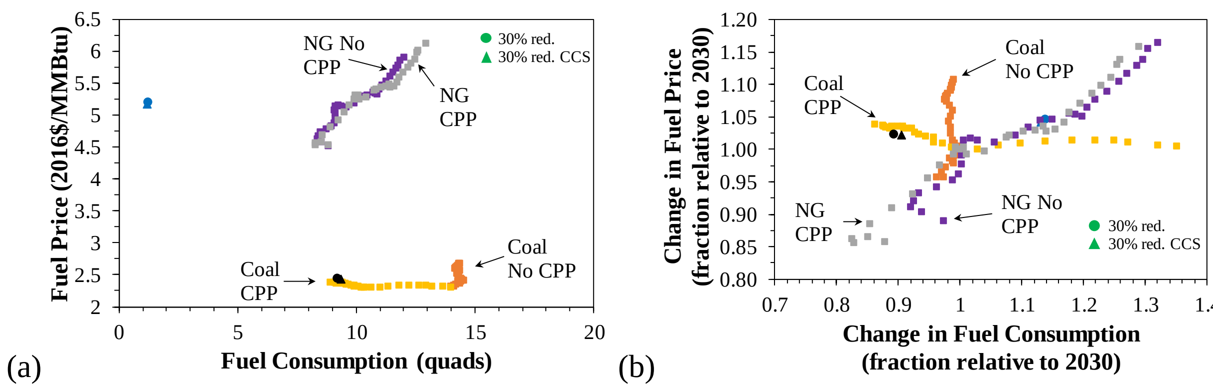
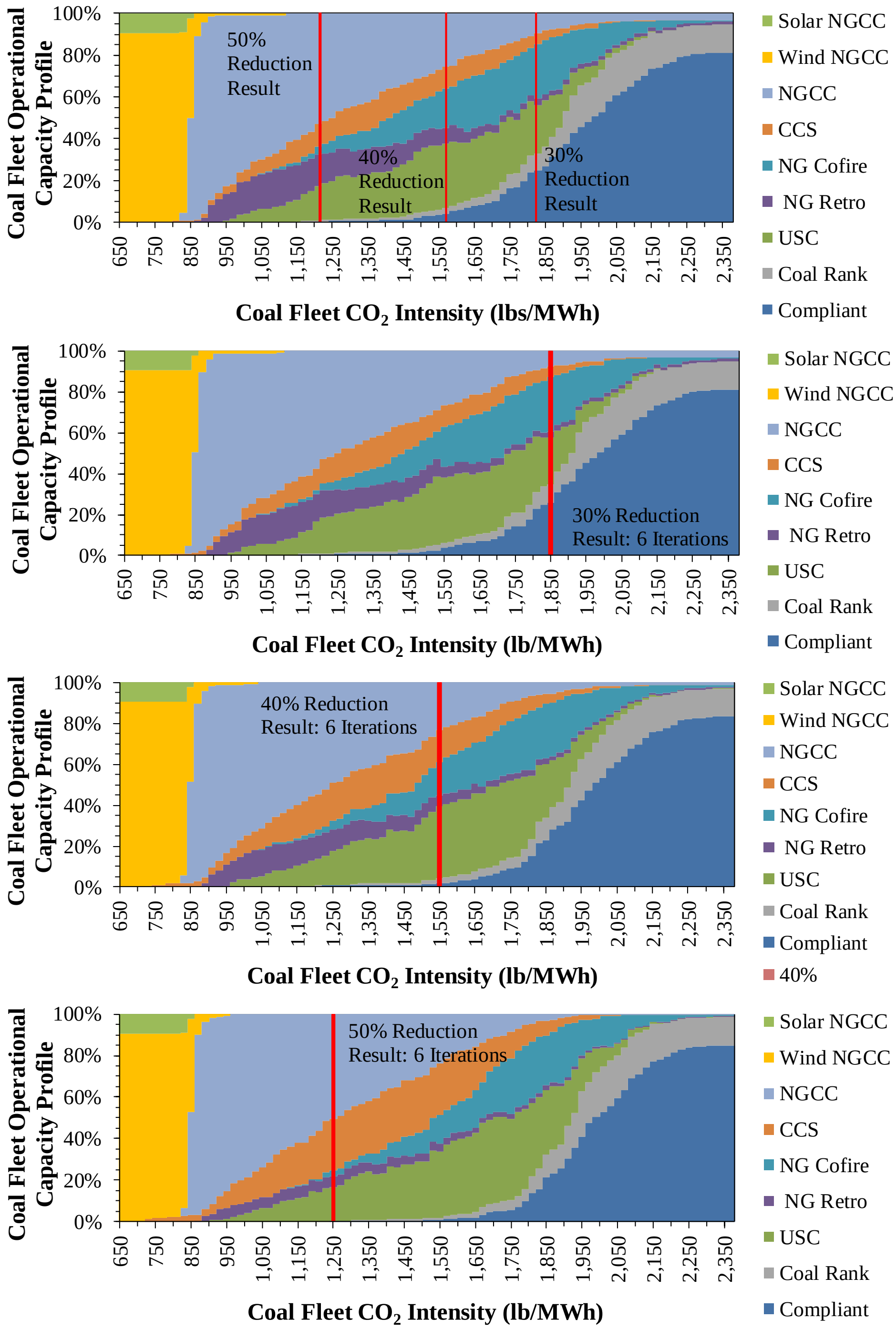


Figure C.27. Equilibrium price for coal and natural gas, based upon EIA projections (15, 32). Panel (a) shows the equilibrium fuel price as a function of consumption for reference case projections between 2020 and 2050 with and without the CPP. Panel (b) shows the relative change in price and consumption relative to that for 2030. In each figure, data for the coal and natural gas consumption and national MMBtu weighted-average price from ESTEAM scenarios for 30% reduction, with and without the $50/tonne CCS tax credit, are shown as reference. Panel (a) shows the fuel prices from ESTEAM, and Panel (b) shows the ESTEAM fuel price adjustments from the elasticity of demand OLS regressions. Here, the natural gas adjustment uses the no CPP regression and the coal adjustment uses the CPP regression.


Coal Fleet Operational Capacity Profile
100%
80%
60%
40%
20%
0%
50% Reduction Result
40% Reduction Result
30% Reduction Result
650 750 850 950 1,050 1,150 1,250 1,350 1,450 1,550 1,650 1,750 1,850 1,950 2,050 2,150 2,250 2,350
Coal Fleet CO2 Intensity (lbs/MWh)
Solar NGCC
Wind NGCC
NGCC
CCS
NG Cofire
NG Retro
USC
Coal Rank
Compliant

(a)

Coal Fleet Operational Capacity Profile
30% Reduction Result: 6 Iterations
Coal Fleet CO2 Intensity (lb/MWh)
Solar NGCC
Wind NGCC
NGCC
CCS
NG Cofire
NG Retro
USC
Coal Rank
Compliant

(b)

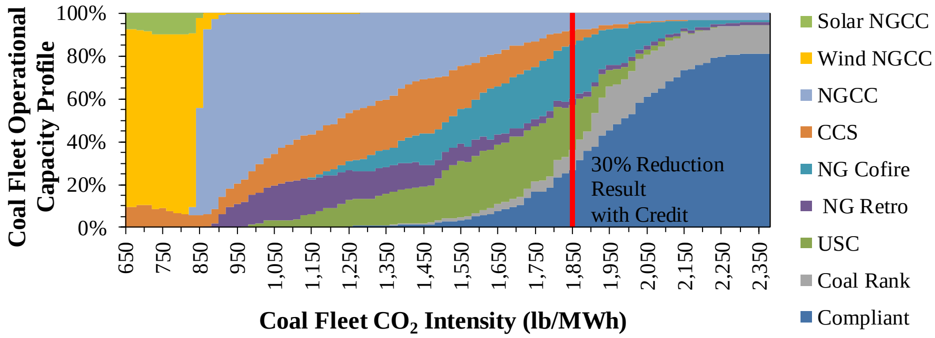
Coal Fleet Operational Capacity Profile
40% Reduction Result: 6 Iterations
Coal Fleet CO2 Intensity (lb/MWh)
Solar NGCC
Wind NGCC
NGCC
CCS
NG Cofire
NG Retro
USC
Coal Rank
Compliant
40%

(c)

Coal Fleet Operational Capacity Profile
50% Reduction Result: 6 Iterations
Coal Fleet CO2 Intensity (lb/MWh)
Solar NGCC
Wind NGCC
NGCC
CCS
NG Cofire
NG Retro
USC
Coal Rank
Compliant

(d)

(e)



(f)

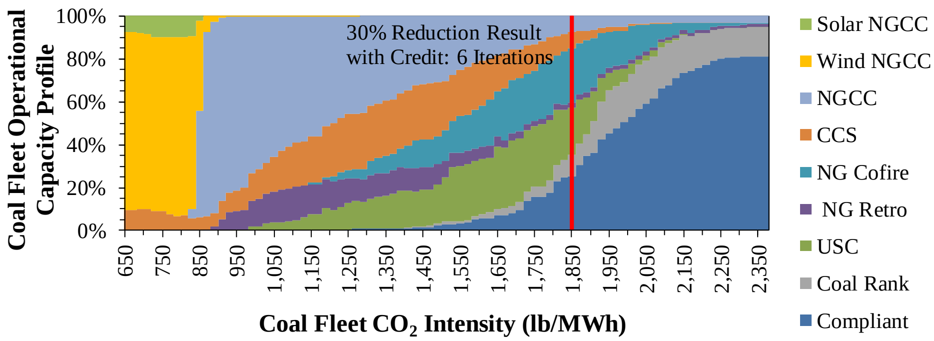


Figure C.28. Coal-fleet mitigation technology profile for various state emission-intensity targets with iterated fuel prices to account for equilibrium prices. Mitigation technology profile for base case fuel prices for reduction scenarios without CCS tax credit is shown in (a). Reduction scenarios without tax credit are (a) 30%, (c) 40%, and (d) 50%. Reduction scenarios with the \$50/tonne tax credit are (e) 30% for the base case fuel prices and (f) 30% for the iterated equilibrium fuel prices. Mitigations shown are inclusive of an HRI to 50% of the difference between the net heat rate for the gold standard and existing EGU up to the maximum improvement of 1,205 Btu.

Table C.15. Equilibrium price coefficients for OLS regression of marginal increase in demand relative to 2030 AEO reference cases (15, 32).

Fuel/Case	β_0	β_1	R^2	RMSE
Natural Gas/CPP	0.394	0.577	.947	0.020
Natural Gas/No CPP	0.413	0.555	.917	0.022
Coal/CPP	1.077	-5.72×10^{-2}	.379	0.011
Coal/No CPP	0.571	0.472	.006	0.051

Table C.16. Fractional increase and change in ESTEAM modeled price for natural gas and coal national MMBtu weighted-average price results due to consideration of equilibrium price. For the two mitigation scenarios shown, the resulting change in price are less than the projected fuel price error and the range in fuel prices for the AEO projected cases and scenarios (15, 32).

	30% Reduction		30% Reduction with CCS Credit	
Fuel/Case	**Increase (fraction)**	**Price Change ($/MMBtu)**	**Increase (fraction)**	**Price Change ($/MMBtu)**
Natural Gas/CPP	1.044	0.23	1.040	0.21
Natural Gas/No CPP	1.046	0.24	1.041	0.21
Coal/CPP	1.023	0.06	1.022	0.05
Coal/No CPP	0.872	-0.31	0.875	-0.30

Table C.17. Fractional increase and change in ESTEAM modeled price for natural gas and coal national MMBtu weighted-average price results due to consideration of equilibrium price. For the three mitigation scenarios shown, the resulting change in price are less than the range in fuel prices for the AEO projected cases and scenarios (15, 32).

	0% Reduction		40% Reduction		50% Reduction	
Fuel/Case	**Increase (fraction)**	**Price Change ($/MMBtu)**	**Increase (fraction)**	**Price Change ($/MMBtu)**	**Increase (fraction)**	**Price Change ($/MMBtu)**
Natural Gas/CPP	0.991	- 0.04	1.153	0.80	1.290	1.50
Natural Gas/No CPP	0.989	-0.05	1.161	0.85	1.307	1.59
Coal/CPP	1.015	0.04	1.035	0.08	1.052	0.12
Coal/No CPP	0.916	-0.20	0.802	-0.47	0.699	-0.69

Table C.18. Iterated fractional increase in ESTEAM modeled price for natural gas and coal national MMBtu weighted-average price results due to consideration of equilibrium price for various emission intensity reduction scenarios. Converged increase is denoted in bold type. For all cases, the first iteration is within 6% absolute of the final price increase.

		Iteration						
Scenario	**Fuel**	**0**	**1**	**2**	**3**	**4**	**5**	**6**
0% Reduction	NG	1.0	0.9895	0.9949	**0.9934**	0.9934	0.9934	0.9934
	Coal	1.0	1.0154	1.016	**1.0158**	1.0158	1.0158	1.0158
30% Reduction	NG	1.0	1.0458	1.039	**1.0386**	1.0386	1.0386	1.0386
	Coal	1.0	1.0228	**1.0221**	1.0221	1.0221	1.0221	1.0221
40% Reduction	NG	1.0	1.1615	1.1267	1.1295	1.1271	**1.1295**	1.1295
	Coal	1.0	1.0347	1.0318	1.0317	**1.0318**	1.0318	1.0318
50% Reduction	NG	1.0	1.307	1.2657	1.2555	**1.2510**	1.2510	1.2510
	Coal	1.0	1.0522	1.0487	1.0498	**1.0472**	1.0472	1.0472
30% Reduction with CCS Credit	NG	1.0	1.0415	1.0392	**1.0373**	1.0373	1.0373	1.0373
	Coal	1.0	1.0222	**1.022**	1.022	1.022	1.022	1.022

Table C.19. Coal fleet mitigation profile and metric details for various state emission-intensity targets with iterated fuel prices to account for equilibrium prices. Iteration 0 is the base case increase in fuel prices. Mitigations shown are inclusive of an HRI to 50% of the difference between the net heat rate for the gold standard and existing CFEGU up to the maximum improvement of 1,205 Btu. Increases in LCOE relate directly to increase in EGU VOM.

		30% Reduction		**40% Reduction**		**50% Reduction**	
Mitigation/Metric	**Units**	**Iteration 0**	**Iteration 6**	**Iteration 0**	**Iteration 6**	**Iteration 0**	**Iteration 6**
Compliant Capacity	GW	67.4	67.6	25.4	23.5	6.1	4.5
Rank Capacity	GW	28.6	28.6	11.5	12.7	1.8	2.2
USC Capacity	GW	26.3	27.4	30.4	42.4	26.7	31.0
NG Retrofit Capacity	GW	6.4	5.5	11.3	7.4	25.6	9.3
NG Co-fire Capacity	GW	26.8	26.6	32.6	27.0	10.8	5.6
CCS Retrofit Capacity	GW	1.5	2.4	18.1	23.2	19.3	34.8
NGCC Capacity	GW	15.5	14.3	42.6	35.1	77.5	77.4
Retired Capacity	GW	75.8	75.8	76.4	77.0	76.9	79.8
Coal Fleet LCOE	$/MWh	41.3	41.9	46.8	49.3	72.58	79.7
Coal Consumption	Million MMBtu	9,267	9,405	7,125	7,670	3,950	4,844
NG Consumption	Million MMBtu	1,268	1,143	3,155	2,597	5,543	4,678

Table C.20. Coal fleet mitigation profile and metric details for a targeted 30% reduction in state-level emission intensity with the $50/tonne CCS tax credit and iterated fuel prices to account for equilibrium prices. Iteration 0 is the base case increase in fuel prices. Mitigations shown are inclusive of an HRI to 50% of the difference between the net heat rate for the gold standard and existing CFEGU up to the maximum improvement of 1,205 Btu. Increases in LCOE relate directly to increase in CFEGU VOM.

Mitigation/Metric	Units	Iteration 0	Iteration 6
Compliant Capacity	GW	67.4	67.6
Rank Capacity	GW	28.6	29.2
USC Capacity	GW	25.6	26.5
NG Retrofit Capacity	GW	5.9	5.0
NG Co-fire Capacity	GW	25.1	24.4
CCS Retrofit Capacity	GW	5.4	4.9
NGCC Capacity	GW	14.3	14.4
Retired Capacity	GW	76.0	76.1
Coal Fleet LCOE	$/MWh	41.3	41.8
Coal Consumption	Million MMBtu	9,377	9,424
NG Consumption	Million MMBtu	1,196	1,127

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Appendix D: A techno-economic assessment of carbon-sequestration tax incentives in the U.S. power sector

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D.1 Dataset analysis

D.1.1 2030 NGCC fleet

In the thirteenth edition of the U.S. Environmental Protection Agency's (EPA) Emissions and Generation Resources Database (eGRID) version 2.0 (U.S. EPA, 2018a), 289 GW of capacity are associated with natural gas combined cycle (NGCC) electricity generation. The operating characteristics of this fleet are shown in Table 4.1. In 2030, almost 20% of the generator capacity will be beyond the assumed 30-year operational life of the plants, and are considered to be retired in the EGU-Specific Techno-Economic Assessment Model (ESTEAM), Figure D.1; furthermore, 78% of the capacity will be retired by 2040. Therefore only 22% of the current NGCC fleet capacity is used in ESTEAM. The elimination of this capacity and the addition of the planned capacity, according to the criteria outlined in *Section D.3*, then reduces the available capacity for retrofitting carbon capture and storage (CCS) to almost one-third of the original fleet capacity, Table D.1. For the modeled plants, the median capacity is 800 MW with a median age of 12-years, Figure D.2. Location and capacity of fleet plants are given in Table D.2.

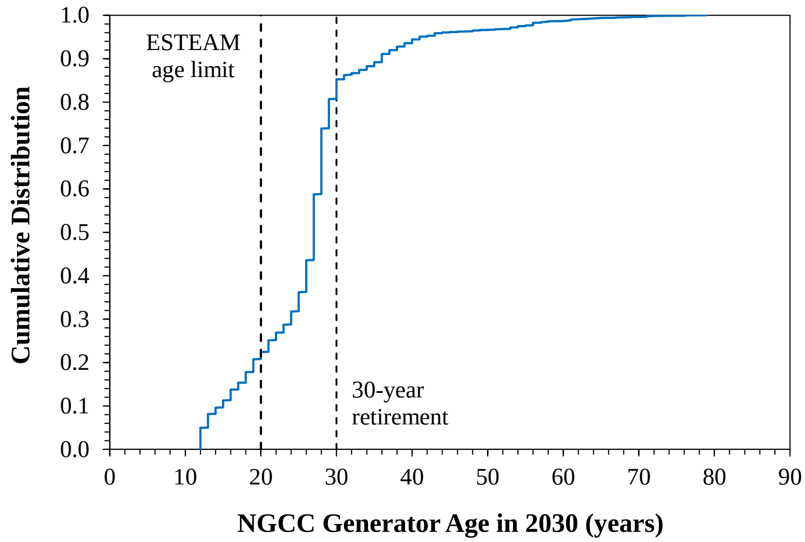


Figure D.1. Capacity-weighted age distribution of eGRID2018 (U.S. EPA, 2018a) existing NGCC generating capacity. Limits indicate assumed retirement age and age limit for ESTEAM.

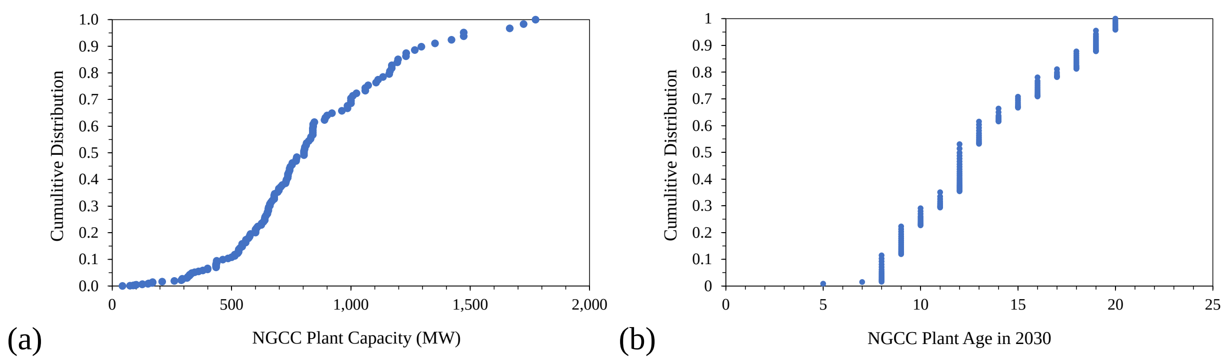


Figure D.2. Distribution of NGCC plant (a) capacity and (b) age in 2030 for the 133 plants, operational or planned with a starting date given before 2030, in eGRID2018 (U.S. EPA, 2018a) that compose the ESTEAM NGCC fleet.

Table D.1. NGCC fleet characteristics from eGRID2018 (U.S. EPA, 2018) without and with 30-year retirement requirement, and capacity used in ESTEAM. Characteristics are capacity-weighted averages, when appropriate.

Dataset	Capacity (GW)	Capacity Factor (fraction)	Net Generation (TWh)	CO_2 Emissions (Mtonnes)	CO_2 Intensity (lbs/MWh)
2018 eGRID	289	0.49	1,233	492	880
2018 eGRID with retirement	246	0.51	1,094	402	810
ESTEAM	107	0.60	612	243	875

Table D.2. ESTEAM NGCC plants modeled in 2030, based upon combined eGRID2018 (U.S. EPA, 2018a) data.

State	Number of Plants	Capacity (MW)
Alabama	1	823
Arizona	1	900
California	11	4,288
Colorado	1	626
Connecticut	4	2,925
Delaware	1	361
Florida	10	10,575
Georgia	1	2,520
Idaho	1	319
Illinois	3	3,104
Indiana	2	2,786
Iowa	1	706
Kentucky	2	1,967
Louisiana	5	3,348
Maryland	4	3,968
Massachusetts	1	798
Michigan	4	2,686
Minnesota	1	345
Mississippi	2	1,007
Nevada	1	559
New Jersey	5	3,442
New Mexico	1	680
New York	5	3,479
North Carolina	8	5,373
Ohio	9	7,726
Oklahoma	2	1,135
Oregon	1	500
Pennsylvania	15	14,886
South Carolina	1	847
South Dakota	1	324
Tennessee	3	2,581
Texas	14	11,577
Utah	1	728
Virginia	6	7,149
West Virginia	2	1,420
Wisconsin	1	726
Wyoming	1	100

D.1.2 2030 Coal-fired fleet

The 635 coal-fired electric generating units (CFEGUs) that comprise the dataset in ESTEAM, as described in *Chapter 3 and Appendix B*, are reduced in this study to 368 CFEGUs from the retirements listed in the EPA's National Electric Energy Data Systems (NEEDS) version 6 rev:6-30-2020 (U.S. EPA, 2018b). Most of the capacity lost through retirement occurs from CFEGUs less than 300 MW in size and in operation for more than 50 years in 2030, Figure D.3, and results in similar fleet capacity factors and emission intensities, Table D.3. CFEGUs remaining after the planned retirement units are removed are repowered in 2030 as NGCC plants (without or with carbon capture and storage (CCS)) or as renewable capacity if the units have been in service for more than 65 years. As expected with older units, these CFEGUs that comprise 6% of the ESTEAM dataset capacity have a lower capacity factor and higher emission intensity than those CFEGUs that remain, Table D.3.

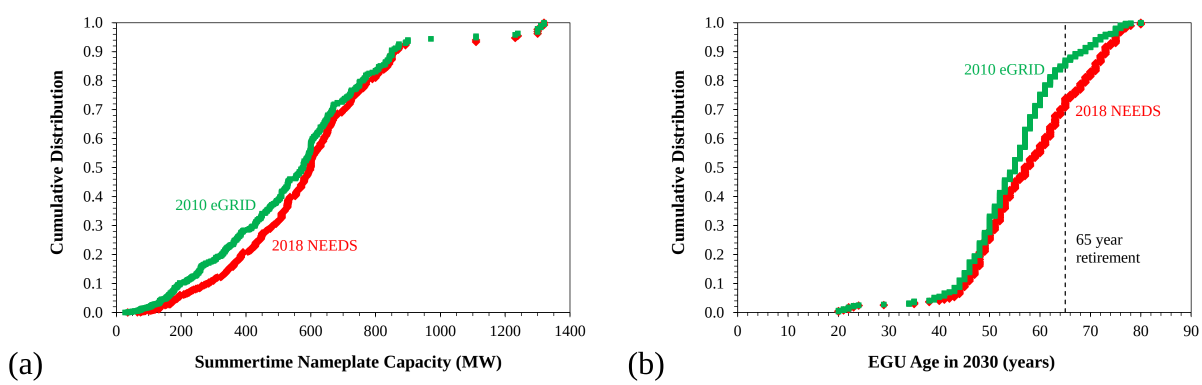


Figure D.3. Distribution of coal-fleet EGU (a) capacity and (b) age in 2030 used in ESTEAM from the 2010 eGRID (U.S. EPA, 2018a) and with the 2018 NEEDS retirement (U.S. EPA, 2018b). Red line labeled "2018 NEEDS" represents the dataset used in this study.

Table D.3. Characteristics of the ESTEAM coal-fired fleet described in *Chapter 3 and Appendix B* from 2010 eGRID (U.S. EPA, 2018a) data, and with the retirements designated in 2018 NEEDS database (U.S. EPA, 2018b) to form the ESTEAM dataset for this study. Dataset EGUs older than 65 years in 2030 are those that are repowered or replaced. Mitigated designates those EGUs that may remain in service as coal-fired CCS units. Characteristics are capacity-weighted averages, where appropriate.

ESTEAM Fleet	Capacity (GW)	Capacity Factor (fraction)	Net Generation (TWh)	CO_2 Emissions (Mtonnes)	CO_2 Intensity (lbs/MWh)
2010 eGRID	248	0.67	1,554	1,525	2,173
2018 NEEDS	173	0.69	1,108	1,080	2,153
Older than 65 years	11	0.58	66	66	2,242
Mitigated	161	0.70	1,043	1,014	2,146

D.2 Uncertainty

D.2.1 Probabilistic confidence bounds

For this study, the previous mitigation technology tolerance-analysis applied in *Chapter 3* and *Appendix B* is updated and expanded. In particular, state-specific fuel prices for 2030 are updated from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2020 (U.S. Energy Information Administration, 2020) and the levelized cost of electricity (LCOE) and emission intensity uncertainty is expanded to include mitigations for coal-fired CCS without the auxiliary boiler and for NGCC equipped with renewable sources and CCS mitigation, Table D.4. The addition of the NGCC analysis requires assessing the variation in heat rate for the proxy NGCC plant, as well as determining the LCOE variation due to future costs and performance uncertainties for the renewables. To assess the impact of annual NGCC heat-rate variation on LCOE and intensity uncertainty due to variations in capacity factor, maintenance, operation, and weather, data on plant heat input and net generation from the EIA and EPA are used to calculate the historical annual heat rate for a 579 MW NGCC plant in Wisconsin that serves as a proxy for the brownfield conversion for the Wisconsin CFEGU, Table D.5. If the net generation and total heat input are not separately given for all components of this NGCC plant, the contributions are approximated with the ratios of the net generation from the combined-cycle combustion turbines and combined-cycle steam turbines to the total net generation and heat input from previous years. In this instance, the percent annual variation in heat rate is calculated from a regression on of the yearly heat rate as a function of the net generation to account for variation in heat rate due to capacity factor. The percent of the root-mean-squared error (RMSE) from this regression relative to the historical annual mean is applied to the theoretical heat rate of the modeled NGCC mitigation as a proxy error term.

The uncertainty in LCOE for the co-located solar and wind generation sources is derived from the 2019 Annual Technology Baseline report (ATB) from the National Renewable Energy Laboratory (NREL) (U.S. NREL, 2019). This uncertainty for each technology is based upon the 2030 upper and lower cost limits defined by the low- and constant-cost technology scenarios relative to the mid-cost technology scenario, which is used as the default cost. These 2017-dollar year LCOEs are converted to 2010-dollar year with Chemical Engineering Plant Cost Index (CEPCI), (CEPCI, 2021). As the proxy NGCC plant is in Wisconsin, the utility solar LCOE scenarios correspond to those in Chicago. The variation in wind LCOE is taken from the TRG8 scenarios for which the wind level corresponds to the 40m NREL wind maps near Lake Michigan (U.S. NREL, 2017). For each technology, the difference between the lower and upper costs relative to the mid-cost scenario determines two ranges where there is assumed to be an equal likelihood for every value within each range. Applying the uniform distribution formula for standard deviation, determines the LCOE confidence limits for these technologies.

Table D.4. Capital and O&M cost error levels for mitigated EGU configurations. Default levels represent those used in the deterministic modeling, while the Low, and High levels are used for uncertainty analysis.

Device or Mitigation	Parameter (units)	Default	Low	High
CCS no auxiliary boiler	PFC for process contingency cost (fraction)*	0.05	0.00	0.70
	PFC for project contingency cost (fraction)*	0.15	0.00	0.35
NGCC with solar	ATB-based LCOE variation ($/MWh)	0	-7.04	7.25
NGCC with wind	ATB-based LCOE variation ($/MWh)	0	-7.48	12.57
NGCC CCS	Capital cost multiplier (fraction)*	1.00	0.80	1.20

*Author chosen limits.

Table D.5. Historical heat rate variation for a Wisconsin NGCC plant from EIA form 923 and eGRID2018 (U.S. Energy Information Administration, 2021; U.S. EPA, 2018a) as a proxy for the heat rate variation for the Wisconsin CFEGU when NGCC mitigation is employed.

Year	Heat Rate (Btu/kWh)
2018	6,987
2016	6,928
2014	7,146
2012	7,010
2010	7,238
2009	7,157
2007	7,475
2006	7,270
2005	7,582
Mean	**7,199**
RMSE	**144**
Adjusted R^2	**.57**

Table D.6. LCOE model error components for the current Wisconsin CFEGU when made compliant for SO_x, NO_x, and Hg emission regulations. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

Compliant CFEGU Component	**LCOE ($/MWh)** +	-
Hg capital cost	0.04	0.04
Hg O&M cost	0.56	0.56
NO_x combustion capital cost	0.22	0.22
NO_x combustion O&M cost	0.02	0.02
NO_x post combustion capital cost	0.48	0.48
NO_x post combustion O&M cost	0.10	0.10
SO_x capital cost	1.83	1.83
SO_x O&M cost	0.23	0.23
Base-plant ECD retrofit capital cost	2.20	2.20
Wet-cooling tower ECD retrofit capital cost	0.37	0.37
Percent increase LCOE for CFEGU with new ECDs	1.28	1.22
Initial heat rate	0.45	0.45
Heat rate improvement	2.80	0.24
Additional heat rate from ECDs	0.04	0.04
Capital cost adder Hg	0.01	0.00
Capital cost adder NO_x combustion	0.01	0.04
Capital cost adder NO_x post combustion	0.08	0.04
Capital cost adder SO_x	0.53	0.06
Coal price	14.17	3.15
Total estimated error without fuel error	**4.35**	**3.28**
Total estimated error with fuel error	**14.82**	**4.54**

Table D.7. LCOE model error components for compliant Wisconsin CFEGU with CCS mitigation technology **with auxiliary boiler** for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

CCS Mitigation	**LCOE ($/MWh)**					
Capture Rate	**10%**		**40%**		**90%**	
Component	+	-	+	-	+	-
Hg capital cost	0.04	0.04	0.04	0.04	0.04	0.04
Hg O&M cost	0.56	0.56	0.56	0.56	0.56	0.56
NO_x combustion capital cost	0.22	0.22	0.22	0.22	0.22	0.22
NO_x combustion O&M cost	0.02	0.02	0.02	0.02	0.02	0.02
NO_x post combustion capital cost	0.48	0.48	0.48	0.48	0.48	0.48
NO_x post combustion O&M cost	0.10	0.10	0.10	0.10	0.10	0.10
SO_x capital cost	1.83	1.83	1.83	1.83	1.83	1.83
SO_x O&M cost	0.23	0.23	0.23	0.23	0.23	0.23
Base-plant ECD retrofit capital cost	2.20	2.20	2.20	2.20	2.20	2.20
Wet-cooling tower ECD retrofit capital cost	0.37	0.37	0.37	0.37	0.37	0.37
Percent increase LCOE for CFEGU with new ECDs	1.28	1.22	1.28	1.22	1.28	1.22
Percent increase LCOE for adding CCS to CFEGU	2.33	2.12	2.57	2.34	2.97	2.73
CCS capital cost	0.43	0.43	0.43	0.43	0.41	0.40
CCS base-plant retrofit cost	0.28	0.23	0.34	0.23	0.40	0.36
CCS wet-cooling tower retrofit cost	0.29	0.18	0.34	0.18	0.27	0.30
CCS SO_x retrofit cost	0.03	0.03	0.03	0.03	0.02	0.02
CO_2 pipeline capital cost	1.36	2.21	1.45	2.21	1.47	2.20
Natural gas pipeline capital cost	0.09	0.14	0.09	0.14	0.09	0.14
CCS coal heat rate	0.45	0.45	0.39	0.39	0.33	0.33
Heat rate improvement	2.80	0.50	2.80	0.50	2.80	0.50
ECD heat rate variation for CCS	0.08	0.08	0.07	0.07	0.06	0.06
Capital cost adder Hg	0.00	0.00	0.00	0.00	0.01	0.00
Capital cost adder NO_x combustion	0.01	0.04	0.01	0.04	0.01	0.04
Capital cost adder NO_x post combustion	0.08	0.04	0.08	0.04	0.08	0.04
Capital cost adder SO_x	0.56	0.06	0.56	0.06	0.56	0.06
Capital cost adder PFC	1.45	0.11	3.89	0.32	9.18	0.69
Capital cost adder PCC	0.44	0.33	0.18	0.97	2.82	2.08
Capital Cost adder NG pipeline	0.06	0.01	0.06	0.01	0.06	0.01
Capital Cost adder CO_2 pipeline	0.92	0.92	0.98	0.96	0.94	0.93
CO_2 storage cost	0.33	0.01	1.15	0.86	2.17	0.06
Coal price	14.13	3.14	12.51	2.73	10.50	2.30
Natural gas price	1.26	0.76	4.47	2.68	8.43	5.08
Total estimated error without fuel error	**5.46**	**4.62**	**6.75**	**4.80**	**11.32**	**5.34**
Total estimated error with fuel error	**15.20**	**5.63**	**14.89**	**6.14**	**17.59**	**7.72**

Table D.8. LCOE model error components for compliant Wisconsin CFEGU with CCS mitigation technology **without auxiliary boiler** for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

CCS Mitigation Capture Rate Component	**LCOE ($/MWh)** 10% +	10% -	40% +	40% -	90% +	90% -
Hg capital cost	0.04	0.04	0.04	0.04	0.04	0.04
Hg O&M cost	0.56	0.56	0.56	0.56	0.56	0.56
NO_x combustion capital cost	0.22	0.22	0.22	0.22	0.22	0.22
NO_x combustion O&M cost	0.02	0.02	0.02	0.02	0.02	0.02
NO_x post combustion capital cost	0.48	0.48	0.48	0.48	0.48	0.48
NO_x post combustion O&M cost	0.10	0.10	0.10	0.10	0.10	0.10
SO_x capital cost	1.83	1.83	1.83	1.83	1.83	1.83
SO_x O&M cost	0.23	0.23	0.23	0.23	0.23	0.23
Base-plant ECD retrofit capital cost	2.20	2.20	2.20	2.20	2.20	2.20
Wet-cooling tower ECD retrofit capital cost	0.37	0.37	0.37	0.37	0.37	0.37
Percent increase LCOE for CFEGU with new ECDs	1.28	1.22	1.28	1.22	1.28	1.22
Percent increase LCOE for adding CCS to CFEGU	0.22	0.21	0.58	0.54	1.35	1.26
CCS capital cost	0.21	0.20	0.38	0.37	0.78	0.76
CCS base-plant retrofit cost	0.19	0.32	0.31	0.27	0.54	0.49
CCS wet-cooling tower retrofit cost	0.16	0.11	0.23	0.18	0.36	0.30
CCS SO_x retrofit cost	0.08	0.07	0.09	0.08	0.11	0.10
CO_2 pipeline capital cost	1.44	2.33	1.83	2.75	2.41	3.40
CCS coal heat rate	0.47	0.47	0.49	0.49	0.53	0.53
Heat rate improvement	2.80	0.24	2.80	0.24	2.80	0.24
ECD heat rate variation for CCS	0.09	0.09	0.09	0.09	0.10	0.10
Capital cost adder Hg	0.01	0.00	0.01	0.00	0.01	0.00
Capital cost adder NO_x combustion	0.01	0.04	0.01	0.04	0.01	0.04
Capital cost adder NO_x post combustion	0.09	0.05	0.09	0.05	0.10	0.05
Capital cost adder SO_x	0.61	0.07	0.61	0.07	0.65	0.07
Capital cost adder PFC	1.12	0.08	2.78	0.21	6.49	0.49
Capital cost adder PCC	0.34	0.25	0.85	0.63	1.99	1.47
Capital Cost adder CO_2 pipeline	0.97	0.97	1.24	1.21	1.58	1.52
CO_2 storage cost	0.34	0.01	0.89	0.66	1.55	1.52
Coal price	14.90	3.28	16.72	3.71	16.47	3.66
Total estimated error without fuel error	**4.88**	**4.19**	**5.82**	**4.62**	**9.43**	**5.45**
Total estimated error with fuel error	**15.68**	**5.31**	**17.70**	**5.93**	**18.98**	**6.56**

Table D.9. LCOE model error components for compliant Wisconsin CFEGU with NGCC mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

NGCC Mitigation Component	LCOE ($/MWh)	
	+	-
Demolition of turbine island	0.45	0.44
Natural gas pipeline	0.15	0.21
Heat rate variation	0.82	0.82
Heat rate penalty	0.14	0.14
Capital cost adder demolition	0.16	0.16
Capital cost adder NG pipeline	0.09	0.01
Capital cost adder NGCC PFC	2.84	2.84
Natural gas price	13.64	8.22
Total estimated error without fuel error	**3.00**	**3.00**
Total estimated error with fuel error	**13.97**	**8.75**

Table D.10. LCOE model error components for compliant Wisconsin CFEGU with NGCC mitigation technology **with CCS** for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

CCS Mitigation	**LCOE ($/MWh)**					
Capture Rate	**10%**		**40%**		**90%**	
Component	+	-	+	-	+	-
Demolition of turbine island	0.46	0.45	0.44	0.43	0.40	0.39
Natural gas pipeline	0.15	0.21	0.16	0.22	0.17	0.24
CCS capital cost	1.16	1.16	1.16	1.16	1.16	1.16
CCS wet-cooling tower retrofit cost	0.47	0.47	0.48	0.48	0.52	0.52
CO_2 pipeline capital cost	1.66	2.58	2.11	3.07	2.76	3.81
Power block FOM	0.01	0.01	0.01	0.01	0.01	0.01
Wet-cooling tower FOM	0.03	0.03	0.01	0.01	0.01	0.01
Wet-cooling tower VOM	0.0	0.0	0.0	0.0	0.0	0.0
CCS FOM	0.28	0.28	0.28	0.28	0.28	0.28
CCS VOM	0.10	0.10	0.10	0.10	0.10	0.10
Heat rate variation	0.83	0.83	0.87	0.87	0.95	0.95
Heat rate penalty	0.14	0.14	0.14	0.14	0.14	0.14
CCS heat rate	0.09	0.09	0.09	0.09	0.09	0.09
Capital cost adder demolition	0.17	0.17	0.17	0.17	0.19	0.19
Capital cost adder NGCC PFC	2.84	2.84	2.84	2.84	2.84	2.84
Capital cost adder for CCS PFC	0.25	0.09	1.05	0.21	5.01	0.39
Capital cost adder for CCS PCC	0.34	0.26	0.84	0.63	1.54	1.16
Capital cost adder NG pipeline	0.09	0.01	0.09	0.01	0.09	0.01
Capital Cost adder CO_2 pipeline	1.10	1.10	1.33	1.33	1.67	1.67
CO_2 storage cost	0.15	0.03	0.63	0.13	1.51	0.31
Natural gas price	13.70	8.18	13.70	8.18	13.70	8.18
Total estimated error without fuel error	**3.89**	**4.35**	**4.53**	**4.85**	**7.34**	**5.71**
Total estimated error with fuel error	**14.25**	**9.26**	**14.43**	**9.51**	**15.55**	**9.97**

Table D.11. CO_2 emission intensity error components for current Wisconsin CFEGU when made compliant for SO_x, NO_x, and Hg emission regulations.

Compliant EGU Component	CO_2 Emission Intensity (lbs/MWh) +	-
ECD heat rate variation	10.4	10.4
EGU heat rate variation	53.5	53.5
Total estimated error	**63.9**	**63.9**

Table D.12. CO_2 emission intensity error components for compliant Wisconsin CFEGU with CCS **with** an auxiliary boiler mitigation technology for CO_2 emission intensity reduction.

CCS Mitigation	CO_2 Emission Intensity (lbs/MWh)					
Capture Rate	10%		40%		90%	
Component	+	-	+	-	+	-
ECD heat rate variation	4.7	4.7	3.1	3.1	0.5	0.5
CFEGU heat rate variation	48.2	48.2	32.1	32.1	5.4	5.4
Intensity regression residual	99	97	81	79	59	57
Total estimated error	**110.5**	**110.5**	**87.6**	**85.8**	**59.4**	**57.4**

Table D.13. CO_2 emission intensity error components for compliant Wisconsin CFEGU with CCS **without** an auxiliary boiler mitigation technology for CO_2 emission intensity reduction.

CCS Mitigation	CO_2 Emission Intensity (lbs/MWh)					
Capture Rate	10%		40%		90%	
Component	+	-	+	-	+	-
ECD heat rate variation	4.7	4.7	3.1	3.1	0.5	0.5
CFEGU heat rate variation	48.2	48.2	32.1	32.1	5.4	5.4
CCS heat rate penalty	88	88	88	88	88	88
Total estimated error	**100.4**	**100.4**	**93.7**	**93.7**	**88.2**	**88.2**

Table D.14. CO_2 emission intensity error components for compliant Wisconsin CFEGU with NGCC mitigation technology for CO_2 emission intensity reduction.

NGCC Mitigation Component	**CO_2 Emission Intensity (lbs/MWh)** +	**-**
Plant heat rate variation	36.	36.
Heat rate penalty regression residual	5.6	5.6
Total estimated error	**41.5**	**41.5**

Table D.15. CO_2 emission intensity error components for compliant Wisconsin CFEGU with NGCC **with CCS** mitigation technology for CO_2 emission intensity reduction.

CCS Mitigation Capture Rate Component	**CO_2 Emission Intensity (lbs/MWh)**					
	10%		**40%**		**90%**	
	+	-	+	-	+	-
CCS heat rate penalty	3.7	3.7	3.7	3.7	3.7	3.7
Heat rate penalty	5.6	5.6	5.6	5.6	5.6	5.6
Plant heat rate variation	28.9	28.9	29.4	29.4	3.2	3.2
Total estimated error	**29.7**	**29.7**	**20.4**	**20.4**	**7.4**	**7.4**

Table D.16. LCOE model error components for compliant Wisconsin CFEGU with NGCC with co-located solar mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

NGCC Mitigation Component	**LCOE ($/MWh)** +	**-**
Demolition of turbine island	0.45	0.44
Natural gas pipeline	0.15	0.21
Heat rate variation	0.82	0.82
Heat rate penalty	0.14	0.14
Capital cost adder demolition	0.16	0.16
Capital cost adder NG pipeline	0.09	0.01
Capital cost adder NGCC PFC	2.84	2.84
ATB Chicago technology variation	7.25	7.04
Natural gas price	13.64	8.22
Total estimated error without fuel error	**7.31**	**7.11**
Total estimated error with fuel error	**15.48**	**10.86**

Table D.17. LCOE model error components for compliant Wisconsin CFEGU with NGCC with co-located wind mitigation technology for CO_2 emission intensity reduction. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

NGCC Mitigation Component	LCOE ($/MWh) +	LCOE ($/MWh) -
Demolition of turbine island	0.45	0.44
Natural gas pipeline	0.15	0.21
Heat rate variation	0.82	0.82
Heat rate penalty	0.14	0.14
Capital cost adder demolition	0.16	0.16
Capital cost adder NG pipeline	0.09	0.01
Capital cost adder NGCC PFC	2.84	2.84
ATB TR8 technology variation	12.57	7.48
Natural gas price	13.64	8.22
Total estimated error without fuel error	**12.60**	**7.54**
Total estimated error with fuel error	**18.57**	**11.15**

Table D.18. LCOE model error components for existing NGCC **with retrofitted CCS** for CO_2 emission intensity reduction. Based upon NGCC CCS mitigation for compliant Wisconsin CFEGU, excluding errors common to NGCC without CCS. Positive capital cost adders are results for High level. Negative capital cost adders are results for Low level.

CCS Mitigation	**LCOE ($/MWh)**					
Capture Rate	**10%**		**40%**		**90%**	
Component	+	-	+	-	+	-
CCS capital cost	1.16	1.16	1.16	1.16	1.16	1.16
CCS wet-cooling tower retrofit cost	0.47	0.47	0.48	0.48	0.52	0.52
CO_2 pipeline capital cost	1.66	2.58	2.11	3.07	2.76	3.81
Power block FOM	0.01	0.01	0.01	0.01	0.01	0.01
Wet-cooling tower FOM	0.03	0.03	0.01	0.01	0.01	0.01
Wet-cooling tower VOM	0.0	0.0	0.0	0.0	0.0	0.0
CCS FOM	0.28	0.28	0.28	0.28	0.28	0.28
CCS VOM	0.10	0.10	0.10	0.10	0.10	0.10
CCS heat rate	0.09	0.09	0.09	0.09	0.09	0.09
Capital cost adder for CCS PFC	0.25	0.09	1.05	0.21	5.01	0.39
Capital cost adder for CCS PCC	0.34	0.26	0.84	0.63	1.54	1.16
Capital Cost adder CO_2 pipeline	1.10	1.10	1.33	1.33	1.67	1.67
CO_2 storage cost	0.15	0.03	0.63	0.13	1.51	0.31
Natural gas price	13.70	8.18	13.70	8.18	13.70	8.18
Total estimated error without fuel error	**2.41**	**3.10**	**3.18**	**3.65**	**6.47**	**4.52**
Total estimated error with fuel error	**13.92**	**8.75**	**14.07**	**8.96**	**15.15**	**9.34**

D.2.2 Sensitivity analysis

Table D.19. Average increase in AEO 2020 projected fuel price between $35/tonne CO_2 price (U.S. Energy Information Administration, 2020) and reference cases, relative to 2012 state-specific fuel prices.

Fuel	Bituminous	Sub-bituminous	Lignite	NG
Increase (fraction)	0.001	0.019	-0.025	0.44

Table D.20. Factors for CCS capacity sensitivity analysis. Default levels are those used in the reference case modeling, while the Low, and High levels are used for sensitivity analysis.

Factor	Unit	Default	Low	High
CCS retrofit capital-cost multiplier*	fraction (absolute)	technology dependent	-0.10	0.10
NGCC capacity factor†	fraction	0.60	0.40	0.87
Solar overnight capital-cost†	2010$/kW	825	541	1,067
Wind overnight capital-cost†	2010$/kW	1,189	1,068	1,529
Change natural gas price† (2012-2030)	fraction (absolute)	State-specific	None	0.44
Bituminous coal price change† (2012-2030)	fraction (absolute)	-0.39	None	-0.39
Sub-bituminous coal price change† (2012-2030)	fraction (absolute)	-0.20	None	-0.18
Lignite coal price change† (2012-2030)	fraction (absolute)	-0.16	None	-0.19

Notes: *: Author chosen limits; †: literature.

D.3 Materials and methods

D.3.1 NGCC selection criteria

The eGRID2018 (U.S. EPA, 2018a) database contains 1,882 generators with a 289 GW capacity that may be used for combined cycle generation. Six criteria are used to select generators from this database to create the NGCC plant the dataset used in the model: (1) the prime mover is either listed as combined single shaft, combined-cycle gas turbine, combined-cycle steam turbine, or combined cycle total-unit, (2) the nameplate capacity is at least 25 MW, (3) the primary fuel is natural gas from which at least 99% of plant generation is derived, (4) the plant is not used for combined heat and power (CHP), (5) the first year of service is no earlier than 2010 and it is not listed for retirement before 2030, (6) and the year at which planned capacity is scheduled to come on-line is given. When these criteria are applied and generators that are common to a plant are combined, according to service year on-line and generator codes, 154 unique combined cycle plants with a 106.9 GW capacity are designated. If more than one NGCC plant is located at the same site, based upon plant longitude and latitude coordinates in eGRID, then the capacity of these plants is combined. Combining the plants in this manner reduces the dataset to 133 NGCC plants.

D.3.2 Retrofitting CCS without an auxiliary boiler to an existing coal-fired EGU

This mitigation option, for the CCS facility described in Table 4.1(c), will incur capital and operation and maintenance (O&M) costs for the CCS, the required retrofits to current subsystems, the CO_2 transport, and the saline sequestration costs. The LCOE contribution from the CCS plant capital and O&M costs are calculated with parameters from a series of linear and nonlinear regressions that are based upon simulations of the cluster of CFEGUs in the Integrated Environmental Control Model (IECM) developed at Carnegie Mellon University (Integrated Env. Control Model (IECM) v8.02, Carnegie Mellon Univ, 2012). For retrofitting costs, we use information from the IECM regarding the impact of the CCS on the CFEGU base plant, sulfur oxides (SO_x) subsystem, nitrogen oxides (NO_x) subsystem, total suspended particles management (TSP) subsystem, and the wet-cooling tower (WT) subsystem. These costs derive from the difference in the capital cost of these subsystems for the cluster CFEGUs with and without the CCS facility. The model also accounts for the variations in sequestration expenditures associated with transportation and storage of the CO_2 product at variable capture rates. The National Energy Technology Laboratory (NETL) storage reservoir database (U.S. NETL, 2017) lists 228 CO_2 sequester sites within the U.S. that ESTEAM uses to determine the lowest overall cost from the combination of transportation and storage costs from the CFEGU to the line-of-sight center of the ten nearest sites, (*Appendix B, Section 8.8*). The resulting LCOE at the required capture rate is calculated from a linear interpolation of the LCOE for the CFEGU at a 10% and 90% capture rate.

The emission intensity of the CFEGU retrofitted with CCS is not directly related to the capture rate, because the steam required for the CCS solvent-regeneration process comes from the existing boiler instead of from an auxiliary source. Rather, the new total emission is a linear function of the compliant CFEGU heat rate, the percent capture, the original CO_2 intensity, and the coal type (Eq. D.1, Table D.21). The parasitic load imposed through this process also causes the heat rate of the CFEGU to increase (Eq. D.2, Table D.22) and the net generation to decrease (Eq. D.3, Table D.23), relative to the compliant CFEGU configuration. The heat rate increase also results in the coal mass flow to increase (Eq. D.4, Table D.24); therefore, the fuel variable operation and maintenance (VOM) increases.

$$I_{ccs\_no\_aux} = I_{HRI}\left(1 + \left(\beta_0 + \beta_1 hr_{HRI} + \beta_2 ccs + \beta_3 R_{lig}\right)\right) \tag{D.1}$$

where $I_{ccs\_no\_aux}$ is the CFEGU emission intensity with the addition of the CCS facility $\left(\frac{lbs}{MWh}\right)$, I_{HRI} is the compliant CFEGU emission intensity after the heat rate improvement (HRI) mitigation, hr_{HRI} is the net heat rate of the compliant CFEGU with the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, ccs is the capture rate for the CCS facility (fraction), and R_{lig} is a dummy variable for the lignite coal rank that is 1 if the CFEGU uses lignite coal and is 0 otherwise.

$$\Delta hr_{ccs\_noaux} = \beta_{0,i} + \beta_{1,i} ccs + \beta_{2,i} ccs(hr_{HRI}) \tag{D.2}$$

where Δhr_{ccs_noaux} is the relative change in CFEGU heat rate after the addition of the CCS facility (fraction), *ccs* is the capture rate for the CCS facility (fraction), hr_{HRI} is the net heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, and the subscript *i* indicates the coal rank and boiler type.

$$G_{net1} = G_{net}\left(1 + \left(\beta_0 + \beta_1 hr_{HRI} + \beta_2 tons_{HRI}(ccs) + \beta_3 hr_{HRI}(ccs) + \beta_4 tons_{HRI}(hr_{HRI})(ccs)\right)\right) \quad \text{(D.3)}$$

where G_{net1} is the net generation of the retrofitted CFEGU with the addition of the CCS facility (MWh), G_{net} is the net generation of the compliant CFEGU (MWh), hr_{HRI} is the net heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, $tons_{HRI}$ is the emission rate of the CO_2 for the compliant CFEGU after the HRI mitigation $\left(\frac{tons}{hour}\right)$, and *ccs* is the capture rate for the CCS facility (fraction).

$$\dot{m}_{ccs\_noaux} = \beta_{0,i} + \beta_{1,i} ccs \quad \text{(D.4)}$$

where $\dot{m}_{ccs\_noaux}$ is the relative change in CFEGU coal mass flow after the addition of the CCS facility (fraction), *ccs* is the capture rate for the CCS facility (fraction), and the subscript *i* indicates the coal rank and boiler type.

The addition of CCS will increase the CFEGU LCOE due to the new capital and O&M costs for the CCS facility, as well as the capital and O&M costs from modifications to the existing plant from retrofitting the CCS facility. These costs are simulated with the proxy CFEGUs, with the capital costs for all components (except the NOx, SOx, and mercury (Hg) emission control devices (ECD)) completely amortized before the addition of the fully amortized CCS facility that has no CO_2 transportation or storage costs. Econometric analysis of the capital cost for the CCS facility indicates that the cost can be predicted for each coal rank and boiler type from the capacity of the original configured CFEGU, the heat rate and CO_2 emission rate of the compliant CFEGU after the HRI mitigation, and the capture rate (Eq. D.5 and Table D.25). For the other subsystems, each of the percent increases in capital cost relative to the compliant CFEGU without CCS is determined by regressions on the percent difference in total capital cost for these subsystems at capture percentages between 10% and 90%. Additionally, the base plant (Eq. D.6 and Table D.26), wet-cooling tower (Eq. D.7 and Table D.27), TSP (Eq. D.8 and Table D.28), SO_x emission-control device (Eq. D.9 and Table D.29), and NO_x post-combustion emission-control device (Eq. D.10 and Table D.30) retrofit cost percentages are each a function of the CFEGU summertime peak capacity, operating hours, heat rate and initial net generation. The total retrofit capital cost for each subsystem is the product of the original subsystem capital cost and this percentage, Eq. D.11. The percent change in LCOE from the additional O&M due to the CCS retrofit, without transportation and storage costs, is calculated from regressions of the compliant CFEGU LCOE without and with the CCS facility at various capture rates. The relative percent increase in LCOE for each coal rank and boiler type is dependent upon the compliant CFEGU heat rate, the new net generation, the tons of CO_2 emitted per hour, and the capture rate (Eq. D.12 and Table D.31). The LCOE related to the CO_2 pipeline is another component of the

CFEGU cost for CCS mitigation; the capital and O&M cost models for CO_2 transportation and storage (*Appendix B*, *Section 8.8*). The CFEGU LCOE for CCS mitigation is the sum of the aforementioned costs, Eq. D.13. Here the capital costs are annualized with the fixed charge factor (FCF) based upon the lesser of the remaining years of operation and the book life for the CFEGU.

$$CC_{ccs,j} = \beta_{0,i} + \beta_{1,i}cap + \beta_{2,i}hr_{HRI}(ccs_j) + \beta_{3,i}hr_{HRI}(ccs_j)(tons_{HRI}) + \beta_{4,i}tons_{HRI} + \beta_{5,i}cap(ccs_j) + \beta_{6,i}hr(tons_{HRI}) + \beta_{7,i}cap(ccs_j)(hr_{HRI}) + \beta_{8,i}ccs_j(tons_{HRI}) + \beta_{9,i}hr_{HRI} \quad \text{(D.5)}$$

where CC_{ccs} is the capital cost for the CCS facility (M$), *cap* is the CFEGU capacity (MW), hr_{HRI} is the heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, *ccs* is the capture rate for the CCS facility (fraction), $tons_{HRI}$ is the emission rate of the CO_2 for the compliant CFEGU after the HRI mitigation $\left(\frac{tons}{hour}\right)$, the subscript *j* indicates the capture rate (0.1, 0.4, or 0.9), and the subscript *i* indicates the coal and boiler type.

$$\Delta CC_{ccs\_noaux\_base} = \beta_{0,i} + \beta_{1,i}ccs + \beta_{2,i}ophrs(ccs) + \beta_{3,i}hr_{HRI}(ccs) + \beta_{4,i}hr_{HRI}(ccs)(ophrs) + \beta_{5,i}cap(ccs) + \beta_{6,i}hr_{HRI} + \beta_{7,i}G_{net}(ccs) \quad \text{(D.6)}$$

where $\Delta CC_{ccs\_noaux\_base}$ is the additional capital cost for retrofitting the base plant due to the capture rate of the CCS facility (fraction), *ccs* is the capture rate for the CCS facility (fraction), op*hrs* is the operating hours, hr_{HRI} is the heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, *cap* is the CFEGU capacity (MW), G_{net} is the net generation of the compliant CFEGU (MWh), and the subscript *i* indicates the coal rank.

$$\Delta CC_{ccs\_noaux\_WT} = \beta_{0,i} + \beta_{1,i}ccs + \beta_{2,i}ophrs(ccs) + \beta_{3,i}cap(ccs) + \beta_{4,i}hr_{HRI}\left(ccs_j\right) + \beta_{5,i}cap(ccs)(ophrs) + \beta_{6,i}hr_{HRI}(ccs)(ophrs) + \beta_{7,i}hr_{HRI}(ccs)(ophrs) + \beta_{8,i}cap + \beta_{9,i}cap(hr) + \beta_{10,i}G_{net}(ccs) + \beta_{11,i}G_{net} + \beta_{12,i}G_{net}(ophrs) + \beta_{13,i}G_{net}(hr_{HRI})(ccs) + \beta_{14,i}G_{net}(ophrs)(ccs) + \beta_{15,i}G_{net}(ophrs)(cap) \quad \text{(D.7)}$$

where $\Delta CC_{ccs\_noaux\_WT}$ is the additional capital cost for retrofitting the wet-cooling tower due to the capture rate of the CCS facility (fraction), *ccs* is the capture rate for the CCS facility (fraction), G_{net} is the net generation of the compliant CFEGU (MWh), *ophrs* is the operating hours, hr_{HRI} is the heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, *cap* is the CFEGU capacity (MW), and the subscript *i* indicates the coal rank and boiler type.

$$\Delta CC_{ccs\_noaux\_TSP} = \beta_{0,i} + \beta_{1,i}ophrs + \beta_{2,i}cap + \beta_{3,i}hr_{HRI} + \beta_{4,i}ophrs(cap) + \beta_{5,i}hr_{HRI}(ophrs) + \beta_{6,i}hr_{HRI}(ccs)(ophrs) + \beta_{7,i}ccs(hr_{HRI}) + \beta_{8,i}ccs + \beta_{9,i}G_{net}(hr_{HRI}) + \beta_{10,i}G_{net}(ccs) + \beta_{11,i}G_{net} + \beta_{12,i}cap(ccs) + \beta_{13,i}ophrs(ccs) \quad \text{(D.8)}$$

where $\Delta CC_{ccs\_noaux\_TSP}$ is the additional capital cost for the TSP ECD from retrofitting the CCS facility (fraction), *ophrs* is the operating hours, *cap* is the CFEGU capacity (MW), hr_{HRI} is the net heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, *ccs* is the capture rate for the CCS facility (fraction), G_{net} is the net generation of the compliant CFEGU (MWh), and the subscript *i* indicates the coal rank and boiler type.

$$\Delta CC_{ccs\_noaux\_SOx} = \beta_{0,i} + \beta_{1,i}hr_{HRI} + \beta_{2,i}G_{net} + \beta_{3,i}ophrs(ccs) + \beta_{4,i}hr_{HRI}(G_{net}) + \beta_{5,i}hr_{HRI}(ccs) + \beta_{6,i}hr_{HRI}(ccs)(ophrs) + \beta_{7,i}G_{net}(ccs)(ophrs) + \beta_{8,i}G_{net}(ccs)(hr_{HRI}) + \beta_{9,i}ccs + \beta_{10,i}cap(ccs) \quad \text{(D.9)}$$

where $\Delta CC_{ccs\_noaux\_SOx}$ is the additional capital cost for the SO_x ECD from retrofitting the CCS facility (fraction), hr_{HRI} is the net heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, G_{net} is the net generation of the compliant CFEGU (MWh), *ophrs* is the operating hours, *ccs* is the capture rate for the CCS facility (fraction), and the subscript *i* indicates the coal rank and boiler type.

$$\Delta CC_{ccs\_noaux\_NOx} = \beta_{0,i} + \beta_{1,i}ccs + \beta_{2,i}ccs(hr_{HRI}) + \beta_{3,i}ccs(G_{net}) + \beta_{4,i}hr_{HRI}(ophrs)(cap) + \beta_{5,i}hr_{HRI}(ccs)(G_{net}) + \beta_{6,i}ccs(cap) + \beta_{7,i}hr_{HRI} + \beta_{8,i}G_{net} + \beta_{9,i}G_{net}(ophrs) \quad \text{(D.10)}$$

where $\Delta CC_{ccs\_noaux\_NOx}$ is the additional capital cost for the NO_x post-combustion ECD from retrofitting the CCS facility (fraction), *ccs* is the capture rate for the CCS facility (fraction), hr_{HRI} is the net heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, G_{net} is the net generation of the compliant CFEGU (MWh), *ophrs* is the operating hours, *cap* is the CFEGU capacity (MW), cap is the CFEGU capacity (MW), and the subscript *i* indicates the coal rank.

$$CC_{ccs\_noaux\_k} = CC_k\left(\Delta CC_{ccs\_noaux\_k}\right) \tag{D.11}$$

where $CC_{ccs\_noaux\_k}$ is the total additional capital cost for a subsystem from retrofitting the CCS facility (M$), CC_k is the original capital cost of the subsystem for the compliant CFEGU (M$), $\Delta CC_{ccs\_noaux\_k}$ is the increase in capital cost for the subsystem due to the capture rate of the CCS facility (fraction), and the subscript *k* identifies the subsystem for which the additional capital cost is calculated.

$$\varepsilon_{ccs\_noaux\_k} = \beta_{1,i}ccs_k^2 + \beta_{2,i}cap^2 + \beta_{3,i}(hr_{HRI}^2) + \beta_{4,i}cap(ccs_k) + \beta_{5,i}hr_{HRI}(ccs_k) + \beta_{6,i}hr_{HRI}(cap) + \beta_{7,i}tons_{HRI}^2 + \beta_{8,i}tons_{HRI}(ccs_k) \tag{D.12}$$

where $\varepsilon_{ccs\_noaux\_k}$ is the relative increase in LCOE from the addition of a CCS facility at a designated capture rate (fraction), *ccs* is the capture rate for the CCS facility (fraction), *cap* is the CFEGU capacity (MW), hr_{HRI} is the net heat rate of the compliant CFEGU after the HRI mitigation $\left(\frac{Btu}{kWh}\right)$, $tons_{HRI}$ is the emission rate of the CO_2 for the compliant CFEGU after the HRI mitigation $\left(\frac{tons}{hour}\right)$, the subscript *k* indicates the capture rate fraction (0.10, 0.40, or 0.90), and the subscript *i* indicates the coal rank and boiler type.

$$LCOE_{CCS\_noaux} = LCOE_{comply} + LCOE_{new} \times \varepsilon_{ccs} + \left(\frac{1\times10^{6}\left(CC_{ccs\_noaux} + CC_{ccs\_noaux\_base} + CC_{ccs\_noaux\_WT} + CC_{ccs\_noaux\_TSP} + CC_{ccs\_noaux\_NOx} + CC_{ccs\_noaux\_SOx}\right)FCF_{remain}}{G_{net1}}\right) + LCOE_{CO_2pipe} \quad \text{(D.13)}$$

where $LCOE_{CCS\_noaux}$ is the total CFEGU LCOE from the addition of the CCS facility $\left(\frac{\$}{MWh}\right)$, $LCOE_{comply}$ is the LCOE for the compliant CFEGU $\left(\frac{\$}{MWh}\right)$, $LCOE_{new}$ is the LCOE for the compliant CFEGU equipped with new all new ECDs $\left(\frac{\$}{MWh}\right)$, ε_{ccs} is the change in the compliant CFEGU LCOE due to the addition of the CCS facility (fraction), CC_{ccs_noaux} is the capital cost for CCS facility (M\$), $CC_{ccs\_noaux\_base}$ is the retrofit capital cost for the base plant (M\$), $CCS_{ccs\_noaux\_WT}$ is the retrofit capital cost for the wet-cooling tower (M\$), $CCS_{ccs\_noaux\_TSP}$ is the retrofit capital cost for the TSP ECD (M\$), $CCS_{ccs\_noaux\_NOx}$ is the retrofit capital cost for the NO_x ECD (M\$), $CCS_{ccs\_noaux\_SOx}$ is the retrofit capital cost for the SO_x ECD (M\$), FCF_{remain} is the fixed charge factor for the remaining life of the CFEGU (fraction), $LCOE_{CO_2pipe}$ is the LCOE for the CO_2 transportation pipeline $\left(\frac{\$}{MWh}\right)$, and $1\text{x}10^{6}$ is a conversion for millions.

Table D.21. Coefficients of the regression model for estimating relative CO_2 emission intensity change associated with a percentage of CO_2 capture by CCS.*

β_0	β_1	β_2	β_3	R^2	RMSE
0.084	4.4×10^{-6}	-1.084	6.4×10^{-3}	.997	0.020

*n = 132

Table D.22. Coefficients of the regression model for relative change in heat rate from addition of CCS facility (fraction).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	R^2	RMSE
Bituminous/ Subcritical*	5.4×10^{-2}	0.164	2.6×10^{-5}	.979	0.022
Bituminous/ Supercritical†	5.2×10^{-2}	0.162	2.2×10^{-5}	.980	0.018
Sub-bituminous/ Subcritical‡	5.1×10^{-2}	0.200	2.7×10^{-5}	.977	0.026
Sub-bituminous/ Supercritical§	4.9×10^{-2}	0.167	2.5×10^{-5}	.978	0.023
Lignite/ Subcritical¶	5.4×10^{-2}	0.275	2.3×10^{-5}	.974	0.030
Lignite/ Supercritical#	5.1×10^{-2}	0	4.2×10^{-5}	.979	0.024

*n = 48; †n = 18; ‡n = 15; §n = 15; ¶n = 15; #n = 12

Table D.23. Coefficients of the regression model for estimating relative change in net generation from addition of CCS.*

β_0	β_1	β_2	β_3	β_4	R^2	RMSE
-0.011	-1.5×10^{-6}	9.7×10^{-5}	-1.3×10^{-5}	-9.8×10^{-9}	.991	0.005

*n = 132

Table D.24. Coefficients of the regression model for estimating fractional change in fuel use from the addition of CCS facility as a function of CCS capture rate from 10% to 90%.

Coal/boiler type	$\beta_{0,i}$	$\beta_{1,i}$	R^2	**RMSE**
Bituminous/ Subcritical*	3.6×10^{-2}	0.212	.973	0.012
Bituminous/ Supercritical†	3.3×10^{-2}	0.184	.973	0.010
Sub-bituminous/ Subcritical‡	3.8×10^{-2}	0.235	.972	0.013
Sub-bituminous/ Supercritical§	3.5×10^{-2}	0.204	.972	0.012
Lignite/Subcritical¶	3.9×10^{-2}	0.250	.969	0.015
Lignite/Supercritical#	3.6×10^{-2}	0.214	.971	0.013

*n = 48; †n = 18; ‡n = 24; §n = 15; ¶n = 15; #n = 12

Table D.25. Coefficients of the regression model for capital cost for CCS facility (M$).
(a) 10% capture rate

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	$\beta_{9,i}$	R^2	RMSE
Bituminous/ Subcritical*	49.324	0.015	-0.029	5.9×10^{-5}	0	0	0	0	0	0	.988	3.015
Bituminous/ Supercritical†	112.105	0	-0.084	0	-0.063	-0.027	1.3×10^{-5}	0	0	0	1.000	0.332
Sub-bituminous/ Subcritical‡	12.312	0	0	0	0	1.859	0	-9.1×10^{-5}	0	0	.996	1.877
Sub-bituminous/ Supercritical§	146.519	0	-0.104	0	0.120	0	0	0	0	0	1.000	0.724
Lignite/ Subcritical¶	101.681	0	-0.071	-7.0×10^{-5}	0	0	1.1×10^{-5}	0	-0.397	0	.997	1.489
Lignite/ Supercritical#	22.412	0	0	0	0	0.253	4.6×10^{-6}	0	0	0	1.000	0.150

*n = 16; †n = 6; ‡n = 8; §n = 5; ¶n = 5; #n = 4

(b) 40% capture rate

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	$\beta_{9,i}$	R^2	RMSE
Bituminous/ Subcritical*	47.363	0	0	0	0	-0.087	0	0	0.847	-0.002	.999	3.213
Bituminous/ Supercritical†	3.683	0	0	0	0	0.159	0	0	0	0	.997	5.865
Sub-bituminous/ Subcritical‡	91.530	0	0	0	0.443	0	0	0	0	-0.005	.999	3.103
Sub-bituminous/ Supercritical§	-8.616	0	0	0	0	0	0	0	0.949	0.002	1.000	0.461
Lignite/ Subcritical¶	21.420	0	0	0	0.400	-0.298	0	0	0	0	1.000	0.436
Lignite/ Supercritical#	32.368	0	0	0	0	0.329	0	0	0	0	1.000	0.481

*n = 16; †n = 6; ‡n = 8; §n = 5; ¶n = 5; #n = 4

(c) 90% capture rate

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	$\beta_{9,i}$	R^2	RMSE
Bituminous/ Subcritical*	24.321	0	0	0	0.744	0	0	0	0	0	.999	9.809
Bituminous/ Supercritical†	13.855	0	0	0	0.734	0	0	0	0	0	.991	24.778
Sub-bituminous/ Subcritical‡	16.053	0	0	8.2×10^{-5}	0	0	0	0	0	0	1.000	5.396
Sub-bituminous/ Supercritical§	44.909	0	-1.5×10^{-3}	-1.3×10^{-5}	0.831	0	0	0	0	0	1.000	0.989
Lignite/ Subcritical¶	30.432	-0.163	0	-4.6×10^{-5}	1.373	0	0	0	0	0	1.000	1.114
Lignite/ Supercritical#	-168.193	0	0	0	0	0.744	3.2×10^{-5}	0	0	0	1.000	0.603

*n = 16; †n = 6; ‡n = 8; §n = 5; ¶n = 5; #n = 4

Table D.26. Coefficients of the regression model for estimating fractional change in base plant capital-cost related to retrofitting CCS facility, as a function of CCS capture rate from 10% to 90%.

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	$\beta_{9,i}$	R^2	RMSE
Bituminous*	$-6.8\text{x}10^{-3}$	0.355	$-5.8\text{x}10^{-5}$	$-1.5\text{x}10^{-5}$	$4.7\text{x}10^{-9}$	0	$-1.0\text{x}10^{-4}$	0	0	0	.996	0.003
Sub-bituminous†	$-7.9\text{x}10^{-3}$	0	$-2.5\text{x}10^{-6}$	$1.5\text{x}10^{-5}$	0	0	0	0	0	$4.9\text{x}10^{-9}$	.995	0.003
Lignite‡	$2.6\text{x}10^{-2}$	-0.129	0	$2.6\text{x}10^{-5}$	0	0	$-2.7\text{x}10^{-5}$	0	$-2.9\text{x}10^{-6}$	$6.0\text{x}10^{-9}$	.996	0.003

*n = 92; †n = 52; ‡n = 36; §n = 4

Table D.27. Coefficients of the regression model for estimating fractional change in wet-cooling tower capital cost related to retrofitting CCS facility, as a function of CCS capture rate from 10% to 90%.

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	$\beta_{9,i}$
Bituminous/ Subcritical*	$9.8\text{x}10^{-3}$	5.864	$-7.9\text{x}10^{-4}$	$-4.9\text{x}10^{-3}$	$-4.1\text{x}10^{-4}$	$3.9\text{x}10^{-7}$	$6.0\text{x}10^{-8}$	$2.2\text{x}10^{-7}$	0	0
Bituminous/ Supercritical†	0.209	0	0	0	$1.3.\text{x}10^{-5}$	$-4.0\text{x}10^{-7}$	0	$1.6\text{x}10^{-7}$	$5.1\text{x}10^{-3}$	$-4.7\text{x}10^{-7}$
Sub-bituminous/ Subcritical‡	0.064	0.528	0	0	0	$3.3\text{x}10^{-7}$	$-7.8\text{x}10^{-10}$	0	0	0
Sub-bituminous/ Supercritical‡	0.064	0.528	0	0	0	$3.3\text{x}10^{-7}$	$-7.8\text{x}10^{-10}$	0	0	0
Lignite/ Subcritical§	0.069	2.841	0	$-6.0\text{x}10^{-3}$	0	$7.1\text{x}10^{-7}$	$-2.2\text{x}10^{-8}$	0	0	0
Lignite/ Supercritical§	0.069	2.841	0	$-6.0\text{x}10^{-3}$	0	$7.1\text{x}10^{-7}$	$-2.2\text{x}10^{-8}$	0	0	0

Table D.27. Continued… coefficients of the regression model for estimating fractional change in wet-cooling tower capital cost related to retrofitting CCS facility, as a function of CCS capture rate from 10% to 90%.

Coal/Boiler type	$\beta_{10,i}$	$\beta_{11,i}$	$\beta_{10,i}$	$\beta_{11,i}$	$\beta_{12,i}$	$\beta_{13,i}$	$\beta_{14,i}$	$\beta_{15,i}$	R^2	RMSE
Bituminous/ Subcritical*	0	0	0	0	0	0	0	0	.905	0.043
Bituminous/ Supercritical†	0	$1.5x10^{-7}$	0	$1.5x10^{-7}$	0	$2.8x10^{-11}$	0	$-2.2x10^{-7}$	.958	0.029
Sub-bituminous/ Subcritical‡	$4.2x10^{-7}$	$4.1x10^{-8}$	$4.2x10^{-7}$	$4.1x10^{-8}$	$-5.1x10^{-12}$	$-7.7x10^{-11}$	0	0	.966	0.030
Sub-bituminous/ Supercritical‡	$4.2x10^{-7}$	$4.1x10^{-8}$	$4.2x10^{-7}$	$4.1x10^{-8}$	$-5.1x10^{-12}$	$-7.7x10^{-11}$	0	0	.966	0.030
Lignite/ Subcritical§	$3.2x10^{-7}$	0	$3.2x10^{-7}$	0	0	0	$-4.9x10^{-11}$	0	.961	0.027
Lignite/ Supercritical§	$3.2x10^{-7}$	0	$3.2x10^{-7}$	0	0	0	$-4.9x10^{-11}$	0	.961	0.027

*n = 68; †n = 24; ‡n = 52; §n = 36

Table D.28. Coefficients of the regression model for estimating fractional change in capital cost of TSP ECD related to retrofitting from addition of CCS facility (fraction).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$
Bituminous/ Subcritical*	-4.294	$6.2x10^{-4}$	$1.9x10^{-3}$	$3.4x10^{-4}$	$-3.0x10^{-7}$	$-5.1x10^{-8}$	$1.5x10^{-9}$	0
Bituminous/ Supercritical†	0.026	0	0	0	0	0	0	$1.4x10^{-5}$
Sub-bituminous/ Subcritical‡	-0.098	0	$-1.5x10^{-4}$	0	0	0	0	0
Sub-bituminous/ Supercritical§	-0.289	0	0	$1.5x10^{-5}$	0	0	0	$-1.2x10^{-5}$
Lignite/ Subcritical¶	-0.041	0	0	0	0	0	0	0
Lignite/ Supercritical#	0.028	0	0	0	0	0	0	0

Table D.28. Continued…coefficients of the regression model for estimating fractional change in capital cost of TSP ECD related to retrofitting from addition of CCS facility (fraction).

Coal/Boiler type	$\beta_{8,i}$	$\beta_{9,i}$	$\beta_{10,i}$	$\beta_{11,i}$	$\beta_{12,i}$	$\beta_{13,i}$	R^2	RMSE
Bituminous/ Subcritical*	0	0	0	0	0	0	.619	0.046
Bituminous/ Supercritical†	0	0	0	0	0	0	.919	0.012
Sub-bituminous/ Subcritical‡	0.133	$1.3x10^{-12}$	$3.8x10^{-9}$	0	0	0	.951	0.010
Sub-bituminous/ Supercritical§	0.257	0	0	0	0	0	.950	0.009
Lignite/ Subcritical¶	0	0	0	$-3.4x10^{-9}$	$7.7x10^{-5}$	$1.6x10^{-5}$	.939	0.012
Lignite/ Supercritical#	0.164	0	0	0	0	0	.956	0.011

*n = 68; †n = 24; ‡n = 32; §n = 20; ¶n = 20; #n = 16

Table D.29. Coefficients of the regression model for estimating fractional change in capital cost of SO_x ECD related to retrofitting from addition of CCS facility (fraction).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$
Bituminous/ Subcritical*	0.104	-2.1×10^{-6}	1.5×10^{-8}	1.6×10^{-12}	5.9×10^{-6}	-1.4×10^{-9}	-2.5×10^{-12}
Bituminous/ Supercritical†	0.200	-1.2×10^{-5}	0	0	8.0×10^{-6}	0	0
Sub-bituminous/ Subcritical‡	0.111	-3.9×10^{-6}	0	0	0	0	0
Sub-bituminous/ Supercritical§	0.098	-2.8×10^{-6}	0	0	-5.7×10^{-6}	0	0
Lignite/ Subcritical¶	0.082	0	0	0	0	0	0
Lignite/ Supercritical#	0.082	0	0	0	0	0	0

Table D.29. Continued…coefficients of the regression model for estimating fractional change in capital cost of SO_x ECD related to retrofitting from addition of CCS facility (fraction).

Coal/Boiler type	$\beta_{7,i}$	$\beta_{8,i}$	$\beta_{9,i}$	$\beta_{10,i}$	R^2	RMSE
Bituminous/ Subcritical*	-2.5×10^{-12}	2.1×10^{-12}	0	0	.945	0.006
Bituminous/ Supercritical†	0	0	0	0	.922	0.008
Sub-bituminous/ Subcritical‡	0	0	0.091	2.5×10^{-5}	.953	0.007
Sub-bituminous/ Supercritical§	0	0	0.152	0	.953	0.006
Lignite/ Subcritical¶	0	0	0	4.9×10^{-5}	.943	0.008
Lignite/ Supercritical#	0	0	0.098	0	.954	0.006

*n = 68; †n = 24; ‡n = 32; §n = 20; ¶n = 20; #n = 16

Table D.30. Coefficients of the regression model for estimating fractional change in capital cost of NO_x post-combustion ECD related to retrofitting from addition of CCS facility (fraction).

Coal/Boiler type	$\beta_{0,i}$	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$
Bituminous*	2.2×10^{-2}	0.191	-6.6×10^{-6}	-4.2×10^{-8}	-4.5×10^{-9}	-4.9×10^{-12}
Sub-bituminous†	2.3×10^{-2}	0.116	0	-2.2×10^{-8}	0	0
Lignite‡	0.125	0.283	-1.2×10^{-5}	0	0	0

Table D.30. Continued…coefficients of the regression model for estimating fractional change in capital cost of NO_x post-combustion ECD related to retrofitting from addition of CCS facility (fraction).

Coal/Boiler type	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	$\beta_{9,i}$	R^2	RMSE
Bituminous*	0	0	0	0	.933	0.010
Sub-bituminous†	2.1×10^{-4}	0	0	0	.951	0.010
Lignite‡	0	-1.2×10^{-5}	1.3×10^{-8}	1.5×10^{-12}	.953	0.009

*n = 92; †n = 32; ‡n = 20

Table D.31. Coefficients of the regression model for estimating relative fractional change in LCOE related to addition of CCS facility (a) 10% capture rate.

Coal/Boiler type	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	R^2	**RMSE**
Bituminous/ Subcritical*	-0.490	-9.9×10^{-9}	-7.4×10^{-10}	-6.1×10^{-5}	2.2×10^{-4}	2.5×10^{-9}	0	0	.450	0.005
Bituminous/ Supercritical†	18.110	2.8×10^{-8}	0	-6.0×10^{-4}	0	0	0	0	.922	0.002
Sub-bituminous/ Subcritical‡	-4.399	-3.9×10^{-8}	-1.1×10^{-9}	3.3×10^{-4}	2.9×10^{-4}	1.5×10^{-9}	0	0	.987	0.000
Sub-bituminous/ Supercritical§	14.575	-2.6×10^{-9}	0	1.9×10^{-5}	0	0	0	0	.913	0.001
Lignite/ Subcritical¶	15.364	-4.6×10^{-8}	0	4.1×10^{-4}	0	0	0	0	.959	0.001
Lignite/ Supercritical#	28.890	2.7×10^{-7}	0	-4.0×10^{-3}	0	0	0	0	.941	0.000

*n = 16; †n = 6; ‡n = 8; §n = 5; ¶n = 5; #n = 4

(b) 40% capture rate

Coal/Boiler type	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	R^2	**RMSE**
Bituminous/ Subcritical*	-0.543	-3.6×10^{-8}	-1.8×10^{-9}	1.5×10^{-4}	1.2×10^{-4}	2.8×10^{-9}	0	0	.673	0.008
Bituminous/ Supercritical†	3.419	6.1×10^{-7}	0	-1.9×10^{-3}	0	0	0	0	.974	0.025
Sub-bituminous/ Subcritical‡	-43.847	-3.8×10^{-7}	-4.4×10^{-8}	1.1×10^{-2}	2.9×10^{-4}	-3.6×10^{-7}	0	0	.997	0.004
Sub-bituminous/ Supercritical§	1.508	-3.9×10^{-8}	0	2.4×10^{-4}	0	0	0	0	.999	0.001
Lignite/ Subcritical¶	1.606	-1.1×10^{-7}	0	3.4×10^{-4}	0	0	0	0	.914	0.006
Lignite/ Supercritical#	5.252	1.1×10^{-6}	0	-4.0×10^{-3}	0	0	0	0	.784	0.002

*n = 16; †n = 6; ‡n = 8; §n = 5; ¶n = 5; #n = 4

(c) 90% capture rate.

Coal/Boiler type	$\beta_{1,i}$	$\beta_{2,i}$	$\beta_{3,i}$	$\beta_{4,i}$	$\beta_{5,i}$	$\beta_{6,i}$	$\beta_{7,i}$	$\beta_{8,i}$	R^2	**RMSE**
Bituminous/ Subcritical*	1.451	$7.9\text{x}10^{-8}$	$4.9\text{x}10^{-9}$	$-3.3\text{x}10^{-3}$	$1.3\text{x}10^{-4}$	$3.0\text{x}10^{-7}$	0	0	.673	0.008
Bituminous/ Supercritical†	0.780	$1.6\text{x}10^{-7}$	0	$-2.9\text{x}10^{-4}$	0	0	0	0	.974	0.025
Sub-bituminous/ Subcritical‡	-4.969	$-5.5\text{x}10^{-7}$	$-2.9\text{x}10^{-8}$	$1.8\text{x}10^{-3}$	$8.1\text{x}10^{-4}$	$-7.2\text{x}10^{-8}$	0	0	.997	0.004
Sub-bituminous/ Supercritical§	0.564	$-2.2\text{x}10^{-7}$	0	$5.1\text{x}10^{-4}$	0	0	0	0	.999	0.001
Lignite/ Subcritical¶	0.638	0	0	0	0	0	$-3.3\text{x}10^{-7}$	$-5.4\text{x}10^{-4}$	.914	0.006
Lignite/ Supercritical#	2.563	$3.1\text{x}10^{-6}$	0	$-4.7\text{x}10^{-3}$	0	0	0	0	.784	0.002

*n = 16; †n = 6; ‡n = 8; §n = 5; ¶n = 5; #n = 4

D.3.3 Conversion from coal-fired EGUs to NGCC plant with CCS

When CCS technology is coupled with the NGCC conversion, we assume that the two mitigation technologies are built concurrently so no additional retrofitting costs are incurred. Capital and O&M costs established for the brownfield NGCC mitigation option (*Appendix B, Section 8.6.6*) are supplemented with those for the CCS facility described in Table 4.1(c). The LCOE contribution from the CCS plant capital and O&M costs are calculated with parameters from a series of regressions from IECM simulations of the NGCC plant with different turbine configurations, and with and without the CCS facility at multiple capture rates. The model also accounts for the variations in sequestration expenditures associated with transportation and storage of the CO_2 effluent, based upon the lowest overall cost from the combination of transportation and storage costs from the EGU to the line-of-sight center of the ten nearest sites from the NETL storage reservoir database U.S. NETL (2017), (*Appendix B Section 8.8*). The resulting LCOE at the required capture rate is calculated from a linear interpolation of the LCOE for the EGU at a 10% and 90% capture rate. To track the capacity changes from this mitigation and others that involve repowering an EGU with a different fuel or replacement with renewable generation, the capacity of the original EGU configuration is retained for graphical purposes only.

As is the case for coal-fired CCS without an auxiliary boiler, the addition of CCS to a gas-fired plant without an auxiliary boiler will not yield a one-to-one reduction in emission intensity with capture rate. A 90% capture rate for the CCS equipped NGCC plant does not produce a 90% reduction in emission intensity for the CCS mitigated plant, because the steam required for the CCS solvent-regeneration process comes from the heat produced by the combustion turbine. Rather, the new total emission intensity is a linear function of the plant emission intensity and the capture rate (Eq. D.14, Table D.32). Furthermore, the parasitic load imposed through this process causes the heat rate of the plant to increase (Eq. D.15, Table D.33) and the net generation to decrease (Eq. D.16, Table D.34), relative to the plant without the CCS facility. Subsequently, the fuel VOM also increases (Eq. D.17).

$$I_{ccs\_NGCC} = I_{NGCC}\big(1 + (\beta_0 + \beta_1 ccs)\big) \tag{D.14}$$

where I_{ccs_NGCC} is the NGCC plant emission intensity with the addition of the CCS facility $\left(\frac{lbs}{MWh}\right)$, I_{NGCC} is the initial NGCC plant emission intensity $\left(\frac{lbs}{MWh}\right)$, and *ccs* is the capture rate for the CCS facility (fraction).

$$\Delta hr_{ccs\_NGCC} = \beta_0 + \beta_1 ccs \tag{D.15}$$

where Δhr_{ccs_NGCC} is the percent change in heat rate for the NGCC plant with the addition of the CCS facility (fraction), and *ccs* is the capture rate for the CCS facility (fraction).

$$G^{net}_{ccs\_NGCC} = G_{net}\big(1 + (\beta_0 + \beta_1 ccs)\big) \tag{D.16}$$

where $G^{net}_{ccs\_NGCC}$ is the net generation of the NGCC plant with the addition of the CCS facility (MWh), G_{net} is the initial NGCC net generation (MWh), and *ccs* is the capture rate for the CCS facility (fraction).

$$VOM_{ccs\_NGCC\_fuel} = \left(\frac{NGP(hr_{NGCC})(\Delta hr_{ccs\_NGCC})}{1000}\right) \quad \text{(D.17)}$$

where $VOM_{ccs\_NGCC\_fuel}$ is the VOM fuel cost from the change in heat rate due to the addition of the CCS facility $\left(\frac{\$}{MWh}\right)$, *NGP* is the natural gas price $\left(\frac{\$}{MMBtu}\right)$, hr_{NGCC} is the NGCC heat rate without the CCS facility $\left(\frac{Btu}{kWh}\right)$, Δhr_{ccs_NGCC} is the percent change in heat rate for the NGCC plant with the addition of the CCS facility (fraction), and 1000 is a conversion factor.

The addition of CCS will increase the NGCC LCOE due to greater capital and O&M costs and a decreased net generation. These costs are simulated in IECM with the NGCC plants completely amortized before the addition of the fully amortized CCS facility and without CO_2 transportation or storage costs, as done with retrofitting a coal-fired EGU with CCS. Econometric analysis of the capital cost for the CCS facility indicates that the cost is a function of the number of NGCC turbines and the capture rate (Eq. D.18 and Table D.35). The other considered capital cost for this addition, excluding those for CO_2 transportation, is that for the wet-cooling tower. This cost is only included in LCOE calculations if it exceeds the wet-cooling tower cost for the existing CFEGU. Here, the additional cooling-tower capital cost is taken as the difference between the costs for the two plant configurations (Eq. D.19 and Eq. D.20, Table D.36). Otherwise, the cost is assumed to be insignificant compared to the other CSS related cost.

The change in LCOE from the additional O&M due to the CCS facility, without transportation and storage costs, for the wet-cooling tower and power block is calculated from regressions on the differences in these fixed operation-and-maintenance (FOM) costs and the VOM costs, without and with the CCS facility at various capture rates. Each cost is a function of the number of NGCC turbines and the CCS capture rate with the wet-cooling tower costs given in Eqs. D.21 and D.22 (Tables D.37 and D.38, respectively) and the power block FOM given in Eq. D.23 (Table D.39). The FOM and VOM costs for the CCS facility are also functions of these two variables (Eqs. D.24 and D.25; Tables D.40 and D.41, respectively).

The LCOE related to the CO_2 pipeline is another component of the EGU cost for CCS mitigation (*Appendix B, Section 8.8*). The LCOE for NGCC plant with CCS mitigation is the sum of the aforementioned costs, Eq. D.26. Here the capital costs are annualized with the FCF based upon the lessor between the remaining years of operation and the book life for the EGU.

$$CC_{ccs\_NGCC} = \beta_0 + \beta_1 turb(ccs) \quad \text{(D.18)}$$

where CC_{ccs_NGCC} is the capital cost for CCS facility (M\$), *turb* is the number of turbines (number), and *ccs* is the capture rate for the CCS facility (fraction).

$$\Delta CC_{ccs\_NGCC\_WT} = CC_{ccs\_NGCC\_WT} - CC_{WT} \quad \text{(D.19)}$$

where $\Delta CC_{ccs\_NGCC\_WT}$ is the difference in wet-cooling tower capital costs for a brownfield NGCC plant equipped with a CCS facility and the NGCC plant without CCS (M\$), $CC_{ccs\_NGCC\_WT}$ is the wet-cooling tower capital cost for a brownfield NGCC plant equipped with a CCS facility (M\$), and CC_{WT} is the water tower capital costs for the existing CFEGU (M\$).

$$CC_{ccs\_NGCC\_WT} = \beta_0 + \beta_1 turb + \beta_2 turb(ccs) \quad \text{(D.20)}$$

where $CC_{ccs\_NGCC\_WT}$ is the wet-cooling tower capital costs for a brownfield NGCC plant equipped with a CCS facility (M\$), *turb* is the number of turbines (number), and *ccs* is the capture rate for the CCS facility (fraction).

$$FOM_{ccs\_NGCC\_WT} = \beta_0 + \beta_1 turb + \beta_2 ccs + \beta_3 turb(ccs) \tag{D.21}$$

where $FOM_{ccs\_NGCC\_WT}$ is the wet-cooling tower FOM costs with the addition of the CCS facility (M$), *turb* is the number of turbines (number), and *ccs* is the capture rate for the CCS facility (fraction).

$$VOM_{ccs\_NGCC\_WT} = \beta_0 + \beta_1 turb + \beta_2 ccs + \beta_3 turb(ccs) \tag{D.22}$$

where $VOM_{ccs\_NGCC\_WT}$ is the wet-cooling tower VOM costs with the addition of the CCS facility $\left(\frac{\$}{MWh}\right)$, *turb* is the number of turbines (number), and *ccs* is the capture rate for the CCS facility (fraction).

$$FOM_{ccs\_NGCC\_power} = \beta_0 + \beta_1 ccs + \beta_2 turb(ccs) \tag{D.23}$$

where $FOM_{ccs\_NGCC\_power}$ is the relative increase in power block FOM costs from the addition of a CCS facility to the NGCC plant (fraction), *ccs* is the capture rate for the CCS facility (fraction), and *turb* is the number of turbines (number).

$$FOM_{ccs\_NGCC} = \beta_0 + \beta_1 turb(ccs) \tag{D.24}$$

where FOM_{ccs_NGCC} is the FOM costs for CCS facility (M$), *turb* is the number of turbines (number), and *ccs* is the capture rate for the CCS facility (fraction).

$$VOM_{ccs\_NGCC} = \beta_0 + \beta_1 ccs + \beta_2 turb(ccs) \tag{D.25}$$

where VOM_{ccs_NGCC} is the VOM costs for CCS facility $\left(\frac{\$}{MWh}\right)$, *ccs* is the capture rate for the CCS facility (fraction), and *turb* is the number of turbines (number).

$$LCOE_{ccs\_NGCC} = LCOE_{NGCC}\left(\frac{G_{NGCC}^{net}}{G_{ccs\_NGCC}^{net}}\right) + \left(\frac{1\times10^6\left(CC_{ccs\_NGCC} + \Delta CC_{ccs\_NGCC\_WT}\right)FCF}{G_{ccs\_NGCC}^{net}}\right) + VOM_{ccs\_NGCC\_WT} + VOM_{ccs\_NGCC} + VOM_{ccs\_NGCC\_fuel} + \left(\frac{FOM_{ccs\_NGCC\_power}(FOM_{NGCC}) + FOM_{ccs\_NGCC\_WT} + FOM_{ccs\_NGCC}}{G_{ccs\_NGCC}^{net}}\right) + LCOE_{CO_2pipe} \tag{D.26}$$

where $LCOE_{ccs\_NGCC}$ is the total LCOE for the NGCC plant with the addition of the CCS facility $\left(\frac{\$}{MWh}\right)$, $LCOE_{NGCC}$ is the LCOE for the NGCC plant without CCS $\left(\frac{\$}{MWh}\right)$, G_{NGCC}^{net} is the initial NGCC net generation for the NGCC plant (MWh), $G_{ccs\_NGCC}^{net}$ is the net generation of the NGCC plant with the addition of the CCS facility (MWh), CC_{ccs_NGCC} is the capital cost for CCS facility (M$), $\Delta CC_{ccs\_NGCC\_WT}$ is the retrofit capital cost for the wet-cooling tower (M$), *FCF* is the fixed charge factor for the NGCC plant (fraction), $VOM_{ccs\_NGCC\_WT}$ is the VOM cost of the NGCC plant with the addition of CCS $\left(\frac{\$}{MWh}\right)$, VOM_{ccs_NGCC} is the additional VOM cost of the CCS facility $\left(\frac{\$}{MWh}\right)$, $VOM_{ccs\_NGCC\_fuel}$ is the VOM fuel cost from the change in heat rate due to the addition of the CCS facility $\left(\frac{\$}{MWh}\right)$, $FOM_{ccs\_NGCC\_power}$ is the relative increase in power block FOM costs from the addition of a CCS facility to the NGCC plant (fraction), $FOM_{ccs\_NGCC\_WT}$ is the wet-cooling tower FOM costs with the addition of the CCS facility (M$), FOM_{NGCC} is the FOM costs for NGCC plant without the CCS (M$), FOM_{ccs_NGCC} is the FOM costs for CCS facility (M$), $LCOE_{CO_2pipe}$ is the LCOE for the CO_2 transportation pipeline $\left(\frac{\$}{MWh}\right)$ for which the net generation is $G^{net}_{ccs\_NGCC}$, the fixed charge factor is per above, and $1x10^6$ is a conversion for millions.

Table D.32. Coefficients of the regression model for the relative change in emission intensity for an NGCC plant with a CCS facility relative to one without (fraction).

β_0	β_1	R^2	RMSE
$2.6x10^{-2}$	-0.998	.998	0.013

n = 20

Table D.33. Coefficients of the regression model for the relative change in heat rate for an NGCC plant with a CCS facility relative to one without (fraction).

β_0	β_1	R^2	RMSE
$-4.7x10^{-3}$	0.179	.998	0.002

n = 20

Table D.34. Coefficients of the regression model for the relative change in net generation for an NGCC plant with a CCS facility relative to one without (fraction).

β_0	β_1	R^2	RMSE
-9.1×10^{-6}	-0.152	1.000	0.000

n = 20

Table D.35. Coefficients of the regression model for the capital cost for CCS facility for an NGCC plant (M$).

β_0	β_1	R^2	RMSE
25.895	106.463	.991	12.458

n = 20

Table D.36. Coefficients of the regression model for the wet-cooling tower capital cost for an NGCC plant with a CCS facility (M$).

β_0	β_1	β_2	R^2	RMSE
2.026	12.069	1.939	.998	1.026

n = 20

Table D.37. Coefficients of the regression for the wet-cooling tower FOM costs for an NGCC plant with a CCS facility (M$).

β_0	β_1	β_2	β_3	R^2	RMSE
2.0×10^{-2}	4.7×10^{-2}	3.0×10^{-2}	3.5×10^{-2}	.976	0.016

n = 20

Table D.38. Coefficients of the regression for the wet-cooling tower VOM costs for an NGCC plant with a CCS facility ($/MWh).

β_0	β_1	R^2	RMSE
6.8×10^{-2}	0.128	.999	0.001

n = 20

Table D.39. Coefficients of the regression for the relative increase in NGCC power block FOM costs for an NGCC plant with a CCS facility relative to one without (fraction).

β_0	β_1	β_2	R^2	RMSE
$5.5x10^{-5}$	$-2.6x10^{-2}$	$-4.1x10^{-3}$	.987	0.001

n = 20

Table D.40. Coefficients of the regression model for the CCS FOM costs for an NGCC plant with a CCS facility (M$)

β_0	β_1	R^2	RMSE
1.821	2.919	.991	0.344

n = 20

Table D.41. Coefficients of the regression for the CCS VOM costs for an NGCC plant with a CCS facility ($/MWh).

β_0	β_1	β_2	R^2	RMSE
-0.025	2.393	-0.019	.995	0.049

n = 20

D.3.4 Retrofitting CCS to an existing NGCC plant

When a coal-fired EGU is repowered as an NGCC plant with CCS, it is done so as one of several fungible generation sources and the LCOE for this mitigated configuration must account for the capital costs of the existing source. When CCS is added to the existing NGCC plant, the remaining capital cost of the existing plant is not considered because it is carried forward in the CCS configuration for the remaining operational life of the NGCC plant. Furthermore, the costs for the natural gas pipeline are not considered because it exists, the length is unknown, and the diameter is assumed to be sufficient to provide any increase in flow rate dictated by the increase in heat rate from the CCS parasitic load. The addition of CCS is the only fungible source; therefore, the existing NGCC plant will dominate the least-cost frontier unless the additional capital and O&M costs of the CCS facility are reduced by any VOM costs from CO_2 emissions taxes that are limited with increasing capture rate and further offset through related credits for sequestration.

The capital and O&M costs, excluding the natural gas pipeline costs that are assumed to remain constant with the addition of CCS, for the existing NGCC plant are calculated as a function of the number of turbines required to meet the nameplate capacity specified in eGRID. For simplicity, the default NGCC plant configuration in IECM that uses a GE 7FB turbine is used to simulate all capacity in this model (247.3 MW_{net} per turbine). Furthermore, a wet-cooling tower is assumed for each NGCC plant. When more than one NGCC plant is located at the same site, then the capacity of these plants is combined, and the capital and O&M costs are scaled according to the number of these turbines required to meet the total site capacity. As IECM only models up to five turbines, costs and performance for plants requiring more than five turbines are extrapolated with the NGCC and CCS regression equations as a function of turbine number. Overall, 14 of the 133 simulated plants require more than five turbines (seven plants require 6 turbines, four plants require seven turbines, and three plants require eight turbines).

The formulaic structure for cost and performance used to model retrofitting CCS technology to an existing NGCC plant is similar to that for replacing the existing coal-fired EGU with a brownfield NGCC plant (*Appendix B, Section 8.6.6*), with the main differences being the absence of additional costs for demolition and that for the natural gas pipeline. However, there is the additional capital cost of retrofitting the NGCC plant with the technology, described in Table 4.1(c). The LCOE contribution from the CCS plant capital and O&M costs, and the monetized performance impact on the NGCC plant are determined with the same regressions described in *Section D.3.3*. The unique transportation and sequestration costs for each existing NGCC plant are determined with the same methods as discussed in *Appendix B, Sections 8.6.8* and *8.8*. The resulting LCOE from the addition of these CCS related costs is calculated at the desired capture rate from a linear interpolation of the LCOE for the EGU at a 10% and 90% capture rate. Here to regarding performance, there is not a one-to-one reduction in emission intensity for the NGCC plant when equipped with CCS at a given capture rate (Eq. D.14, Table D.32), because the increase in steam-cycle heat rate, related to some of the generated steam being required in the CCS solvent-regeneration process, causes a decrease in efficiency and plant net generation (Eq. D.16, Table D.34), and an increase in VOM (Eq. D.17) from the increased heat rate (Eq. D.15, Table D.33). Furthermore, for all NGCC generation, the capacity factor constraints necessitate that a heat rate penalty[1] that increases the emission intensity be assessed to account for requiring the plant to operate less efficiently below the design point (Oates and Jaramillo, 2013; Valentino et al., 2012).

The resulting LCOE equation for the retrofitted NGCC plant (Eq. D.27) is the same as Eq. D.26, with the inclusion of the capital-cost retrofit factor that is applied to the CCS and wet-cooling tower (WT) capital costs. This factor is applied to account for site-specific difficulties in construction of the CCS facility and is taken as 1.10. Additionally, these capital costs and those for the effluent pipeline are annualized with an FCF based upon the lessor of the remaining years of operation and the book life for the NGCC plant.

[1] For a discussion of heat rate penalty as implemented in model, see *Appendix B*.

$$LCOE_{ccs\_NGCC\_retro} = LCOE_{NGCC}\left(\frac{G_{NGCC}^{net}}{G_{ccs\_NGCC\_retro}^{net}}\right) + \left(\frac{1\times10^{6}\left(CC_{ccs\_NGCC} + \Delta CC_{ccs\_NGCC\_WT}\right)(F_r)FCF}{G_{ccs\_NGCC\_retro}^{net}}\right) + VOM_{ccs\_NGCC\_WT} + VOM_{ccs\_NGCC} + VOM_{ccs\_NGCC\_fuel} + \left(\frac{FOM_{ccs\_NGCC\_power}(FOM_{NGCC}) + FOM_{ccs\_NGCC\_WT} + FOM_{ccs\_NGCC}}{G_{ccs\_NGCC\_retro}^{net}}\right) + LCOE_{CO_2pipe} \tag{D.27}$$

where $LCOE_{ccs\_NGCC\_retro}$ is the total LCOE for the existing NGCC plant with the addition of the CCS facility $\left(\frac{\$}{MWh}\right)$, $LCOE_{NGCC}$ is the LCOE for the existing NGCC plant without CCS $\left(\frac{\$}{MWh}\right)$, G_{NGCC}^{net} is the initial NGCC net generation for the NGCC plant (MWh), $G_{ccs\_NGCC\_retro}^{net}$ is the net generation of the existing NGCC plant with the addition of the CCS facility (MWh), CC_{ccs_NGCC} is the capital cost for CCS facility (M$), $\Delta CC_{ccs\_NGCC\_WT}$ is the retrofit capital cost for the wet-cooling tower (M$), F_r is the CCS retrofit factor (fraction), *FCF* is the fixed charge factor (fraction), $VOM_{ccs\_NGCC\_WT}$ is the VOM cost of the NGCC plant with the addition of CCS $\left(\frac{\$}{MWh}\right)$, VOM_{ccs_NGCC} is the additional VOM cost of the CCS facility $\left(\frac{\$}{MWh}\right)$, $VOM_{ccs\_NGCC\_fuel}$ is the VOM fuel cost from the change in heat rate due to the addition of the CCS facility $\left(\frac{\$}{MWh}\right)$, $FOM_{ccs\_NGCC\_power}$ is the relative increase in power block FOM costs from the addition of a CCS facility to the existing NGCC plant (fraction), $FOM_{ccs\_NGCC\_WT}$ is the wet-cooling tower FOM costs with the addition of the CCS facility (M$), FOM_{NGCC} is the FOM costs for existing NGCC plant without the CCS (M$), FOM_{ccs_NGCC} is the FOM costs for CCS facility (M$), $LCOE_{CO_2pipe}$ is the LCOE for the CO_2 transportation pipeline $\left(\frac{\$}{MWh}\right)$ for which the net generation is $G_{ccs\_NGCC\_retro}^{net}$, the FCF is per above, and $1\text{x}10^6$ is a conversion for millions.

D.3.5 State-specific fuel prices

Table D.42. State-specific 2030 projected fuel prices from percent increase from 2012 based upon AEO 2020 reference case (U.S. Energy Information Administration, 2020).

State	Bituminous ($/MMBtu)	Sub-bituminous ($/MMBtu)	Lignite ($/MMBtu)	NG ($/MMBtu)
Alabama	$2.09	$1.72	$1.57[*]	$3.09
Arizona	$1.16	$1.64	$1.38[*]	$3.32
Arkansas	$1.27[*]	$1.75	$1.99[*]	$3.07
California	$1.95[*]	$1.44[*]	$1.54[†]	$3.18
Colorado	$1.34	$1.38	$1.38[*]	$3.87
Connecticut	$2.18[*]	$3.64	$1.54[†]	$3.16
Delaware	$2.49	$1.88[*]	$1.54[†]	$2.94
Florida	$2.06	$2.06[*]	$1.54[†]	$4.20
Georgia	$2.63	$1.83	$1.54[†]	$2.97
Idaho	$1.95[*]	$1.44[*]	$1.54[†]	$4.06
Illinois	$0.94	$1.54	$1.54[†]	$3.03
Indiana	$1.43	$2.04	$1.54[†]	$2.81
Iowa	$1.55[*]	$1.15	$1.26[*]	$3.84
Kansas	$1.33	$1.43	$1.26[*]	$2.94
Kentucky	$1.37	$1.76	$1.57[*]	$3.57
Louisiana	$1.80	$1.80	$2.70	$2.91
Maryland	$2.26	$3.26	$1.54[†]	$2.26
Massachusetts	$1.86	$3.64[*]	$1.54[†]	$2.90
Michigan	$2.13	$2.18	$1.54[†]	$2.95
Minnesota	$2.02	$1.60	$1.26[*]	$3.39
Mississippi	$2.33	$2.56	$1.57	$2.88
Missouri	$1.61	$1.46	$1.26[*]	$3.16
Montana	$1.15[*]	$1.06	$1.38	$3.92
Nebraska	$1.55[*]	$1.20	$1.26[*]	$3.52
Nevada	$1.40	$2.17	$1.38[*]	$3.28
New Hampshire	$2.61	$3.64[*]	$1.54[†]	$4.53
New Mexico	$1.21	$1.52	$1.38[*]	$3.23
New York	$1.91	$2.50	$1.54[†]	$2.98
North Carolina	$2.29	$1.88[*]	$1.54[†]	$3.87
North Dakota	$1.55[*]	$1.43	$1.26[*]	$5.22
Ohio	$1.47	$2.58	$1.54[†]	$2.78
Oklahoma	$0.90[*]	$1.56	$1.67	$2.93
Oregon	$1.95[*]	$1.44	$1.54[†]	$2.93
Pennsylvania	$1.54	$2.51[*]	$1.54[†]	$2.73
South Carolina	$2.44	$1.88[*]	$1.54[†]	$3.21
South Dakota	$1.55[*]	$1.20[*]	$1.26[*]	$3.16
Tennessee	$1.57	$2.04	$1.57[*]	$2.91
Texas	$1.27[*]	$1.49	$1.57	$2.90

Notes: [*]: Regional default price; [†]: U.S. default price.

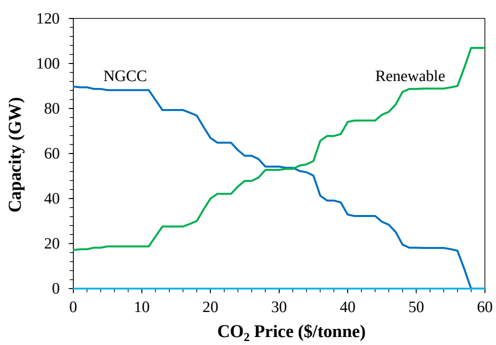
Table D.42. Continued…state-specific 2030 projected fuel prices from percent increase from 2012 based upon AEO 2020 reference case (U.S. Energy Information Administration, 2020).

State	Bituminous ($/MMBtu)	Sub-bituminous ($/MMBtu)	Lignite ($/MMBtu)	NG ($/MMBtu)
Utah	$1.05	$1.98	$1.38*	$2.84
Virginia	$2.14	$1.88	$1.54†	$2.90
Washington	$1.95*	$1.69*	$1.54†	$3.85
West Virginia	$1.54	$2.99	$1.54†	$2.84
Wisconsin	$2.13	$1.79	$1.54*	$3.00
Wyoming	$1.15*	$1.14	$1.38	$5.66

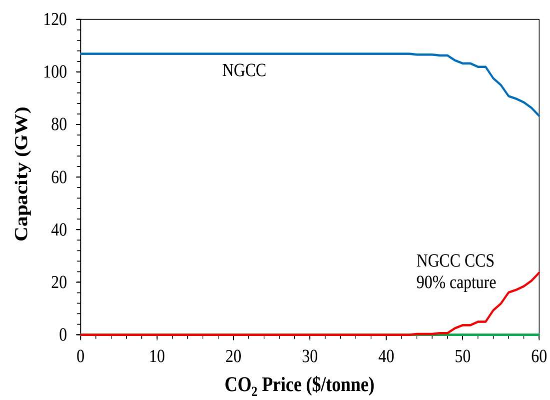
Notes: *: Regional default price; †: U.S. default price.

D.4 Results

D.4.1 Figures



(a)



(b)

Figure D.4. Supply curve for NGCC retrofit mitigation option with a $50/tonne credit for 12 years with a 0.5 Mtonne CO_2 sequestration requirement for NGCC sequestration credit (a) with and (b) without renewable generation as an alternative.

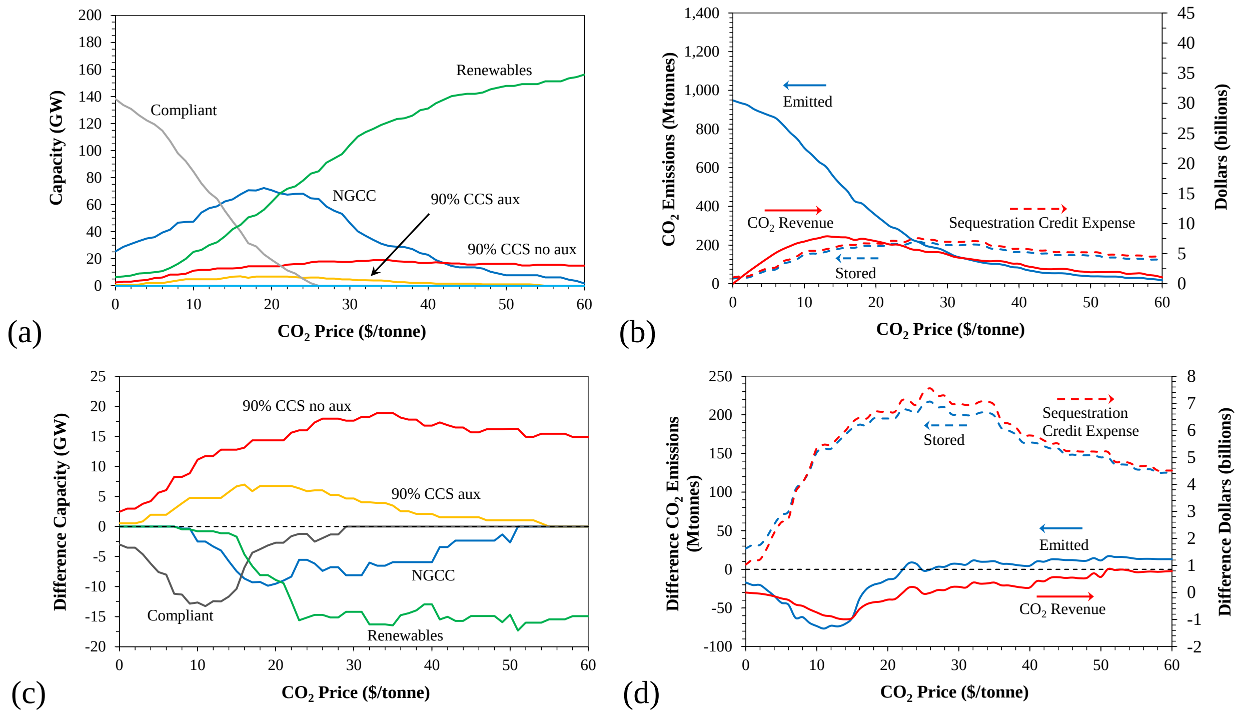


Figure D.5. Variation in coal-fleet (a) mitigation capacity and (b) performance parameters with CO_2 price from a $50/tonne 45Q sequestration credit with a 12-year duration. Difference in coal-fleet (c) mitigation capacity and (d) performance parameters with CO_2 price between a $50/tonne 45Q sequestration credit with a 12-year duration and the absence of a sequestration credit ($50/tonne minus $0/tonne).

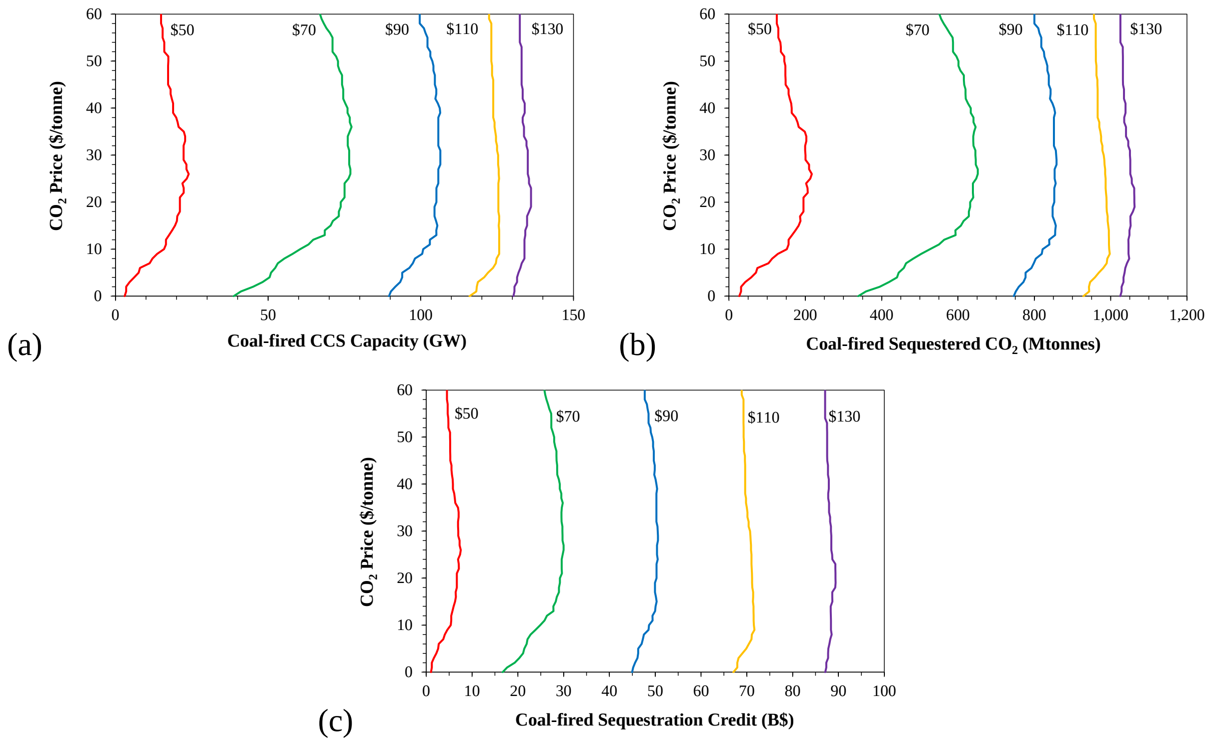


Figure D.6. Coal-fired fleet contours for (a) CCS capacity, (b) sequestered CO_2, and (c) sequestration credit from coal-fired CCS capacity with 90% capture for alternative 45Q credit levels ($50-130/tonne) with 12-year duration.

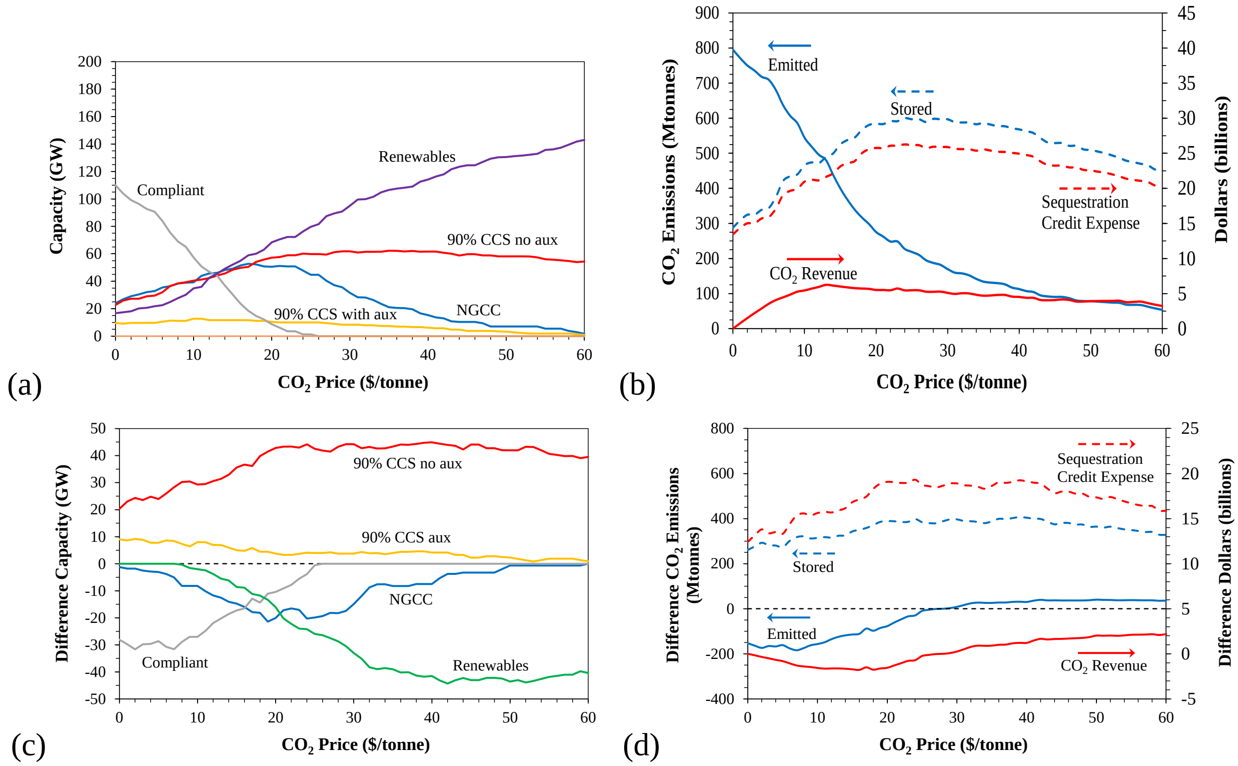


Figure D.7. Variation in coal-fleet (a) mitigation capacity and (b) performance parameters with CO_2 price from a \$66/tonne 45Q sequestration credit with a 12-year duration. Difference in coal-fleet (c) mitigation capacity and (d) performance parameters with CO_2 price between a \$66/tonne 45Q sequestration credit with a 12-year duration and the current 45Q sequestration credit (\$66/tonne minus \$50/tonne).

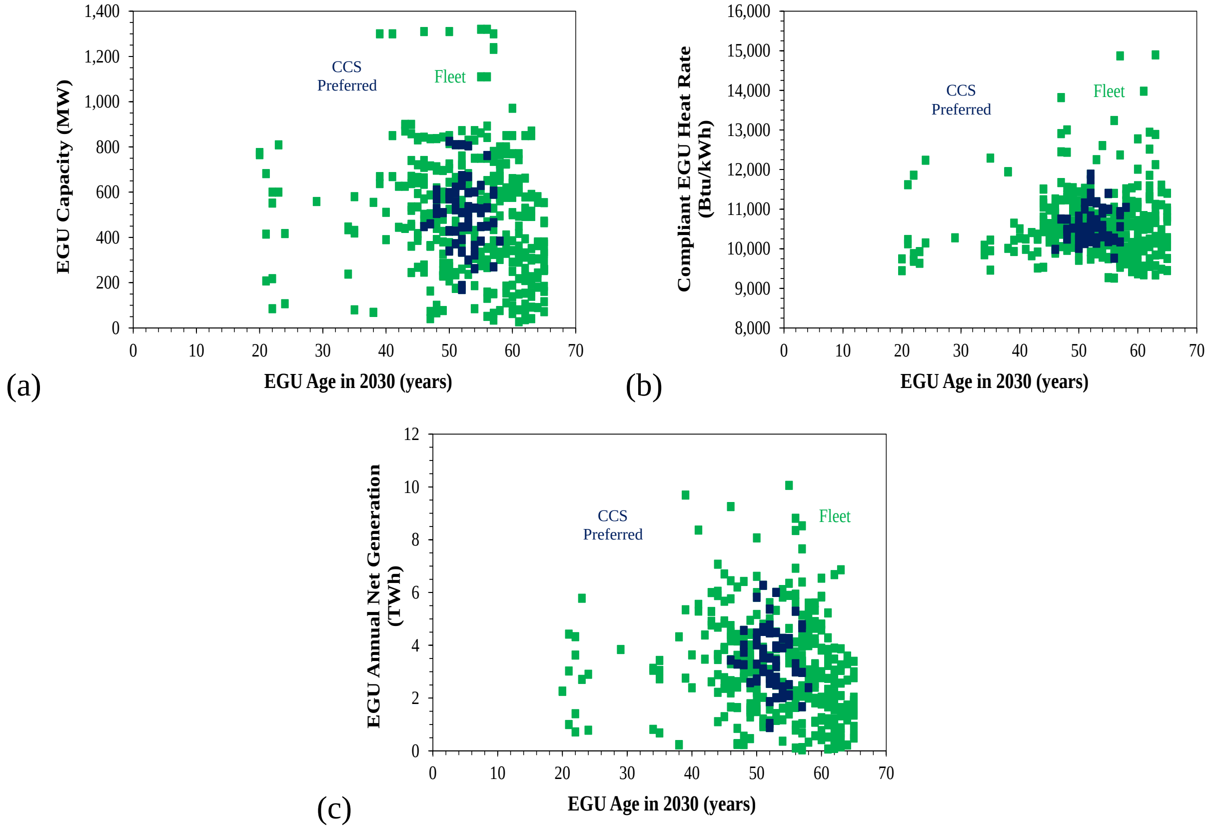


Figure D.8. Relationship between EGU age and (a) capacity, (b) compliant heat rate, and (c) net generation for the coal fleet when promoting coal-fired CCS at 90% capture rate with a \$66/tonne 45Q sequestration credit with a 12-year duration, absent a CO_2 price.

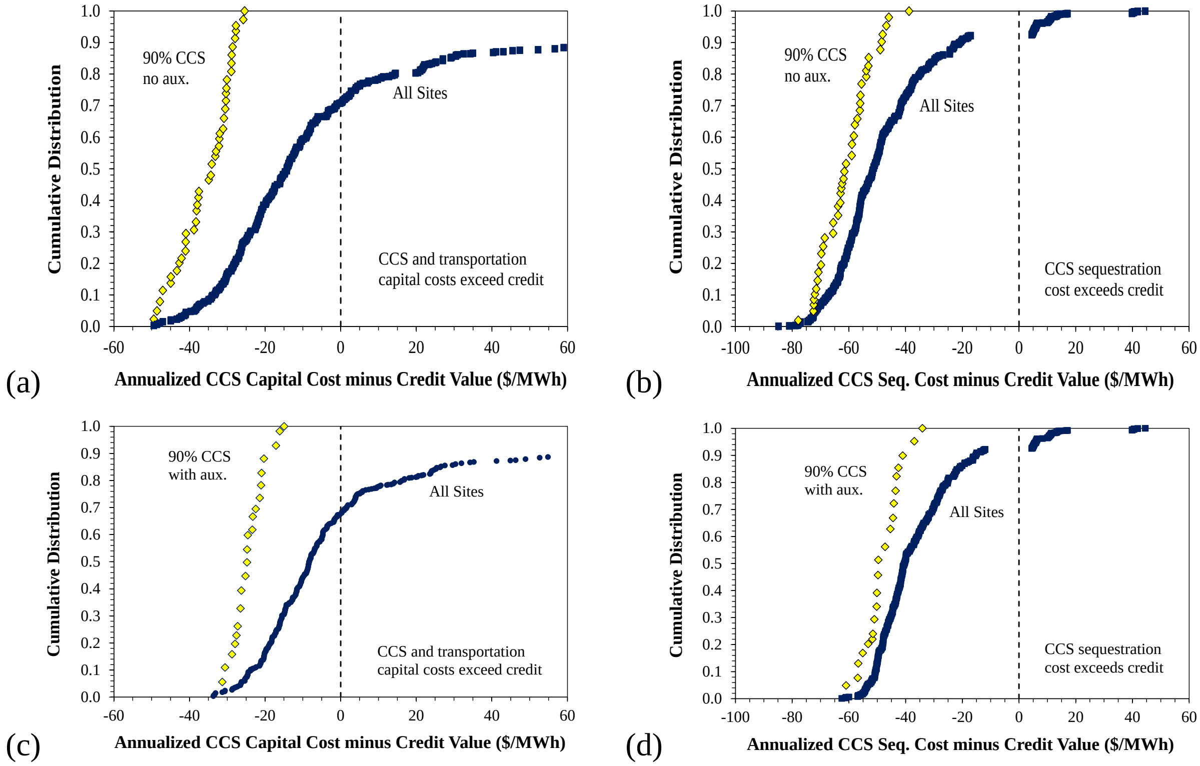


Figure D.9. Capacity-weighted cumulative distribution of the amount of capital and sequestration cost covered by sequestration credit at $66/tonne for 12 years for fleet with coal-fired CCS at 90% capture for CCS without auxiliary boiler (a, b) and CCS with auxiliary boiler (c, d). Panels (a, c) are for CCS and transportation capital costs. Panels (b, d) are for sequestration costs, excluding capital costs. No CO_2 price is applied.

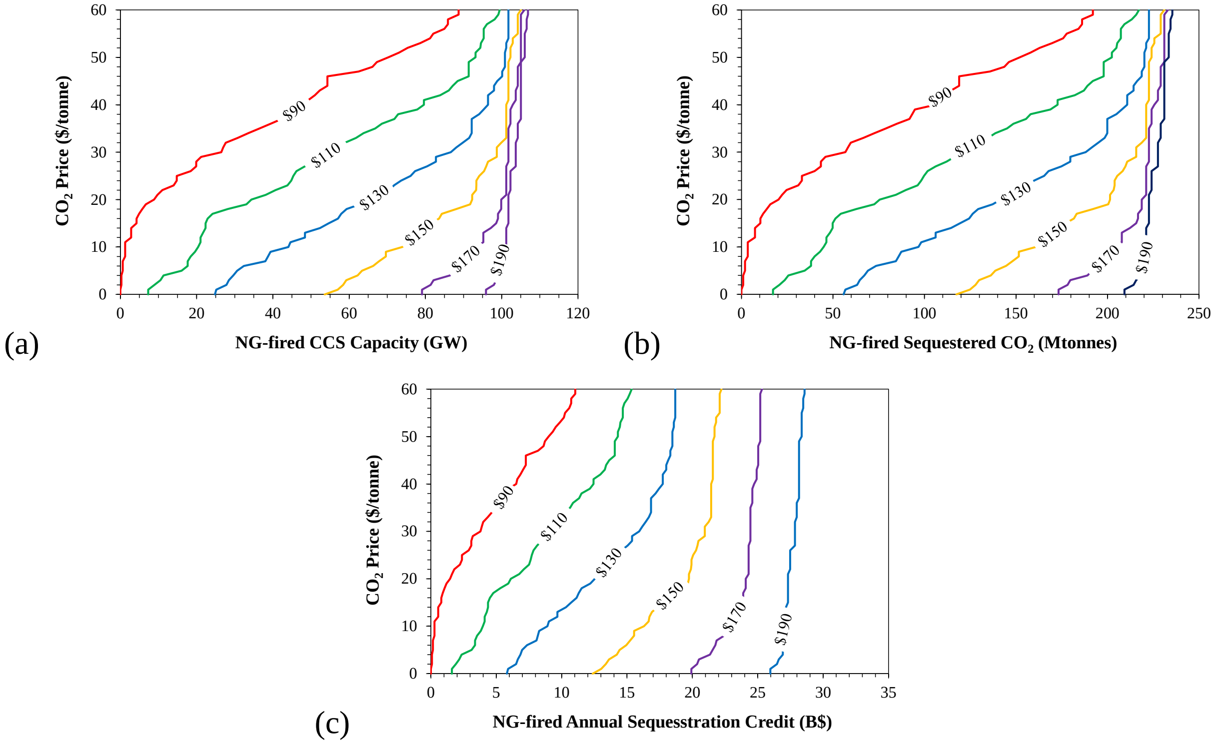


Figure D.10. NGCC fleet contours for (a) capacity, (b) sequestered CO_2, and (c) sequestration credit from NGCC retrofitted CCS capacity with 90% capture for alternative 45Q credit levels ($50-190/tonne) with 12-year duration.

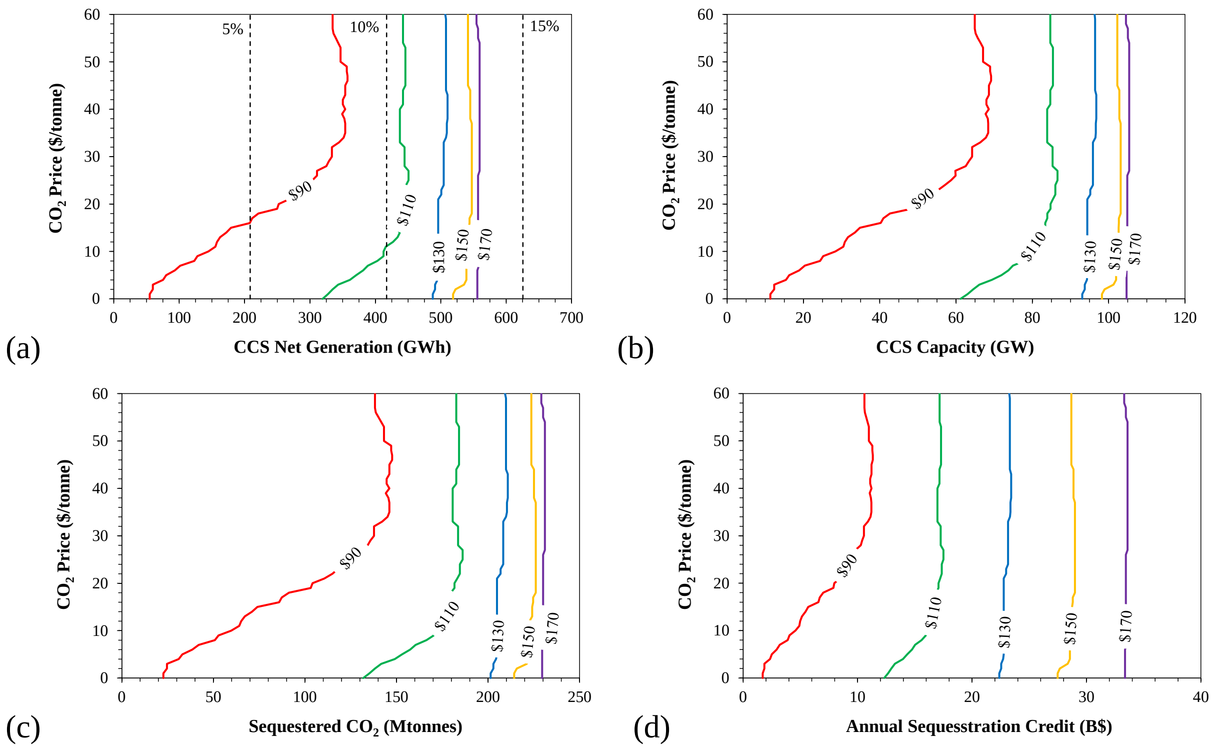


Figure D.11. NGCC fleet contours for (a) net generation to achieve AEO 2020 (U.S. Energy Information Administration, 2020) projected levels of power sector generation, (b) capacity, (c) sequestered CO_2, and (d) annual sequestration cost from NGCC retrofitted CCS capacity for alternative 45Q credit levels ($90-170/tonne) at 20-year duration.

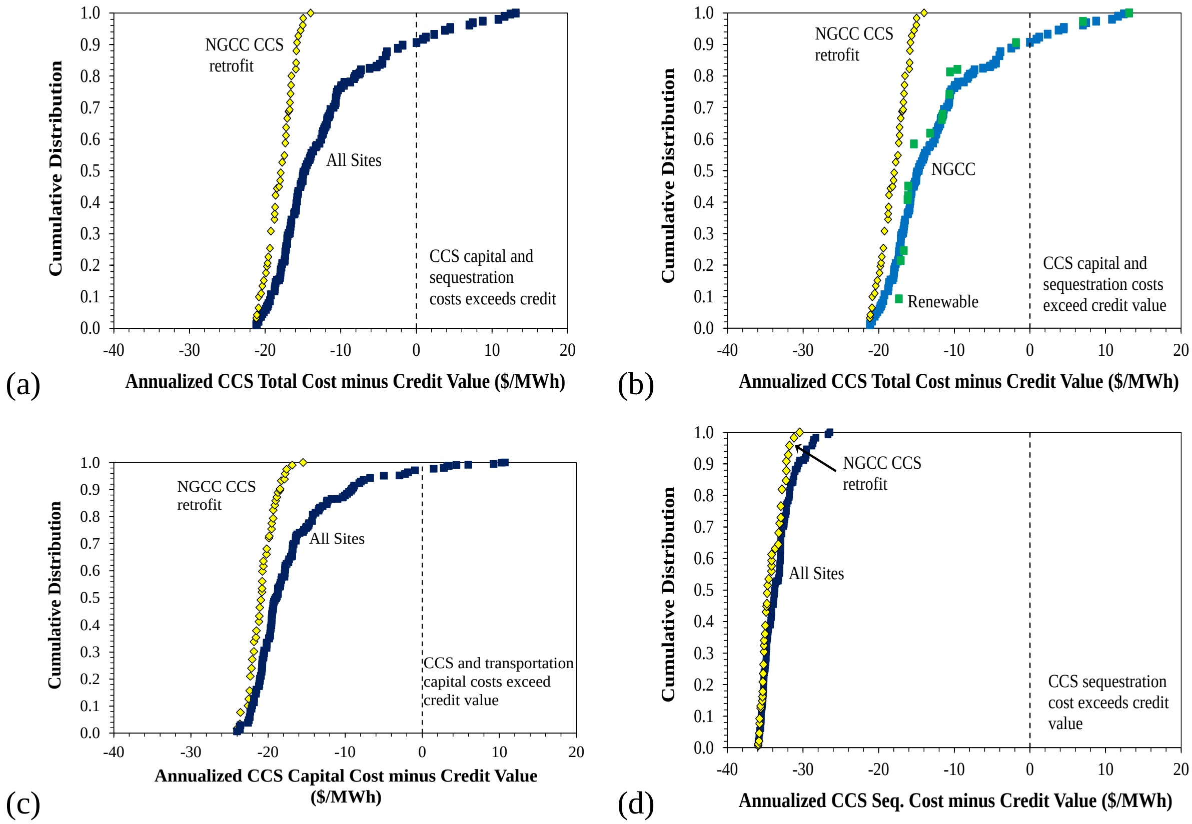


Figure D.12. Capacity-weighted cumulative distribution for the amount of the total capital and sequestration costs covered by a sequestration credit of $104/tonne (Panels (a) and (b)), for a 20-year duration for existing and planned NGCC fleet retrofitted with CCS at 90% capture rate. In Panel (b), the preferred mitigation technology is differentiated. Panel (c) is the capacity-weighted cumulative distribution for the amount of CCS and transportation capital costs covered by a sequestration credit. Panel (d) is the capacity-weighted cumulative distribution for the amount of sequestration cost covered by a sequestration credit. No CO_2 price is applied.

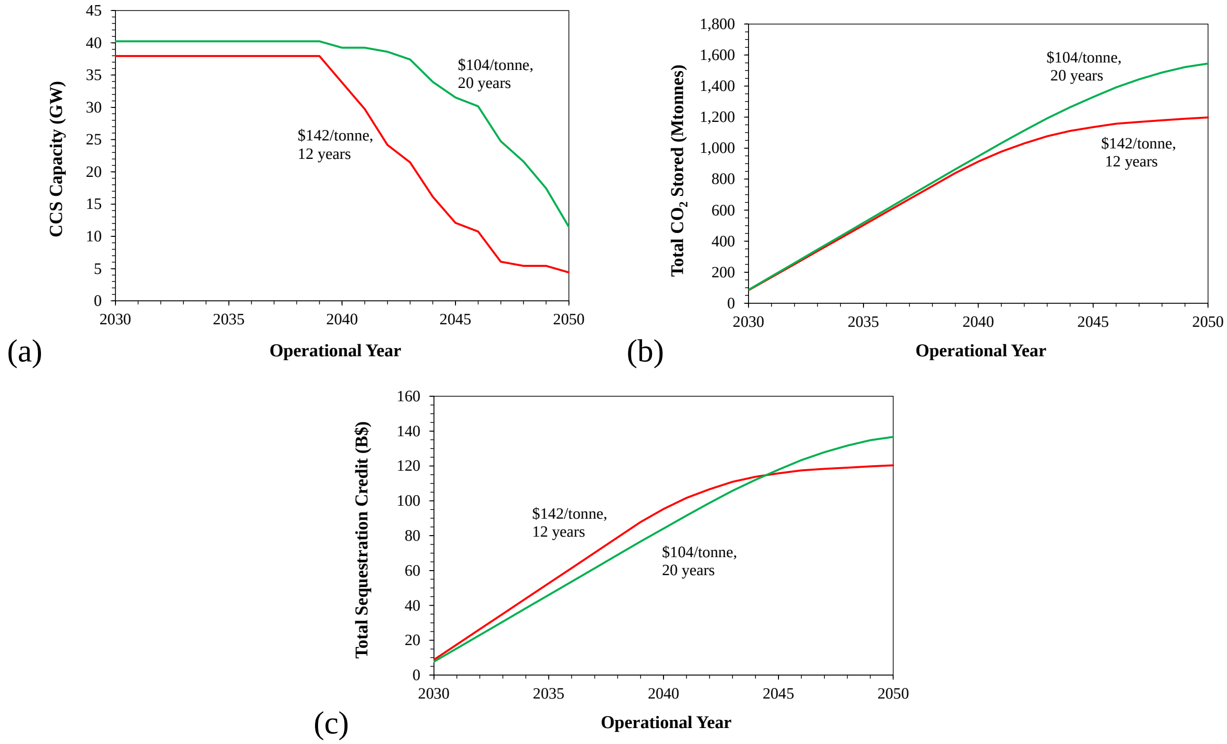


Figure D.13. Evolution of NGCC fleet with preference for CCS technology at 90% capture with \$142/tonne sequestration credit for 12 years and a \$104/tonne sequestration credit for 20 years. A 30-year retirement is assumed for (a) capacity, (b) cumulative sequestered CO_2, and (c) cumulative sequestration credit performance metrics. No CO_2 price is applied.

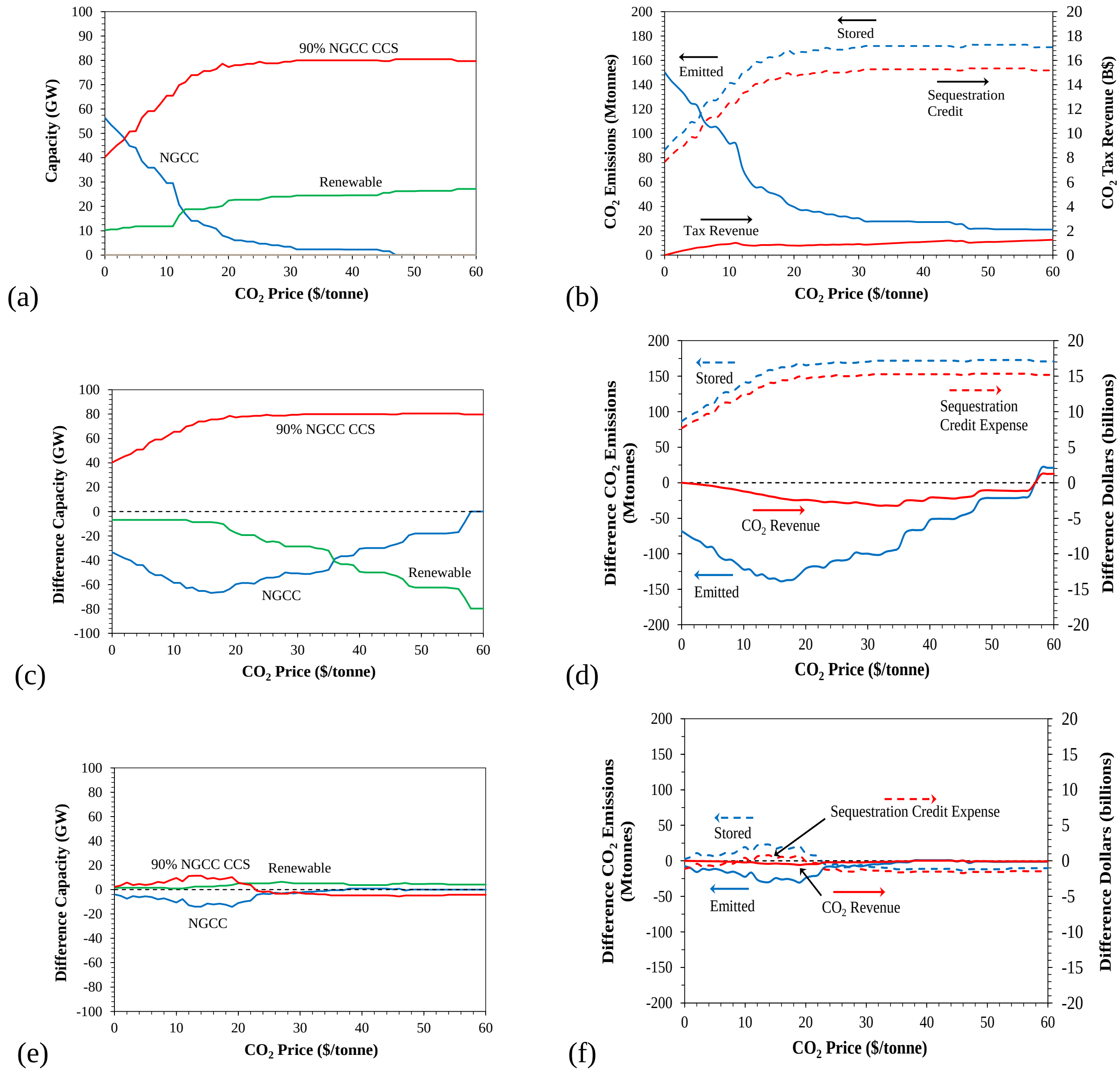


Figure D.14. Variation in NGCC-fleet (a) mitigation capacity and (b) performance parameters with CO_2 price from a $104/tonne 45Q sequestration credit with a 20-year duration. Difference in NGCC-fleet (c) mitigation capacity and (d) performance parameters with CO_2 price between a $104/tonne 45Q sequestration credit with a 20-year duration and the current 45Q sequestration credit ($104/tonne minus $50/tonne). Difference in NGCC-fleet (e) mitigation capacity and (f) performance parameters with CO_2 price between a $104/tonne 45Q sequestration credit with a 20-year duration and the $142/tonne credit with a 12-year duration ($104/tonne minus $142/tonne).

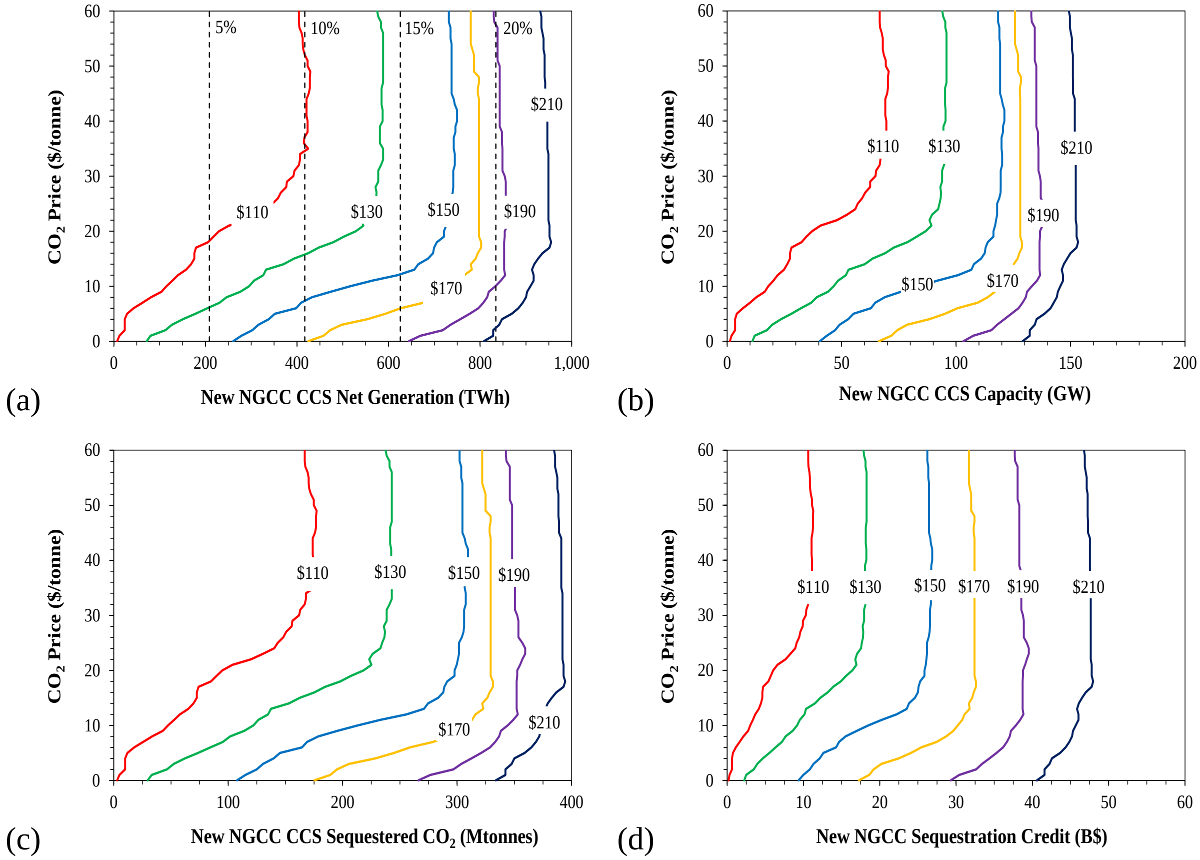


Figure D.15. Coal-fired fleet contours for (a) net generation to achieve AEO 2020 (U.S. Energy Information Administration, 2020) projected levels of power sector generation, (b) capacity, (c) sequestered CO_2, and (d) annual sequestration cost for alternative 45Q credit levels ($110-210/tonne) at 20-year duration when coal-fleet EGUs are repowered as new NGCC CCS with 90% capture.

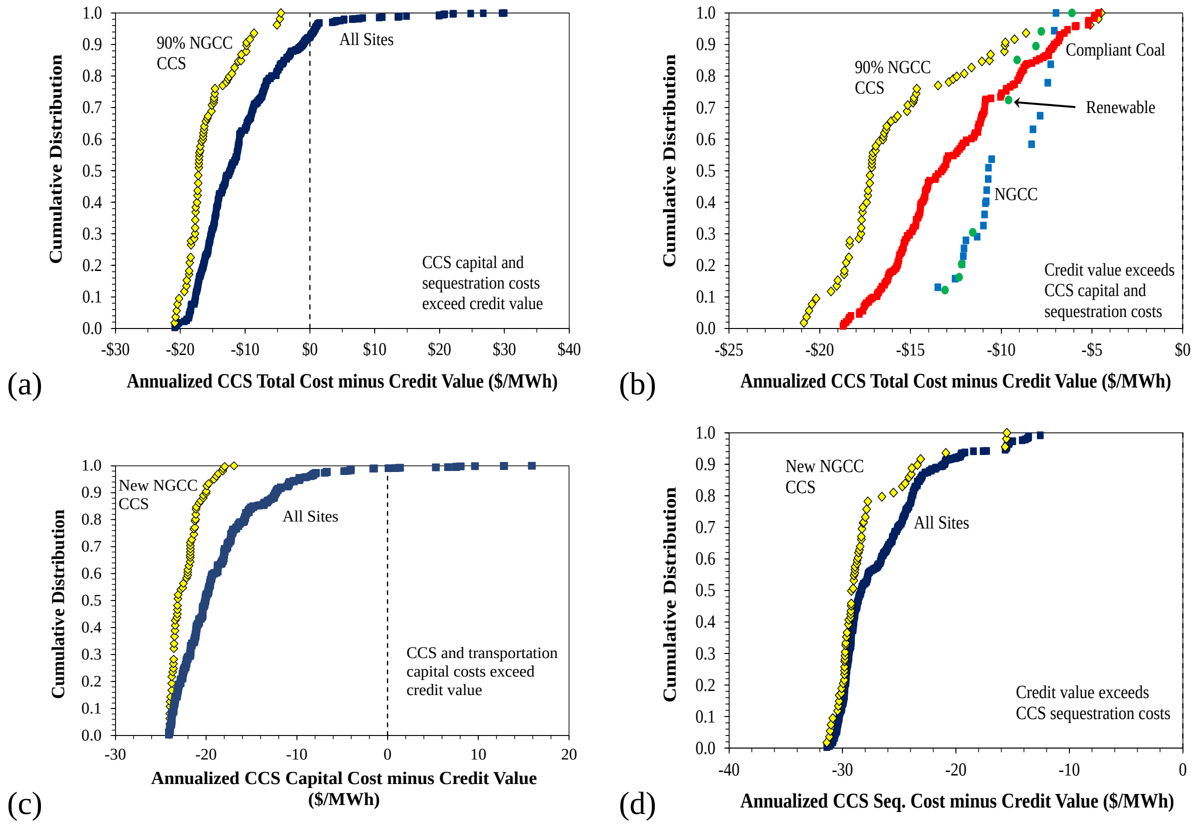


Figure D.16. Capacity-weighted cumulative distribution for the amount of the total capital and sequestration costs covered by a sequestration credit of $144/tonne (Panels (a) and (b)), for a 20-year duration applied solely to repower the coal fleet as new NGCC CCS plants at 90% capture. In Panel (b), preferred mitigation technology is segregated within the range defined by the preference for CCS technology. Panel (c) is the capacity-weighted cumulative distribution for the amount of CCS and transportation capital costs covered by a sequestration credit. Panel (d) is the capacity-weighted cumulative distribution for the amount of sequestration cost covered by a sequestration credit. No CO_2 price is applied.

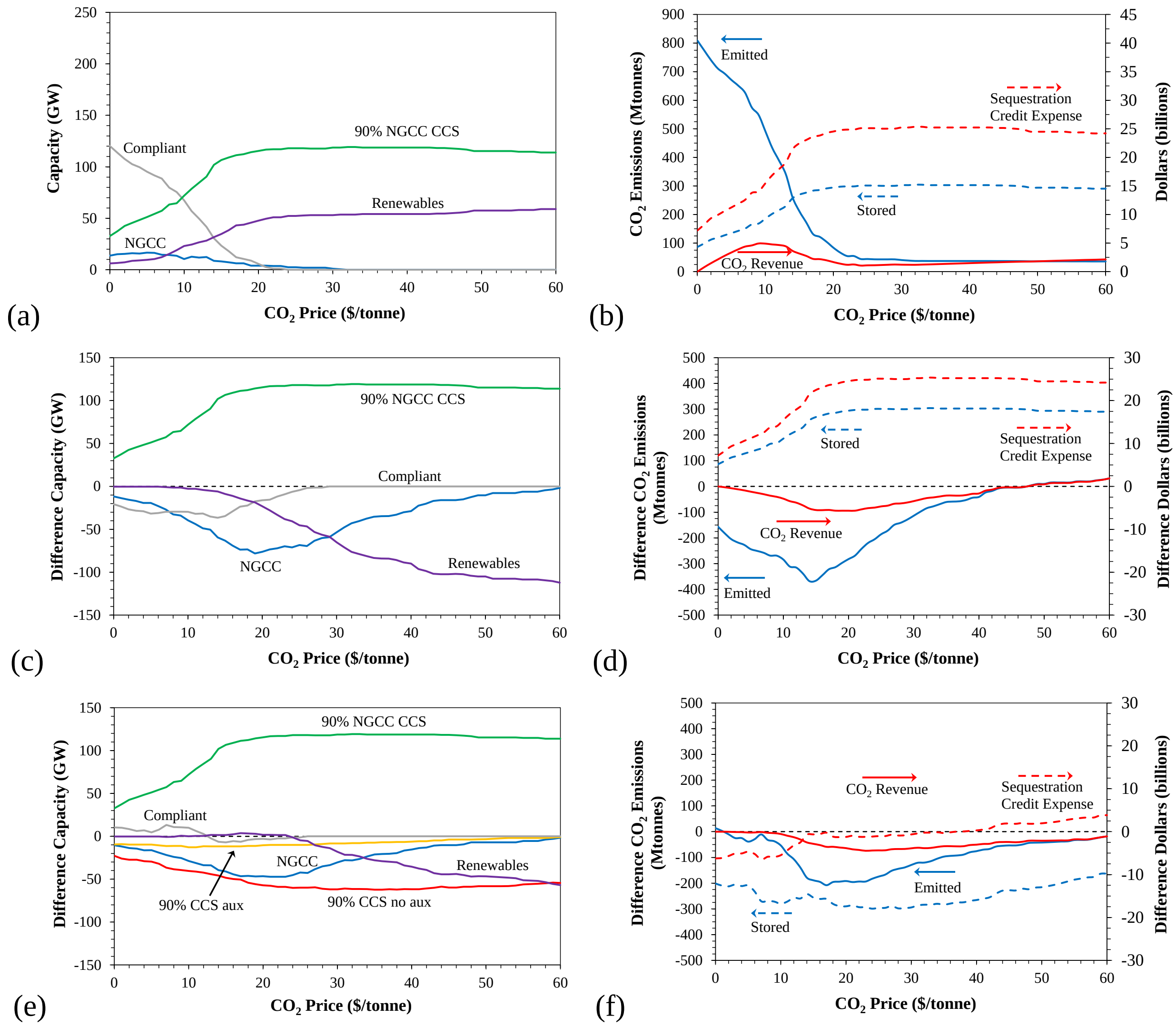


Figure D.17. Variation in coal-fleet (a) mitigation capacity and (b) performance parameters with CO_2 price from a \$144/tonne 45Q sequestration credit with a 20-year duration applied only for repowering with NGCC CCS mitigation. Difference in coal-fleet (c) mitigation capacity and (d) performance parameters with CO_2 price between a \$144/tonne 45Q sequestration credit with a 20-year duration applied only for repowering with NGCC CCS mitigation and no 45Q sequestration credit (\$144/tonne minus \$0/tonne). Difference in coal-fleet (e) mitigation capacity and (f) performance parameters with CO_2 price between a \$144/tonne 45Q sequestration credit with a 20-year duration applied only for repowering with NGCC CCS mitigation and the \$66/tonne credit with a 12-year duration applied for all CCS mitigations (\$144/tonne minus \$66/tonne).

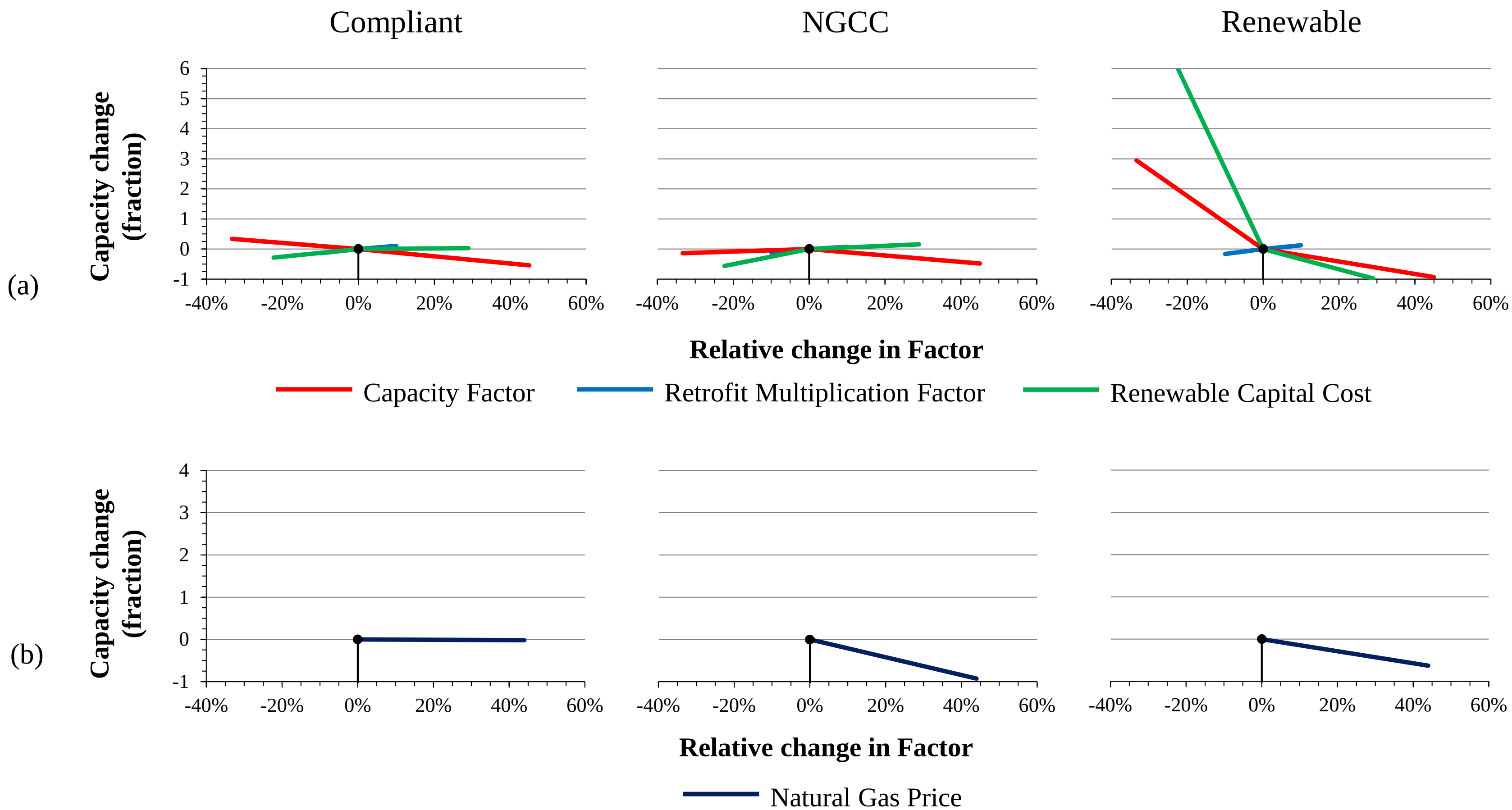


Figure D.18. Sensitivity of capacity for non-CCS technologies to (a) NGCC capacity factor, retrofit multiplication factor, renewable capital cost, and (b) natural gas price relative to baseline levels for unique 45Q sequestration credit levels and durations applied to different technologies. A $66/tonne credit with a 12-year duration is applied to the coal fleet for retrofitting CCS, while a $144/tonne credit with a 20-year duration is applied for repowering EGUs as new NGCC plants with CCS. A $104/tonne credit with a 20-year duration is applied to the NGCC fleet for retrofitting existing NGCC plants with CCS. No CO_2 price is applied.

D.4.2 Tables

Table D.43. Comparison of simulated coal fleet characteristics for two sequestration credit levels in 2030 to 2010 performance. 45Q sequestration credit duration is 12 years and no CO_2 price is applied. The \$0/tonne case is the avoided cost counterfactual.

Metric	Units	2010 Base	\$0/tonne	\$50/tonne
Fleet net generation	TWh	1,108.4	1,210.2	1,208.8
CCS Net generation	TWh	0	0	19.6
Emitted mass	Mtonnes	1,048	965	948
Intensity	lbs/MWh	2,085	1,758	1,729
Sequestered CO_2	Mtonnes	0	0	26.9
Credit expense	\$ billion	0	0	1.0
LCOE*	\$/MWh	38.3	35.7	35.6
Avoided cost*	\$/tonne	NA†	NA	55.3

*Sequestration credit expense is not included in the LCOE calculation and is included in the avoided cost calculation. † NA: not applicable.

Table D.44. Comparison of simulated NGCC fleet characteristics for 2018 performance and two sequestration credit levels in 2030. 45Q sequestration credit duration is 12 years with a 0.5 Mtonne CO_2 sequestration requirement for NGCC sequestration credit and no CO_2 price is applied. The \$0/tonne case is the avoided cost counterfactual.

Metric	Units	2018 Base	\$0/tonne	\$50/tonne
Fleet net generation	TWh	541.3	660.4	660.4
CCS Net generation	TWh	0	0	0
Emitted mass	Mtonnes	212	218	218
Intensity	lbs/MWh	864	728	728
Sequestered CO_2	Mtonnes	0	0	0
Credit expense	\$ billion	0	0	0
LCOE*	\$/MWh	NA	41.1	41.1
Avoided cost*	\$/tonne	NA	NA	NA

*Sequestration credit expense is not included in the LCOE calculation and is included in the avoided cost calculation.

Table D.45. Coal fleet characteristics for \$66/tonne sequestration credit with 12-year duration, absent a CO_2 price. The \$0/tonne case is the avoided cost counterfactual case.

Metric	Units	\$66/tonne
Fleet net generation	TWh	1,202.5
CCS Net generation	TWh	218.9
Emitted mass	Mtonnes	795
Intensity	lbs/MWh	1,458
Sequestered CO_2	Mtonnes	287.8
Credit expense	\$ billion	13.4
LCOE*	\$/MWh	34.3
Avoided cost*	\$/tonne	72.1

*Sequestration credit expense is not included in the LCOE calculation and is included in the avoided cost calculation.

Table D.46. Comparison of NGCC fleet characteristics for three sequestration credit levels in 2030, absent a CO_2 price. The \$0/tonne case is the avoided cost counterfactual case.

Metric	Units	\$0/tonne, 12 years	\$142/tonne, 12 years	\$104/tonne, 20 years
Fleet net generation	TWh	660.4	628.3	627.3
CCS Net generation	TWh	0	203.2	209.2
Emitted mass	Mtonnes	218	158	150
Intensity	lbs/MWh	728	553	528
Sequestered CO_2	Mtonnes	0	83.9	86.4
Credit expense	B\$	0	8.8	7.7
LCOE*	\$/MWh	41.3	38.9	40
Avoided cost*	\$/tonne	NA	146.2	121

*Sequestration credit expense is not included in LCOE calculation and is included in the avoided cost calculation.

Table D.47. Coal fleet characteristics for \$144/tonne sequestration credit with 20-year duration for replacement solely with new NGCC CCS capacity, absent a CO_2 price. No credit is given for coal-fired CCS. The \$0/tonne case is the avoided cost counterfactual case.

Metric	Units	\$144/tonne
Fleet net generation	TWh	1,187.7
CCS Net generation	TWh	209.2
Emitted mass	Mtonnes	809
Intensity	lbs/MWh	1,501
Sequestered CO_2	Mtonnes	86.4
Credit expense	\$ billion	7.2
LCOE*	\$/MWh	35.2
Avoided cost*	\$/tonne	48.0

*Sequestration credit expense is not included in the LCOE calculation and is included in the avoided cost calculation.

Table D.48. State-specific coal-fired fleet mitigation preference for coal-fired CCS at 90% capture rate. 45Q sequestration credit for coal-fired CCS is \$66/tonne for a 12-year duration and \$144/tonne for a 20-year duration for new NGCC CCS, without a CO_2 price.

	Without Auxiliary Boiler		With Auxiliary Boiler	
State	**# Sites**	**Capacity (MW)**	**# Sites**	**Capacity (MW)**
Alabama	1	673	0	0
Arizona	1	372	0	0
Colorado	4	1,566	0	0
Florida	0	0	2	830
Illinois	5	2,341	2	358
Indiana	1	622	4	2,066
Kentucky	0	0	3	1,175
Michigan	2	1,587	0	0
Missouri	2	1,206	0	0
North Dakota	3	1,453	0	0
New Mexico	0	0	2	828
Ohio	0	0	2	1,020
Oklahoma	1	522	0	0
Texas	13	7,647	0	0
Utah	0	0	5	2,247
Wyoming	7	3,593	0	0
Total	**40**	**21,582**	**20**	**8,524**

Table D.49. State-specific coal-fired fleet mitigation preference for new NGCC CCS at 90% capture rate. 45Q sequestration credit for coal-fired CCS is $66/tonne for a 12-year duration and $144/tonne for a 20-year duration for new NGCC CCS, without a CO_2 price.

State	# Sites	Capacity (MW)
Alabama	2	1,088
Delaware	1	430
Florida	1	291
Illinois	7	2,949
Indiana	11	5,143
Louisiana	2	1,124
Maryland	7	3,474
Michigan	3	1,253
Missouri	1	493
Mississippi	2	1,020
Pennsylvania	3	2,084
Texas	5	3,505
Wisconsin	3	861
Total	**48**	**23,715**

Table D.50. Average increase in AEO 2020 projected fuel price between $35/tonne CO_2 price (U.S. Energy Information Administration, 2020) and reference cases, relative to 2012 state-specific fuel prices.

Fuel	Bituminous	Sub-bituminous	Lignite	NG
Increase (fraction)	0.001	0.019	-0.025	0.44

Table D.51. Factors for CCS capacity sensitivity analysis. Default levels are those used in the reference case modeling, while the Low, and High levels are used for sensitivity analysis.

Factor	Unit	Default	Low	High
CCS retrofit capital-cost multiplier*	fraction (absolute)	technology dependent	-0.10	0.10
NGCC capacity factor†	fraction	0.60	0.40	0.87
Solar overnight capital-cost†	2010$/kW	825	541	1,067
Wind overnight capital-cost†	2010$/kW	1,189	1,068	1,529
Change natural gas price† (2012-2030)	fraction (absolute)	State-specific	None	0.44
Bituminous coal price change† (2012-2030)	fraction (absolute)	-0.39	None	-0.39
Sub-bituminous coal price change† (2012-2030)	fraction (absolute)	-0.20	None	-0.18
Lignite coal price change† (2012-2030)	fraction (absolute)	-0.16	None	-0.19

Notes: *: Author chosen limits; †: literature.

D.4.3 Simultaneous application of the individual 45Q sequestration credits to promote CCS in both the coal and NGCC fleets

When each of the 45Q credits discussed in Chapter 4, Sections 4.3.3-4.3.5 in the paper are simultaneously applied to promote the associated CCS technologies, the compliant configuration is still the preferred mitigation for the coal-fired EGUs and is the overall dominant capacity, absent a CO_2 price; however, natural gas is now the dominant fuel, Figure D.19. The emissions decrease sharply as the CO_2 price increases to $20/tonne, since retrofitted and new NGCC CCS capacity, which already comprises 24% of the fossil fuel capacity absent a price, has the greatest marginal gain and achieves 23% of the targeted net generation at this price. Therefore, it may be possible to lower the total sequestration credit expense and the avoided cost through changing the distribution of the credits, Table D.52. Location and state-specific capacity of CCS capacity from simultaneous application of this 45Q scheme is shown in Table D.53.

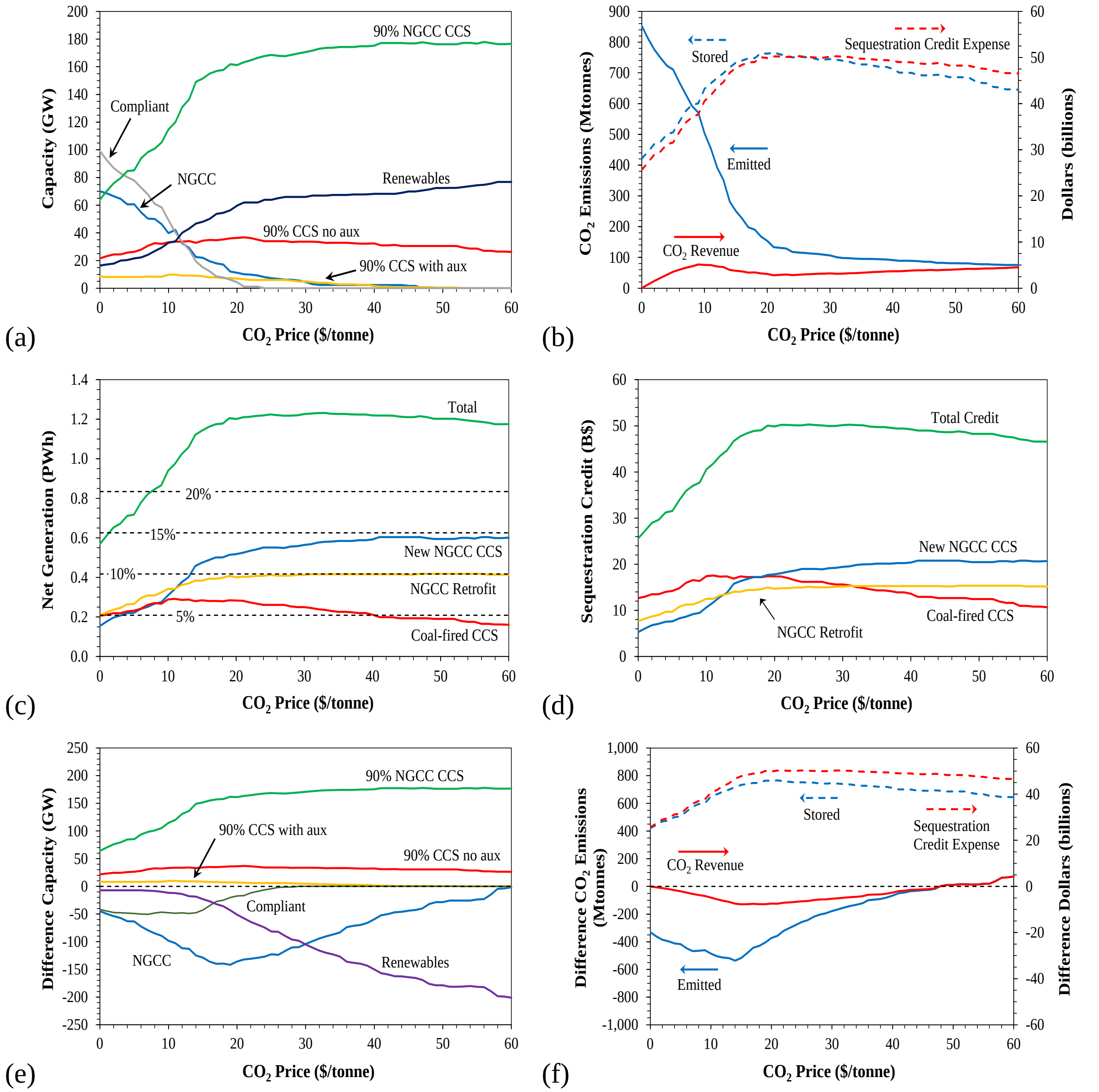


Figure D.19. The effect of CO_2 price and the combined application of 45Q sequestrations credits for coal-fired CCS ($66/tonne, 12-year duration), repowering CFEGUs with new NGCC CCS ($144/tonne for 20-year duration), and retrofitting existing NGCC plants with CCS ($104/tonne for 20-year duration) on the projected 2030 fossil-fuel, power-sector fleet. Panel (a) details the mitigation technology capacity, (b) shows the performance-parameters, while (c, d) highlight the CCS (c) net generation, and (d) sequestration credit expense by CCS technology. Panels (e, f) show the differences in (e) capacity and (f) performance metrics between the combined 45Q credits and in the absence of the credits (combined minus $0/tonne).

Table D.52. Comparison of 2030 combined-fleet performance without a 45Q sequestration credit and with unique 45Q sequestration credit levels and durations applied to different technologies. A $66/tonne credit with a 12-year duration is applied to the coal fleet for retrofitting CCS, while a $144/tonne credit with a 20-year duration is applied for repowering EGUs as new NGCC plants with CCS. A $104/tonne credit with a 20-year duration is applied to the NGCC fleet for retrofitting existing NGCC plants with CCS. No CO_2 price is applied. The $0/tonne case is the avoided cost counterfactual.

Metric	Units	$0/tonne	Combined 45Q
Fleet net generation	TWh	1,870.6	1,816.5
CCS Net generation	TWh	0	569.5
Emitted mass	Mtonnes	1,183	853
Intensity	lbs/MWh	1,394	1,035
Sequestered CO_2	Mtonnes	0	421
Credit expense	$ billion	0	25.6
LCOE*	$/MWh	41.2	36.0
Avoided cost*	$/tonne	NA	93.0

*Sequestration credit expense is not included in the LCOE calculation and is included in the avoided cost calculation.

Table D.53. Locations, number of sites, and capacity for combined-fleet CCS mitigation with unique 45Q sequestration credit levels and durations applied to different technologies. A $66/tonne credit with a 12-year duration is applied to the coal fleet for retrofitting CCS, while a $144/tonne credit with a 20-year duration is applied for repowering CFEGUs as new NGCC plants with CCS. A $104/tonne credit with a 20-year duration is applied to the NGCC fleet for retrofitting existing NGCC plants with CCS. No CO_2 price is applied.

State	# Sites	Capacity (MW)
Alabama	3	1,761
Arizona	1	372
California	6	3,167
Colorado	4	1,566
Delaware	1	430
Florida	5	4,196
Illinois	16	8,124
Indiana	18	10,617
Kentucky	5	3,142
Louisiana	3	3,774
Maryland	11	7,442
Michigan	6	4,011
Mississippi	3	1,860
Missouri	3	1,699
New Mexico	3	1,508
North Dakota	3	1,453
Ohio	5	3,944
Pennsylvania	6	5,802
Texas	30	21,514
Utah	6	2,975
Wisconsin	3	861
Wyoming	7	3,593
Total	**151**	**94,333**

D.5 Validation

Many of the underlying equations to determine the LCOE or emission intensity of the current, compliant, and CCS-mitigated CFEGU states are derived from regressions based upon simulations of CFEGUs in the IECM or from similar analyses. These regressions are implemented piecewise into the model such that there is no one equation based upon one regression that can solely describe the LCOE or intensity of an CFEGU for these states.

Therefore, the accuracy of the model equations for these metrics, relative to the simulations upon which these piecewise regressions are based, can be demonstrated by assessing the difference in these metrics as obtained with the two methods. To determine the accuracy, nine CFEGUs that span the capacity and net generation range for the sub-bituminous subcritical cluster are modeled and simulated in the IECM. The CFEGU baseline operating parameters are used for inputs in the comparison, as are default IECM coal and natural gas prices. Since the IECM simulation does not address all options in ESTEAM and uses different equations and values to determine some costs, some of these ESTEAM costs are calculated external to the IECM component-level simulation results. Mitigations for repower as a NGCC plant (with and without CCS), co-locating this plant with renewable generation, and retrofitting an existing NGCC plant with CCS are not validated. These mitigations are from external calculations and are based upon IECM regressions that are primarily a function of turbine number with no associated error.

When the IECM simulated LCOE is subtracted from the modeled LCOE, Figure D.20, the difference for the CCS mitigated CFEGUs tends to be within ± $5/MWh. In all but one case, this difference falls between the 95% tolerance limits for the metric, which are established with the uncertainty analysis for Wisconsin CFEGU ORIS Unique ID 4050_B_5 at the low and high1 uncertainty levels; the one LCOE point, Figure D.20(b), that is not within the 95% confidence bounds is within 4% of the $252/MWh IECM value. Furthermore, the difference tends to be unbiased with regard to capacity for all capture rates.

As discussed *in Appendix B*, there is an initial difference between regressed and simulated compliant intensity values for four CFEGUs (that can be as great as 70-300 lbs/MWh) that will subsequently affect the comparison for the CCS mitigated intensities, Figure D.21. While this difference propagates through the modeled mitigation, the difference diminishes with increasing capture rate because the emitted CO_2 difference decreases proportionally. Therefore, the initial offset does not affect the relative change in compliant emission intensity for the deep reduction mitigations studied nor the least-cost frontier for an individual CFEGU.

Validation for renewable and NGCC retrofitted capacity parameters are not presented, as these are derived completely from IECM or primary source projections.

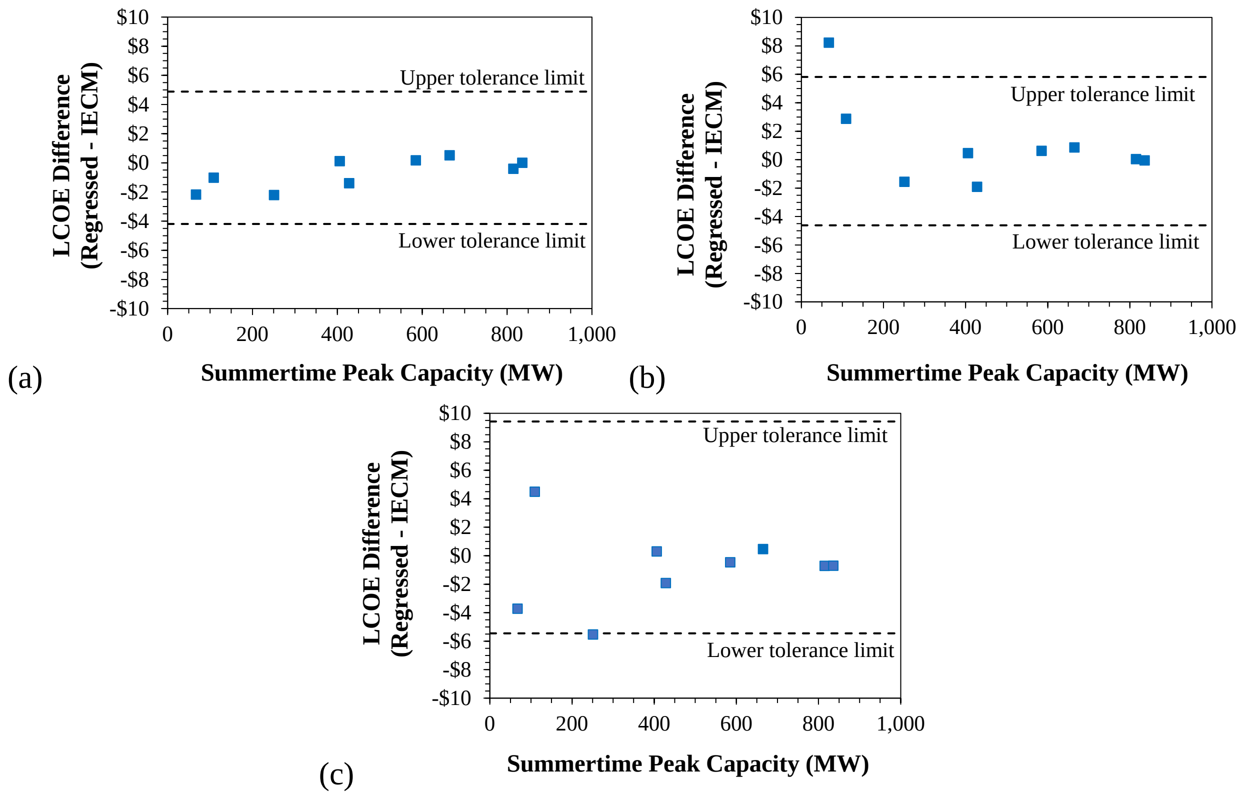


Figure D.20. Validation comparison of LCOE for coal-fired CCS **without** auxiliary boiler (a) at 90%, (b) at 40%, and (c) at 10% capture rate. These validations are the difference between the LCOE of the CFEGUs as simulated in the IECM and those as determined with the model equations for the default operating conditions and commodity prices. The nine CFEGUs were selected to span the capacity range for this cluster. The dashed horizontal lines represent the 95% tolerance limits for the metric, as determined in the uncertainty analysis for Wisconsin CFEGU ORIS Unique ID 4050_B_5 at the low and high uncertainty levels, without cost adders in Table S8.

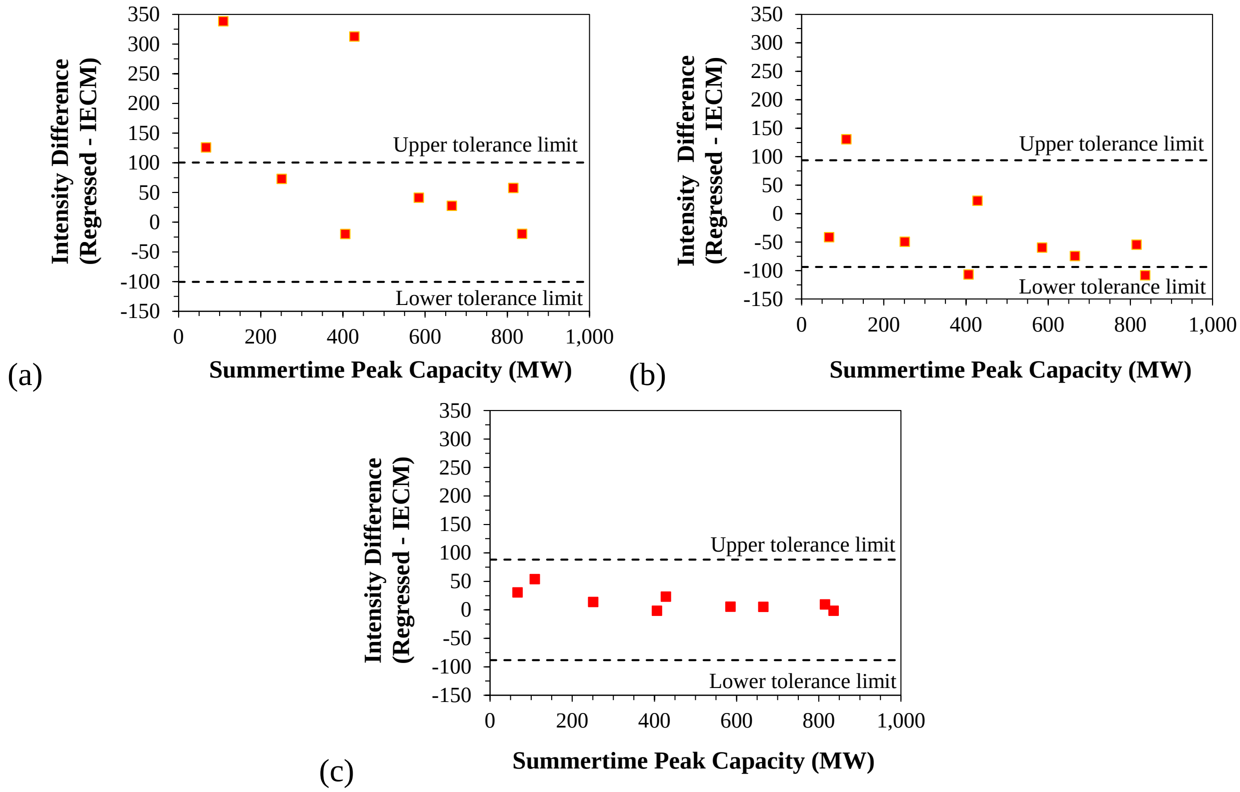


Figure D.21. Validation comparison of emission intensity for CCS **without** auxiliary boiler (a) at 90%, (b) at 40%, and (c) at 10% capture rate. These validations are the difference between the CO_2 emission intensities of the CFEGUs as simulated in the IECM and those as determined with the model equations for the default operating conditions. The nine CFEGUs were selected to span the capacity range for this cluster. The dashed horizontal lines represent the 95% tolerance limits for the metric, as determined in the uncertainty analysis for Wisconsin CFEGU ORIS Unique ID 4050_B_5 at the low and high uncertainty levels, without cost adders in Table D.13.

D.6 References.

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Appendix E: Who let the dinosaurs in? Fossil fuel options for power sector net-zero emissions.

This appendix is under review for *Environmental Science & Technology*.

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E.1 Abstract

Three of the main challenges in achieving rapid decarbonization of the electric power sector are getting to net-zero while maintaining grid reliability and minimizing cost. In this policy analysis, we evaluate the performance of a variety of generation strategies using this “triple objective” including nuclear, renewables with different energy storage options, and carbon-emitting generation with carbon capture and storage (CCS) and direct air capture and storage (DACS) technologies. Given the current U.S. tax credits for carbon sequestration under Section 45Q of the Internal Revenue Code, we find that two options: (1) co-firing biomass in existing coal-fired assets equipped with CCS, and (2) coupling existing natural gas combined-cycle plants equipped with CCS and DACS, robustly dominate other generation strategies across many assumptions and uncertainties. As a result, capacity-expansion modelers, planners, and policymakers should consider such combinations of carbon-constrained fossil-fuel and negative emissions technologies, together with national incentives, when designing the pathways to a carbon-free economy.

E.2 Introduction

According to the 2018 Intergovernmental Panel on Climate Change (IPCC) recommendations, limiting the future climate impact of anthropogenic carbon dioxide (CO_2) emissions to 1.5 °C warming will require reducing global greenhouse gas emissions to 55% of the 2010 level by 2030 and achieving a net-zero carbon economy by 2050, [1]. Electrification of many sectors of the economy will be required to meet these economy-wide goals, thereby putting pressure on the power sector to increase generation while rapidly decarbonizing [1-6]. The apparent path forward for many nations to achieve these goals is to incorporate high levels of variable renewable energy (VRE) sources (primarily solar and wind generation) by increasing the global capacity growth rate from almost 250 gigawatt (GW) per year in 2020 to 1,100 GW per year in 2030 and then to sustain that pace through 2050 [6].

Studies of the European and United States' (U.S.) electricity grids that have modeled feasible renewable-generation penetration levels of 50% and more (and are heavily dominated by VRE capacity) indicate that such an approach may be feasible [7-26]. However, achieving both net-zero carbon emissions and reliable coverage of 100% of the forecasted demand becomes both difficult and expensive for such portfolios as VRE penetration surpasses 80% [17, 22, 25]. The inherent variability of solar and wind patterns leads to periods of generation and demand imbalances [17, 27]. Adding more VRE capacity to cover these periods can lead to dramatic asset overbuilding and many hours of excess generation curtailment. This curtailed overcapacity can be as high as 3.4 times the annual generation [17] and has a direct effect on levelized cost of electricity (LCOE) calculations. Mixing and geographically distributing VRE assets can reduce the imbalance but may require continental distribution and additional generation sources [7, 8, 10, 16, 17, 20, 22, 24, 26, 30, 32].

Balance can be restored in high-penetration VRE systems by shifting both generation and demand. The addition of technologies to store the excess energy in chemical, mechanical or thermal states [28-30] allows the available electricity to shift from periods of resource abundance and low demand to periods of resource scarcity and high demand [30, 31]. However, large-scale shifting of electricity availability will lead to much greater system costs, as more storage—12 hours of annual generation in the same U.S. study [17]—is required for balancing. On the demand side, flexibility strategies [30, 31, 33] can be employed to reduce some of the need for additional VRE capacity and the increase in VRE LCOE from underutilized assets (mechanisms not considered in this analysis). This shifting of demand is not without costs; the variability of the VRE assets must still be designed for, and the consumer inconvenience considered and possibly compensated.

In addition to generation portfolios with large VRE components, carbon-free energy is also available from fossil-fuel and co-fired bioenergy (BE) electric generating units (EGU) whose carbon emissions are either captured immediately at the power plant with carbon capture and storage (CCS) technology or are captured indirectly from the ambient air with direct air capture and storage (DACS) technology. Generation with such options employing carbon capture is more attractive under the current U.S. tax policy (i.e., Section 45Q: credit for carbon oxide sequestration [34]) that provides significant incentives for capturing and storing carbon emissions (Section E.6.1, *Supplementary Note 1*). While CCS and DACS technologies have been included as mitigation technologies in at least one study of the U.S. power-sector configuration with decreasing CO_2 emissions between 2030 and 2050 [35], no studies have included the 230 GW of coal and 240 GW of natural gas combined cycle (NGCC) existing assets and the planned additions of both to 2030 [36] with 45Q incentives.

In this study, we complete a LCOE comparison of 17 generation technologies at the national level in 2030 (shown in Table E.1) that satisfy two constraints: 1) net-zero or zero-carbon emissions, 2) 100% resource adequacy. From this comparison, we contend that employing existing fossil-fuel assets with CCS and DACS technologies to achieve net-zero emissions may enable the U.S. power sector to decarbonize at a lower cost than relying on large VRE penetration with adequate energy storage to achieve resource adequacy (Section E.6.2, *Supplementary Note 2*). As a result, capacity-expansion modelers, planners, and policymakers should consider such combinations of carbon-constrained fossil-fuel technologies in the fuller context of the national grid, together with national incentives to capture the emissions, when designing the pathways to a carbon-free economy.

Table E.1. Generation technology, energy source and carbon control configuration for studied technologies.

Technology	Energy Source	Carbon Controls
Existing co-fire BECCS	Coal & 20% Biomass	90% CCS
New NGCC* CCS	Natural Gas	90% CCS & DACS
Existing NGCC CCS	Natural Gas	90% CCS & DACS
USC* co-fire BECCS	Coal & 20% Biomass	90% CCS
Small Modular Reactor	Nuclear	N/A
Advanced Water Reactor†	Nuclear	N/A
Dedicated BE	100% Biomass	N/A
Existing coal CCS	Coal	90% CCS & DACS
Wind	Wind	N/A
Solar	Solar	N/A
USC CCS	Coal	90% CCS & DACS
Dedicated BECCS	100% Biomass	90% CCS
Long-duration Storage	Solar/Wind/Hydrogen	N/A
Existing NGCC	Natural Gas	DACS
New NGCC	Natural Gas	DACS
Existing co-fire BE	Coal & 20% Biomass	DACS
Existing coal	Coal	DACS

*Notes: NGCC: natural gas combined cycle; USC: ultra-supercritical.
†While the advanced water reactor is modeled, the small modular reactor results are used as proxy because the LCOE results are within US$1 MWh^{-1} of each other.

E.3 Methods

E.3.1 Modeling resource adequacy

Because of globally declining capital costs [37] and the absence of variable operation and maintenance (VOM) costs for solar and wind capacity, VRE technologies have the lowest LCOE compared to the other modeled technologies if the 100% resource adequacy constraint is relaxed. Adding the constraint forces the modeling of solar and wind generation variability and in turn the integration of balancing strategies and the associated costs [38] when one considers the addition of a (N-1) VRE source that might require the aforementioned addition of battery capacity or

VRE capacity overbuild to meet this constraint in a high-penetration scenario. Previous studies have varied in how the distributions of VRE generation are created. Some high-penetration VRE capacity expansion models have relied on relatively short periods of historical data (e.g., one year of insolation and wind data) over limited geographical regions (e.g., California or the western U.S.) that are averaged over time steps of a certain size (e.g., typically hours) [7, 12, 13, 22, 23]. Increasing the length of the historical dataset (e.g., 39 years) [8, 16-21, 23, 24] and shortening the time step increases the variability of the generated electricity and complicate the balancing model requirements as periods of mismatched generation and demand must be accounted for. Long-duration variation [20, 27] requires additional and/or negatively correlated VRE capacity, storage, or backup with dispatchable (firm) zero or net-zero carbon capacity to achieve resource adequacy [39]. Similar considerations are needed for demand-side modeling.

Adding only storage to the generation portfolio can achieve resource adequacy notwithstanding resource intermittency [16-20, 22], with the type and amount of storage required depending upon the power and energy requirements [28, 30]. Several types of chemical batteries are cost-effective storage technologies for several-hour durations; lithium-ion (Li-ion) batteries are often modeled for this purpose as cost reductions are projected to make this form the dominant technology for battery storage with longer duration requirements [29]. When tens of hours of storage are required, pumped hydroelectric and compressed air storage are often modeled; however, these sources are geographically restricted and additional capacity is not available for all grids. For longer periods of low generation, using VRE capacity to produce hydrogen from electrolysis and then storing the gas until there is demand to use fuel cells or turbine generators to convert the gas into electricity (herein termed power-to-gas-to-power (PGP)), is possible as long-duration storage (LDS) [6, 18, 20, 29].

Resource adequacy can also be achieved with backup capacity provided by firm non-renewable, net-zero and zero-carbon emission EGUs, Table E.1. Both existing and new coal-fired electric generating units (CFEGU) and NGCC plants can provide the requisite capacity with or without CCS, given that DACS or another negative emissions technology (NET) are employed to remove any remaining emissions. Dedicated bioenergy with carbon capture and storage (BECCS) is one such technology that is often modeled with NGCC CCS generation to provide net-zero CO_2-emitting backup [24, 35, 40-42]. When coal-fired EGUs equipped with CCS at 90% capture employ 20% biomass co-fire on an energy basis (herein termed co-fire BECCS), approximately net-zero emissions are achieved from a life-cycle analysis perspective [43-45]. Similarly, dedicated BE EGUs without CCS and co-fire BE at 20% co-fire with subbituminous coal and DACS are also considered net-zero emissions capacity. Finally, advanced nuclear capacity, such as small modular reactors (SMR), are often modeled in high VRE penetration systems to provide zero-carbon backup capacity [18, 23-25, 46].

E.3.2 Modeling LCOE

Certain simplifying assumptions are made in this cost model to examine how fossil-fuel generation sources might be used as firm capacity for the VRE sources and to identify decarbonization options. These options that help bound the solution set can then be added to capacity-expansion dispatch models to further the policy discussion. One assumption is that this (N-1) source is a standalone unit and must maintain a target generation level to fulfill the exogenous adequacy requirement. The requirement for continuous load balancing is ignored for the VRE capacity (except for the costs that may be incurred from the weather-induced, long-duration shortfalls associated with longer weather datasets [20, 27]), which is studied parametrically as the additional cost of storage capacity and overcapacity [17]. Therefore, the storage and overcapacity costs for the typical daily load balancing or shifting and system integration [38] are not considered. Furthermore, costs related to battery charging are assumed to be negligible. Finally, only technology-specific average capacities factors are considered as the target generation is expected to be maintained over at least 15 years with the greater resource variability given in the long-duration weather dataset.

The technology LCOE comparison for achieving net-zero CO_2 emissions in 2030, agnostic of policy, is based on two fossil-fuel EGU configurations (one a 650 MW_{gross} subcritical coal-fired EGU and the other an NGCC plant of comparable capacity) operating at a 60% capacity factor based upon the U.S. Energy Information Administration's (EIA) projection of coal-fired capacity factor in 2030 [36]. The performance and cost projections for these EGUs are derived with the Integrated Environmental Control Model (IECM) version 11.2, a power-plant simulation tool developed by Carnegie Mellon University [47], using region-specific inputs for the Midwest and national fuel prices projected for 2030 from the EIA's 2020 Annual Energy Outlook [36]. The emission intensity and fuel cost estimates derived from this IECM model are adjusted exogenously with fuel-specific regressions to account for the impact of the capacity factor deviation from maximum load on the plant net heat-rate (see Section E.6.6.2.3 for details).

Options for reducing emissions from these baseline plants (while maintaining net generation) include co-firing with biomass, adding CCS, and building new fossil-fuel EGUs at the same capacity that are equipped with CCS. The performance and cost estimates for the EGUs fitted with these options are also simulated in the IECM or determined exogenously and added to the IECM output. When necessary, DACS is employed in conjunction with these options to achieve net-zero emissions from fossil-fuel plants, the removal rate and estimated cost of which is derived from a National Academy of Science, Engineering, and Medicine report [48] and is studied parametrically with an initial estimate of $212/tonne (see Section E.6.6.3 for emissions reduction details).

Solar, wind, nuclear, and dedicated BE without and with CCS generation technologies serve as zero-carbon and negative emissions alternatives to net-zero emissions with these fossil-fuel technologies. Solar and wind capacities are added to equal the target net generation given their associated national capacity factors [49] with costs determined in the National Renewable Energy Laboratory 2019 Annual Technology Baseline report [50]. Two types of nuclear technologies are evaluated: SMR and advanced light water (see SI, Section E.6.6.4.2 for cost details). The capacity factors for both reactor types are held constant at 90% to simulate current operation of nuclear power plants in the U.S., even though SMR operations are capable of flexible operation and larger facilities in Europe are operated as such [51]. However, the SMR capacity is adjusted to maintain the target generation at this capacity factor. While both types of reactors are modeled, the advanced water reactor results are omitted as these, results are within US$1 MWh^{-1} of those for the small modular reactor.

The capacity for the dedicated BE EGU, modeled by the EIA [52], is also adjusted to provide the target generation at a 60% capacity factor [35, 42]. To determine the adjusted capital cost, the power rule (Equation E.22) is applied to the EIA's capital cost estimate. This EGU is modeled in the IECM for additional capital and O&M costs when equipped with CCS at 90% capture for negative emissions. [The dedicated BE and BECCS EGU capacities can also be adjusted for higher utilization so that the target generation is achieved at 90% capacity factor. In this case, both units advance in merit order but do not alter the conclusion. LCOE results for this case, as a comparison to Figure E.1, are shown Figure E.13.]

While fossil fuel, BE, and nuclear generation are dispatchable technologies and are capable of resource adequacy, variable renewable technologies on their own may not be capable of reliably supplying the grid for periods of high demand when the realized capacity factors are not adequate and a large portfolio of renewable resources that are temporally and geographically diverse is not available [10, 17, 20, 32, 53]. Additional renewable and/or energy storage capacities may be required to meet this requirement. The addition of these capacities in the model simulates the change to VRE LCOE as more VRE capacity is added to the system while this zero-carbon system is constrained to maintain adequacy [38, 54]. To determine these costs, periods of renewable-energy resource intermittency requiring additional battery storage (from 0-40 hours) are examined parametrically during which the target generation can be met by overbuilding capacity (by 0-50%) that will result in curtailment in resource excess conditions and/or adding storage from Li-ion batteries that are charged prior to curtailment or without cost from the grid, Table E.18. In lieu of battery storage, LDS comprised of renewable generating capacity sufficient to meet demand *and* capable of producing hydrogen from dedicated or surplus generation in a PGP generation scenario is also evaluated as a standalone generation source. A US\$80-150 MWh^{-1} cost range for the combination of these technologies [18], at an average cost of \$115/MWh, is assumed for comparison to renewable curtailment and battery storage options, and the net-zero fossil-fuel equivalents for this is analysis.

Fossil-fuel technologies configured for net-zero emissions and the zero-carbon and negative emissions technologies configured to provide adequate grid reliability are evaluated on a cost basis that includes 45Q tax credits for carbon sequestration. The general form of the LCOE equation used to make the least-cost configuration decisions for the net-zero fossil fuel and biomass configurations is given in Eq. E.1, and the equation for renewable generation inclusive of battery storage is shown in Eq. E.2. The general LCOE equation for nuclear generation takes the form of Eq. E.1 without the CO_2 emissions term. Details for LCOE components particular to a technology configuration are given in Section E.6.6 Methods.

$$LCOE_i = \frac{CC_i \times FCF_i + FOM_i}{G_{net,i}} + VOM_{fuel,i} + VOM_{nonfuel,i} + \frac{(Seq - TC_i)m_{CCS,i} + (DAC + Seq - TC_i)m_{DAC,i}}{G_{net,i}} \tag{E.1}$$

where *LCOE* is the levelized cost of electricity (US$ MWh^{-1}), *CC* is the EGU capital cost (US$), *FCF* is the fixed charge factor (fraction), *FOM* is the annual fixed operation and maintenance cost for the EGU (US$), G_{net} is the EGU target annual net-generation (MWh), VOM_{fuel} is the variable operation and maintenance cost related to fuel (US$ MWh^{-1}), $VOM_{nonfuel}$ is the nonfuel variable operation and maintenance cost (US$ MWh^{-1}), C_{bat} is the total cost of the battery system (US$), *TC* is the 45Q emission tax credit level proportionally derated for the EGU economic lifetime (US$ $tonne^{-1}$), *Seq* is the CO_2 storage cost (US$ $tonne^{-1}$), m_{CCS} is the annual CO_2 emissions mass captured with CCS (tonnes), DACS is the direct air capture cost (US$ $tonne^{-1}$), m_{DAC} is the annual CO_2 emissions mass captured with DACS (tonnes), and *i* is the subscript specific for the generation technology and project life.

$$LCOE_i = \frac{1000(Cap_i)\big((CC_i)(FCF_i) + FOM_i\big) + C_{bat,i}}{G_{net,i}} \tag{E.2}$$

where *LCOE* is the levelized cost of electricity for the renewable source (US$ MWh^{-1}), *CC* is the capital cost of the renewable source (US$ kW^{-1}), *Cap* is the renewable source capacity (MW), *FCF* is the fixed charge factor (fraction), *FOM* is the fixed operation and maintenance cost for the renewable source (US$ kW^{-1}), C_{bat} is the annual cost for the batteries (US$), G_{net} is the target annual net-generation equivalent to that in Eq. E.1 (MWh), 1000 is a conversion factor, and *i* is the subscript indicating solar or wind capacity.

E.4 Results and Discussion

E.4.1 Cost ranking of technology choices for resource adequacy

Without a resource adequacy constraint, VRE technologies have the lowest LCOE. However, satisfying the resource adequacy constraint during generation shortfall conditions increases the costs of VRE technologies to such a degree that they become non-competitive, Figure E.4. When low/no generation periods for VRE capacity require battery storage, solar and wind generation becomes non-competitive to multiple fossil fuel technologies. With a requirement of four hours of battery storage duration, Figure E.1, the LCOE of VRE options are dominated by several net-zero fossil fuel options while maintaining the target generation: 20% co-fire BECCS with existing subcritical and new ultra-supercritical (USC) coal with CCS, and existing and new NGCC plants equipped with CCS and relying upon DACS to remove the remaining emissions. Such options are even preferred to the net-zero and zero-carbon technologies that are typically modeled: dedicated BE and BECCS, SMR, and LDS (even at the low-LCOE estimate). This dominance at a small battery requirement suggests that at the current 45Q levels (US\$50 tonne^{-1} tax credit for immediately-sequestered CO_2, applicable for 12 years), decarbonized fossil-fuel EGUs have an important role in the carbon transition as VRE penetration reaches high penetration levels that require almost any sized battery storage.

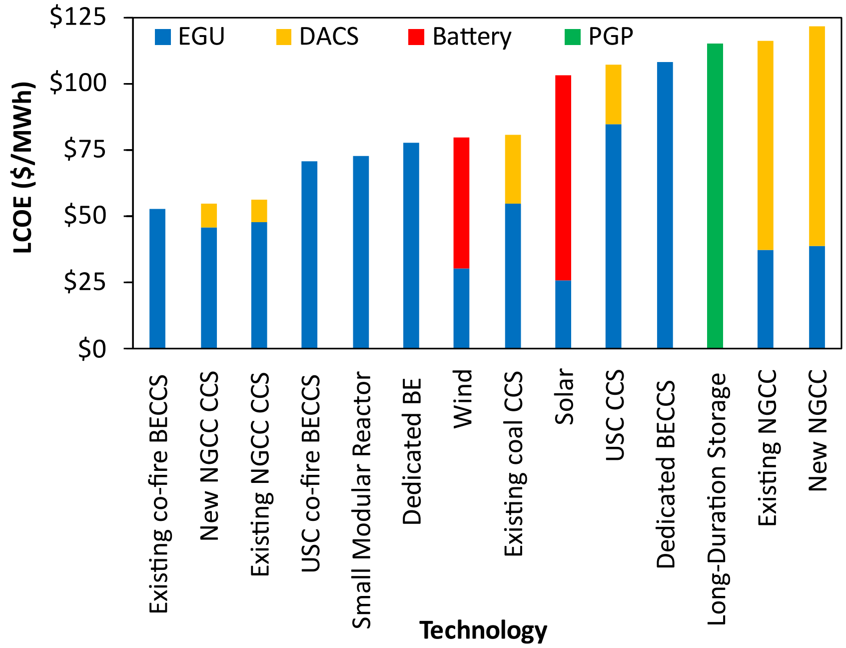

Figure E.1. LCOE for generation technology options producing net-zero emissions and zero-carbon electricity while maintaining target generation. Four-hour duration battery storage is used for VRE technologies. Existing coal with DACS and existing co-fire BE are not shown because LCOE exceeds US$160 MWh^{-1}.

While co-fire BECCS is the LCOE-dominant option for the default conditions in this analysis, the LCOE for the fossil-fuel alternative of using NGCC with CCS and DACS—be it constructing a new plant or retrofitting an existing plant—is within US$4 MWh^{-1} (7%) of the least-cost option. DACS removal cost and the EIA's projected fuel prices are significant uncertainties in these LCOE calculations [36]. A parametric analysis of DACS cost and the ratio of a variable natural gas (NG) price relative to the default co-fire fuel prices (i.e., a combination of coal and biomass), Figure E.2, shows that technology choice is more sensitive to the ratio of the projected fuel prices (Further analysis is shown in Figure E.5). From the default fuel-price ratio of 1.65, this ratio must decrease by 6% and the DACS cost estimate must decrease by 15% before co-fire BECCS is not the preferred choice. This change in the fuel-price ratio is equivalent to the realized natural gas price decreasing by 6% or the realized coal price increasing by 9%, given the 20% co-fire by energy-basis condition and a fixed biomass price. Since the co-fire fuel is a composite, the projected biomass price needs to increase by over 20% for the 6% ratio reduction to occur, *ceteris paribus*. Given the uncertainties, such values in projected and realized natural gas and coal prices are possible [55]. Therefore, financial regret over the technology choice (defined as the difference in LCOE between the generation option chosen *ex ante* based upon the least-cost for the expected fuel prices and costs, and the corresponding *ex post* option with the projected fuel price and cost uncertainties) is more likely to come from variations in fuel prices and greater emphasis should be placed on estimating these variables.

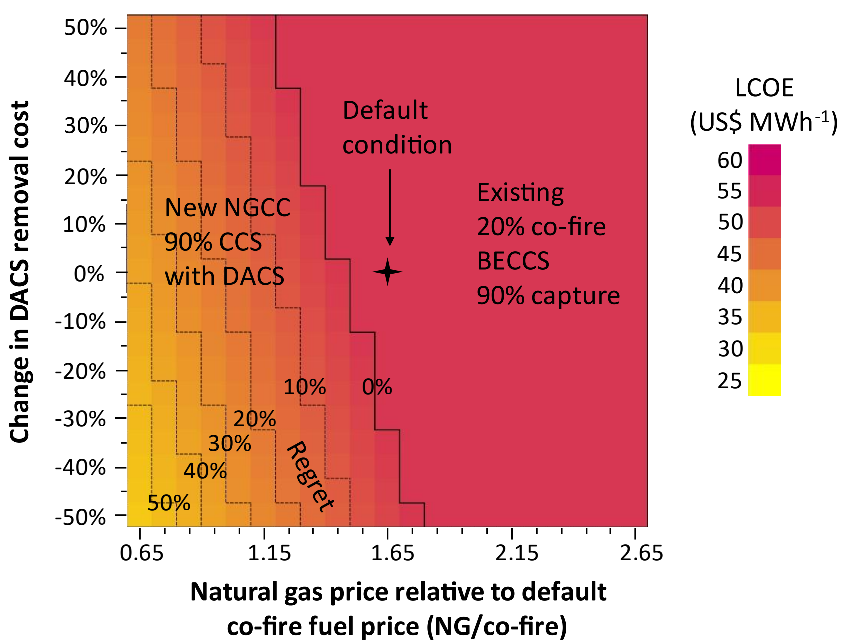

Figure E.2. LCOE and regret based upon dominant generation technology choice for DACS removal cost and natural gas price relative to default co-fire fuel price ranges with net-zero for fossil fleet, while fossil is meeting target generation. Regret is expressed as the percent difference between the realized LCOE and the LCOE for the *ex-ante* choice

Under the current 45Q policy, co-fire BECCS is the least-cost generation option. This is due in part to the incentives that favor EGUs that emit large amounts of CO_2 and have a remaining operational life that is aligned with the 12-year duration of the credits. A fully-depreciated CFEGU with 15 years of remaining operation is well-aligned with such a policy, as the annual capital cost expenditure is the lowest of all options except for dedicated BE, Table E.2. The policy can be tailored to further incentivize other fossil-fuel generation sources by modifying the credit level and duration. When the 45Q credit and duration are segregated by fuel and capture technology type (i.e., the CFEGUs and DACS technology credits are maintained at the current level), the credit level and/or duration must be increased before other fuel types dominate, Figure E.3. Here, natural gas dominates because the VOM and capital costs are lower than those for the other carbon-based alternatives. In general, the credit duration must be increased beyond 15 years before existing assets that are not fully depreciated dominate. Therefore, retrofitting existing NGCC assets with CCS and DACS is the net-zero technology next-best to retrofitted existing co-fire BECCS and can be as robust of a solution, Figure E.6. Furthermore, dedicated BECCS can be the least-cost solution if greater credit levels for longer durations are applied to offset the greater VOM costs, Figure E.7. These characteristics suggest that any modifications to the 45Q incentives should consider alignment between project life and the credit duration and should incentivize NET differently from net-zero emission technologies, as the latter are less expensive alternatives. Conversely, increasing the incentives for DACS while leaving the incentives for CCS at the current 45Q levels does not promote CCS-reliant generation, due to the higher DACS removal cost, unless the credit level is greater than US$145 tonne^{-1}, Figure E.8. Therefore, a recent proposal in the U.S. Senate [56] to increase the DACS credit level to $120/tonne (2019 dollars) with 12-year duration may be insufficient to promote such use for new plants. Similarly, a recent proposal in the U.S. House [57] to increase the credit level to $85/tonne (2019 dollars) with 20-year duration, may only further existing co-fired BECCS deployment rather than promote new construction with other fuel types.

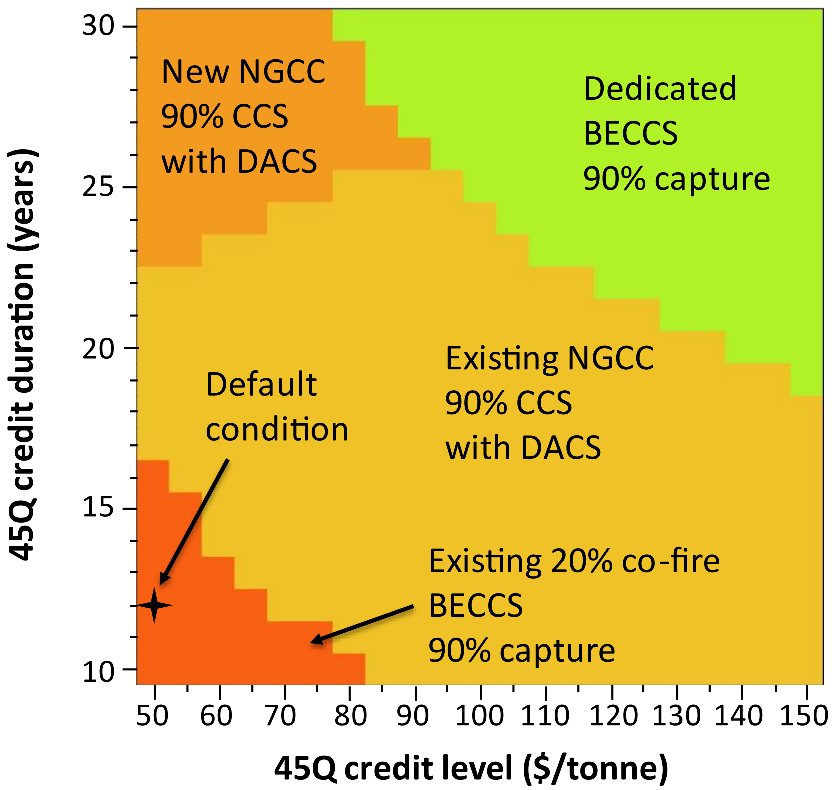

Figure E.3. Dominant generation technology choice from modifying 45Q credit level and duration for immediate storage and constraining for net-zero emissions. Battery storage requirement is four hours for VRE technologies.

E.4.2 Net-zero technology dominance

Adding a resource adequacy constraint to the LCOE cost minimization model by requiring each EGU technology to produce the same net generation highlights the importance of firm capacity when there is high VRE penetration [18-21, 23-26, 35]. While SMR capacity is sized to produce the requisite generation at a 90% capacity factor, the other non-VRE generation technologies do so at capacity factors from 60-72% (Table E.3). If the net-zero EGUs can operate at flexible loads, co-fire BECCS and NGCC CCS with DACS are still the preferred options for firm capacity unless battery capital costs decline by 20%, Figure E.9. Further capital cost reductions increase the minimum capacity factor at which the fossil-fuel EGUs are preferred and increase the allowable VRE-shortfall battery requirement beyond the 4-hour duration used in this analysis, Figure E.10a. However, even at a 10-fold decrease in battery capital costs, net-zero EGUs at the target-generation capacity factors are still preferred to VREs with a 10-hour storage requirement, Figure E.10b. Therefore, if batteries are to be a resource-intermittency solution for the 2035 decarbonization path [58], the target for future battery costs must be reduced dramatically, Figure E.10c [17-19, 26, 46, 59].

Technology choice for the resource-intermittency solution can also depend upon the sensitivity to other capital and O&M costs. At the 4-hour battery duration, battery cost is so expensive that it is irrelevant to the choice between renewable technology with storage and the net-zero fossil-fuel alternatives. Instead, the choice is driven by the co-fire fuel price and the DACS removal cost, Figure E.11. The choice between SMR and the net-zero technologies is not as clear. Because the SMR capacity is sized for a higher capacity factor (baseload operation) for this analysis, the SMR technology dominates the alternatives when the capacity factors for the net-zero options are analyzed below the load-following capacity factors for the target generation, Figure E.9. However, the high capital cost for the SMR demotes this technology relative to the others when the target-generation capacity factors are used, unless the realized capital cost is more than 40% below the projected cost, Figure E.12. Therefore, net-zero alternatives will continue to dominate SMR technology in load-following flexible operation, unless a large reduction in SMR capital cost is realized.

The dominance of net-zero technologies at load-following capacity factors suggests a further false equivalence. While VRE and SMR technologies operate at the target-generation capacity factors, other net-zero and zero-carbon emissions are governed by the target generation. In a competitive market—even one that restricts CO_2 emissions—the capacity factors should be governed by each technology's position in the merit order. Increasing the capacity factor does decrease the LCOE for the net-zero technologies, despite the increasing DACS-related cost to achieve net-zero emissions; however, the VOM costs establishing merit order for these technologies are higher than those for VRE and SMR EGUs (Figure E.7 and Table E.4). It is only with the 45Q incentives that the high VOM expenses can be offset, absent mechanisms such as feed-in tariffs and renewable portfolio standards, to yield zero or negative marginal-production costs. For co-fire BECSS, the resulting tax credits from the current 45Q are great enough to produce a negative VOM, indicating that co-fire BECSS should be first in the merit order and run as much as possible. The credits are insufficient for dedicated BECCS and the other technologies to change the merit order relative to VRE technologies: For dedicated BECCS to supplant VRE generation in economic dispatch, the credit level must be increased to more than US\$160 tonne^{-1}, for a 12-year duration. The net-zero NGCC EGUs (with and without CCS) lag VRE and SMR technologies even with the modified 45Q levels shown in Figure E.6 (US\$65 tonne^{-1} for 15-year duration); therefore, NGCC technologies may be load-following unless a higher credit level and longer duration, or other mechanisms, are present to promote these technologies for greater utilization. For this to occur, the credit level must exceed US\$95 tonne^{-1} for a 20-year duration for an existing plant. Yet even without this higher credit level, the merit order for NGCC CCS technologies with the current 45Q is higher than that for dedicated BE or BECCS technologies. This indicates that the combination of NGCC CCS and DACS not only dominates these dedicated options, but also that coupling NGCC CCS with DACS may be a preferred solution for the remaining CO_2 emissions than dedicated BECCS.

E.4.3 Fleet-wide insights for 45Q application

As VRE capacity is not observed as the least-cost solution, fossil-fuel alternatives with CCS, DACS, and 45Q incentives should be considered as net-zero options in capacity-expansion dispatch models. Although the use of models with simplified dispatch assumptions have been shown to underestimate the costs of VRE integration at high levels [54] and models based on LCOE have been shown to neglect system integration costs [38], we note that VRE capacity is not included in the least-cost solution *even when its costs may be underestimated.* By making first-pass simplifying assumptions regarding the full extent of VRE load balancing and integration costs, and the dynamic response of the alternative capacity, we are able to consider a broader range of available options for the 2030 fossil fuel fleet than would otherwise be possible in more computationally-intensive models. Subsequent analysis with full dispatch models may then be performed in more detail on the specific areas of interest identified by our modeling.

Achieving a power sector with high VRE penetration, be it through a CO_2 price policy or a net-zero mandate, will likely require political will as well as resource adequacy. Currently, there is no indication of such for these policies without protracted legal battles, but there is bipartisan political will to support incentives for capturing and storing carbon emissions [34, 56, 57]. While 45Q incentives alone are unlikely to achieve a net-zero power sector, such an approach may decrease the resistance to other policies. This model to bound the capacity options for a net-zero power sector illustrates the various interdependencies of resource capital cost and availability, and fuel type and asset age that 45Q must balance to successfully promote carbon capture and the role that such an incentive can play in decarbonizing the U.S. power sector without further decarbonization policies. When the modeling is expended to a region-specific fleet of existing fossil-fuel EGUs and future capacity additions, the combination of credit level and duration within these broad technology options should be determined to promote the required generation from net-zero technologies in order to minimize the total system cost, inclusive of resource intermittency, as not all existing CFEGUs or NGCC plants are suitable for CCS retrofit and site-specific attributes are important [60, 61]. This may require as much as 20% of U.S. generation be produced by net-zero technologies to minimize the exponential rise in system costs from curtailment and storage solutions at high VRE penetrations [17, 22, 25].

Promotion of existing and new assets to build a net-zero U.S. power sector in 2035 and to bridge to a net-zero economy in 2050 [58] may require extending the 45Q eligibility construction-start date to beyond 2030, as recently introduced in the U.S. Senate [56], and a longer credit duration to make the economic proposition for higher capital cost and newer assets attractive, Table E.2. In concert, the credit level should be set to adequately decrease the LCOE and VOM such that the CCS and DACS technologies are promoted relative to other options. These parameters will need to be set separately for coal and natural gas, as the carbon content, technology heat rates, and existing fleet ages differ. Notwithstanding this, such modifications in credit level and duration have little impact on DACS, because promoting this technology comes from coupling it with already low emission NGCC CCS to achieve net-zero generation, Table E.5. This reliance may accelerate adoption of DACS and decrease the cost for future applications [48, 62-64]. Similarly, increasing credit levels for immediate sequestration, rather than those for CO_2 utilization as an input for bioenergy or converted to synthetic fuels for other sectors, will drive CCS and DACS deployment to be applied for deeper decarbonization while new applications and markets for such utilization develop [62, 65-67] and these net-zero technologies become viable without the 45Q incentives. The dependence of commercially available CCS on DACS to achieve net-zero emissions will diminish as future CCS capture rates approach 99% and reduce the residual emissions load for DACS. However, if these higher rates are technically and economically feasible (see Section E.6.5 *Supplementary Note 3*), additional existing and new fossil fuel assets that require DACS may be promoted over zero-carbon technologies, Figure E.14.

E.4.4 Policy insights

Pursuing these technologies with policy incentives does not come without risks. In addition to poor public acceptance of carbon-removal technologies [35, 68, 69], their large-scale deployment will require regional pipeline backbones to make storage options cost-effective [6, 70-72]. Furthermore, these options have inherent technology issues [35, 43, 48, 62, 70, 73, 74]. Specific concerns for BECCS include availability and additional stress on land, water and forest resources from competition with demands from food supply, biodiversity, other forms of bioenergy, and other sequestration methods [20, 43, 48, 70, 75]. CCS and DACS expansion may be restricted by land, water, and storage constraints, while DACS expansion may be further restricted by the high electrical and thermal requirements [42, 48, 62, 66, 70, 73, 74]. Additionally, methane leakage issues for NGCC CCS must be addressed to dissuade concerns. Finally, some may consider that policies incentivizing these net-zero technologies pose a moral hazard from the extension of fossil fuel use. Yet, there is a need for such firm capacity technologies until LDS costs fall below the least-cost estimates and battery costs are dramatically reduced. As climate change progresses, weather extremes are expected to be more severe [17, 48, 76, 77] and put additional stress on the generation-demand imbalance, possibly hindering or delaying high VRE penetration because of resource adequacy concerns, higher capital costs, and the development of other solutions.

The emergence in this analysis of existing and new co-fire BECCS and NGCC CCS with DACS as lower-cost, firm-capacity solutions for these imbalances (at LCOEs lower than more conventional options such as SMR, LDS, and additional storage) indicates the importance of these fossil-fuel assets as technologies that policymakers, and capacity-expansion modelers and planners should consider for providing the resource adequacy required to achieve a net-zero grid and economy at a lower total system cost. CCS and DACS are both seen as highly necessary technologies to meet the 1.5 °C threshold [1, 2, 3, 48]; therefore, it is important to promote these technologies with incentives [41, 42, 64, 65] in the power sector now to avoid delays in using them in industrial and other sectors to achieve a net-zero economy by 2050. Furthermore, the finding that co-fire BECCS can be on the least-cost path to net-zero emissions in the U.S. is not only a potentially faster decarbonization path forward for the U.S. Mountain West subregion that is coal-rich and natural-gas-poor, or even for regions bereft of solar (New England) or wind (South Atlantic) resources, it may also be a decarbonization path for similar-situated regions in developing nations that are heavily reliant on coal, such as in China [78] and India [79].

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E.6 Supplementary Information

E.6.1 Supplementary Note 1: 45Q background

In the 2018 revised Internal Revenue Code [1], fossil-fuel power plants are given tax credits for capturing CO_2 that is immediately sequestered or used for other purposes, for which no total cap on available credits for a CCS facility or the program is applied. Those plants that annually capture at least 500,000 tonnes of CO_2 are allowed a tax credit for immediate sequestration in dedicated storage that starts at $28/tonne in 2018 and increases to $50/tonne in 2026, while the credit for uses such as enhanced oil recovery and other special utilizations (such as feedstock for chemicals and plastics, synthetic fuels, biofuels, building materials, fertilizers, and food [2]) increases from $17/tonne in 2018 to $35/tonne in 2026. Thereafter, the credits are indexed to inflation. Direct air capture and industrial facilities can receive the same credits if the annual capture rate is at least 100,000 tonnes. All credits are available for 12 years once CCS operation commences, with construction of the CCS facility needing to start before 2025, and are transferrable from the owner of the CCS facility to a downstream operator.

While the deadline for commencing CCS construction is within four years of this analysis (and as such demonstrates that the deadline should be extended at least to 2030 to permit greater promotion of CCS), operation of the CCS facility in this analysis is assumed to commence in 2030, with construction beginning in 2025, and therefore meet the safe harbor criteria for physical work throughout this period [3]. When the operational life of the generating source exceeds the duration of the credit, the base credit level is proportionally derated over the life of the source. Furthermore, we assume the power plant operator takes on the capture-related capital costs for the EGU and DACS and has a sufficient tax appetite to fully monetize the credits;

therefore, the credit ownership remains with the power plant, rather than being transferred to another party.

E.6.2 Supplementary Note 2: Resource adequacy

Resource adequacy concerns the condition in which the bulk power system has sufficient resources such that the aggregate electrical demand is always met within the prescribed voltage and frequency limits [4]. This condition considers both supply-side (generating and transmission facilities) and demand-side (customer demand-response) resources. For the supply-side resources, scheduled and reasonably-expected unscheduled outages, such as from equipment failure and fuel scarcity, are considered. Industry standards for resource adequacy have as an objective ensuring that there is sufficient reserve capacity such that generation shortfalls occur not more frequently than once over a ten-year period [5]. Such occurrences are termed loss-of-load events (LOLE).

In this analysis, the definition of adequacy is modified to account for using a levelized cost rather than a variable cost, as used in a dispatch model, to determine the generation preference. We restrict the impact of the adequacy requirement to the addition of the next zero- or net-zero carbon generation source. In lieu of a system-wide reserve margin, this capacity is embedded in the unique electric generating units by the target generation level that each candidate technology is assumed to meet with a technology-specific capacity factor. For this analysis, we use the least-cost assumption for renewable generation that load-shifting is not required. However, we impose a battery-storage requirement for weather-induced shortfalls to ensure that the target net generation meets the annual demand with perfect foresight. As in the North American Electric Reliability Corporation (NERC) definition, these shortfalls in generation are considered to be expected given the long-duration weather data. The nuclear, fossil-fuel and biomass generation technologies as firm capacity are assumed to always meet the target generation.

E.6.3 Supplementary Tables

Table E.2. LCOE and annual total capital cost for generation technology options producing net-zero emissions and zero-carbon electricity while maintaining target generation. Battery storage requirement is 4 hours above load-shifting capacity with no imposed curtailment. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, $50/tonne with 12-year duration. LDS capital cost is excluded as this technology is studied parametrically with low and high estimated LCOE of $80/MWh and $150/MWh, respectively.

Technology	LCOE ($/MWh)	Total annual capital cost (M$/year)*
Co-fire BECCS	53	53
New NGCC CCS	55	57
Existing NGCC CCS	56	74
USC co-fire BECCS	71	66
Small Modular Reactor	73	151
Dedicated BE	78	26
Existing coal CCS	81	172
Wind	80	190
Solar	103	272
USC CCS	107	194
Dedicated BECCS	108	69
Existing NGCC	116	126
New NGCC	122	130
Existing co-fire BE	169	190
Existing coal	208	246

*Notes: M$: million dollars.

Table E.3. Capacity factors for net-zero technologies to achieve target generation (3,135 TWh).

Technology	Capacity factor
Existing coal	60%
Existing co-fire BE	60%
Existing coal CCS	72%
USC coal CCS	68%
Existing co-fire BECCS	72%
New USC co-fire BECCS	68%
Dedicated BE	60%
Dedicated BECCS	71%
New and existing NGCC	61%
New and existing NGCC CCS	71%

Table E.4. LCOE components ($/MWh) and merit order for generation technology options producing net-zero emissions and zero-carbon electricity while maintaining target generation. Battery storage requirement is 4 hours above load-shifting capacity with no imposed curtailment. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, $50/tonne with 12-year duration. Supporting data for Figure E.7.

Technology	45Q credit	Capital	FOM	VOM	Merit order
Existing co-fire BECCS	-51	36	20	47	1
New NGCC CCS	-9	18	6	40	9
Existing NGCC CCS	-13	24	6	40	7
New USC co-fire BECCS	-19	35	19	35	6
Small Modular Reactor	0	48	13	12	5
Dedicated BE	0	8	23	47	10
Existing coal CCS	-56	55	20	63	4
Wind	0	60	19	0	2
Solar	0	87	16	0	2
USC coal CCS	-22	62	18	49	8
Dedicated BECCS	-26	22	30	82	11
Existing NGCC	-12	40	3	85	12
New NGCC	-8	41	3	85	13
Existing co-fire BE	-28	60	12	124	14
Existing coal	-38	79	12	155	15

Table E.5. Number of DACS facilities required to achieve net-zero emissions for CO_2 emitting EGUs for capacity factors to achieve target generation.

Technology	DACS facilities required (fraction)
Existing coal	4.2
Existing co-fire BE	3.1
Existing coal CCS	0.7
USC coal CCS	0.5
Co-fire BECCS	0
USC co-fire BECCS	0
Dedicated BE	0
Dedicated BECCS	0
New and existing NGCC	1.8
New and existing NGCC CCS	0.2

E.6.4 Supplementary Figures

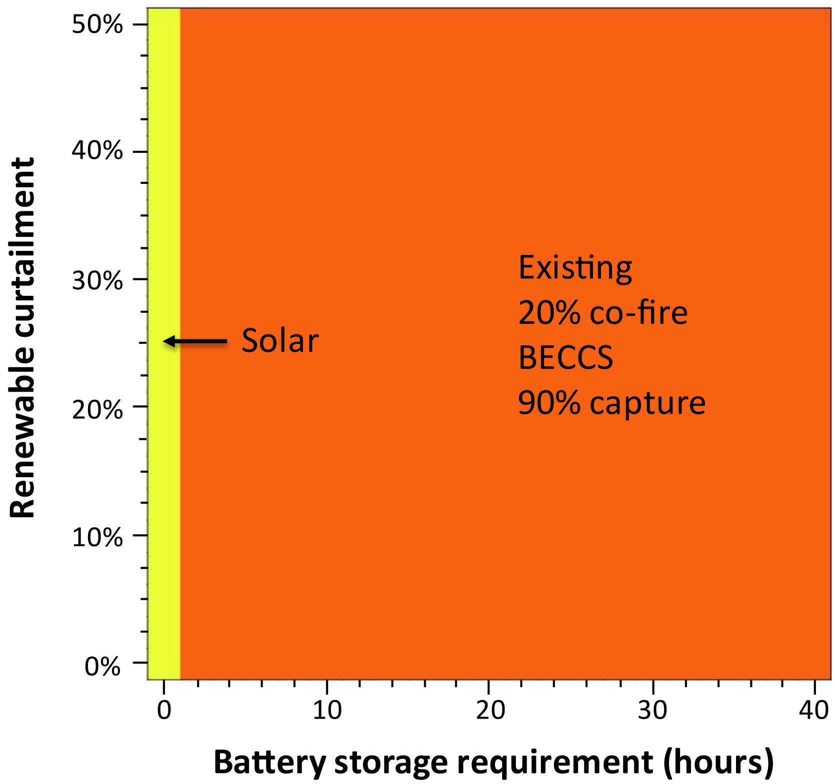
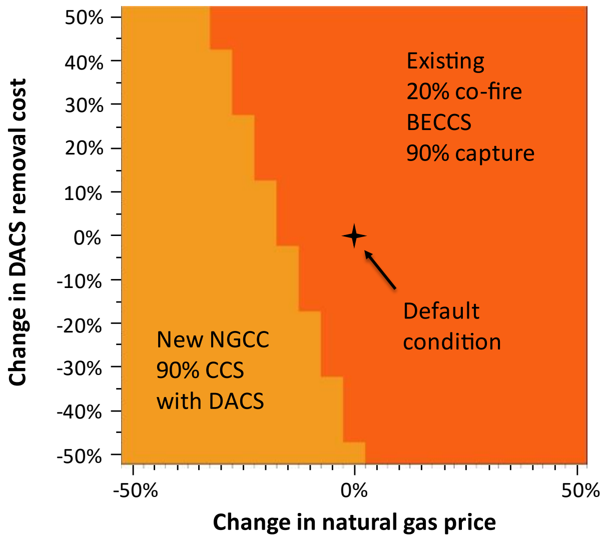
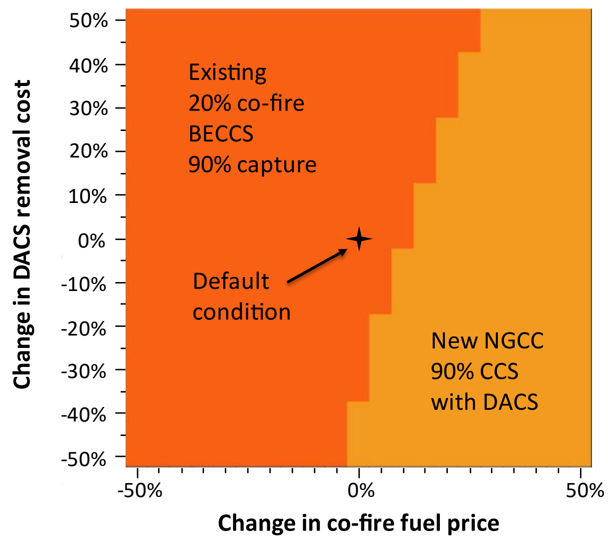


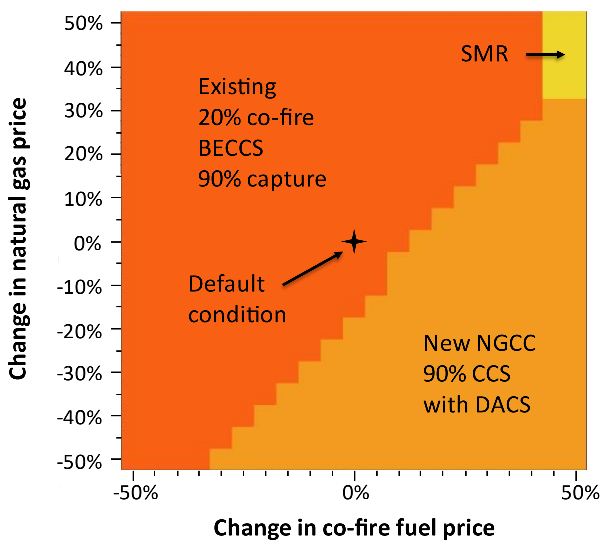
Figure E.4. Dominant generation technology choice from VRE resource shortfall in comparison to alternative net-zero emissions fossil fuel and zero-carbon generation technologies. Targeted generation is maintained for VRE capacity through overcapacity that results in curtailment and with battery storage. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, $50/tonne with 12-year duration.



(a)



(b)



(c)

Figure E.5. Dominant generation technology choice with varying DACS removal cost and fuel price for net-zero EGUs. Panel (a) shows DACS relationship to natural gas price, and Panel (b) shows DACS relationship to co-fire fuel price. Panel (c) shows fuel price relationship. Battery storage requirement is 4 hours above load-shifting capacity with no imposed curtailment. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, \$50/tonne with 12-year duration.

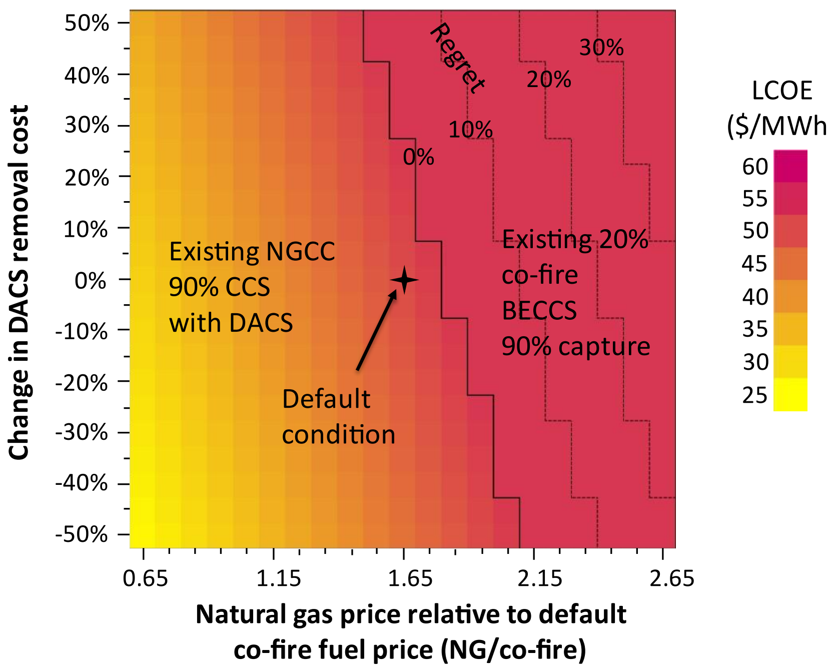


Figure E.6. LCOE and regret based upon dominant generation technology choice for DACS capture cost and natural gas price relative to default co-fire fuel price ranges with net-zero for fossil fleet, while fossil is meeting target generation. 45Q incentive set at $65/tonne credit level for 15-year duration for NGCC CCS. Current 45Q incentive is applied for CO_2 emissions captured with coal-fired CCS and DACS technologies, $50/tonne with 12-year duration. Regret is measured relative to having chosen existing NGCC with CCS and DACS to achieve net-zero emissions.

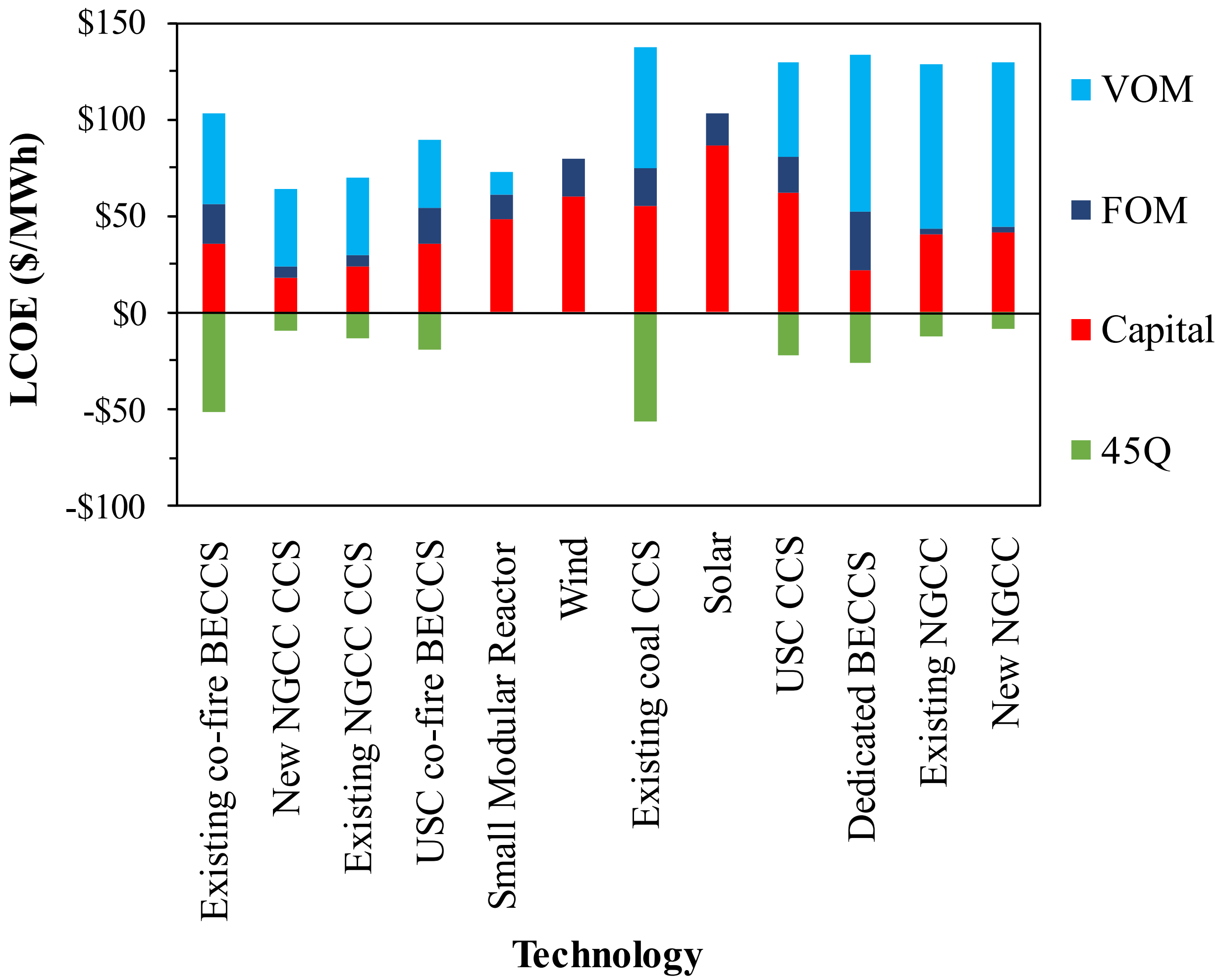


Figure E.7. LCOE components for generation technology options producing net-zero emissions and zero-carbon electricity while maintaining target generation. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, \$50/tonne with 12-year duration. Battery storage requirement is 4 hours above load-shifting capacity with no imposed curtailment. Existing coal with DACS and existing BE co-fire are not shown because LCOE exceeds \$150/MWh. Long-duration storage is not shown because LCOE range components are not defined.

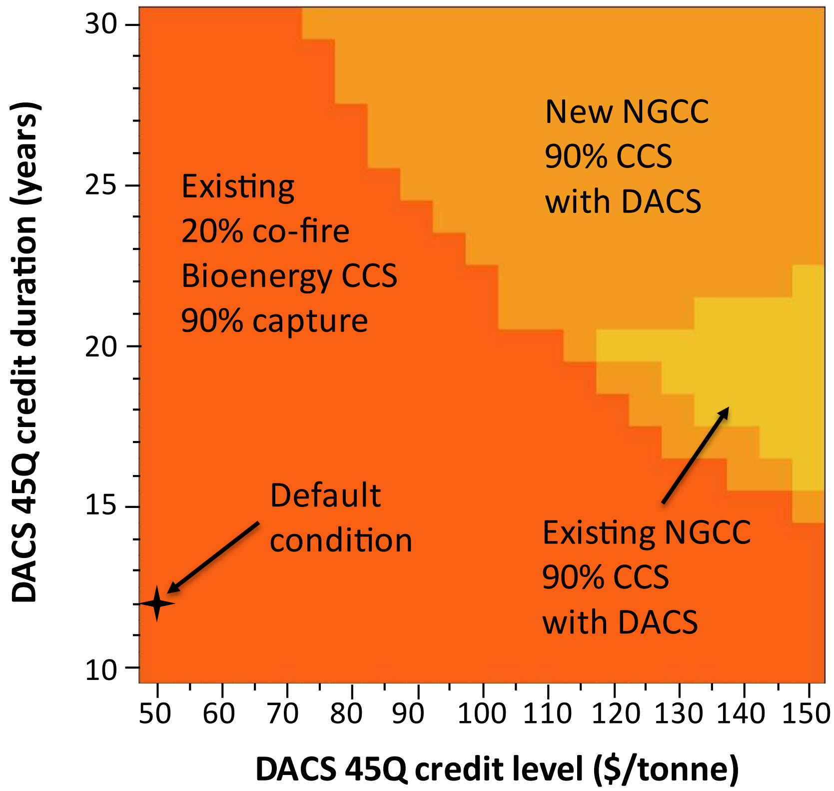


Figure E.8. Dominant generation technology choice from modifying DACS 45Q credit level and duration for immediate storage and constraining for net-zero emissions. Battery storage requirement is 4 hours above load-shifting capacity with no imposed curtailment. Current 45Q incentive is applied for CO_2 emissions captured with CCS technology, $50/tonne with 12-year duration.

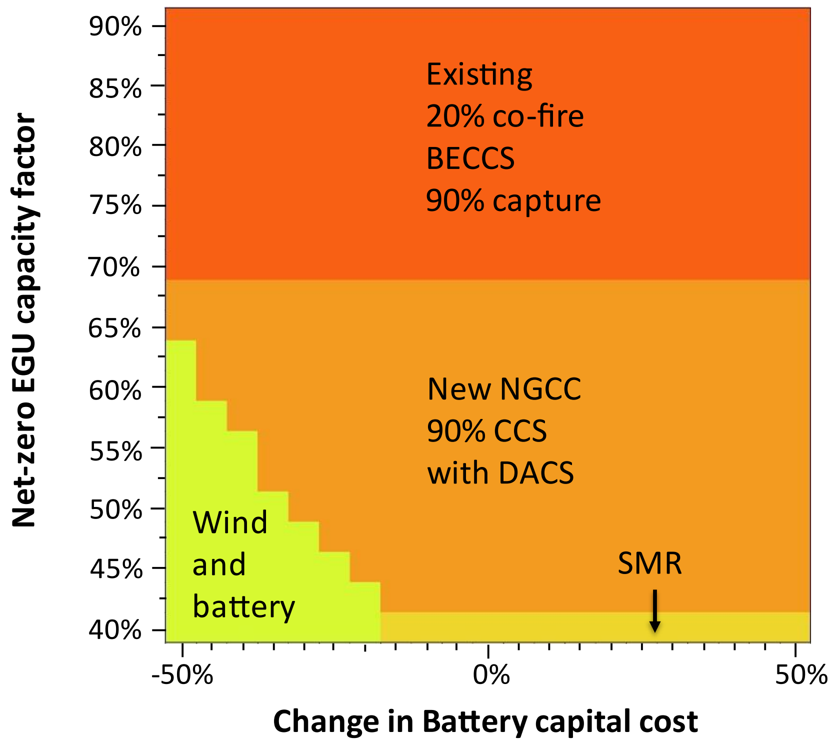


Figure E.9. Dominant generation technology choice from variations in battery capital cost and capacity factor for net-zero EGUs. Targeted generation is only maintained for SMR and VRE capacity. Battery storage requirement is 4 hours above any load-shifting capacity with no imposed curtailment. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, $50/tonne with 12-year duration.

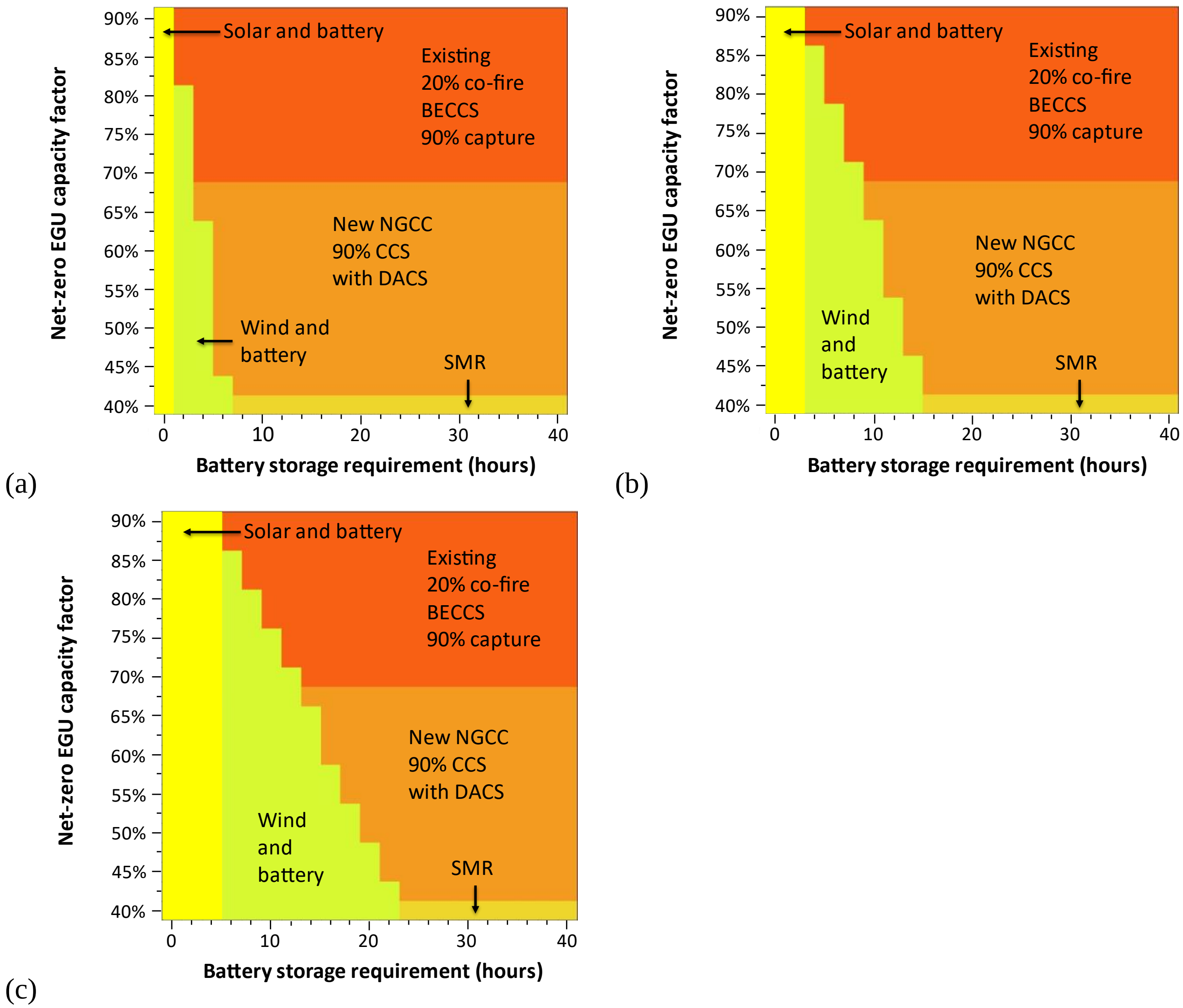


Figure E.10. Dominant generation technology choice with varying battery storage requirement for resource shortfall and capacity factor for net-zero EGUs, with decreasing battery capital cost. Panel (a) shows a 50% reduction in default battery capital-cost (to $409/kW). Panel (b) shows a 90% reduction in battery cost (to $82/kW), and Panel (c) shows a 99% reduction in cost (to $8.2/kW). Targeted generation is only maintained for SMR and VRE capacity. VRE adequacy from battery storage only. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, $50/tonne with 12-year duration.

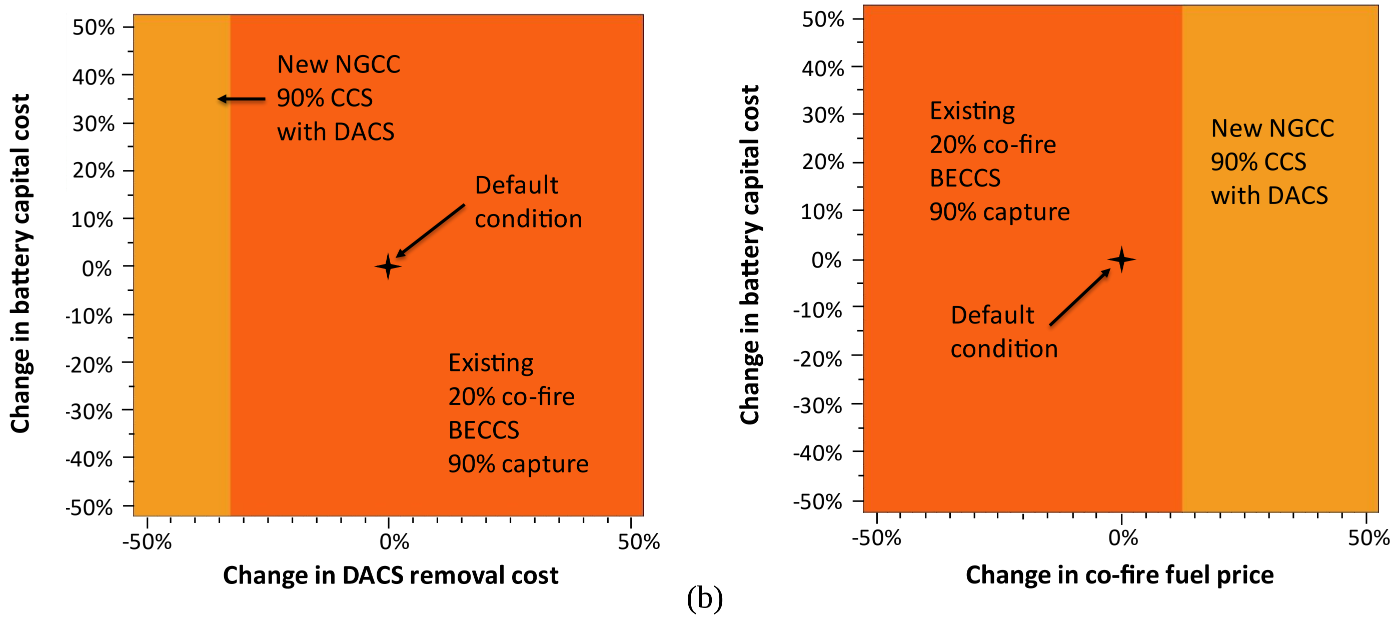


Figure E.11. Dominant generation technology choice for variations in battery capital cost for 4-hour duration battery storage requirement and (a) DACS removal cost and (b) co-fire fuel. Targeted generation is maintained. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, \$50/tonne with 12-year duration.

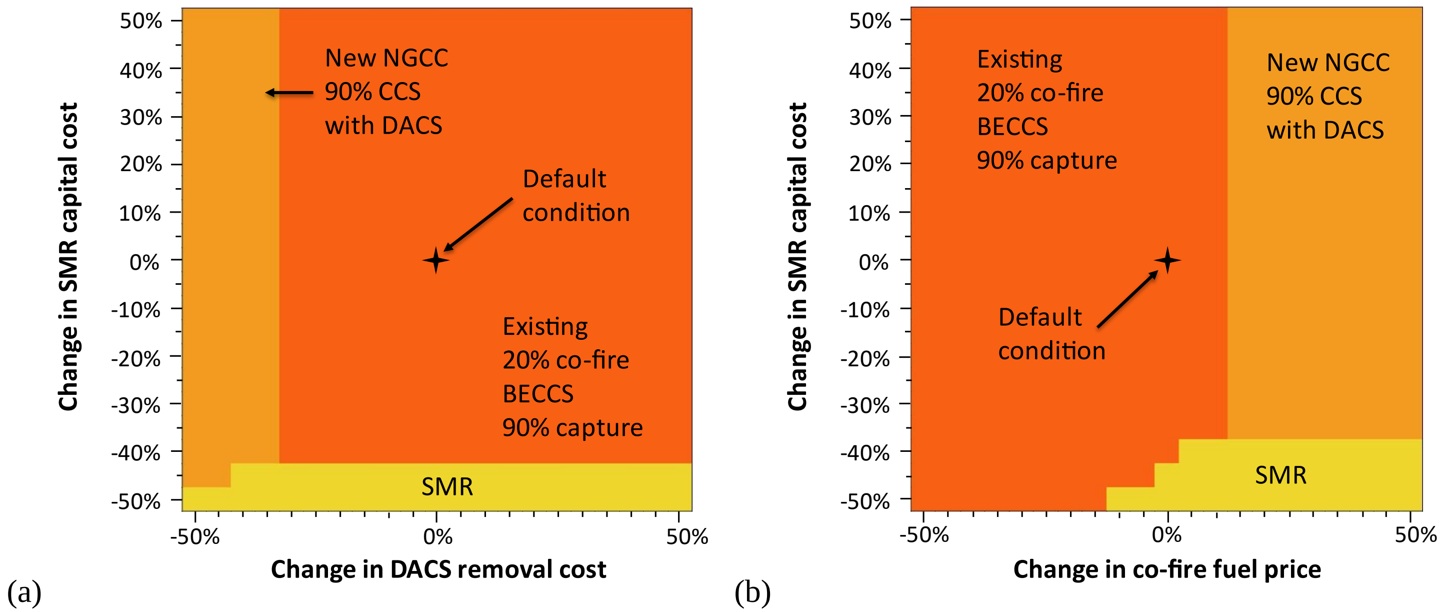


Figure E.12. Dominant generation technology choice for variations in SMR default capital cost and (a) DACS removal cost and (b) co-fire fuel. Targeted generation is maintained. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, \$50/tonne with 12-year duration.

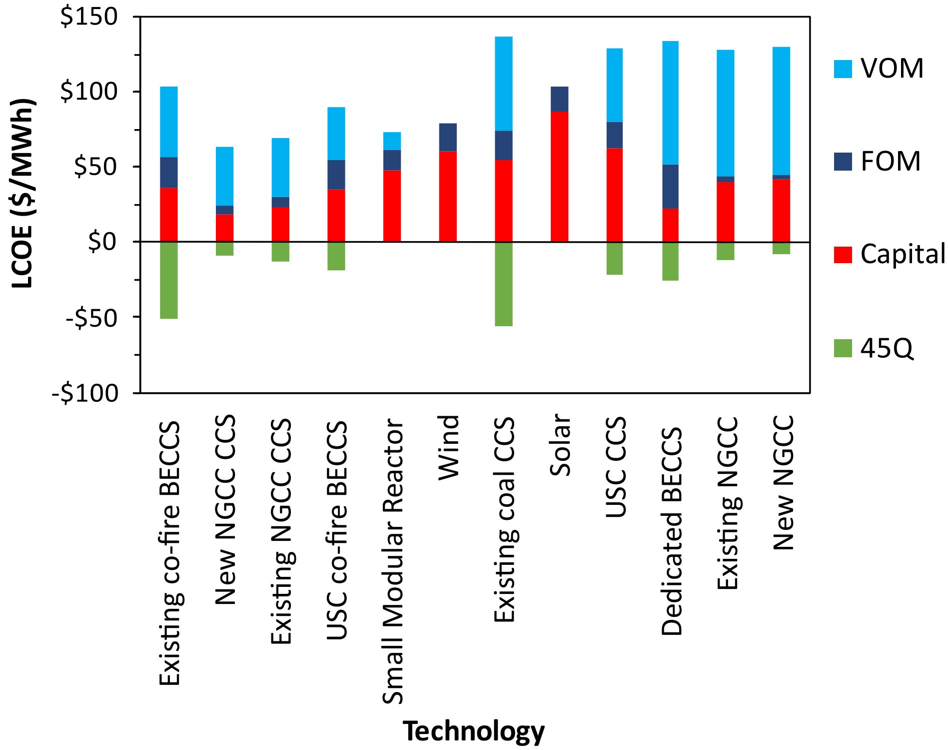


Figure E.13. LCOE for generation technology options producing net-zero emissions and zero-carbon electricity while maintaining target generation. Capacity factor for dedicated BE and BECCS EGUs is 90%. Current 45Q incentives for immediate storage are applied for CO_2 emissions captured with CCS and DACS technologies, $50/tonne with 12-year duration. Existing coal with DACS and existing BE co-fire are not shown because LCOE exceeds $160/MWh.

E.6.5 Supplementary Note 3: 99% CCS capture rate

While this analysis uses a 90% capture rate for CCS, other studies suggest that capture rates as high as 99.7% are both technically feasible and economically viable for USC and NGCC CCS systems [6, 7]. Increasing the capture rate decreases the residual CO_2 removal requirement for the EGU but also decreases the efficiency of the unit and increase the overall LCOE. An International Energy Agency study [7] reports that for an USC EGU, the higher heating value efficiency will decrease 5.2% and the LCOE will increase by 8% when the capture rate is increased from 90% to 99%. For a NGCC plant this efficiency will decreases by 4.5% and the

LCOE will increase by 6.2%. When these estimates are applied to the respective modeled EGUs that use CCS (inclusive of the extra storage cost and 45Q incentives, and assuming that the CO_2 pipeline originally modeled is still sized correctly for the greater sequestered volume), we find that the groupings are predominantly the same, Figure E.14.

In this figure, the lowest cost net-zero emission technologies still dominate the zero carbon solutions, though the order is changed. NGCC with CCS, either new or existing, is now preferred to existing co-fire BECCS, however the gap between their LCOE is less than US$5 MWh^{-1} (Table E.6). The next grouping between SMR and wind is also similar with the notable exception that the LCOE for existing coal with CCS is now lower than that for SMR, further emphasizing that decarbonized existing fossil-fuel assets can economically provide firm capacity in a net-zero power sector. This promotion in order is also found for USC with CCS and is due to less reliance on DACS for emissions reduction, which has a higher CO_2 avoidance cost (Table E.7 and Eq. E3). BECCS technologies that do not require DACS to achieve net-zero emissions generally increase in LCOE. This increase may be because the efficiency and LCOE trends are not applicable for these technologies, or the co-fire level is not optimized to reduce VOM costs and achieve no more than net-zero emissions, as no further economic benefit is gained from negative emissions in this model other than the 45Q incentives.

$$Avoidance = \frac{LCOE_2 - LCOE_1}{I_1 - I_2} \tag{E.3}$$

where *Avoidance* is the CO_2 avoidance cost for the mitigation (US$/tonne), *LCOE* is the levelized cost of electricity for the EGU (US$/MWh), *I* is the EGU CO_2 emissions intensity (kg/MWh), the subscript *1* denotes the EGU without the CO_2 mitigation, and the subscript *2* denotes the EGU with the CO_2 mitigation.

Table E.6. Comparison of technology LCOE for 90% and 99% CCS capture rate with 45Q incentives.

	LCOE (US$ MWh^{-1})		
Technology	**99% capture rate**	**90% capture rate**	**Difference (99%-90%)**
New NGCC CCS	49	55	-6
Existing NGCC CCS	51	56	-5
Existing co-fire BECCS	54	53	1
Existing coal CCS	59	81	-22
Small Modular Reactor	73	73	0
USC co-fire BECCS	76	71	5
Dedicated BE	78	78	0
Wind	80	80	0
USC CCS	93	107	-14
Solar	103	103	0
Dedicated BECCS	115	108	7
Long-duration Storage	115	115	0
Existing NGCC	116	116	0
New NGCC	122	122	0
Existing co-fire BE	169	169	0
Existing coal	208	208	0

Table E.7. Technology CO_2 avoidance cost for 99% CCS capture rate without 45Q incentives.

Technology	**Avoidance cost (US$ $tonne^{-1}$)**
Existing coal CCS	86
USC CCS	64
Existing NGCC CCS	64
New NGCC CCS	46
DACS average estimate	212

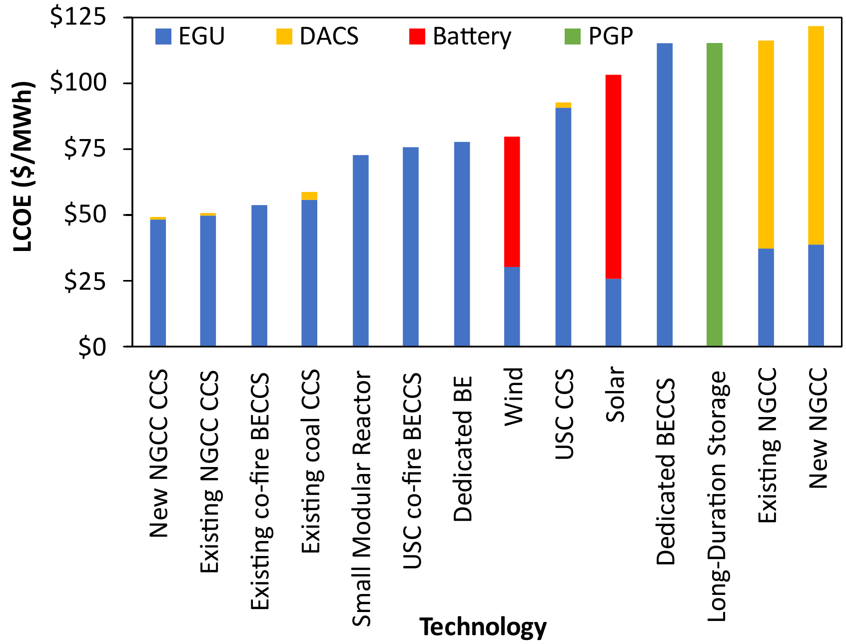


Figure E.14. 99% capture rate rank order LCOE for generation technology options producing net-zero emissions and zero-carbon electricity while maintaining target generation. Four-hour duration battery storage is used for VRE technologies. Existing coal with DACS and existing co-fire BE are not shown because LCOE exceeds US$160 MWh^{-1}.

E.6.6 Supplementary Methods

E.6.6.1 Total system modeling

The performance and cost modeling for the fossil-fuel electricity generation units (EGUs), without and with carbon capture and storage (CCS), in this analysis are based upon the default region-specific inputs for the Midwest in the Integrated Environmental Control Model (IECM) version 11.2 [8]. General and technology-specific model assumptions and inputs for the IECM and other calculations are discussed in the following technology-specific sections and are summarized in Tables E.8-E.17. The coal and natural-gas fuel prices for 2030 (Tables E.9 and 10) are taken from the 2030 projected national prices for power-sector steam coal and natural gas in the Energy Information Administration's (EIA) 2020 Annual Energy Outlook (AEO) [9] for the reference case and are converted to 2017 dollars with the Consumer Price Index (CPI) [10]. The steam coal properties are based on subbituminous coal because the carbon dioxide (CO_2) emissions for this coal are higher than those for bituminous coal. The general equations for variable fuel costs (Eq. E.4) and annual emissions (Eq. E.5) for the different types of fuel are shown below.

$$VOM_{fuel,i} = \frac{(HR_i)C_{fuel,i}}{1000} \tag{E.4}$$

where VOM_{fuel} is the EGU variable fuel operation and maintenance cost (\$/MWh), HR is the heat rate for the EGU (kJ/kWh), C_{fuel} is the fuel price (\$/GJ), 1000 is a conversion factor, and the subscript i denotes the fuel type.

$$m_i = \frac{I_i G_{net,i}}{1000} \tag{E.5}$$

where m is the annual CO_2 emissions (tonnes), I is the EGU CO_2 emission intensity (kg/MWh), G_{net} is annual EGU net generation (MWh), 1000 is a conversion factor, and the subscript i denotes the EGU type.

Direct air capture and storage (DACS) technology can be employed to achieve net-zero emissions for the fossil fuel EGUs both without and with CCS. The incremental levelized cost of electricity (LCOE) for this technology, based upon the DACS cost and performance assumptions discussed in the technology-specific section and Table E.17, is added to the simulated LCOE for the fossil-fuel EGU configuration. For coal-fired EGUs (CFEGUs), net-zero emissions can also be achieved when co-firing with 20% biomass by energy and 90% capture CCS are employed [11, 12]. The combination of dedicated bioenergy and DACS for negative emissions is not evaluated.

The zero-carbon solar, wind, and nuclear EGU cost and performance modeling presented is based on projections provided by the National Renewable Energy Laboratory (NREL) for the Annual Technology Baseline (ATB) report [13], and in the EIA utility-scale power generation capital-cost study for the 2020 AEO [14]. These are described in the technology-specific sections and given in Tables E.18 and E.19. Lithium-ion battery (Li-ion), Table E.20, and long-duration storage technologies are used to determine total system cost when the variable solar or wind capacity must provide 100% reliability for the given curtailment and solar and wind resource-shortfall constraints. These storage technologies are described in the zero-carbon section.

Table E.8. Overview of EGU, CCS, and DACS operational and financial parameters.

Parameter	Value
Location	Midwest
2030 fuel prices	National 2020 AEO electric power sector
Source CFEGU, NGCC, and CCS performance modeling and costing	IECM version 11.2
Source coal, biomass, and natural gas properties	IECM version 11.2, EIA
Target annual net generation (TWh)	3.135
Year costs reported	2017
Dollar costs basis	Constant
Fossil-fuel project book life new (years)	30
Fossil-fuel project book life existing (years)	15
Zero-carbon generation book life (years)	30
Direct air capture book life (years)	30
Fossil fuel remaining value calculation	Straight-line amortization
Regional construction adders	None
Technology-specific fixed charge factor source	NREL 2019 ATB
Construction costs	Overnight

*Notes: CEPCI: Chemical Engineering Plant Cost Index; CPI: Consumer Price Index

Table E.9. As-received default properties and price of fuels for coal-fired and bioenergy EGUs used in the IECM [8].

Variable	Coal	Forest residue	20% biomass co-fire simulated coal
Heating value (kJ/kg)	19,400	13,490	17,840
Carbon (% wt.)	48.18	32.00	43.90
Hydrogen (% wt.)	3.31	3.80	3.40
Oxygen (% wt.)	11.87	28.00	16.10
Chlorine (% wt.)	0.01	0.0	0.0
Sulfur (% wt.)	0.37	0.01	0.30
Nitrogen (% wt.)	0.7	0.2	0.60
Ash (% wt.)	5.32	0.4	4.0
Moisture (% wt.)	30.24	35.59	31.70
Cost ($/GJ)	1.763	2.578	1.990

Table E.10. As-received default properties and price of natural gas used in the IECM [8].

Variable	Units	Natural gas
Heating value	kJ/kg	52,290
Methane (CH_4)	vol. %	93.1
Ethane (C_2H_6)	vol. %	3.2
Propane (C_3H_8)	vol. %	1.1
Carbon Dioxide (CO_2)	vol. %	1.0
Oxygen (O_2)	vol. %	0.0
Nitrogen (N_2)	vol. %	1.6
Hydrogen Sulfide (H_2S)	vol. %	0.0
Density	kg/m^3	0.731
Cost	$/GJ	3.270

E.6.6.2 Fossil fuel modeling

E.6.6.2.1 Coal-fired EGU

Each CFEGU modeled, Tables E.4 and E.11, is based upon a 650-megawatt gross (MW_{gross}) capacity (the default capacity for a new CFEGU in the IECM) operating at capacity factor sufficient to produce 3.135 TWh net generation. For the default CFEGU, this target generation is achieved with a 60% capacity factor, which is similar to the projected capacity factor for the coal-fired fleet in the carbon-free generation standard case presented in the 2020 AEO (64%) [9]. Therefore, CFEGUs operating with higher parasitic loads from CCS are doing so at a capacity factor below the 80-87% capacity factors that are often used in LCOE-based models for new generation sources. As such, these generators are oversized for the requisite generation, a condition similar to overbuilding renewable capacity and needing to curtail generation. Existing CFEGUs are assumed to have been in service for 50 years by 2030 and to have a remaining operational life of 15 years and a 15-year book life. Greenfield construction is assumed to have at least a 30-year operational life and a 30-year book life. Each CFEGU uses wet-cooling and is equipped with the necessary traditional emission control devices (ECDs) to comply with current air-quality standards. The CFEGUs are fueled with subbituminous coal, Table E.9. When the boiler is not operating at maximum load, a heat rate penalty is applied that increases the variable fuel cost and the emission intensity of the unit (See Section E.10.6.2.3 *Heat rate penalty*).

E.6.6.2.2 Natural gas combined cycle

For this simulation, the default GE 7FB turbine (247.3 MW_{net} per turbine) with a wet-cooling tower configuration is used for the IECM modeled natural gas combined cycle (NGCC) plant (Table E.12). At this net capacity, two turbines are sufficient to produce the requisite net generation at a 60% capacity factor. While nitrogen oxide controls are not added to the modeled configuration, these controls may be necessary if the EGU is required to operate at low-capacity factors to follow baseload variable renewable energy (VRE). Existing NGCC plants are assumed to have been in service for 15 years by 2030 and to have a remaining operational life of 15 years; therefore, 50% of the plant and natural gas pipeline costs have been amortized. Greenfield construction, to which the cost of a new natural gas pipeline is added, is assumed to have at least a 30-year operational life.

E.6.6.2.3 Heat rate penalty

Lowering the capacity factor of the generating unit to operate at a level that is below the maximum achievable load may incur an increase in the design heat rate, the associated fuel consumption costs, and the emission intensity [15] (all of which are calculated exogenously to the IECM and added to the IECM results). Such a heat rate penalty is characterized as a cubic function (Eq. E.6), the coefficients of which are derived for the coal-fired and NGCC units (Tables E.13 and E.14, respectively) by compensating the data presented in [15] such that the

100% load has no penalty.[101] This penalty is relative to the IECM-derived net heat rate (Eq. E.7), which is independent of capacity factor, and is applied to the theoretical emission intensity to determine the change in emission intensity, Eq. E.8, and to the fuel price to determine the resulting change in fuel-related variable operation and maintenance (VOM) cost, Eq. E.9.

$$HR_{penalty} = \beta_0 + \beta_1 CF + \beta_2 CF^2 + \beta_3 CF^{-1} \tag{E.6}$$

where $HR_{penalty}$ is the heat rate penalty for the EGU (fraction) and CF is the adjusted capacity factor required for the EGU.

$$HR_1 = HR_0\left(1 + HR_{penalty}\right) \tag{E.7}$$

where HR_1 is the adjusted net heat rate for the EGU (kJ/kWh), HR_0 is the default heat rate for the EGU derived in the IECM (kJ/kWh), and $HR_{penalty}$ is the heat rate penalty for the EGU due to the adjusted capacity factor (fraction).

$$\Delta I_1 = I_0\left(HR_{penalty}\right) \tag{E.8}$$

where ΔI_1 is the change in CO_2 emission intensity for the EGU (kg/kWh), I_0 is the default emission intensity for the EGU derived in the IECM (kg/kWh), and $HR_{penalty}$ is the heat rate penalty for the EGU due to the adjusted capacity factor (fraction).

[101] Coefficients for the heat rate penalty curve are determined from a nonlinear regression using data points measured from the curve generated in [15].

$$\Delta VOM = \frac{(HR_1 - HR_0)C_{fuel}}{1000} \tag{E.9}$$

where ΔVOM is the change in fuel related variable operations and maintenance cost for the plant ($/MWh), HR_1 is the adjusted net heat rate for the EGU (kJ/kWh), HR_0 is the default heat rate for the EGU derived in the IECM (kJ/kWh), C_{fuel} is the fuel price ($/GJ), and 1000 is a conversion factor.

Table E.11. CFEGU default cost, finance, and performance parameters.

Parameter	Value
CFEGU current configuration	Subcritical boiler, pulverized coal, tangential wall, wastewater ash pond, no mixing fly ash disposal, wet-cooling tower, cold-side electrostatic precipitator
Coal rank	Subbituminous
CFEGU retirement age (years)	65
Existing EGU fixed charge factor (fraction)	0.121
New EGU fixed charge factor (fraction)	0.083
Gross capacity (MW)	650
Year compliant with non-CO_2 air quality regulations	2016
NO_x compliance combustion controls	Low NO_x burner (LNB)
NO_x compliance post combustion controls	Hot-side selective catalytic reduction (SCR)
SO_x compliance post combustion controls	Wet flue-gas desulfurization (FGD)
Hg compliance post combustion controls	Carbon injection

Table E.12. NGCC default cost, financial, and performance parameters.

Parameter	Value
NGCC default configuration	GE 7FB, wet-cooling tower
Turbines	2
Gross capacity (MW)	650
NGCC retirement age	30 years
Existing EGU fixed charge factor (fraction)	0.094
New EGU fixed charge factor (fraction)	0.057
New NG pipeline distance (km)	32
Booster pump	No
New NG pipeline cost (M$/km)*	0.75

*Notes: M$: million dollars.

Table E.13. Coefficients for the cubic function describing the fractional heat rate penalty associated with capacity factors less than the maximum load for the CFEGUs as modeled in the IECM.

β_0	β_1	β_2	β_3	RMSE
-0.400	0.510	-0.234	0.124	0.004

Table E.14. Coefficients for the cubic function describing the fractional heat rate penalty associated with capacity factors less than the maximum load for the NGCC plants as modeled in the IECM.

β_0	β_1	β_2	β_3	RMSE
0.217	-0.516	0.241	0.057	0.003

E.6.6.3 CO_2 reduction modeling for fossil-fuel EGUs

E.6.6.3.1 Biomass co-firing

One method to reduce emissions for the existing or new CFEGUs is to co-fire the coal with biomass such as forest residue (wood chips). This method reduces the emissions in two ways. First, the carbon content of the combined fuel is reduced when the coal is replaced by the biomass on an energy basis. Second, the CO_2 emissions from the biomass are considered carbon neutral; therefore, the overall annual emissions from the CFEGU using 20% co-fire are reduced by 26% on a weight basis. Co-firing is modeled in the IECM to determine the cost and performance characteristics by creating a coal that is a weight-averaged blend of the coal and forest residue properties [14] given the 20% forest residue energy-content mix. As the moisture, sulfur, and carbon content of the residue differ from that of the coal (Table E.9), some capital costs for the CFEGU increase in the IECM relative to the counterfactual and are determined directly in the IECM based upon new construction, with the capital cost increases defined by the differences in the two cases for the various capital components. These differences in capital costs, with an additional 1.2 multiplier for retrofit adjustment [16], are added to the modeled LCOE calculation since upgrading an existing asset may be more costly than a simulated change based upon new construction.

Additional costs are also added exogenously to the simulated LCOE to account for handling and drying costs for the residue (Table E.15). The capital cost for this retrofit is derived as the average of the average of the ranges in estimated $/kW cost from ten studies [17-25] on a co-fire percent basis and converted to 2017 dollars with the Chemical Engineering Plant Cost Index (CEPCI) [26]. This value is also increased by 20% to account for retrofitting [16]. The operation and maintenance (O&M) costs used are defined by the International Renewable Energy Agency (IRENA) [17]. The fixed operation and maintenance (FOM) cost is taken as the percent of the installed cost from the average of the range, whereas the VOM cost that is not fuel related is taken as $5/MWh on a co-fire percent basis. The forest residue cost is derived from the NREL 2019 ATB [13] wood chip price for 2030 for a fully-dedicated biomass generator, Table E.9. Fixed maintenance cost increases for the existing CFEGU due to co-firing are assumed to be negligible because the co-fire percentage is below 20% [17]. Equations for these costs and the resulting additional LCOE for co-firing, excluding fuel VOM, are shown in Eqs. E.10-E.13.

$$CC_{cofire} = 1000(Cap)(Cofire)\left(CC_{cofireretro}\right)(MF_1) + (\Delta CC_{EGUretro})(MF_2) \quad \text{(E.10)}$$

where CC_{cofire} is the total capital cost for equipping the CFEGU to co-fire with biomass ($), *Cap* is the EGU capacity (MW), *Cofire* is the percent of biomass co-fire by energy (fraction), $CC_{cofireretro}$ is the capital cost related to the additional costs of equipping the CFEGU to use biomass ($/kW), MF_1 is a multiplication factor for retrofitting these items (fraction), $\Delta CC_{EGUretro}$ is the IECM-determined additional capital cost related to modifying the existing CFEGU to use biomass ($), MF_2 is a multiplication factor for the previous term (fraction), and 1000 is a conversion factor.

$$FOM_{cofire} = 1000(Cap)(Cofire)\left(CC_{cofireretro}\right)\left(FOM_{cofireadder}\right) \quad \text{(E.11)}$$

where FOM_{cofire} is the fixed operation and maintenance cost from equipping the CFEGU to co-fire with biomass ($), *Cap* is the EGU capacity (MW), *Cofire* is the fraction of biomass co-fire by energy (fraction), $CC_{cofireretro}$ is the capital cost related to the additional costs of equipping the CFEGU to use biomass ($/kW), $FOM_{cofireadder}$ is the additional FOM cost as a fraction of the additional capital cost of adding biomass co-firing (fraction), and 1000 is a conversion factor.

$$VOM_{cofirenonfuel} = (Cofire)\left(VOM_{cofirenonfueladder}\right) \quad \text{(E.12)}$$

where $VOM_{cofirenonfuel}$ is the variable nonfuel operation and maintenance cost from equipping the CFEGU to co-fire with biomass ($/MWh), *Cofire* is the fraction of biomass co-fire by energy (fraction), and $VOM_{cofirenonfueladder}$ is the additional nonfuel VOM cost from adding biomass co-firing ($/MWh).

$$LCOE_{cofire} = \frac{CC_{cofire}(FCF_{cofire,i}) + FOM_{cofire}}{G_{netcofire}} + VOM_{cofirenonfuel} \quad \text{(E.13)}$$

where $LCOE_{cofire}$ is the levelized cost of electricity from the addition of the co-firing with biomass ($/MWh), CC_{cofire} is the total capital cost for equipping the CFEGU to co-fire with biomass ($), *Cap* is the CFEGU capacity (MW), FCF_{cofire} is the fixed charge factor for co-firing for the book life of the project (fraction), FOM_{cofire} is the fixed operation and maintenance cost for the CFEGU ($/kW), $G_{netcofire}$ is the CFEGU annual net-generation (MWh), and the subscript i denotes the book life of the project (15 or 30 years).

E.6.6.3.2 Ultra-supercritical CFEGU with CCS

Emissions from the existing EGU, coal-fired or natural gas-fired, can also be decreased by replacing the EGU with an ultra-supercritical (USC) coal-fired EGU equipped with 90% CCS (Tables E.11 and E.16). In this option calculated in the IECM, the lower steam-cycle heat rate of the boiler increases the efficiency of the unit compared to the coal-fired options with CCS and has a lower emission intensity than the NGCC unit without CCS. The IECM parameters for the CCS are described in the following section. No retrofit adjustments are added to this scenario, as it is taken as a greenfield build. Further reduction can be achieved when co-firing with 20% forest residue, for which the assumptions and procedures for performance and cost parameters are the same as those discussed in the previous section without the addition of EGU retrofitting costs and the multiplier factors.

E.6.6.3.3 CCS

Emissions for the existing and new EGUs can also be decreased through the addition of commercially-available amine-based CCS to achieve a 90% capture rate [27, 28]. For this analysis, low-quality steam from the steam cycle is extracted for the CCS solvent-regeneration process, thereby reducing the net generation because of the CCS parasitic load. In this mitigation, additional components of the LCOE calculation include the capital and operation and maintenance costs associated with the CCS facility, the pipeline for CO_2 transportation, and the CO_2 sequestration. These costs are calculated in the IECM simulation, based upon the assumptions in Table E.16, with the addition of a 1.2 retrofit factor [16] applied in IECM to all CCS subsystem capital costs for an existing EGU. Furthermore, costs associated with retrofitting the CCS subsystem to an existing base plant and wet-cooling tower configuration are calculated based upon the difference in component costs with and without the CCS subsystem. To this, a 1.2 multiplier for retrofit adjustment [16] is also applied. The pipeline length is taken as the capacity-weighted average length for 90% capture for CFEGUs used in [29]. Mt Simon 1 was chosen as the sequestration site with the associated rate [30]. The general equation for annual emissions after capture (Eq. E.14) for the different EGUs is shown below.

$$m_{CCS} = \frac{I_i(G_{net})(\phi_{CCS})}{1000} \tag{E.14}$$

where m_{CCS} is the annual CO_2 emissions captured (tonnes), I is the EGU CO_2 emission intensity (kg/MWh), G_{net} is annual EGU net generation (MWh), ϕ_{CCS} is the CCS capture rate (fraction), and 1000 is a conversion factor.

E.6.6.3.4 Direct air capture

The direct air capture system cost and performance parameters are taken from the National Academies of Science, Engineering, and Medicine (NASEM) analysis of a generic liquid-solvent system with a 1 Mt/year capacity [31] and are based upon Holmes and Keith [32] and Keith et. al [33]. In our analysis of the default case, we assume that the facility electricity is supplied with NG generation from the grid and that the necessary thermal energy is supplied by natural gas, according to NASEM Table 5.11 [31]. While we further assume the same capital costs and non-fuel O&M costs as in the NASEM model, the published net-removed capture costs are modified with low and high fixed charge factor (FCF) estimates that are aligned with those used for ATB-modeled mature and nascent technologies [13], the natural gas price used in our model, and an electricity price updated for the projected industrial electricity price for 2030 [9]. Furthermore, we add $8/tonne cost for compressing the CO_2 to this total, assuming that the facility is located over the common geologic storage site and there is no additional transportation cost. In the NASEM report, the 1 Mt/year removal rate for the facility is derated to 0.74 Mtonnes/year to account for the CO_2 emissions of the thermal and electrical process requirements. While this report assumes a 744 kg/MWh grid intensity, which is higher than the 297 kg/MWh projected intensity for 2030 in the 2020 AEO report [9], we do not modify the net removed cost to account for this decrease in facility electricity related emissions. The storage cost calculation for DACS is shown in Eq. E.15 and the required tonnage to capture is shown in Eq. E.16. These modifications result in a US$143-282 tonne^{-1} cost range for DACS removal. Given the annual net CO_2 removal for the facility, the number of facilities required to remove this effluent from the air to achieve net-zero emissions is determined by dividing the remaining EGU emissions by the DACS net-removal rate (Eq. E.17). Fractional facility requirements are not rounded up because these cases indicate opportunities for negative emissions or for using a facility to remove emissions from multiple EGUs. To account for uncertainty in the DACS net-removal cost, the average DACS removal cost is determined from the low and high values given in Table E.17 and used as the basis for a parametrical analysis.

$$DAC_i = \frac{FCF_{DAC,i}(CC_{DAC,i}) + NG(Therm_i) + E(Elect_i)}{\zeta} + Comp \quad \text{(E.15)}$$

where *DACS* is the removal cost for DACS ($/tonne), FCF_{DAC} is the DACS fixed charge factor (fraction), CC_{DAC} is the DACS capital cost ($), *NG* is the natural gas price ($/GJ), *Therm* is the DACS thermal requirement ($/GJ), *E* is the electricity price ($/MWh), *Elect* is the DACS electricity requirement (MWh), ζ is the net-removal rate (Mtonnes/year), *Comp* is the compressor cost ($/tonne), and the subscript *i* denotes the low or high estimate.

$$m_{DAC} = \frac{I_i(G_{net})}{1000} - m_{ccs} \quad \text{(E.16)}$$

where m_{DAC} is the required DACS captured CO_2 emissions per year to have net-zero emissions (tonnes), *I* is the annual EGU CO_2 emission intensity (kg/MWh), G_{net} is annual EGU net generation (MWh), m_{CCS} is the annual CCS CO_2 emissions captured (tonnes), and 1000 is a conversion factor.

$$n_{DAC} = \frac{m_{DAC}}{\zeta} \tag{E.17}$$

where n_{DAC} is the required number of DACS facilities to remove EGU CO_2 emissions to achieve net-zero emissions (fraction), m_{DAC} is the required DACS captured CO_2 emissions per year to have net-zero emissions (tonnes), and ζ is the DACS net-removal rate (Mtonnes/year).

Table E.15. Co-firing with biomass default cost, finance, and performance parameters.

Parameter	Symbol	Value
Biomass fuel type	None	Forest residue (wood chip)
Fraction co-fire by energy	*Cofire*	0.20
Fraction co-fire by weight	None	0.26
Biomass retrofit capital cost ($/kW-%cofire)	CC_{cofire}	490
Biomass co-fire equipment multiplication factor	MF_1	1.2
CFEGU co-fire multiplication factor	MF_2	1.2
Biomass co-fire FOM adder (percent of co-fire additional retrofit capital cost)	$FOM_{cofireadder}$	4.5
Biomass co-fire non-fuel VOM adder ($/MWh-%cofire)	$VOM_{cofirenonfueladder}$	5
Existing CFEGU fixed charge factor (fraction)	$FCF_{cofire,15}$	0.089
New CFEGU fixed charge factor (fraction)	$FCF_{cofire,30}$	0.054

Table E.16. CCS default cost and performance parameters.

Parameter	Value
Capture method	FG+ amine
Capture efficiency (fraction)	0.90
Auxiliary steam and electricity source	None
SO_x polisher use	Yes
CO_2 purity (fraction)	0.995
Coal-fired and NGCC CCS new adjustment multiplication factor for CCS subsystem (fraction)	1.20
Coal-fired and NGCC CCS retrofit multiplication factor for base plant, WT* (fraction)	1.20
CO_2 transportation method	Pipeline
Booster pump	No
CO_2 storage method	Geological
CO_2 storage site	Mt. Simon 1
CO_2 storage cost ($/tonne)	7
Annual pipeline FOM ($/km)	3,100
Pipeline distance (km)	362.1

*Notes: WT: wet-cooling tower.

Table E.17. DACS system default cost, finance, and performance parameter ranges [31].

Parameter	Low	High
Fixed charge factor (fraction)	0.05	0.073
Operational expenditures (M$/year)	67	114
Total capital expenditures (M$)	675	1,255
Annual thermal energy requirement (TJ)	7.692	10.769
Annual electricity requirement (MWh)	200,000	466,667
CO_2 compression cost ($/tonne)	8	8
Grid electricity cost (2019$/MWh)	65	65
Net CO_2 removed for a 1 Mtonne/year facility (Mtonnes)	0.74	0.74
CO_2 storage site	Mt. Simon 1	Mt. Simon 1
CO_2 storage method	Geological	Geological
CO_2 sequestration cost ($/tonne)	7	7

E.6.6.4 Zero-carbon EGU modeling

E.6.6.4.1 Solar and wind

VRE overnight capital and O&M costs for the utility solar and land-based wind capacity are taken from the mid-technology cost scenario in the NREL 2019 ATB report [13] (Table E.18). The VRE capacity is then built overnight, for which transmission costs are excluded, so that the annual net generation is 3.135 TWh at the national capacity factors for utility solar and land-based wind sources. These national capacity factors are calculated with net generation and capacity data provided in the NREL future generation scenarios in 2030 with 90% renewable energy penetration and incremental technology improvements (90% RE-ITI) scenario [34]. We assume that 100% of the VRE net generation is required and that assurance of this supply is provided by additional capacity and battery storage. As such, extra capacity is built to meet the net generation represented by the percent curtailment, but the total net generation is not increased. The equation for necessary capacity is given in Eq. E.18.

$$Cap_i = \frac{TG_{net}}{8760(CF_i)} \tag{E.18}$$

where *Cap* is the capacity for the renewable source (MW), TG_{net} is the target net generation (MWh), *CF* is the capacity factor for the renewable source (fraction), 8760 is the number of hours in a year, and the subscript *i* denotes solar or wind generation.

E.6.6.4.2 Nuclear

Two types of nuclear power generation are modeled in this analysis: advanced light-water and small modular reactors (SMR). The capacity, and capital and operating costs for each are taken from the 2020 AEO LCOE assumptions [14] and the Lazard LCOE analysis [35].

Decommissioning cost is considered. The capacity factors for both reactors are held constant at 90% to simulate current operation of nuclear power plants in the U.S., even though SMR operations are capable of flexible operation and larger facilities in Europe are operated as such. Calculating the LCOE with this high-capacity factor does lower the facility LCOE and indicates that if the LCOE for the nuclear capacity is lower than that for the marginal renewable with storage and curtailment or long-duration storage, the nuclear capacity may likely replace other net-zero carbon sources on the grid. As both technologies have similar LCOEs, the SMR technology is the only one considered in this analysis because the capacity is similar to those for the fossil-fuel EGUs. The LCOE cost equation is shown in Eq. E.19 and the cost components in Table E.19.

$$LCOE_i = \frac{1000(Cap_i)\left((CC_i)(FCF_i)+FOM_i\right)}{G_{net,i}} + VOM_{nonfuel,1} + VOM_{fuel,1} + Decom_i \qquad \text{(E.19)}$$

where *LCOE* is the levelized cost of electricity for the nuclear source (\$/MWh), *Cap* is the nuclear source capacity (MW), *CC* is the capital cost of the nuclear source (\$/kW), *FCF* is the nuclear source fixed-charge factor (fraction), *FOM* is the fixed operation and maintenance cost for the nuclear source (\$/kW), G_{net} is the nuclear source annual net-generation (MWh), $VOM_{nonfuel}$ is the nonfuel related VOM of the nuclear source (\$/MWh), VOM_{fuel} is the fuel-related VOM of the nuclear source (\$/MWh), *Decom* is the decommissioning charge expressed as a unitized sinking-fund payment (\$/MWh), 1000 is a conversion factor, and *i* is the subscript indicating the nuclear technology.

E.6.6.4.3 Battery storage

Li-ion batteries are used in this analysis as a mechanism to reduce over-capacity of VRE sources, curtailment, and to allow for time-shifting generation to provide adequacy to meet demand but without supplying more than the intended 3.135 TWh. These batteries are assumed to be either charged by the VRE to which the expense is allocated to avoid curtailment or by the grid at no cost. As such, any curtailment assigned in the simulations is after the batteries are charged. Furthermore, any battery capacity related to resource shortfall storage is considered to be in addition to capacity that might be already used for time-shifting generation. The technical specifications and costs for these batteries is based upon those described in the EIA utility-scale power generation capital-cost analysis for 4-hour duration, 60 MW_{DC} batteries [14]. The calculation for the number of batteries required to meet the renewable shortfall requirement and the added battery cost calculation are shown in Eqs. E.20 and E.21. Parameters for these equations are shown in Table E.20.

$$Q_i = \left(\frac{L}{S}\right)\left(\frac{(8760(CF_i)-D)}{(Cap_{AC})(hr)(\eta)} + (S-1)\left\lceil\frac{R(8760(CF_i)-D)}{(Cap_{AC})(hr)(\eta)}\right\rceil\right) \tag{E.20}$$

where Q is the total required number of batteries for the book life of the project (number), L is the book life of the project (years), S is the service life of the batteries (years), CF is the capacity factor for the renewable generation (fraction), D is duration of battery storage requirement for the resource shortfall (hours), Cap_{AC} is AC capacity of the batteries (MW), hr is the storage duration for the batteries (hours), η is the battery efficiency (fraction), R is the average annual battery replacement rate (fraction), 8760 is the number of hours in a year, and i is the subscript indicating solar or wind generation.

$$C_{bat,i} = \frac{(CC_{bat})(Q_i)(Cap_{AC})(FCF_i)}{1000} + 1000(FOM_{bat})(Cap_{AC})\left(\frac{(8760(CF_i)-D)}{(Cap_{AC})(hr)(\eta)}\right) \quad \text{(E.21)}$$

where C_{bat} is the total annual cost for the batteries over the project life ($), CC_{bat} is capital cost of the batteries ($/kW), *Q* is the total number of batteries required for the project (integer), Cap_{AC} is AC capacity of the batteries (MW), *FCF* is the fixed charge factor (fraction), FOM is the annual battery fixed O&M cost ($/kW), *CF* is the capacity factor for the renewable generation (fraction), *D* is duration of battery storage for the resource shortfall (hours), *hr* is the storage duration for the batteries (hours), η is the battery efficiency (fraction), 1000 is a conversion factor, and *i* is the subscript indicating solar or wind generation.

E.6.6.4.4 Long-duration storage

Long-duration storage (LDS) represents the storage technology-required backup capacity to fill the seasonal and decadal VRE generation variations [36-38]. In this analysis, we only consider power-to-gas-to-power (PGP) generation technology that is a combination of solar/wind generation to produce hydrogen through electrolysis and convert the stored gas to electricity when required [36, 37]. Rather than study the interaction of the various components to find an optimal solution, LDS is parametrically studied relative to the other generation solutions, and is given a cost range of $80-150/MWh [36, 37] (Table E.18).

E.6.6.4.5 Dedicated bioenergy without CCS

Generating electricity from 100% biomass (forest residue) without CCS results in CO_2 neutral emissions. Cost parameters for modeling this generation technology are taken from the 2019 ATB cost analysis [13] derived in part from the EIA utility-scale generation capital cost analysis [14] for a dedicated bioenergy (BE) 50 MW power plant. Rather than construct enough plants to produce the target net generation, our analysis uses the power rule to estimate the capital costs for building one plant to meet the target generation at the same capacity factor as the existing fossil fuel EGUs (Eq. E.22). The resulting overnight cost is converted to 2017 dollars with CEPCI [26]. The 2019 ATB O&M and fuel costs are also used and converted to 2017 dollars with the CPI [10]. Each of these parameters is listed in Table E.21. Similar to the fossil fuel EGUs, a heat rate penalty is imposed on BE and BECCS generation, for which the coal-fired coefficients are used and Eqs. E.4-E.9 are applicable.

$$CC_{BE} = C_{base}\left(\frac{Cap_{base}}{Cap_{BE}}\right)^{\beta} \tag{E.22}$$

where CC_{BE} is the capacity-normalized overnight capital cost for the BE plant $\left(\frac{\$}{kW}\right)$, C_{base} is the baseline overnight capital cost for a 50 MW BE EGU $\left(\frac{\$}{kW}\right)$, Cap_{base} is the capacity of the baseline BE EGU (MW), Cap_{BE} is the BE EGU net capacity required to meet the target generation at a 60% capacity factor (MW), and β is the coefficient for the power rule.

E.6.6.4.6 Dedicated bioenergy with CCS

The combination of generating electricity from 100% biomass (forest residue) and CCS results in negative CO_2 emissions. For this analysis, the IECM is used to derive econometric equations for the costs and performance of the base BE plant from the addition of CCS at 90% capture. Here, eleven subcritical EGUs using only forest residue for fuel are constructed in varying capacities from 10-1,700 MW, the operations of which are simulated at an 80% capacity factor. CCS at 90% capture, which uses the same CCS parameters (Table E.16) and pipeline costs as for the biomass co-fire CFEGUs, is then added to these baseline plants and the resulting changes in cost and performance metrics are noted. The results of these comparisons are shown in Table E.22 and the econometric equations and coefficients for the BECCS cost parameters that are used to calculate the LCOE are given in equations Eq. E.23-E.27 and Table E.23.

$$FOM_{CCS} = \beta_0 + \beta_1 Cap + \beta_2 Cap^2 + \beta_3 Cap^3 + \beta_{4,i} Cap^4 \tag{E.23}$$

where FOM_{CCS} is the modeled CCS FOM (M$) and *Cap* is the net capacity (MW).

$$CC_{CCS} = \beta_0 + \beta_1 Cap + \beta_2 Cap^2 + \beta_3 Cap^3 \tag{E.24}$$

where CC_{CCS} is the modeled CCS capital cost (M$) and *Cap* is the net capacity (MW).

$$\Delta FOM_{BE} = \beta_0 + \beta_1 Cap + \beta_2 Cap^2 + \beta_3 Cap^3 + \beta_{4,i} Cap^4 \tag{E.25}$$

where ΔFOM_{BE} is the modeled percent increase in BE base-plant FOM from the addition of CCS (fraction) and *Cap* is the net capacity (MW).

$$\Delta VOM_{BE} = \beta_1 e^{(\beta_2 Cap)} + \beta_0 \tag{E.26}$$

where ΔVOM_{BE} is the modeled increase in BE base-plant non-fuel VOM from the addition of CCS ($/MWh) and *Cap* is the net capacity (MW).

$$LCOE_{BECCS} = 1 \times 10^6 \left(\frac{(CC_{BE}(1+\Delta CC_{CCS})+CC_{CCS}+CC_{pipe})FCF_{BE}+FOM_{BE}(1+\Delta FOM_{BE})+FOM_{CCS}+VOM_{BE}(1+\Delta VOM_{BE})}{G_{net}}\right) + VOM_{CCS} + \left(\frac{(TC \times m_{cap})}{G_{net}}\right) \tag{E.27}$$

where $LCOE_{BECCS}$ is the LCOE for BE with CCS at 90% capture $\left(\frac{\$}{MWh}\right)$, CC_{BE} is the capital cost for the BE EGU (M$), ΔCC_{CCS} is the increase in BE capital cost from incorporating CCS (fraction), CC_{CCS} is the capital cost for CCS (M$), CC_{pipe} is the CO_2 pipeline capital cost (M$), FCF_{BE} is the fixed charge factor for the project (fraction), FOM_{BE} is the fixed O&M cost for the BE plant (M$), ΔFOM_{BE} is the increase fixed O&M cost for the BE plant from incorporating CCS (fraction), FOM_{CCS} is the fixed O&M cost for the CCS subsystem (M$), VOM_{BE} is the variable O&M cost for the BE plant (M$), ΔVOM_{BE} is the increase variable O&M cost for the BE plant from incorporating CCS (fraction), G_{net} is the net generation for the BECCS plant (MWh), VOM_{CCS} is the variable O&M cost for the CCS subsystem $\left(\frac{\$}{MWh}\right)$, *TC* is the 45Q emission tax credit level proportionally derated for the EGU economic lifetime ($/tonne), m_{cap} is the annual CO_2 captured emissions mass (tonnes per year) and $1x10^6$ is the conversion for millions.

Table E.18. Utility solar, land-based wind, and long-duration storage default cost, finance, and performance parameter ranges.

Parameter	Value
Solar capacity factor	23%
Solar generation capacity (MW)	1,530
Solar generation capital cost ($/kW)	850
Solar generation O&M cost ($/kW/year)	10.2
Solar fixed charge factor (fraction)	0.05
Wind capacity factor	38%
Wind generation capacity (MW)	950
Wind generation capital cost ($/kW)	1,225
Wind generation O&M cost ($/kW/year)	39
Wind fixed charge factor (fraction)	0.05
Long-duration storage baseline ($/MWh)	80-150

Table E.19. Nuclear power default cost, finance, and performance parameters from AEO and Lazard [14, 35].

Parameter	SMR	Advanced light water
Capacity (MW_{net})	398	2,156
Capital cost ($/kW)	6,427	5,987
Fixed operation and maintenance ($/kW-year)	90	116
Non-fuel variable operation and maintenance ($/MWh)	3	2.4
Heat rate (kJ/kWh)	10,455	10,455
Fuel price ($/GJ)	0.806	0.806
Decommissioning ($/MWh)	1.5	1.5
Capacity factor (fraction)	0.9	0.9
Fixed charge factor (fraction)	0.059	0.059

Table E.20. Li-ion batteries default cost, finance, and performance parameters per AEO [14].

Parameter	Value
Capacity (MW_{AC})	50
Duration (hours)	4
Efficiency (fraction)	0.85
Capital cost ($/kW)	800
Fixed operation and maintenance ($/kW-year)	20
Annual capacity replacement (fraction)	0.03
Service life (years)	15
Fixed charge factor (fraction)	0.05

Table E.21. Dedicated bioenergy generation without CCS performance, cost, and finance parameters.

Parameter	Value
Baseline plant net capacity (MW)	50
Baseline heat rate without penalty (kJ/kWh)	14,085
Baseline CO_2 emission intensity (kg/MWh)	1,247
Power rule (fraction)	0.6
Baseline overnight capital cost ($/kW)	3,620
Baseline annual FOM ($/kW)	120
$VOM_{nonfuel}$ ($/MWh)	4.61
Fixed charge factor (fraction)	0.054*

*Notes: Same FCF also applies to dedicated bioenergy with CCS.

Table E.22. Dedicated bioenergy performance and cost changes from simulation of the addition of CCS with 90% capture.

Parameter	Value
Heat rate (fraction)	0.18
Net generation (fraction)	-0.15
Net emission intensity (fraction)	-0.88
BE capital cost (fraction)	0.14
CCS VOM ($/MWh)	1

Table E.23. Coefficients of BECCS regression model as a function of capacity (MW) for fully amortized base plant, water tower, and particulate materials stack. EGU equipped with all required emission control devices that are unamortized.

Variable	$\boldsymbol{\beta_{0,i}}$	$\boldsymbol{\beta_{1,i}}$	$\boldsymbol{\beta_{2,i}}$	$\boldsymbol{\beta_{3,i}}$	$\boldsymbol{\beta_{4,i}}$	RMSE
ΔFOM_{BE}	0.203	$3.9\text{x}10^{-4}$	$5.1\text{x}10^{-7}$	$3.1\text{x}10^{-10}$	$-6.8\text{x}10^{-14}$	0.007
ΔVOM_{BE}	12.68	40.58	-0.028	0	0	1.213
FOM_{CCS}	1.67	0.021	$5.5\text{x}10^{-6}$	$-4.8\text{x}10^{-9}$	$6.8\text{x}10^{-13}$	0.266
CC_{CCS}	18.87	0.89	$-2.3\text{x}10^{-5}$	$-4.1\text{x}10^{-8}$	0	13.05

*n = 16; †n = 13; ‡n = 5; §n = 4

E.6.6.5 Supplementary References

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Appendix F: Future U.S. Energy Policy: Two paths diverge in a woods…does it matter which is taken?

Reprinted with permission from Anderson J, Rode D, Zhai H, Fischbeck P. Future U.S. Energy Policy: Two Paths Diverge in a Wood - Does It Matter Which Is Taken? Environ Sci Technol 2020;54:12807–9. https://doi.org/10.1021/acs.est.0c04155.

Viewpoint

As the U.S. is currently the second-largest global emitter of greenhouse gases, global emission reduction efforts are profoundly impacted by the environmental policy paths blazed with the representative mechanics of the U.S. political system, the operation of which may mirror the dynamics in other countries in Europe and Asia with similar systems facing similar contentious policy trade-offs. Since the 1970s, the gulf between the political stands of the U.S. conservative (Republican) and liberal (Democratic) parties over the prioritization of environmental issues has grown to the extent that adherence to these positions is seen as a litmus test for party membership.[1,2] As social identity is often equated with party identity,[2] this polarization has created a societal schism concerning the causes, degree, and even existence of climate change and what actions—if any—should be taken to stem it. In recent polling, Democrats contend that climate change should be a "very high" governmental priority[3,4] and is an issue for which they overwhelmingly feel that the government is doing too little.[5] Contradistinctively, Republicans view it less so and contend that the government's action is at least adequate. Many in the Republican establishment with more conservative views even strongly maintain that the societal status quo of a fossil fuel-based economy is the correct energy pathway[2,6] and that there should be an expansion of oil and gas drilling, hydraulic fracturing, and coal mining.[5] In contrast, the Democrats oppose such an expansion.[5] It seems that the visions of climate change and future energy policy are propelling the country in opposite directions.

But does this political rift foreshadow a difference in actual *outcomes* of the resulting energy policies in 2030? These dichotomous approaches to fossil fuel and renewable energy policy can be simplified to two cases in the U.S. Energy Information Administration's 2020 Annual Energy Outlook—the high-oil-and-gas-supply case (Republican) and the low-oil-and-gas-supply case (Democrat).[7] Here, the greater availability of fossil fuels in the high-supply case results in the average price of natural gas for the power sector being only 6% greater than the 2019 price, while the coal price is 10% lower. In the low-supply case, restrictions on natural gas production cause the price to be 70% higher than in 2019, while coal prices are almost 2% higher. The impact of these price reversals on the generation portfolio mix for the electric power sector is surprising, yet inconsequential in the long-term for environmental climate change metrics, Figure F.1(a).

The natural-gas supply goals of each party are achieved, with natural gas generation increasing 30% for the pro natural-gas party and decreasing 31% for the opposition (relative to the 2030 reference case). However, there are market-driven consequences for these intentions. While the greater generation from natural gas results in an 8% decrease in generation from renewable resources, it also reduces the generation from nuclear power plants by 17% and that from coal-fired generation by 28% (i.e., from generation sources advocated by conservative Republicans).[5] Equally puzzling is the Democratic case. While generation from green sources increases by 15%, generation from nuclear sources increases by 8% and**,** since the environmental policy announced recently by the Democratic campaign does not include a price on CO_2, generation from coal increases by 20%. Certainly, these are not the outcomes intended by either party.

More perplexing still is that the resulting carbon dioxide (CO_2) emissions for the two cases differ by only 1% and that each is more than 400 million tonnes below the goal of Obama's 2015 Clean Power Plan. *Each* party can boast of a 48% overall reduction from 2005 power-sector emissions.[8,9] Does this mean that while the goals, intentions, and pathways of the parties are headed off in opposite directions, both results are environmentally beneficial in the near-term? Yes, both party's policies are arguably beneficial for reducing CO_2 emissions, in the near-term.

However, both fall short of the new medium- to long-term guidelines proposed by the Intergovernmental Panel on Climate Change (IPCC). While the Panel recommends a 45% global CO_2-emission reduction from 2010 levels by 2030, they also recommend a net-zero carbon economy by 2050 to limit future climate impact to the 1.5° C warming threshold.[10] Therefore, while the projected reductions meet the proposed IPCC 2030 target (absent heightened electrification and country-specific apportionment), the 2050 projections for either perspective fall substantially short of this mark, Figure F.1(b). Here, even though the more "radical" approach of putting a price on CO_2 achieves deeper reductions in 2030, a $35/tonne price is still inadequate to achieve net-zero emissions is 2050, Figure F.1(c, d). To do so would likely incur greater costs and be path dependent. As such, while the total annual cost of electricity for the Republican path to 2030 is 11% lower (by $28 billion or $220 per household),[7] it may ultimately be more costly because it does not account for the possibility of stranding fossil-fuel assets through early retirement to meet the 2050 target. Both the big picture and the details matter.

What then is the path forward for the two parties to meet this 2050 goal? Currently, deep political polarization has caused wide swings in environmental policy as political power transitions between administrations. This trend will likely continue unless a bridge can be built between the parties to bypass court delays and policy resets. However, even with the possibility of an alliance, a looming question remains: can the momentum in environmental concern gained since the Great Recession[1,2] be maintained in the face of the Covid-19 economic collapse, or will the recent climate-change urgency be lost in favor of economic-recovery urgency?[5]

Yes, the momentum can be maintained, but it requires walking a difficult tightrope. Democrats must reach out to likeminded Republicans[3-6] and appeal to their free market, growth, and innovation-orientation values[6,11] to foster CO_2 emissions reduction without crushing a weakened economy—an action that will also have international impact. Policy tools, invoking economic stimulus in public and private sectors, that include continuing and increasing tax incentives and investments in renewable energy, electrification, energy efficiency, low-cost long-duration power storage, and advanced carbon capture, utilization and storage technologies that permit fossil fuel use beyond 2030 can educe such values and also speed innovation in clean-energy technology platforms that are lagging in global readiness for net-zero emissions.[12] Furthermore, a national price on carbon through which the information content in the price enables the free market to spur competition, promote consumer choice, and further nurture innovation is a necessary tool for the global community's net-zero future.

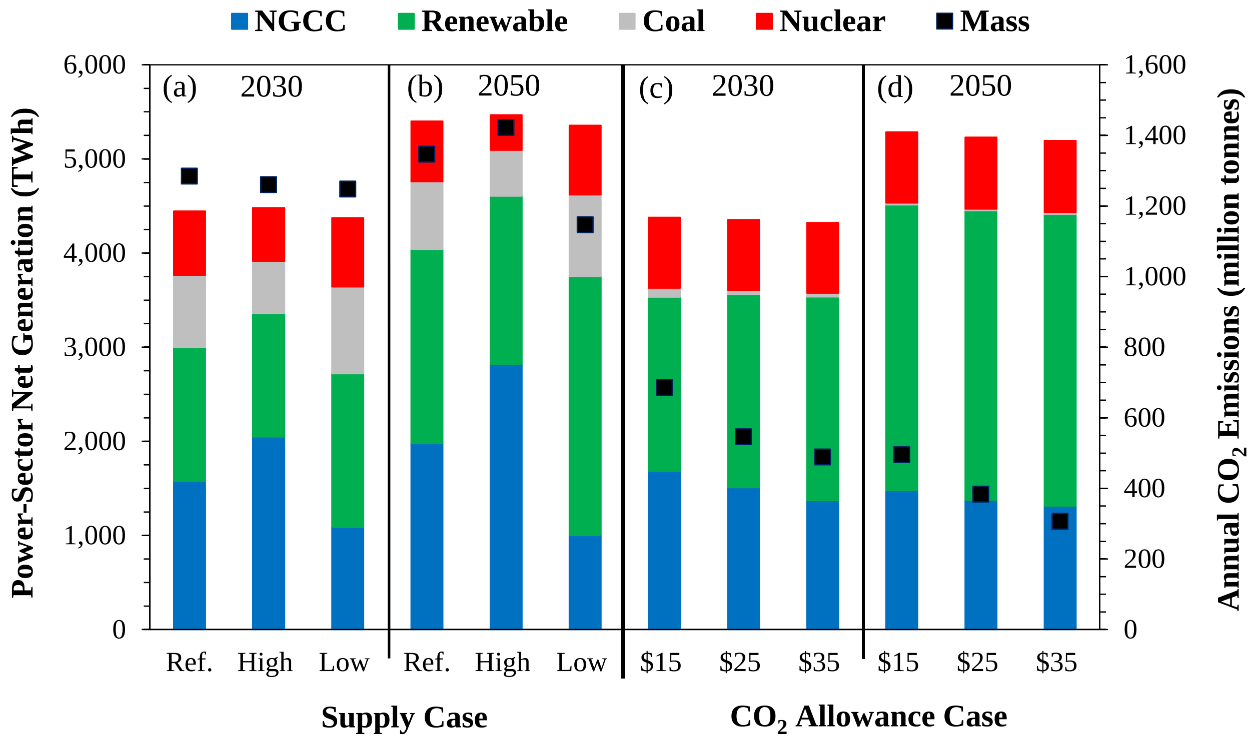

Figure F.1. The Energy Information Administration's 2020 Annual Energy Outlook projections for power-sector net generation (a, b) and emitted CO_2 (c, d) in 2030 (a, c) and 2050 (b, d). The reference (Ref.), high and low oil and natural gas supply (High, Low), and CO_2 allowance fee ($/tonne) cases are plotted.

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