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US power sector carbon capture and storage under the Inflation Reduction Act could be costly with limited or negative abatement potential

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Abstract

The United States' (US) largest-ever investment in expected climate mitigation, through 2022's Inflation Reduction Act (IRA), relies heavily on subsidies. One major subsidy, the 45Q tax credit for carbon oxide sequestration, incentivizes emitters to maximize production and sequestration of carbon oxides, not abatement. Under IRA's 45Q changes, carbon capture and storage (CCS) is expected to be profitable for coal- and natural gas-based electricity generator owners, particularly regulated utilities that earn a guaranteed rate of return on capital expenditures, despite being costlier than zero-carbon resources like wind or solar. This analysis explores investment decisions driven by profitability rather than system cost minimization, particularly where investments enhance existing assets with an incumbent workforce, existing supplier relationships, and internal knowledge-base. This analysis introduces a model and investigates six scenarios for lifespan extension and capacity factor changes to show that US CCS fossil power sector retrofits could demand \$0.4–\$3.6 trillion in 45Q tax credits to alter greenhouse gas emissions by −24% (\$0.4 trillion) to +82% (\$3.6 trillion) versus business-as-usual for affected generators. Particularly given long lead times, limited experience, and the potential for CCS projects to crowd or defer more effective alternatives, regulators should be extremely cautious about power sector CCS proposals.

1. Introduction

Decarbonization, and specifically a goal of eliminating net anthropogenic greenhouse gas (GHG) contributions to climate change (reaching 'net zero') by mid-century in order to increase the likelihood of keeping climate change-driven global temperature increases at or below the Paris Agreement's target of well below 2 °C, with a goal of 1.5 °C, has become a major policy driver in the energy sector and elsewhere (Pye *et al* 2017, Eyre *et al* 2018, Waisman *et al* 2019, Sun *et al* 2021, White House 2021, Allen *et al* 2022). In the United States (US), pollution control policies have historically involved mainly command-and-control regulatory approaches aimed at limiting or eliminating pollution of a specific type from a particular source, or market-based approaches aimed at limiting total pollution of a specific type from a group of sources by incentivizing the lowest-cost actions (Kraft 2000). For climate pollution, particularly from the energy sector, command and control (e.g. fossil fuel bans or net-zero laws) and direct market-based approaches (e.g. carbon taxes and cap-and-trade) have seen some limited uptake at the state and regional levels. The most common recent federal mechanism for climate policy, however, has been to subsidize zero-emissions technologies and greenhouse gas controls in the power sector, including investment and production tax credits (PTC) for renewable electricity and carbon dioxide (CO_2) capture and storage (CCS). This approach relies on the theory that making a desirable outcome (in this case, less GHG intensive electricity generation) cheaper than a less desirable outcome (more GHG intensive electricity generation) will ultimately result in uptake of the preferred technologies and strategies because of a systematic market advantage for the preferred policy outcome.

The latest US law to subscribe to this theory of change in a decarbonization context is August 2022's Inflation Reduction Act (IRA), described as the country's largest-ever climate change investment and most significant climate law. Although the Biden–Harris Administration has a goal of 100% carbon pollution-free electricity by 2035 and a net-zero greenhouse gas economy by 2050 (White House 2021), IRA does not include emissions targets, timelines, or requirements to promote these goals. Rather, IRA's climate benefits are expected to come primarily from tax incentives, accounting for $270 billion of an estimated $370 billion federal climate expenditures through IRA through 2031 (CBO 2022, IRS 2022).

One of the challenges of projecting expenditures and climate impacts from tax incentive-driven policy is that both the costs and the benefits are driven by individual taxpayers' decisions (or the decisions of entities that can monetize tax credits) rather than an overall requirement to reach certain levels of spend or emissions cuts. While the congressional budget office (CBO) has projected an estimated $270 billion in additional tax revenue reductions from IRA over the next 10 years, a report by Credit Suisse estimates the 10 year value may exceed $800 billion (Jiang *et al* 2022). Evaluations of IRA's potential climate impact also vary, with the White House estimating emissions reductions of about 1 billion tonnes of CO_2-equivalent (CO_2e) per year in 2030 (White House 2022), which is about a 15% reduction relative to the 2005 emissions baseline used for the US' Nationally Determined Contribution target of an economy-wide 50%–52% reduction in GHG emissions relative to 2005 by 2030 (United States 2021). Preliminary model results estimate IRA might reduce emissions by (277 1192) million metric tonnes of CO_2 in 2030 versus business as usual (Jenkins *et al* 2022, Mahajan *et al* 2022, Roy *et al* 2022, Larsen *et al* 2022), with major contributions from power sector decarbonization. These models evaluate cost competitiveness of technological and other interventions at a system level within a set of assumed constraints. As modelers acknowledge, this approach is designed to illustrate a cost-optimal, plausible outcome, not necessarily a most likely outcome in a context where decisions about individual investments are not made at a system-optimizing level and are not controlled by decision makers in perfect competition with one another.

Electricity generating units (EGUs) are built and owned by a combination of merchant producers, regulated utilities granted monopoly status, industrial and commercial entities, and others, all with somewhat different incentives and with very different levels of control. Regulated utilities especially are not subject to direct market competition and enjoy considerable control over their investment strategies, which means that understanding how IRA and other policy actions might affect utility decisions is of particular interest. In general, though, EGU owners tend to make decisions based on their own assets, inflected by their expertise. An owner with experience and organization optimized around a fleet of fossil assets will not necessarily elect to voluntarily shutter its fossil assets and develop a new fleet of zero-carbon facilities just because the zero-carbon facilities are slightly cheaper, especially if the fossil assets remain profitable. Given the way that US electricity markets and regulation work (e.g. allowing for self-scheduling (Daniel 2019)), the existence of lower-cost alternatives does not necessarily mean that those alternatives will be able to enter the market or that if they do, they will be able to outcompete existing resources to the point of closure. Emissions are not directly reduced by the addition of lower or zero GHG-emitting resources: they are reduced by the subtraction of GHG emissions. As such, it is relevant to investigate the incentives that IRA poses for owners of GHG emitting EGUs, the topic of this piece.

GHG-emitting EGUs are disproportionately owned by utilities relative to modern renewable EGUs, at about 59% of total fossil capacity (74% of coal capacity; 52% of natural gas capacity) versus 14% of total geothermal, solar, and wind capacity (EIA 2019). This ownership disparity is particularly relevant in the context of capital expenditure incentives, as regulated utilities are often given the opportunity to earn profits on capital investments via a regulated rate of return while passing operational costs on to their ratepayers (Douglas *et al* 2009, Waggoner *et al* 2018). As such, utilities are both incentivized to overcapitalize and are relatively insensitive to high operational costs. In the US electricity market context where many utilities acquire renewable energy through power purchase agreements (PPAs) or leases rather than building their own facilities, and given that investment decisions are driven by profit rather than price (Christophers 2022), mechanisms for utilities to make capital investments, regardless of operational costs, might be expected to have higher uptake than a pure cost optimization would suggest. In practice, given disproportionate utility ownership of fossil EGUs relative to modern renewable EGUs, the balance of capital stock and expertise strongly favors investment in fossil assets assuming there are no guardrails to prevent this outcome.

The question, then, is whether IRA includes any opportunities for capital investment in fossil EGUs that might be profitable. (Although the profit structure is different, non-utility fossil EGU owners might also be expected to prioritize investment in their existing assets rather than shifting to completely different technologies and organizational needs.) The main mechanism for fossil investment through IRA is the extension and expansion of the 45Q carbon oxide sequestration credit (45Q), which is effectively a production tax credit for CO_2 (or CO) that is utilized and/or stored out of the atmosphere, e.g. underground. IRA made three important changes to 45Q: (1) much smaller facilities are now eligible (the tonnage threshold was cut by about 96%); (2) the deadline to commence construction was extended to the end of 2032 (previously the end of 2026); and (3) the value of the credit was raised, to a maximum of $85/tonne for CO or CO_2 utilized and/or stored after capture from a facility rather than the atmosphere (previously $50/tonne) (117th Congress 2022, U.S. Code 2022). For direct air capture of CO_2 from the atmosphere (rather than from a power plant or industrial facility), the tax credit is valued at a maximum of $180/tonne utilized and/or stored after capture from the atmosphere.

An ongoing challenge is that the tax credit is still issued per tonne of CO or CO_2 utilized and/or stored rather than tonne of life cycle CO_2e abated or removed relative to some baseline. Although the House version of the enhanced 45Q program proposed a safeguard against increasing facility emissions by requiring that a CCS project sequester 75% of facility emissions against a yearly baseline, the Senate version, which became law, requires only a 'capture design capacity' of 75%—without any proven performance metrics (Smyth 2022). As a very simple example, a facility that initially emits 1 tonne of CO_2 could install energy-intensive capture equipment that generates 2 tonnes of CO_2e in order to capture the initial tonne of CO_2, then claim the credit for storing 1 tonne of CO_2 even though the overall emissions (2 tonnes generated - 1 tonne capture and stored, with 1 tonne emitted) do not change from the initial level. Because the tax credit is paid based on stored tonnage, there is an incentive to maximize storage tonnage and thus to generate as much CO_2 as can be captured and stored, regardless of CO_2e abatement level compared to the original baseline. Another challenge is that the tax credit remains available for 12 years of operations, but operational costs are sufficiently high that it is unlikely a facility would continue to capture and store CO_2 without the credit or some other incentive or requirement. That is, after 12 years, the financial incentive is for a facility to turn off the capture unit and return to unabated operations.

Capturing CO_2 typically entails separating CO_2 from other gases (e.g. in a flue stack) at a relatively low partial pressure, which is energy intensive and requires physically large infrastructure that can be challenging to site, especially at existing plants (Haszeldine 2009, Wilcox 2012, Vasudevan *et al* 2016, Preston *et al* 2018). Once captured, CO_2 must be transported to a site where it can be stored and/or utilized (noting that utilization might or might not result in eventual release back into the atmosphere) (Munkejord *et al* 2016, Onyebuchi *et al* 2018). Storage, also called sequestration, requires appropriate reservoirs (Dooley *et al* 2005, Menefee *et al* 2018, Kelemen *et al* 2019) and special infrastructure (e.g. wells) that can accommodate CO_2 characteristics like corrosivity (Mahlobo *et al* 2017), often at very high pressures to enable supercritical fluid behavior. To date, CCS is very rare, largely because it is both capital intensive and operationally costly with limited incentives and no requirements to do it. The adjustments to 45Q change this incentive structure by increasing the payments per tonne to a level that could enable profitability for a number of power and industrial applications (Larsen *et al* 2022). In the US electricity sector, where capital expenditures are structurally incentivized and operational costs are structurally deemphasized in profit-driven decision contexts, and where these factors are most acute for fossil EGUs due to higher utility ownership, IRA's adjustments to 45Q could incentivize substantially more fossil power CCS than system-wide cost optimization might suggest.

The remainder of this paper explores the question: how might the IRA changes to the 45Q carbon oxide sequestration credit affect CCS retrofit decisions in the US power sector? The core hypothesis is that profit maximizing behavior on the part of fossil EGU owners is not emissions- or cost-minimizing behavior, and that IRA is likely to foster more fossil power CCS proposals than cost minimization models suggest. The analysis particularly explores the emissions and cost impacts of two major dynamics associated with CCS retrofit decisions: the incentive to extend facility lifespans after major capital investments (e.g. for capture) and the structural incentive under 45Q to generate more CO_2 for storage. In general, assumptions used here are systematically favorable for CCS on coal and natural gas-fired EGUs, mainly by assuming that any desired retrofit could succeed. This approach is intended to reveal the extent to which fossil EGU owners (including utilities) might plausibly propose CCS to regulators, investors, and other decision makers who might need to deeply interrogate assumptions and potential impacts of such proposals.

2. Methods

This analysis adapts the US generator-level, utility-specific emissions projection model from Grubert (2021) to produce a first-order estimate of potential CCS retrofit activity for existing US coal- and natural gas-fired power plants, given the carbon oxide sequestration tax credit under Section 45Q as modified by IRA. This model is used as a base because of its explicit inclusion of generator-level ownership, which allows for a detailed investigation of utility incentives and behavior, and because it projects emissions forward at the generator level. Overall, this evaluation assumes generator- rather than system-level decision making.

That is, the intent of this analysis is to identify how power sector CCS outcomes might differ from a system-level cost optimization when choices about CCS are driven by generator-level evaluations of potential profitability, independent of opportunity cost (and particularly, of the potential for lower cost provisioning of power). This approach loosely approximates how independent decisions might be made by existing asset owners without desire or capacity to diversify fuels. That is, someone (or some utility) who owns a coal-fired generator and can profitably invest in CCS might not decide to close that existing, familiar generator and invest in a new, unfamiliar wind farm instead, even if the wind farm is more profitable on paper. Calculations can be investigated in the model file, available as supplementary data.

2.1. Data sources

Following (Grubert 2021), fossil fuel-fired EGU data are taken from energy information administration (EIA) 860, 861, and 923, using a 2019 base year. Although both 2020 and 2021 data were available as of this writing, the 2019 base year was retained because of unusual circumstances in both 2020 (primarily, COVID disruptions) and 2021 (COVID disruptions and Winter Storm Uri (Busby *et al* 2021)) As this model relies on the assumption that EGUs continue to operate as they did in the base year until they reach a modeled retirement age (Grubert 2020a, 2020b, 2021), it is particularly sensitive to irregularities in the base year. Thus, the 2019 base year is retained from the underlying model, although this means that some plant retirements or significantly altered operating regimes might not reflect conditions as of this writing in late 2022. For this first-order analysis, this tradeoff was considered acceptable in exchange for an overall more typical, and still quite recent, operating base year.

This model uses a combination of EIA's Annual Energy Outlook (AEO) 2019 and 2022 values for CCS costs and heat rate impacts (EIA 2022a), assuming EIA's assumptions about new-build ultrasupercritical (USC) coal-fired generation and new-build natural gas combined cycle (NGCC) generation with CCS can be directly applied to all retrofitted coal and natural gas EGUs, respectively. Model values for the cost and energy intensity of retrofitted CCS are calculated as the difference between overnight costs and heat rate for EIA's base and CCS-equipped new-build plants, using the 90% capture rate values and the baseline advanced or single shaft combined cycle units. Coal assumptions exclusively rely on AEO 2022 values. The heat rate penalty for combined cycle units is taken from AEO 2019 due to some inconsistencies described below. AEO 2022 data are used for capital costs in both cases; note that the AEO 2019 estimate for the cost of CCS on a combined cycle unit is within 10% of the AEO 2022 value after adjusting for inflation. Outputs relying on total cost estimates (including operations and maintenance) for combined cycle units were tested against both AEO 2019 and 2022 values and were not sensitive to the differences. Applying EIA's estimates for new build plants to retrofitted plants requires several major assumptions, detailed below. In general, the use of EIA values here likely underestimates actual cost and energy intensity for CCS retrofits of US EGUs.

2.2. Assumptions

This analysis makes several major assumptions focused on CCS eligibility, CCS timing, and plant operations.

2.2.1. CCS eligibility

The model assumes only coal- or natural gas-fired generators can retrofit CCS, but also that any coal- or natural gas-fired generator with sufficient emissions to be eligible for 45Q tax credits and sufficient lifespan to enable profitability can successfully do so—including simple cycle natural gas generators. Issues like space constraints, permit acquisition, and other limitations are not considered for this first order analysis. Although the AEO assumes only plants with capacity over 500 MW and a heat rate below 12 000 btu kWh^{-1} are eligible for retrofit, this analysis only applies tonnage and lifespan eligibility limits, particularly given that the lowered tonnage limit under IRA suggests interest in enabling deeper deployment of CCS.

Under the IRA changes to 45Q eligibility, the emissions capture threshold is lowered from 500 000 to 18 750 metric tonnes of CO_2 per year (117th Congress 2022), so sufficient emissions are modeled at 18 750 metric tonnes of CO_2 divided by the capture rate. The designed capture capacity, which must be at least 75% of baseline operations (117th Congress 2022), is a variable with a baseline of 90% for this analysis, with the rationale described below.

Generators are assumed to have sufficient lifespan for CCS if their assumed baseline retirement date (end of lifespan, with some randomization for units that have exceeded a typical lifespan (Grubert 2021)) is at least as many years in the future (starting in 2022) as the assumed time to build CCS (variable with a baseline of 4 years for coal and 3 years for natural gas, per AEO 2022 assumptions (EIA 2022a)) plus a minimum number of years the unit needs to operate to offset capital expenses with tax credits. That minimum value is a variable set to 4 years for coal and the full 12 years of the 45Q credit for natural gas, based on a coarse analysis of simple payback assuming an \$85/tonne CO_2 tax credit, capital expenditures as described above, 90% emissions sequestration, and a plausible post-CCS capacity factor (see supplementary data). For coal, breakeven occurs after 4 years for capacity factors of 90% and higher, and is less than 12 years (the period of the 45Q tax credit) for capacity factors as low as 31%; for natural gas, breakeven of 12 years or less (the period of the 45Q tax credit) only occurs with capacity factors of about 70% and higher, suggesting that such capacity factors, and full access to the tax credit, is necessary for natural gas-fired CCS under the assumptions here.

For generators that meet the emissions and lifespan thresholds, the model presumes all captured CO_2 enters dedicated storage (i.e. is not utilized, including for enhanced oil recovery (EOR)) and meets the prevailing wage and apprenticeship requirements necessary for eligibility for the \$85/metric tonne 45Q tax credit as amended by IRA (117th Congress 2022).

2.2.2. CCS timing

Based on the IRA adjustments to the 45Q tax credit, the model assumes CCS construction must commence by the end of 2032 (117th Congress 2022), which means the latest allowable online date is 2032 plus the build time for either coal or natural gas CCS (2036 and 2035, respectively). The tax credit is available for 12 consecutive years after operations start, with some exceptions, e.g. for disasters (U.S. Code 2022): in the model, these exceptions are ignored. One key assumption of this analysis is that generator owners wait until the latest date that maximizes the tax credit before the unit retires, a proxy for the idea that owners prefer higher *n* for *n*th-of-a-kind investments, to take advantage of learning and any benefits from delaying major capital expenditures.

The model assumes that without the 45Q tax credit, ongoing operation of the CCS units is not profitable, so generators with CCS run the capture system until either the end of the generator's life or until the 12 year credit is exhausted. If the generator has not reached end of life after 12 years (including for scenarios with lifespan extensions resulting from the retrofit), the generator returns to its pre-CCS operational profile (including its original capacity factor, for scenarios where CCS is presumed to alter the capacity factor).

2.2.3. Plant operations

Plant operational assumptions include both without-CCS and with-CCS conditions. Following (Grubert 2020a, 2021), generators maintain their baseline output and then retire upon reaching either an announced closure date recorded in EIA 860 (EIA 2019) or the mean age-on-retirement for generators with the same fuel and prime mover, unless the date is adjusted based on model inputs. Specifically, the date can be adjusted to reflect a lifespan extension as a result of a CCS retrofit (e.g. due to repairs or equipment replacements) or to reflect a closure deadline. Similarly following prior work, fuel consumption, annual net generation, CO_2 emissions, and upstream methane emissions from the natural gas supply chain (for natural gas-fired generators only) are assumed to match 2019 values for generators and years without CCS. For generators and years where CCS is operating, fuel input (and thus CO_2 production) is initially assumed to be held constant. Annual net generation is downrated using the heat rate impact of 90% capture (separately for coal and natural gas generators) from AEO as described above. CO_2 emissions are calculated by multiplying without-CCS CO_2 emissions by 1 - capture rate, and captured CO_2 emissions are calculated by multiplying without-CCS CO_2 emissions by the capture rate. Upstream methane emissions for natural gas-fired power plants do not change when fuel input is constant. Finally, these with-CCS values (including methane emissions) are adjusted by multiplying by the ratio of the with-CCS to without-CCS capacity factor, where the with-CCS capacity factor is specified by the user for coal and natural gas plants.

For generators with CCS, the CO_2 capture rate is assumed to be 90% and is presumed to be fully successful for all retrofits. This value is taken from heat rate and cost impact estimates from AEO, and also reflects a common capture target. Although IRA allows for the 45Q tax credit to be claimed for capture rates as low as 75% of base operations (117th Congress 2022), literature suggests that there is no clear benefit to lower capture (Rao and Rubin 2006, Biermann *et al* 2018) from a cost effectiveness perspective. In the context of 45Q, if sequestering a marginal tonne of CO_2 is more profitable than avoiding the energy penalty for doing so, the incentive is to maximize capture. This analysis also assumes that the capture system is always online (i.e. there is no partial load capture). If electricity is more valuable than the CO_2 sequestration tax credit, generators might elect to bypass capture at times (Cohen *et al* 2011). Using a simplified breakeven cost analysis, the assumptions in this model suggest that bypassing the capture system would only be profitable if electricity prices were above about \$200 MWh^{-1} for coal or about \$160 MWh^{-1} for natural gas (supplementary data). Although in practice, some plants might experience prices high enough to motivate capture bypass, historical data suggest that such prices are rare on an annual basis (Berkeley Lab 2022, EIA 2022c), so for this first order model, the impact of such hours can be ignored. Note that a plant could also achieve 90% annual capture even with bypass hours if the base capture rate is higher than 90% or by using strategies like solvent storage (Craig *et al* 2017).

As there is no active power sector CCS in the US (the single commercial-scale unit to date, Petra Nova at Texas' W. A. Parish coal-fired power plant, went offline in 2020), and very little globally (with none on natural gas-fired power plants to date) (Global CCS Institute 2022), cost, heat rate, and other operational details about commercially deployed CCS for coal- and natural gas-fired power generators are based on models, tests at noncommercial scale, and extrapolations from analogous processes rather than empirical. As described above, this analysis uses AEO assumptions about CCS cost and heat rate for coal and natural gas generators, but these values were not developed for retrofit conditions. As such, the use of these values requires two major assumptions that are expected to lead to conservatively low estimates for cost and energy intensity for the systems they are applied to in this analysis. That is, this model likely underestimates cost and energy penalties of CCS. First, this model assumes that EIA's assumptions about new-build USC coal-fired generation and new-build natural gas combined cycle generation with CCS can be directly applied to all retrofitted coal and natural gas EGUs, respectively. In practice, existing generators are less efficient and might have significantly different operating patterns relative to these modeled units, particularly for simple cycle (i.e. non-NGCC) natural gas plants. Second, this model assumes that costs and energy intensity for capture alone can be calculated as the difference between costs and heat rate for EIA's base and CCS-equipped plants, using the 90% capture rate values.

For the heat rate, this assumption effectively treats the demand for fuel per unit CO_2 captured as constant across generator efficiency and other conditions, which might be insufficient for a more detailed analysis. AEO 2022's heat rate assumptions for USC coal with and without 90% capture imply an energy requirement of about 3.8 GJ/tonne CO_2, which is consistent with literature values (House *et al* 2009, Vasudevan *et al* 2016, Biermann *et al* 2018, Dods *et al* 2021). For combined cycle units, however, the published value is much lower, at about 2.1 GJ/tonne. This low value is surprising given that minimum work for natural gas flue capture is higher than that of coal flue capture given the lower CO_2 concentration (i.e. capture is more difficult when less CO_2 is present; Dods *et al* 2021), though the impact on primary energy demand is moderated by the typically higher conversion efficiency at natural gas versus coal units (Vasudevan *et al* 2016). Further, using work estimates from (Dods *et al* 2021) and assuming all energy for separation and compression is provided via electricity from the unit using its without-CCS heat rate, achieving the AEO 2022 energy penalties implies separation efficiency (here defined as thermodynamically minimal separation work divided by actual separation work) of $\sim$14% for coal, but 30% for natural gas—an unexpectedly high value. Given target separation efficiencies of 16%–20% based on similar processes (Vasudevan *et al* 2016), a published thermodynamic minimum for MEA systems of 1.9 GJ/tonne (Gingerich and Mauter 2018), and literature values (Rubin and Zhai 2012, Luo *et al* 2015), the combined cycle CCS energy penalty under AEO 2022 appears to be unusually low. Notably, the AEO combined cycle CCS energy penalty dropped significantly between the 2019 and 2020 editions, without explanation. AEO 2019's estimates imply an energy requirement of 3.8 GJ/tonne, which suggests a separation efficiency of $\sim$13% (supplementary data). The values from AEO 2019 are also used in a recent detailed thermodynamic analysis of NGCC-CCS for direct air capture (McQueen *et al* 2021). Although it is possible that the AEO 2020–2022 values incorporate some design element that reduces the overall energy penalty of natural gas power CCS, such as solvent storage or other innovations (Craig *et al* 2017), the lack of explanation suggests that the AEO 2020–2022 value is possibly an error. As such, this work adopts the AEO 2019 energy penalty of 3.8 GJ/tonne instead of the AEO 2022 energy penalty of 2.1 GJ/tonne for natural gas given the older value's greater consistency with literature values and expectations that natural gas CCS should not have a substantially lower energy penalty than coal CCS due to lower concentrations of CO_2 in flue gas.

Although the energy required per tonne of CO_2 varies nonlinearly with capture rate (Dods *et al* 2021), it is sufficiently flat per average tonne through the range of rates allowable under IRA's adjustment of 45Q that for this first order analysis, preserving the static energy penalty per kWh is likely acceptable even under sensitivity tests for lower capture rates (House *et al* 2009).

This analysis assumes no additional cost, energy penalty, or CO_2 losses between capture and sequestration. That is, transport and storage are free and every captured unit of CO_2 is sequestered in dedicated storage. This assumption also contributes to a conservative underestimate of resource intensity for CCS.

2.3. Inputs and variables

The Excel model underlying the analysis in this work (supplementary data) takes seven user inputs related to CCS (CCS allowed; years of EGU lifespan extension with CCS; minimum coal EGU capacity factor with CCS; minimum natural gas EGU capacity factor with CCS) and retirement deadlines (coal retirement deadline; natural gas retirement deadline; and other fossil retirement deadline). These are found on the tab 'User inputs.'

Table 1. Inputs and variables used in this analysis.

Variable description	Variable name in excel model	Value	Unit	Source
Time to build CCS, coal	build_time_coal	4	Years	AEO 2022
Time to build CCS, natural gas	build_time_ngas	3	Years	AEO 2022
Minimum operating years to pay back coal CCS	min_years_coal	4	Years	Breakeven calculation using AEO 2022 costs; this model
Minimum operating years to pay back gas CCS	min_years_ngas	12	Years	Breakeven calculation using AEO 2022 and AEO 2019 costs (value is the same); this model
Minimum capture tonnage	min_capture_tonnage	18 750	Tonnes/year/unit	IRA amendments to 45Q
Number of consecutive years 45Q credits can be claimed	years_45Q	12	Years	IRA amendments to 45Q
Value of 45Q tax credit	Credit_per_tonne_45Q	85	\$/tonne CO_2 stored[a]	IRA amendments to 45Q assuming conditions are met
Capture rate	Capture_rate	0.9	Captured CO_2/produced CO_2	Assumption; AEO 2022
Fuel for 90% capture, coal	Coal_capture_fuel	3869	btu/kWh	AEO 2022
Fuel for 90% capture, Natural gas	Ngas_capture_fuel	1225	btu/kWh	AEO 2019
Capital expenditure for 90% capture, coal	Coal_capture_capex	2551	2021\$ kW^{-1}	AEO 2022
Capital expenditure for 90% capture, natural gas	Ngas_capture_capex	1644	2021\$ kW^{-1}	AEO 2022

[a] Assumed to be 100% of captured volume.

The model also includes a number of named variables that users can adjust for sensitivity analysis (found on tab 'Conversions and assumptions'). Table 1 summarizes variables and their default values, which are based on the assumptions described above. All results presented here use default variable values, with inputs specific to scenarios described in the next section.

Other values, including default asset lifespan, methane intensity of upstream natural gas supplies by state, etc are included in the supplementary data for reference, but the outputs they inform are included as values rather than formulas. See Grubert (2021) for the original model and associated formulas.

2.4. Scenarios

As described above, users can adjust variables and change key inputs directly in the model (supplementary data). The results presented here are for nine total scenarios: six with CCS allowed, and three baseline no-CCS scenarios. The six CCS scenarios are defined by two capacity factor conditions (scenario groups 1 and 2) and three lifespan extension conditions (scenario categories a, b, and c). Scenario group 1 assumes that coal- and natural gas-fired generators operate with at least 90% and 70% capacity factor, respectively (EGUs with baseline capacity factors higher than those levels continue to operate with their pre-CCS capacity factors). These values are selected based on the simple breakeven analysis described above, whereby coal EGUs operating at 90% or higher only need 4 years of tax credits, while natural gas EGUs need capacity factors of 70% or higher to break even with the full 12 years. Scenario group 2 assumes no change to pre-CCS capacity factors, even when this means EGUs might not break even on the capital investment. As utilities can generally rate base capital expenditures, this scenario illustrates possible underperformance relative to revenue projections used to secure the capital investment. Each of these scenario groups is evaluated assuming 0, 12, and 20 years of lifespan extension (categories a, b, and c) resulting from the investment made in the CCS system, reflecting no extension, extension sufficient to ensure full utilization of 45Q, and an arbitrary capital asset extension. For context, note that the Boundary Dam CCS retrofit to a Canadian coal-fired EGU was explicitly designed to extend that unit's lifespan by 30 years (Giannaris *et al* 2021).

Table 2. Summary of analyzed scenarios.

Scenario ID	Descriptor[a]	CCS allowed?	Retirement deadline	Lifespan extension from CCS retrofit	Minimum capacity factor with CCS, coal	Minimum capacity factor with CCS, natural gas
1a	(0,0.9,0.7)	Yes	None	None	0.9	0.7
1b	(12,0.9,0.7)	Yes	None	12 years	0.9	0.7
1c	(20,0.9,0.7)	Yes	None	20 years	0.9	0.7
2a	(0,0,0)	Yes	None	None	0	0
2b	(12,0,0)	Yes	None	12 years	0	0
2c	(20,0,0)	Yes	None	20 years	0	0
3	BAU	No	None	n/a	n/a	n/a
4	2035 deadline	No	2035 (all fossil)	n/a	n/a	n/a
5	2030 coal deadline	No	2030 (coal only)	n/a	n/a	n/a

[a] For CCS scenarios this takes the form of (CCS lifespan extension in years, minimum coal EGU capacity factor with CCS, minimum coal EGU capacity factor with CCS).

The three baseline no-CCS scenarios (scenarios 3–5) differ by retirement timelines. Scenario 3 is a business-as-usual scenario that allows no CCS, no change in assumed retirement year, and no changes to capacity factor. Scenario 4 is the same but assumes all fossil-fired EGUs are required to close by 2035, President Biden's target for a 100% carbon pollution free power sector (White House 2021). Scenario 5 is identical to scenario 3 but assumes all coal-fired EGUs must close by 2030.

Table 2 summarizes the scenarios, which are referenced both by their IDs and short descriptors throughout for clarity.

3. Results

Under the assumptions and scenarios described here, more natural gas- than coal-based CCS is retrofitted in all cases, but with much higher proportional uptake among coal-fired EGUs. The population of EGUs considered in this analysis is 689 coal-fired EGUs (249 GW) and 6090 natural gas-fired EGUs (544 GW). Where no life extension accompanies a CCS retrofit, 35% of coal EGUs (39% of capacity) and 11% of natural gas EGUs (19% of capacity) add CCS. With a 12 or 20 year life extension, this value jumps to 90% of coal EGUs (98% of capacity). For natural gas EGUs, 41% (65% of capacity) retrofit CCS with a 12 year life extension, and 45% (73% of capacity) retrofit with a 20 year life extension.

At a fleet level, availability of the 45Q tax credit contributes to lower-than-BAU emissions when CCS does not enable EGU lifespan extension because retirement timelines are identical, but some plants also control emissions for a period of time (scenarios 1a, 2a). For scenarios with lifespan extension (1b, 1c, 2b, 2c), CO_2 emissions drop below BAU CO_2 emissions for several years and then increase to levels above BAU CO_2 emissions, reflecting that plants turn off capture when the tax credit expires. For scenarios 1b and 1c (higher capacity factor and lifespan extension) CO_2e emissions from direct CO_2 emissions and natural gas supply-associated methane are only lower than BAU emissions for 2027–2029, largely due to disproportionate increases in generation from natural gas-fired power plants for which methane emissions increase with CCS. For scenarios 2b and 2c (no capacity factor change, with lifespan extension), CO_2e emissions are below BAU levels for 2026–2034 (figure 1). Note that the CO_2-only case also reflects the unlikely scenario where methane emissions are eliminated from the natural gas supply chain (Ravikumar and Brandt 2017).

Intuitively, although the energy penalty for CCS reduces electricity output assuming identical fuel consumption, increasing EGU capacity factor and lifespan tends to increase overall generation as well. Figure 2 shows that for all scenarios other than 2a (CCS is added with no impact to lifespan or capacity factor), fossil fuel-fired electricity generation increases relative to BAU.

As would be expected, both average CO_2 and CO_2e intensity of fossil fuel-fired generation are strictly lower for CCS scenarios than non-CCS scenarios, ranging from (0.18, 0.47) tonne CO_2/MWh ((0.20, 0.54) tonne CO_2e/MWh) relative to (0.56, 0.62) tonne CO_2/MWh ((0.62, 0.68) tonne CO_2e/MWh). As figure 1 shows, however, these lower intensities are not accompanied by absolute decreases in GHG emissions from the existing fossil power fleet. Cumulative emissions from CCS scenarios are only lower than those from non-CCS scenarios for the scenarios with no lifespan extension (1a, 2a). Table 3 shows cumulative emissions, implied 45Q payments, abatement percentage relative to BAU, and equivalent cost per tonne abated by scenario for 2021–2050.

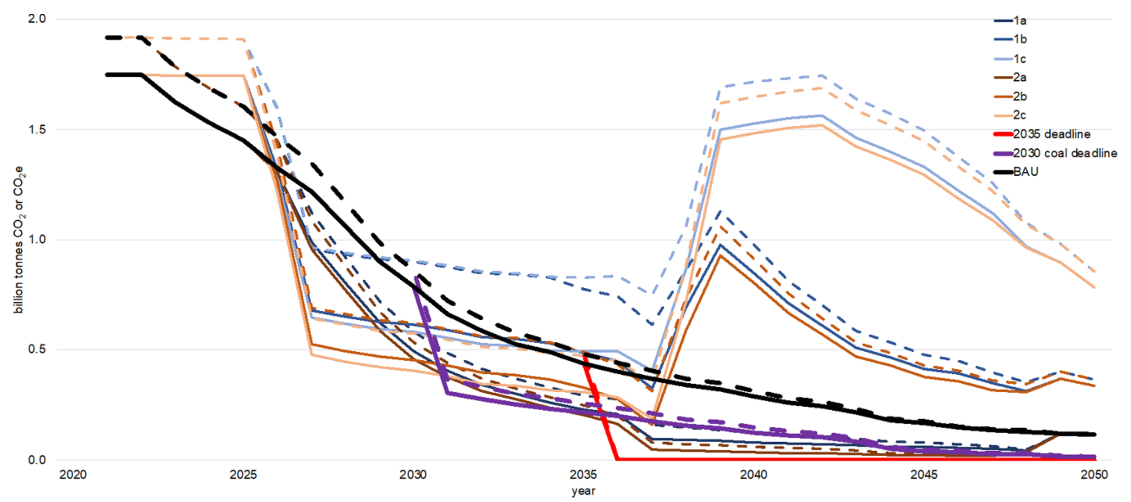

Figure 1. CO_2 and natural gas upstream methane emissions for the US fossil fuel-fired EGU fleet operating as of 2019 by scenario, through 2050. Solid lines show CO_2; dashed lines show CO_2e including natural gas upstream methane, GWP-100 = 29.8.

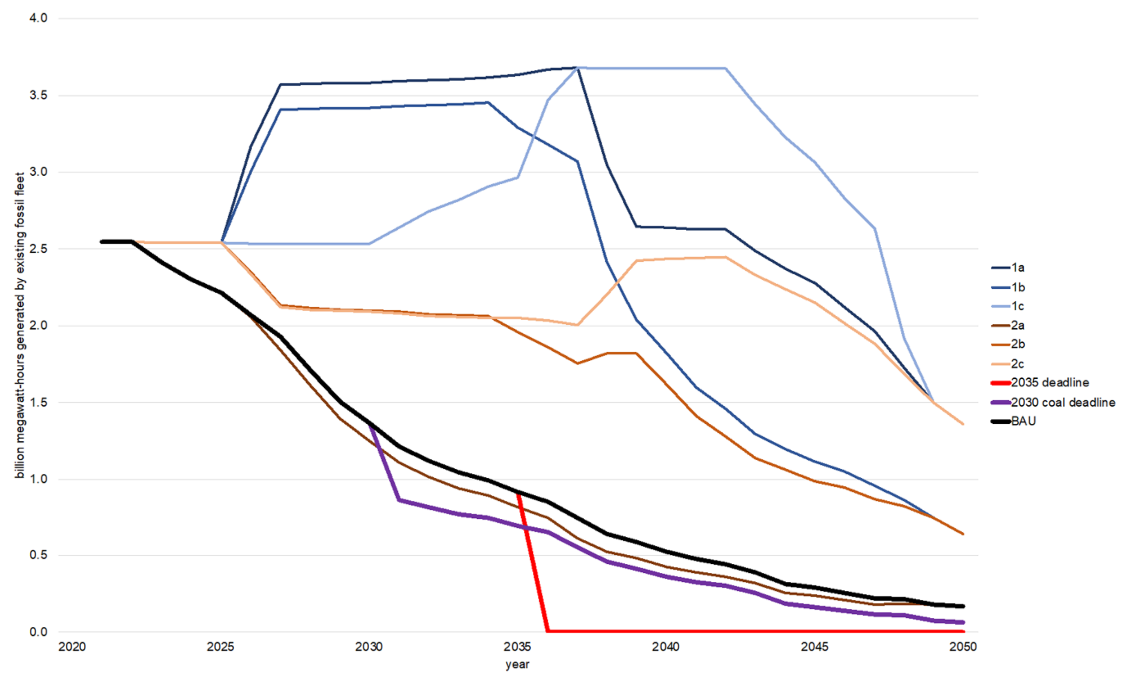

Figure 2. Electricity generation for the US fossil fuel-fired EGU fleet operating as of 2019 by scenario, through 2050.

As table 3 shows, only scenarios 1a and 2a reduce GHG emissions relative to BAU conditions using CCS. For scenarios with lifespan extension, 45Q credit payments range from ($123, $469]) per tonne of increased emissions—that is, 45Q is effectively subsidizing higher GHG emissions rather than paying for abatement from the existing fossil fleet. Only scenario 2a spends less than $1 trillion on 45Q credits for the power sector. As users can verify in the model (supplementary data), cumulative emissions are very sensitive to lifespan extensions. Assuming no capacity factor changes, the cumulative abatement potential for fossil power EGU CCS retrofits reaches 0 relative to BAU if retrofits extend EGU lifespans by about 5 years relative to BAU, at a cost of $760 billion in 45Q tax credits and $730 billion of capital expenditures (1–2 years relative to a 2035 fossil EGU retirement deadline or 2030 coal EGU retirement deadline). Assuming capacity factors increase to at least 90% for coal EGUs and 70% for natural gas EGUs while CCS is operational, cumulative abatement potential reaches 0 relative to BAU with lifespan extensions of less than 4 years (less than 1 year relative to the 2035 fossil EGU and 2030 coal EGU retirement deadlines).

Requiring all fossil EGUs to close by 2035 or all coal EGUs to close by 2030 both result in roughly 17% CO_2e abatement relative to BAU, compared with 19% for scenario 1a (higher capacity factors, no lifespan

Table 3. Emissions, 45Q payments, abatement, and cost of fossil power CCS retrofits by scenario.

Scenario	Cumulative CO_2 emissions, 2021–2050 (billion tonnes CO_2e)	Cumulative CO_2e emissions, 2021–2050 (billion tonnes CO_2e)	45Q payments (2021$ billion)	CO_2e abatement relative to BAU (%)	45Q cost per tonne abated relative to BAU (2021$/tonne)
1a	15.1	17.3	1024	19%	253
1b	23.1	28.4	3207	−33%	−455
1c	32.1	38.9	3552	−82%	−203
2a	14.4	16.2	440	24%	85
2b	20.8	24.5	1462	−15%	−469
2c	29.5	34.2	1576	−60%	−123
BAU	19.5	21.4	0	(BAU)	(BAU)
2035 deadline	16.1	17.7	0	17%	0
2030 coal deadline	16.0	17.8	0	17%	0

Table 4. Summary 45Q impacts for 15 plants with highest potential 45Q value[a].

Plant name	45Q payments (2021$b)	CCS capex (2021$b)	Cumulative emissions with CCS (million tonnes CO_2e)	Lifetime CO_2e abatement versus BAU (%)	Cost per tonne abated versus BAU (capex & 45Q 2021$b/tonne CO_2e)
W A Parish	18.0	7.0	157	43%	210
Cross	16.8	6.1	192	29%	297
Scherer	15.6	6.8	67	42%	454
James H Miller Jr	14.4	5.4	125	51%	148
Prairie State	13.3	4.5	381	26%	134
Oak Grove (TX)	12.7	4.6	83	61%	134
Springerville	12.2	4.5	118	38%	234
Crystal River	11.9	5.8	91	40%	291
J K Spruce	10.3	3.7	144	31%	214
Elm Road	10.1	3.6	214	27%	177
Brandon Shores	10.1	3.5	32	29%	1063
Colstrip	9.3	4.2	78	50%	175
Independence Steam Electric Station	9.0	4.6	44	39%	481
W H Zimmer	9.0	3.6	36	41%	498
Trimble County	8.7	3.6	151	32%	174

[a] Mustang is excluded due to a capacity factor of 0 in the base year; Spruance is excluded due to 2021 closure.

extension), with \$1 trillion in 45Q credits, or 24% for scenario 2a (no change to capacity factors, no lifespan extension) with \$0.4 trillion in 45Q credits. Notably, the cost of 45Q is generally lower for higher abatement levels, which makes sense given that 45Q is effectively a CO_2 production tax credit.

Table 3 suggests that 45Q could be expensive, and thus potentially very valuable for EGU owners. Which power plants and which utilities have the greatest incentive to install CCS to claim 45Q value? tables 4 and 5 summarize expected private value and cost of adding CCS for the 15 US power plants (which might include multiple units with independent CCS retrofit decisions) and 15 US utilities with the highest anticipated total capture volumes under IRA's amendments to 45Q, using scenario 1a (0, 0.9, 0.7) as the CCS scenario and the BAU baseline. Full results, across plants, utilities, and scenarios, are available in the supplementary data.

For the 15 plants with the highest potential 45Q value under scenario 1a, abatement costs range from \$148 to \$1063/tonne CO_2e, for 27%–61% abatement at the plant level relative to BAU. Overall, lifetime abatement relative to BAU is always negative at the plant level for the scenarios with lifespan extension due to CCS (that is, lifetime CO_2e emissions increase). The highest observed lifetime abatement for an individual plant under the scenarios where plants do not extend their lifespan is 68%.

For the 15 utilities with the highest potential 45Q value under Scenario 1a, abatement costs range from \$148 to \$418/tonne CO_2e, for 21%–46% abatement at the utility level relative to BAU. As with the plants, lifetime abatement relative to BAU is always negative at the utility level for the scenarios with lifespan extension due to CCS (that is, lifetime CO_2e emissions increase). The highest observed lifetime abatement for a utility under the scenarios where plants do not extend their lifespan is also 68%.

Table 5. Summary 45Q impacts for 15 utilities with highest potential 45Q value[a].

Utility name	45Q payments (2021$b)	CCS capex (2021$b)	Cumulative emissions with CCS (million tonnes CO_2e)	Lifetime CO_2e abatement versus BAU (%)	Cost per tonne abated versus BAU (capex & 45Q 2021$b/tonne CO_2e)
NRG Texas Power LLC	22.5	11.7	229	37%	251
Florida Power & Light Co	19.2	10.3	395	21%	284
South Carolina Public Service Authority	18.9	7.7	227	24%	377
Archer Daniels Midland Co	17.7	2.3	152	33%	266
Southwestern Public Service Co	16.8	6.7	104	35%	418
Luminant Generation Company LLC	16.3	8.2	198	42%	170
Basin Electric Power Coop	15.2	7.1	183	35%	228
Alabama Power Co	14.0	5.3	155	46%	148
Duke Energy Carolinas, LLC	14.0	9.0	260	27%	233
Virginia Electric & Power Co	13.4	5.3	176	32%	225
Tennessee Valley Authority	13.3	8.0	297	27%	192
Duke Energy Progress—(NC)	12.3	7.4	140	29%	343
Duke Energy Florida, LLC	12.0	6.9	174	26%	308
Georgia Power Co	10.8	6.7	159	33%	227
City of San Antonio—(TX)	10.8	3.9	184	26%	229

[a] Oklahoma Gas & Electric Co. and Spruance GenCo LLC are excluded given their reliance on plants excluded as described in table 4 footnotes.

Figure 3 shows total 45Q value and average cost (capital expenditures plus tax credit) per abated tonne of CO_2e relative to BAU for scenario 1a (no lifespan extension; 90% minimum capacity factor for coal EGUs with CCS; 70% minimum capacity factor for natural gas EGUs with CCS) at the state level.

Values for other scenario and reference case pairs can be generated using the underlying model (supplementary data). Recall that scenario 1a is one of two (out of 6) CCS scenarios with lower emissions than BAU.

4. Discussion

4.1. Limitations

This analysis is intentionally designed with assumptions that are unrealistically favorable for power sector CCS, including unlimited access to zero cost, zero loss CO_2 transport and storage; no cost premium for retrofits over new-build capture units; the use of overnight capital costs; no site restrictions for retrofits; fully successful retrofits and operations; and others. As such, results are structurally biased toward higher-CCS outcomes. Note, though, that these assumptions used for this analysis broadly reflect federally published assumptions about cost, capability, and timelines: that is, the analysis effectively asks what would happen if we believed CCS could perform as expected, without making extreme assumptions (e.g. $\gg$90% capture rate; major cost declines versus EIA projections). This choice means that capital costs are probably understated, and operational costs and CO_2 sequestration (and thus 45Q cost to taxpayers) are probably overstated relative to a more realistic scenario that accounts for capital expenditure overruns and operational challenges or project failures. As such, the overall conclusion that capital investment in US power CCS could be

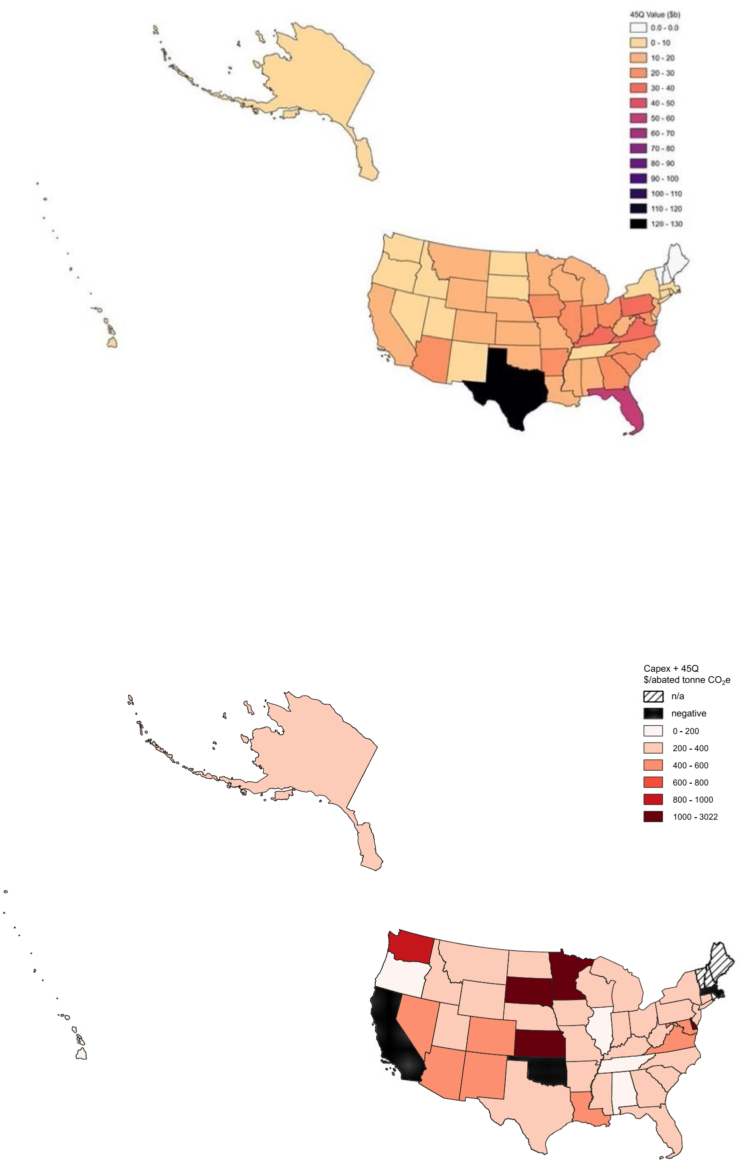

Figure 3. State-level 45Q value and abatement cost. 3 (a) Total 45Q credit value for coal and natural gas EGUs, scenario 1a. 3 (b) Average cost (capex plus 45Q value) per abated tonne CO_2e from coal and natural gas EGUs, scenario 1a relative to BAU.

extremely costly with limited benefit is robust, as is the caution that utility ratepayers might bear excessive risk from CCS projects. Within that context, major limitations include the use of constant energy and financial costs for all coal and all natural gas, independent of fuel type, EGU prime mover, plant efficiency, other pollution controls, etc, and the assumption that new-build energy penalties and costs for USC coal and combined cycle units are universally applicable to retrofits for coal and natural gas, respectively. No CCS was assumed for oil- or biomass-fired facilities, in one of the only assumptions that might underestimate rather than overestimate CCS potential in the power sector. The analysis also only considers retrofits, so any CCS on new-build fossil EGUs is out of scope but could be meaningful. No upstream emissions are considered for the coal fuel cycle, though they are for natural gas. When EGU closure deadlines are applied, they are applied instantaneously after constant operations, which might overestimate emissions given that generation replacements in anticipation of a closure deadline would likely be more gradual. Only full dedicated sequestration of CO_2, rather than utilization of CO_2 for EOR, is considered: although the tax credit is lower for EOR, mechanisms to share revenue from oil production associated with CO_2 storage could potentially lead to higher profitability, and oil production itself could lead to higher induced emissions. This analysis inherits the major limitations of its base model, described in Grubert (2021).

4.2. IRA and power sector CCS

Profit maximizing behavior for the regulated utility sector is unlikely to be emissions or cost minimizing behavior in response to a tax credit like 45Q that incentivizes production and storage of CO_2. Essentially, 45Q rewards higher generation of CO_2 in exchange for not allowing it to escape to the atmosphere, creating potentially perverse incentives to generate more CO_2 than would have otherwise occurred, much like those observed with refrigerant destruction under the Clean Development Mechanism of the Kyoto Protocol (Wara 2008). Subsidies for CCS that are intended to drive emissions abatement or carbon dioxide removal (CDR) can mitigate this issue by tying subsidies to demonstrated net abatement or removal, considering both counterfactuals (Haya *et al* 2020) and life cycle emissions (Burns and Grubert 2021). Counterfactuals and life cycle emissions can both be more challenging to analyze than CO_2 flow volumes, and fundamental uncertainties can pose particular challenges in contexts like tax credits that rely on extremely clear, precise accounting and liability allocation. These challenges also highlight the urgent need for monitoring, reporting, and verification standards and other supportive policies to achieve sustained decarbonization.

Although deeper CCS ($\gg$90% capture) is plausible and increasingly discussed (Dods *et al* 2021), both upstream emissions associated with fuel and incomplete capture and sequestration mean that CCS as motivated by 45Q neither presents a path to zero emissions in the power sector nor supports the administration's target of a 100% carbon pollution free power sector by 2035 (White House 2021). For example, adapting this work's scenario 1a (no lifespan extension; increased capacity factor) to assume 98% rather than 90% capture increases abatement through 2050 from 4.1 to 5.1 Gt CO_2e versus BAU, with \$1.1 rather than \$1 trillion in 45Q credits. This does not account for the higher energy penalty associated with higher capture so is likely an overestimate of abatement at 98% capture, but still suggests 16 Gt in cumulative residual CO_2e emissions (14 Gt CO_2; 2021–2050) from the US fossil power sector.

Even if all units installed CCS with high capture rates, achieving net zero emissions via fossil power CCS (which is not compliant with a 100% carbon pollution free goal) would require compensatory CDR, a costly and precious resource that is widely expected to be needed to compensate for extremely difficult to decarbonize processes and for atmospheric drawdown (Wilcox *et al* 2021). Relying on CDR to offset avoidable emissions is unlikely to be a successful strategy for achieving net zero, due to costs, resource limitations, and limitations on deployment relative to demand. Further, 45Q is very costly relative to tax credits for zero-carbon electricity, with higher value for EGUs with higher emissions, which contributes to the much deeper uptake for coal versus EGU units. Under the default heat rate and capture rate assumptions used here, the 45Q credit is worth about \$0.091 kWh^{-1} for coal and about \$0.030 kWh^{-1} for natural gas—compared with the \$0.026 kWh^{-1} PTC for wind and, starting in 2025, technology-neutral zero or net-negative generating technologies (Department of Energy 2022). Notably, this credit value suggests that coal and natural gas-fired power plants with CCS could potentially sell power at negative prices (as low as about -\$80 MWh^{-1} for coal and -\$24 MWh^{-1} for natural gas, based on AEO estimates for variable costs (EIA 2022a)), which supports the idea that CCS could displace even zero marginal cost renewable resources (selling as low as -\$26 MWh^{-1} with tax credits) even without distortions from self-scheduling and other non-profit maximizing dispatch practices (Daniel 2023). Even without tax credits, EIA cost projections suggest that fully zero carbon resources are cheaper than or similar to the marginal cost of CCS on a fossil plant: overnight capital costs for wind are estimated at \$1718 kW^{-1} and for solar photovoltaics with storage at \$1748 kW^{-1}, while the marginal cost of CCS for coal and natural gas are estimated at \$2551 kW^{-1} and \$1644 kW^{-1}, respectively (EIA 2022a). Note that existing fleet capacity factors for coal and natural gas are about 44% and 33%, respectively, compared to wind and solar photovoltaic (without storage) capacity factors of about 34% and 24% (EIA 2022b), and that the fossil generators have higher operating costs.

Numerous analyses of IRA, market conditions, and other policies suggest that on an overall US systemwide basis, zero emissions power is expected to be lower cost than CCS. The analysis here calls attention to the point that investment decisions are not made at a systemwide level with the goal of minimizing costs, and that despite apparently lower costs for alternative generation, costly investments in CCS with low or potentially negative climate benefits relative to reasonable counterfactuals could be profitable for asset owners. As a result, even cost competitiveness from zero-GHG EGUs might not result in displacement, and given the incentive under 45Q for fossil EGUs with CCS to operate at higher capacity factors, fossil generation might even increase (figure 2). Load growth from electrification could also reinforce the incentive to delay retirements. Fossil EGUs are disproportionately in the electric utility sector, which often includes incentives to maximize capital expenditures due to the structure of rate recovery. Utilities that are able to pass through operational expenses to customers while also deriving profit primarily from capital expenditures are probably more likely to invest in high capital, high operational cost facilities than a pure cost optimization might suggest. Regulated utility fossil EGU owners might also be incentivized to delay closure and remediation costs that might be triggered by 'retire-and-replace' but not CCS retrofit decisions, although this simplified, first order analysis does not include this dynamic. Notably, the incentive to delay end of life costs would also tend to increase the attractiveness of using the CCS retrofit to extend the plant's lifespan.

Although this analysis is heavily simplified, the types of dynamics included here reflect the incentive structures for owners of fossil EGUs that are potentially retrofittable for CCS, especially regulated utilities. Owners have an incentive to retrofit if the tax credit is large enough to cover CCS expenses and an incentive to delay the retrofit (while continuing unabated operations) to take advantage of learning curves and the time value of money, both of which are structural assumptions in the model (supplementary data). The scenarios address two other incentives: lifespan extensions and higher capacity factors during the 45Q credit period. Lifespan extensions, which could lead to substantially increased committed emissions from existing assets relative to BAU conditions (figure 1, (Grubert 2020a)), are attractive given the need to pay back large capital expenditures (like capture retrofits) over time; the advantages of continuing to operate existing assets; and the delay of remediation obligations. Increasing capacity factors to increase CO_2 production while the 45Q tax credit is available is also incentivized, as 45Q is effectively a CO_2 production tax credit (as long as the CO_2 is sequestered). As figure 1 shows, this incentive to increase capacity factor could lead to disproportionately higher upstream methane emissions (modeled here only for natural gas), as CCS is energy intensive and only mitigates flue stack emissions (and even flue stack emissions are only partially mitigated). The combination of incentives for longer operating lifespan and higher capacity factor could drive higher overall committed generation from existing fossil EGUs (figure 2). Although this higher generation could displace new-build fossil assets, it could also displace investment in new zero-GHG EGUs and, when capacity factors are high, reduce net demand for generation from facilities that are not must-run or self-scheduled, potentially reducing profitability for renewable EGUs. This dynamic was not explored in detail here but could be a relevant area for further research. Regardless, increased fossil generation with or without CCS could present challenges for the US goal of a carbon pollution-free power sector by 2035.

A major dilemma for 45Q is that CCS has both high capital and high operating costs, which means that when the credit is no longer available (under IRA, after 12 years), EGUs would likely stop capturing and storing CO_2 unless some other mechanism to either pay for or require the sequestration is in place. Unlike PTCs applied to clean electricity generation from capital intensive but operationally cheap investments, 45Q pays for waste management rather than a cleaner product, and that waste management is both capital intensive and operationally costly. As a result, 45Q does not structurally incentivize continued operations once the tax credit expires the way a PTC for capital intensive clean electricity generation does. For example, the wind PTC enables construction of a wind farm, which can continue to operate at very low costs while selling its structurally cleaner electricity after the tax credit expires. By contrast, 45Q enables construction of a CCS unit that is expensive to run and not required for the underlying revenue generating activity of the EGU, which is producing power. As such, without the ongoing tax credit, the EGU is incentivized to shut off the costly CCS activity and continue to sell its original product of GHG-intensive electricity, though a future replacement tax credit or similar mechanism could potentially be lower value if the capital expenditures made possible by the high credit value under IRA were already made. The GHG abatement is not structurally guaranteed by the addition of CCS capability because the plant can run without sequestering the emissions it produces, which is a fundamentally different abatement mechanism than replacing a GHG-generating facility with one that does not generate GHGs. Overall, it is not unreasonable to expect that the IRA changes to 45Q could result in longer operations with higher output for CO_2-producing EGUs.

An additional complexity from an emissions perspective is the potential impact of delay or project failures. CCS, and particularly power sector CCS, is globally rare (Global CCS Institute 2022). In the US, it has never been demonstrated on a full coal EGU or at all on a natural gas EGU, and the sole commercial scale coal demonstration project (Petra Nova) was coupled to an EOR project rather than dedicated storage before it was shut down in 2020 (Global CCS Institute 2022). Petra Nova (on a slipstream of one unit at the US' W. A. Parish coal-fired power plant) and Boundary Dam (on one unit at Canada's Boundary Dam coal-fired power plant), the first- and second-of-a-kind North American commercial scale power sector CCS demonstrations (Global CCS Institute 2022), both experienced significant operational problems and underperformed capture and sequestration targets. The Kemper Project, which would have been an integrated gasification combined cycle coal-fired power plant with CCS coupled to EOR, was heavily delayed and budgeted at three times its original expected cost before it was canceled and demolished. The need to link CO_2 capture, transport, and sequestration for first and low-*n*th of a kind projects presents industrial complexity that could lead to delays and cost overruns even without major construction issues. For example, dedicated Class VI CO_2 storage wells are very rare to date, with long permit timelines. As Energy Innovation notes in a memo on implementation, public utility commissions 'should…exercise[e] healthy skepticism on carbon capture technology' (O'Boyle *et al* 2022).

If fossil EGU owners commit to abatement levels they are ultimately unable to deliver, using CCS instead of an alternative, the resultant delayed action could have large emissions consequences. This consequence is particularly concerning in cases where utility commissions and other regulators and policy makers elect not to move forward with more stringent rules because of a promise of future action (for an example in the carbon offsets context, see (Haya *et al* 2020)). Consider a case where a state is weighing requiring coal unit closures (see, e.g. Illinois (State of Illinois 2021)) against a low-GHG energy standard that allows for CCS. A coal EGU owner pledges to add CCS to a 40 year-old EGU, arguing that it is pragmatic to wait until 2032 to break ground to maximize time for stakeholder engagement and design while allowing the technology and industrial ecosystem to mature, while still being eligible for 45Q credits. The state agrees and allows the EGU to stay online rather than participating in a state-sponsored transition plan that would have closed it in 2028. If the CCS project is successful, in a best case scenario, the EGU operates unabated for 8 years longer than it otherwise would have—the time between the alternative closure date and breaking ground, plus the time to complete the CCS retrofit. Project delays would lengthen this. If the CCS project is not successful, the EGU still operates unabated for longer than it otherwise would have, then closes suddenly with no support, structure, or plan for closure, with major community impacts that could have been avoided in the scenario with a state transition plan (Haggerty *et al* 2018, Roemer and Haggerty 2022). Given discussion even of bringing closed plants back online due to the potential for CCS (Global CCS Institute 2022, Robinson-Avila 2022), the idea that plants might stay online longer than they otherwise would have because of the possibility of adding CCS, even with a low success probability, is not inconceivable. As such, even if 45Q claims are ultimately low in the power sector, the existence of the policy could change behaviors in ways that could increase emissions relative to BAU.

Without an accompanying requirement to reduce or eliminate GHG emissions, 45Q could conceivably increase GHG emissions from existing fossil EGUs relative to BAU (figure 1, table 3), and potentially at very high cost. As table 3 shows, scenarios with 12- or 20 year lifespan extensions would on average cost ratepayers and taxpayers \$120–470 per increased tonne of CO_2 equivalent. The CCS scenarios considered here—including one with no lifespan extension and no change to facility capacity factors—include \$440–3600 billion in taxpayer funded 45Q credits alone, in addition to the costs of the CCS itself that would likely be borne by ratepayers. Note that the Congressional Budget Office, which estimates marginal budgetary impacts through 2031, suggests IRA's 45Q enhancement would cost a total of \$3.2 billion through 2031 (CBO 2022)—as the program is unconstrained and extends well beyond 2031, costs could be substantially higher. As tables 4 and 5 show, multiple individual plants and individual utilities could potentially claim over \$10 billion in 45Q credits over the credit period. Combined with increased fuel demand due to the energy penalty of CCS, IRA's 45Q enhancement could increase consumer electricity costs and exposure to fuel-related inflation pressures, rather than decrease them as intended (Larsen *et al* 2022). Demand for and use of more fuel, coupled with requirements of carbon capture processes themselves, could also increase other disbenefits, like increased mining, water use, air pollution, and solid waste generation (Grubert *et al* 2012, Rosa *et al* 2021, Wang *et al* 2021, Grubert and Zacarias 2022). Although the loss of benefits like property taxes ($\sim$\$2 billion yr^{-1} from fossil fuel-fired power plants in the US (Raimi *et al* 2022)) and jobs (estimated at $\sim$120 000 for fossil fuel-fired power plants and associated extraction as of 2022 (Grubert 2020a)) accompany plant closures, the majority of US fossil fuel-fired power generation assets will have reached end of typical lifespan by 2035 (Grubert 2020a). Utility-owned fossil EGUs with longer remaining typical lifespans are disproportionately in states with higher poverty levels (Grubert 2020a), suggesting higher capital and operational costs might add to already high energy burdens and other injustices associated with fossil power operations.

Past experience suggests high potential for cost overruns for CCS (GAO 2021) that might mean projects are approved based on an expectation of profitability with 45Q, but are ultimately more costly and burden ratepayers. Similarly, as 45Q is credited on an as-sequestered basis, a costly capture facility that ultimately does not succeed in meeting sequestration targets might incur substantial costs for ratepayers with limited or negative benefit. CCS retrofits that create opportunities for other capital projects to extend a facility's useful lifespan might also add to ratepayer burdens, all without the benefit of structurally clean electricity that would reduce the risk of needing to replace these assets for compliance with potential future GHG requirements. Especially as states increasingly pass laws requiring zero- or net-zero GHG electricity, the risk of expensive investments in CCS that cannot eliminate emissions is high, especially given the availability of zero GHG-compatible alternatives that could be lower cost. This gap—between potential EGU owner incentives and societal incentives—is potentially large, highlighting again that 45Q is not structured to align with broad cost- and emissions-minimizing actions. Tables 4 and 5, and figure 3, show that social costs and potential private value could be quite high at the plant and utility level, and unevenly distributed across geographies. Note these results are for Scenario 1a (no lifespan extension; at least 90% capacity factor for coal CCS; at least 70% capacity factor for natural gas CCS), which is one of two scenarios with net GHG abatement from existing fossil EGUs; full details for plants and utilities across scenarios, including all the lifespan extension scenarios for which 45Q increases emissions, are available in the supplementary data.

This analysis explicitly uses unrealistically favorable conditions to evaluate potential US power sector CCS outcomes under IRA's expansion of the 45Q tax credit, with the goal of assessing how EGU-level profit maximizing decisions based on widely available federal assumptions about cost and performance for fossil CCS might lead to different outcomes than system-wide cost-minimizing decisions about energy investments—including challenges that might arise if EGU owners use plausible but highly favorable assumptions to argue for investments or make claims about adherence to emissions trajectories. That is, this analysis errs on the side of assuming more rather than fewer EGUs could make a case for CCS in front of a regulator, in order to identify potential systemic risks and opportunities for regulators to prepare. As such, this analysis suggests much higher potential for IRA to facilitate power sector CCS in the US, or at least plausible proposals, than is immediately obvious from comprehensive, largely cost-minimizing analyses of IRA provisions (Jenkins *et al* 2022, Mahajan *et al* 2022, Roy *et al* 2022, Larsen *et al* 2022).

Close inspection of other models of IRA impacts suggests that the qualitative finding that 45Q incentivizes large amounts of fossil power CCS is consistent with those analyses despite relatively low reported uptake, in part because they generally report top line results for 2030. Given that 45Q eligibility extends to projects breaking ground by the end of 2032 (and, as discussed above, the plausible incentive for projects to delay action), the level of power sector CCS deployment facilitated by IRA is masked by this choice. The two models with some values reported out to 2035 (REPEAT and Rhodium, (Jenkins *et al* 2022, Larsen *et al* 2022)) both show rapid expansion of CCS between 2030 and 2035. REPEAT shows power sector CCS explicitly, with about 330 MMT of CO_2 capture from coal and natural gas EGUs projected for 2035—versus 430 MMT and 230 MMT in 2035 from this work's scenarios 1a and 2a, respectively (the no lifespan extension scenarios). Rhodium does not include a power sector CCS estimate but did publish an industrial CCS breakout, showing industrial capture capacity growing from ∼100 MMT/year industrial capture capacity in 2030–270–310 MMT/year by 2035. Estimates of CCS uptake are highly sensitive to the reporting date or interval (this analysis extends through 2050 because that interval covers the latest build year plus 12 years of tax credits). For example, Credit Suisse estimates that IRA could incentivize an additional $50 billion in 45Q credits by 2031, relative to CBO's estimate of $3 billion (in addition to the baseline no-IRA value of $30 billion) (Jiang *et al* 2022)—much less than this work's finding that existing fossil EGUs could plausibly demand $120–$1300 billion in 45Q credits, but suggestive of very high potential demand. Again, these estimates are sensitive to timing given that 45Q eligibility extends to any facility breaking ground by the end of 2032. To illustrate this, consider that adjusting CCS build times from 4 to 7 years for coal and 3–6 years for natural gas, which is reasonable for complex and multi-industry projects like capture retrofits and storage complex buildout, drops the 2022–2031 estimated 45Q payments for this work's scenario 1a from $250 to $50 billion—similar to the Credit Suisse value. As such, models that do not extend through the full 45Q payment period might not report high power sector CCS uptake even if it consistent with the model environment's assumptions.

In addition to timeline sensitivity, note that the two models reviewed here that explicitly report power sector CCS uptake both constrain it by assumption. REPEAT assumes capture deployment is constrained by injection capacity, reaching 200 MMT/year by 2030, suggesting that an unconstrained scenario would include more power sector CCS. That injection capacity limit very likely exists in practice, but might not be evident to regulators considering CCS retrofit proposals. As Jenkins *et al* point out, injection could be a limiting factor shared across power and industry (Jenkins *et al* 2022), which suggests a potential need to prioritize sequestration for projects with higher abatement potential and fewer alternatives for deep decarbonization (e.g. cement over power). Resources for the future (RFF) explicitly disallowed any power sector CCS retrofits by assumption, which masks the degree to which IRA incentivizes power sector CCS efforts.

5. Conclusions

Widespread deployment of CCS in the US fossil power sector under conditions incentivized by the IRA adjustments to the 45Q tax credit is an extremely costly and likely ineffective GHG abatement strategy compared to alternatives. Given that the credit is now federal law, state and local regulators tasked with approving power sector CCS proposals should be diligent in evaluating the cost, emissions impact, and general viability of projects before approving them. The tax credit itself incentivizes facilities to run more, with attendant increases in fuel extraction and related impacts that CCS does not mitigate. Even on a simple payback basis under the favorable conditions evaluated here, natural gas facilities need to run at 70% capacity factors or higher for the full 12 years of the credit to break even, compared to the existing fleet weighted average capacity factor of about 33% (44% for combined cycles) (supplementary data)—suggesting that in practice, 45Q is likely to strongly favor coal EGUs that could break even with capacity factors as low as 40%, compared to the existing fleet weighted average capacity factor of about 44%. Given that these facilities are generally older and have more significant fenceline pollution challenges than natural gas facilities, a costly policy that strongly incentivizes investment in coal EGUs could have major energy and environmental justice implications.

Without a permanent tax credit or other mechanism to ensure capture and storage continues for the life of the facility, reasonable lifespan extensions beyond BAU (common with large capital projects) could drive higher lifetime emissions as a result of the CCS project. As table 3 shows, either a 2035 fossil EGU retirement deadline or a 2030 coal EGU retirement deadline would deliver about a 17% abatement relative to BAU retirements (through 2050). Scenario 1a, the primary scenario evaluated here, spends over $1 trillion on CCS tax credits through 2050 to deliver a 19% abatement with no path to zero emissions.

Even with very favorable conditions, much of the fossil EGU fleet is not eligible for CCS or would not break even on costs even with the IRA adjustments, so other policy actions to eliminate fossil power emissions would be required even if fossil CCS driven by 45Q were to achieve maximum technical abatement potential. IRA provisions are expected to enable zero-GHG EGUs to outcompete fossil EGUs, but given that generation decisions are not made on a cost minimizing basis (and indeed, that many of the US' fossil EGUs were not competitive with clean energy even before IRA (Bodnar *et al* 2020)), additional policy is necessary if power sector GHG emissions are to be eliminated. As the enhanced 45Q credit program goes into effect, it will be particularly incumbent upon state regulatory bodies to weigh full evidence when presented with utility proposals. Designing policy to ensure actual and permanent life cycle emissions elimination while enabling planned transition for host communities and ratepayers should be a major regulatory focus, even as fossil EGU owners might present costly and risky plans for widespread CCS deployment.

Data availability statement

All data that support the findings of this study are included within the article (and any supplementary information files).

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Conflict of interest

The authors declare no potential conflicts of interest with respect to the research, authorship, and/or publication of this article.

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