Distributional Impacts of Carbon Capture in the U.S. Power Sector

Online Appendix

Ana Varela Varela, Daniel Shawhan, Christoph Funke, Maya Domeshek, Sally Robson, Steven Witkin, Dallas Burtraw, and Burçin Ünel

June 2024

A. E4ST Description and Assumptions

E4ST represents decisions that generation investors/owners, system operators, and electricity users each make to maximize the sum of the net benefits for themselves. To do this, the model requires extensive input data and assumptions. This section briefly explains key features of our modeling.

The model uses a representation of the U.S. electric grid reduced to roughly five thousand nodes and twenty thousand transmission segments. Power flow through the transmission segments is represented using a standard linear approximation of the physics of alternating-current power flow, known as a "DC linear approximation" (Yang et al. 2017). These equations assume that the power flow through each alternating-current transmission segment is a linear function of the net injection of power at each node in its region (its "interconnection" in power sector parlance).

E4ST simulates the operation of the electricity system in a set of 52 representative hours of the year. The use of a set of 52 representative hours instead of more, such as all of the hours of a year, keeps the model solvable within a day. Because of its detail and the tens of thousands of buildable or retirable generating units in the model, the model has approximately ten million optimization variables and ten million constraints. With more representative hours, it would have proportionately more variables and constraints. These 52 hours were carefully selected to mimic the frequency distributions of load, solar resource, and wind resource in the historical period 2008-2010, which at the time of our dataset construction in 2020 was the only period for which detailed location-by-location, hour-by-hour wind, solar, and load data were available for both the U.S. and Canada, to our knowledge. The representative hours are grouped into 16 representative days, which allows for the simulation of diurnal energy storage. Five of these days represent non-extreme conditions and are comprised of six evenly spaced representative hours. The remaining 11 days represent periods of potential extreme scarcity (high load, low sun, low wind, or a combination) in some parts of the U.S. and Canada and consist of only two hours (the most and least extreme hour in that day). These 11 extreme days are a carefully selected set that represents every kind of extreme scarcity condition in every NERC region of the U.S. and Canada. Using these representative periods with appropriate weights based on the frequency of hours with similar characteristics, E4ST is able to represent the joint probability distribution of electricity demand, wind, and sun across time and space in a typical year, including the extreme scarcity hours. Appendix D3 of Shawhan et al. (2020) describes the selection and weighting of the representative hours.

Expected U.S. electricity consumption is drawn from the Annual Energy Outlook 2021 reference case projection for 2035. Then it's increased to account for additional expected load as a result of the Inflation Reduction Act, based on modeling done by Energy Innovation Policy and Technology, LLC.[1]

Wholesale electricity prices are calculated as the locational marginal prices, which are the marginal cost of supplying electricity at each node in the transmission system. Electricity user prices are adjusted from the wholesale prices to also include distribution charge, taxes and fees, rebates of transmission

[1] Bistline et al (2024) use a similar approach to compute load growth by 2035 as a result of the Inflation Reduction Act subsidies for end-use electrification.

merchandising surplus to users, rebates of net earnings of cost-of-service-regulated generating units to users, and any policy costs (such as renewable energy credit prices) that should be paid by users to generators. The electricity transmission and distribution cost paid by consumers varies by state.

State renewable portfolio standards (RPSs), clean energy standards (CESs), and technology carveouts as of July 2022 are included in our modeling, based on information from the Lawrence Berkeley National Laboratory's State Renewable Portfolio Standards Status Update (Barbose 2021). In states where an RPS or CES ends or plateaus before 2050, we assume it will instead keep increasing at the rate it has been, representing states' pattern of extending clean energy commitments, to avoid biasing upward our estimate of the emission-reduction effects of allowing CCUS. We also model the Regional Greenhouse Gas Initiative (RGGI) as a power sector CO_2 cap for the RGGI states.[2] California's AB32 is represented as a carbon price. We maintain these state and regional policies in all four simulations. Some of them are slack in all four simulations, some of them are slack only in the two simulations with a U.S. national CO_2 cap, and some of them are not slack in any of the simulations.

The investment in, retirement of, and operation of generating units depends on the revenues and costs of the units. For existing electricity generators, we use historical costs and emissions rates provided by the S&P Global/SNL database. We use unit-specific variable costs, fixed costs, and fuel costs to determine the profit-maximizing operation and retirement of each existing generator. For new and potential new generators, we use cost assumptions in the NREL Annual Technology Baseline (Vimmerstedt et al. 2022). Typical cost and performance characteristics used for each newly buildable generator are reported in Table A. 1 below. The costs vary by region, according to the assumptions of the Electricity Market Module of the National Energy Modeling System (U.S. EIA 2022).

Other additional information about the E4ST model, including more detailed documentation, codebase, and publications in which the model has been used, can be found at Resources for the Future (2023) or via links provided there.

---

[2] In RGGI we included New Jersey and Virginia but not Pennsylvania. At the time of the modeling, it seemed likely that either Pennsylvania or Virginia would not be part of RGGI.

Table A. 1. Typical Cost and Performance Assumptions for New Technologies Buildable in the E4ST Model.

	Total Cost to Build (mln $/MW)	Annual fixed costs ($/MW)	Variable cost ($/MWh)	Heat Rate (MMBtu / MWh)	Levelized cost of energy ($/MWh)	Assumed Capacity Factor in LCOE calculation
Fossil-gas Turbine	0.76	21000	47.22	9.72	57.00	85%
Fossil-gas Combined Cycle	0.89	28000	27.37	6.36	39.31	85%
Fossil Gas with Carbon Capture and Storage	1.37	58971	31.41	6.88	51.96	85%
New Nuclear	7.35	145960	2.84	10.44	83.27	92%
Solar	0.75	14721	-	-	37.47	20%
Wind	0.94	37489	-	-	38.75	30%
Offshore Wind	2.72	81471	-	-	76.28	40%
Battery	0.83	20980	83.18	-	158.92	17%

Note: All dollar values are in 2020 dollars. We assume an economic lifetime of 30 years and a capital recovery factor of 6.8% for all buildable technologies. Battery variable cost is based on the average wholesale price of electricity which determines the cost to charge.

B. Coal Retrofit Functions

For coal-fueled electricity generating units retrofitted with CO_2 capture, the current leading technology options for capturing CO_2 are two post-combustion capture options: the use of amine gases or membranes. These technologies may also be cost-competitive for new generating units. There are at least three additional options that could be competitive for new generating units but probably not for retrofits: the use of a supercritical CO_2 cycle, fuel cells, or gasification of the fuel. Gonzales et al. (2020) further describes CCUS and the available technology options.

Cost and performance characteristics of coal CCUS retrofits are determined based on the characteristics of the existing generating unit. To do so, we use equations derived from the coal CCUS retrofit cost estimates used in the EPA's Integrated Planning Model (U.S. EPA 2021), specifically Chapter 6, Table 6-2 in the Platform v6 documentation. Inputs to the functions are capacity in MW ("avgcap") and heat rate ("hr") in MMBtu/MWh. The equations follow. "FOM" is fixed operating and maintenance cost. "VOM" is variable operating and maintenance cost. If an existing generating unit is retrofitted, the calculated incremental costs are added to the existing costs of the generating unit. The capacity and heat rate penalty are applied as scalars such that the net capacity decreases because of the additional CCUS load and the heat rate increases to match the increased fuel use per MWh of electricity exported to the grid.

[1] $$Capital\ Cost\ \left(\frac{2016\$}{kW}\right) = 2496.4444 - 6.9022 * avgcap + 0.003544 * avgcap^2 + 267.3333 * hr$$

[2] $$FOM\ \left(\frac{\$}{kW} - yr\right) = 48.503704 - 0.116685 * avgcap + 0.0000598148 * avgcap^2 + 3.000000 * hr$$

[3] $$VOM\left(\frac{\$}{MWH}\right) = 1.4281 - 0.0060963 * avgcap + 0.0000031481 * avgcap^2 + 0.4233333333 * hr$$

[4] $$Capacity\ penalty\ (\%) = 49.2333 - 0.112000 * avgcap + 0.0000533333 * avgcap^2 + 2.4333333333 * hr$$

[5] $$Heat\ Rate\ Penalty\ (\%) = 89.774 - 0.2513148 * avgcap + 0.00012907 * avgcap^2 + 5.00000 * hr$$

We also apply the heat rate penalty to the pollution emissions rates. For instance, if the heat rate penalty is 30%, then we assume that carbon and local pollutants' emissions are 30% higher per MWh than without the heat rate penalty.

C. Emissions Rates from CCUS Power Plants

Table 2 in the main paper summarizes the upper- and lower-bound emissions rate changes assumed for SO_2, NO_X, $PM_{2.5}$, and NH_3 for electric generating units that adopt CCUS. The percentages in this Table represent the percentages of emissions rates per MMBtu of the same generating units before retrofitting (in the case of coal) and of new plants without CCUS (in the case of fossil gas). CCUS increases heat required per MWh of net generation, so 100% implies that the emissions rate per MWh of net electricity generation would increase.

These emissions rates were taken from existing literature, Department of Energy (DOE) front end engineering design (FEED) studies on existing and proposed CCUS plants, and consultation with experts. Each emissions rate was determined using a unique process, which is detailed below. The upper-bound emissions rate assumptions often reflect either no change in the emissions rate, or a technical limit on the emissions type, such as the necessary removal of SO_2 before CO_2 capture. The lower-bound emissions rate assumptions often reflect the reported emissions rates in the FEED studies, which show a promising reduction in many pollutants. Emissions are dependent on the type of carbon capture that is used as well as plant-specific configuration and emissions restrictions. The range between the lower- and upper bounds encompasses the uncertainties about what CCUS technologies will be used and about the stringency of emissions regulations that will apply to generators with CCUS.

As noted in the body of the paper, the main results presented in the paper use the midpoint set between the upper-bound and lower-bound rates. Section V in the main paper tests the sensitivity of the positive aggregate monetized impact of CCUS deployment to assuming the upper- and lower-bound rates.

Beyond local pollutant emissions rates, we assume a heat rate of 6.88 MMBtu/MWh for new fossil-gas plants with CCUS, based on the expert elicitation reported in Shawhan et al. (2021), and a heat rate of 6.36 for new fossil-gas plants without CCUS (Vimmerstedt et al. 2022). We assume 90% CO_2 capture rate for both coal CCUS and fossil-gas CCUS.

i. Coal CCUS Retrofits

<u>**Upper bounds**</u>

$PM_{2.5}$: The European Environment Agency (2020) indicates that adopting CCUS can have little effect on primary $PM_{2.5}$ emissions rate per unit of heat input. Amine CO_2 capture systems can tolerate normal concentrations of $PM_{2.5}$ and can allow it to pass through the CO_2 capture system and be emitted into the atmosphere. Reported projected $PM_{2.5}$ emissions per unit of heat input do not change at the FEED Dry Fork project (Merkel et al. 2022). However, they are projected to increase by an unstated amount at the FEED San Juan site (Crane 2022) because of the addition of another cooling tower, which can increase $PM_{2.5}$ emissions because some of the dissolved solids in cooling water that escapes and evaporates in the air become airborne particulate matter. The San Juan front-end engineering design (FEED) study does not estimate the extent to which $PM_{2.5}$ emissions will increase, but the San Juan project will be similar to the Petra Nova project (Kennedy 2020). Based on data reported in the EPA's eGrid (U.S. EPA 2020) for the years 2016 and 2018, the Petra Nova $PM_{2.5}$ emissions rate per MMBtu increased by approximately 4% between 2016 (the last full year before its CCUS retrofit) and 2018 (the first full year after its CCUS retrofit). Based on this finding, we estimate that if a high proportion of facilities add cooling towers when they retrofit for carbon capture, as the Petra Nova capture project did, and if the EPA does not prevent emissions increases, then average $PM_{2.5}$ emissions per unit of heat input could increase by 4%.

NO_x: In the CCUS FEED studies submitted to DOE to date, the San Juan generator is projected to have no change, or at least no increase, of NO_x emissions per unit of heat input (Crane 2022). The Dry Fork generator is projected to have a 9% decrease in NO_x per unit of energy input (Merkel et al. 2022). The European Environment Agency (2020) and the Petra Nova project (Kennedy 2020) indicate that adopting CCUS can have little effect on the NO_x emissions rate per unit of heat input. Amine CO_2 capture systems can tolerate normal concentrations of NO_x and can allow most of it to pass through the CO_2 capture system and be emitted into the atmosphere. Consequently, our upper bound assumption is that NO_x emissions rate per unit of heat input remains unchanged.

We note that, given the regulatory practices of the U.S. EPA, this is a pessimistic assumption. The EPA is unlikely to allow power plants that adopt CCUS to retain the same NO_x emissions rates per unit of energy input they had before adopting CCUS because they are likely to have higher heat rates and higher capacity factors after adopting CCUS, implying that their annual emissions would increase if they kept the same emissions rate per unit of energy input, which might violate other EPA regulations of NO_x levels. Based on our modeling, we project that, on average, coal power plants that adopt CCUS will have to reduce their NO_x emissions rates per unit of heat input by nearly 50% to prevent the adoption of CCUS from increasing total electric sector NO_x emissions relative to what they would be without the adoption of CCUS.

SO_2: Amine-based CO_2 capture systems are fouled by SO_2, and the planned membrane-based system captures SO2, so both types emit nearly zero SO_2. The SO_2 value in the Dry Fork FEED study, which will use a membrane-based capture technology, is the highest of the three values in the coal CO_2 capture FEED studies submitted to the US DOE since 2017 (Merkel et al. 2022). It is 2.53% of that generator's pre-retrofit SO_2 emissions rate, which we have rounded up to 3%.

NH_3: In the U.S., the Environmental Protection Agency typically requires sources of particulate-forming emissions, such as ammonia, to meet an emissions standard based on what it deems to be the most effective available emissions control technology. Ammonia emissions rates from CO_2 capture systems are highly controllable (Heo et al. 2015). It would be unusual for the U.S. EPA to allow an existing source, such as a power plant, to raise its permitted emissions rate, and the many U.S. power plants with catalytic and non-catalytic emissions reduction systems already commonly have ammonia emissions concentration limits in place, typically of 2 to 10 ppm (Majewski 2022; U.S. EPA 2003). Consistent with these patterns, the owners of the coal-fueled San Juan generating station seem to be planning to leave their permitted ammonia concentration limit of 7 ppm unchanged as they add carbon capture to the plant (Crane 2022). Regulations and control systems usually result in emissions concentrations considerably lower than the limits (Sorrels et al. 2019). Additionally, in the six power plant CO_2 capture projects that have submitted FEED studies to the U.S. DOE since 2017, the highest ammonia emissions rate after the addition of CO_2 capture is 0.006 lbs per MMBtu. These facts strongly suggest that the U.S. EPA will ultimately set ammonia emissions concentration limits that will keep ammonia emissions concentrations below 10 ppm at power plants with carbon capture. Therefore, we assume 10 ppm as a high bound emissions rate. Conversion from ppm to pounds per MMBtu assumes 15% O_2, which is standard practice for EPA regulation (Schrader 2005), and an F_d of 8710 for fossil gas and 9780 for coal (U.S. EPA 2023a). The formula used is (Santa Barbara County, Pollution Control District 2023):

$$\frac{lb}{MMBtu} = ppm * \frac{1}{molar\ volume} * (molar\ weight) * F_d * (\frac{20.9}{20.9 - \%\ O_2})$$

Applying this formula yields an emissions rate for coal CCUS of 0.0155 lbs/MMBtu.

Lower bounds

$PM_{2.5}$: The Boundary Dam project (SaskPower 2018) reports that $PM_{2.5}$ emissions are reduced to 30% of non-retrofitted rates. We use 30% as the assumed lower bound, though we note that lower is conceivable. $PM_{2.5}$ is damaging to membrane-based CO_2 capture systems, such as the one planned for use at the Dry Fork coal power plant, so membrane-based CO_2 capture might be expected to have a lower $PM_{2.5}$ emissions rate. No expected $PM_{2.5}$ emissions rate reduction is reported in the Dry Fork FEED study, but that may be because the generating unit already has an extremely low $PM_{2.5}$ emissions rate (less than 4% of the $PM_{2.5}$ emissions rate of the Petra Nova generating unit) (Kennedy 2020).

NO_x: The Boundary Dam project (SaskPower 2018) reports a 50% reduction in NO_x emissions. We use this as the lower bound, but we note that lower is possible.

SO_2: The Boundary Dam report by Saskpower states that CCUS projects are "capable of reducing the SO_2 emissions from the coal process by up to 100 percent" (SaskPower 2018). We use 0% as the lower bound.

NH_3: Membrane-based CCUS does not produce ammonia (Purswani and Shawhan 2023), so we use a lower bound of 0%.

ii. Fossil-gas CCUS

Upper bounds

$PM_{2.5}$: Amine CO_2 capture systems can tolerate normal power plant flue concentrations of $PM_{2.5}$ and can allow it to pass through the CO_2 capture system and be emitted to the atmosphere. There is no change in reported projected $PM_{2.5}$ per unit of heat input at the Elk Hills project (Bhown 2022). There is also no change in reported projected $PM_{2.5}$ per hour at the Sherman project (Elliott 2021). None of the other power plant FEED studies submitted by the time of this writing gives $PM_{2.5}$ both before and after adding CO_2 capture. We therefore assume an upper bound of 100%.

NO_x: Amine CO_2 capture systems can tolerate normal flue concentrations of NO_x and can allow it to pass through the CO_2 capture system and be emitted to the atmosphere. We therefore assume an upper bound of 100% for NO_X rate per unit of heat input for new gas-fueled generators.

SO_2: According to its FEED study, the projected SO_2 emissions rate of the Dry Fork coal-fueled generator with carbon capture using MTR membrane-based capture system is 0.0017 lbs/MMBtu (Merkel et al. 2022). This value gives us a threshold for allowable SO_2 emissions rates going into CO_2 capture systems. Fossil-gas combined cycle SO_2 emissions rates are almost always below that threshold, so, in our set of high emission assumptions, CO_2 capture systems would be able to tolerate existing fossil-gas combined cycle SO_2 emissions rates and SO_2 emissions rates per unit of heat input would not be reduced by CCUS.

NH_3: We follow the same approach detailed above for the NH_3 upper bound under the Coal CCUS retrofit section. Therefore, we assume 10 ppm as a upper-bound emissions rate. Converting to pounds per MMBtu yields an emission rate of 0.0138 lbs/MMBtu.

Lower bounds

$PM_{2.5}$, NO_x, SO_2, and NH_3: According to a testing project done by NET Power (Cusano 2021), plants using oxy-combustion can be built to produce zero or essentially zero amounts of $PM_{2.5}$, NO_x, SO_2, and ammonia.

D. Emissions Rates for Plants without CCUS

Beyond the CCUS generation described in the section above, we assume emissions rates for some pollutants and types of plants for which we did not have unit-by-unit historical emissions rate measurements or estimates. This was the case for the ammonia emissions rates of coal-fueled generators and all emissions rates of new fossil gas-fueled generators. These assumed emissions rates are indicated in Table A. 2. The process and sources followed to derive these rates are noted below.

Table A. 2. Assumed Emissions Rates of Plants Without CCUS, when Empirical Rates Unavailable

	Emissions Type	Emissions Rate (lbs/MMBtu)
Coal power plants without CCUS	NH_3	0.00055
New fossil-gas CC plant without CCUS	$PM_{2.5}$	0.0054 (CC), 0.0126 (GT), 0.007(other)
	NO_x	0.0075
	SO_2	0.0006
	NH_3	0.00240

Coal power plant without CCUS – NH_3: We derived this average emissions rate from these data: Total 2020 Ammonia emissions from coal electricity generation were 2,273 short tons (U.S. EPA 2023c). The 2020 Coal consumption for electricity generation was 8,224,162 billion Btus (U.S. EIA 2023).

New fossil-gas plant without CCUS – $PM_{2.5}$: We derive average rates from existing fossil-gas generators, whose emissions rates are provided in the EPA eGRID data (U.S. EPA 2020). We only use data from the new generators (went online on or after 2015), and distinguish between combined cycle (CC), simple-cycle gas turbine (GT), and other fossil-gas generation types. We average the emissions rates from the existing generators, weighting by heat input.

New fossil-gas plant without CCUS – NO_x: We adopt the emissions rate in Sargent and Lundy (2020).

New fossil-gas plant without CCUS – SO_2: 0.0006 lbs/MMBtu is the average SO_2 emissions rate for fossil-gas combined cycle generation in our dataset of existing generators.

New fossil-gas plant without CCUS – NH_3: We derived this average emissions rate from these data: 2020 Ammonia emissions from fossil-gas electricity generation were 14,802 short tons (U.S. EPA 2023c). 2020 fossil-gas consumption for electricity generation was 12,314,201 billion Btus (U.S. EIA 2023).

E. Process to Assess Pollution Mortality-Related Impacts

This section details the steps taken to evaluate mortality-related impacts associated with changes in pollution concentrations.

To estimate mortality-related impacts, we use empirical estimates of concentration-response (C-R) functions, which map changes in $PM_{2.5}$ exposure to mortality. Specifically, we use the general form of damages for any relative risk function that InMAP adopts to estimate pollution-related mortality for demographic group i living in census block group b, M_{ib} (Goodkind et al. 2019):

$$M_{ib} = Pop_{ib} \cdot \lambda_{ib} \cdot [RR_{ib} - 1] \qquad [1]$$

The first term in equation [1] is Pop_{ib}, the count of individuals from group i living in census block group b. We obtain these data from the 2012-2016 ACS.[3]

The second term in equation [1] is λ_{ib}, the baseline mortality rate from group i living in census block group b. We obtain all-cause mortality rate data from the Centers for Disease Control and Prevention. As we compare mortality changes across socioeconomic groups, we use age-adjusted mortality rate estimates, which control for different age structures across counties that might affect mortality rates in these counties. Aggregate mortality rate data is made publicly available only at the county level; therefore, we assume the same mortality rate for all block groups b in a county c: $\lambda_{ib} = \lambda_{ic} \;\; \forall b \in c$.

Finally, the third term in equation [1] is RR_{ib}, the relative risk of mortality group i living in census block group b associated with changes in pollution exposure. To estimate it, we adopt a linear C-R function that assumes a constant relative risk for a given change in $PM_{2.5}$ concentration ($\Delta PM_{2.5}$). The relative risk of mortality is then given by the following expression:

$$RR_{ib} = \exp\{\gamma_{ib} \cdot \Delta PM_{2.5}\} \qquad [2]$$

Where γ_{ib} are empirical coefficients estimating the mortality impacts of a $PM_{2.5}$ increase for the population of group i living in census block group b. As noted in the paper, we adopt recently estimated coefficients from Di et al (2017), which indicate that an increase in $PM_{2.5}$ concentration of 10 $\mu g/m^3$ raises the mortality risk by 7.3% on average. This estimate is similar to others commonly used in the literature (such as Krewski et al (2009), 6% increase, and Lepeule et al (2012), 14%). In Section V of the paper, we check how sensitive our estimation of mortality impacts is to the consideration of these different estimates.

In the main results presented in the paper, we assume a constant γ_{ib} for all of the U.S. population (that is, $\gamma_{ib} = \gamma \;\; \forall i, b$ in equation [2] above), as well as the average mortality rate for all demographic groups in a county (that is, $\lambda_{ic} = \lambda_c \;\; \forall i$ in equation [1] above). This assumption allows us to attribute differences in mortality impacts for different demographic groups to changes in exposure, given that we are assuming an average response to a marginal change in exposure. However, recent literature has highlighted that this assumption can yield biased estimations for specific groups (Spiller et al. 2021). Indeed, Di et al (2017) find that every 10 $\mu g/m^3$ increase in $PM_{2.5}$ concentration increases mortality

[3] We use ACS data from 2016 to match other datasets used in the household finance incidence Section.

risk by 20.8% for Black populations and by 11.6% for Hispanic populations, versus 7.3% on average and 6.3% for White populations. Mortality rates also vary by demographic groups, with rates tending to be higher than average for Black populations and lower than average for Hispanics. Table A. 4 summarizes concentration-response estimates and U.S. average mortality rates by race and ethnicity. In Figure A. 10, we allow concentration-response estimates and mortality rates to vary by demographic group, specifically for Black, Hispanic, and non-Hispanic White populations.

F. Dimensions to Evaluate Distributional Impacts: Income and Race/Ethnicity

To evaluate the distributional impacts of CCUS deployment through an energy and environmental justice lens, we would ideally compare communities that fall along a "disadvantage" spectrum. There is no agreed-upon definition of what makes a community disadvantaged, and, indeed, these factors might vary by locality (U.S. EPA 2023b). Some attempts to find a common metric for disadvantaged communities from an environmental perspective—like the EPA's EJScreen tool (U.S. EPA 2022) or the CalEPA's CalEnviroScreen (California EPA 2023)—consider a wide array of indicators to determine disadvantage, including socioeconomic factors, environmental exposure, and communities' sensitivity to this exposure. Recent works in economics have adopted these comprehensive metrics of disadvantage, such as Campa and Muehlenbachs (2024) and Hernandez-Cortes and Meng (2023).

We use a narrower approach to proxy for disadvantaged communities and characterize them only by income level and race/ethnicity. This approach allows us to evaluate the distribution of financial impacts, considering that data on expenditure shares are readily available only along these dimensions. Moreover, income and race/ethnicity, albeit not a comprehensive metric, are fundamentally related to energy and environmental justice.

Therefore, despite focusing exclusively on income and race/ethnicity dimensions, our methodology allows us to evaluate a wide range of both health and financial impacts on those groups and, thus, to provide valuable insights on the distributional impacts of CCUS.

G. Impact of CCUS Cost Sensitivities

For fossil-gas CCUS units, our high and low cost assumptions come from an expert elicitation. We use values for the 10th percentile of the costs for the low estimate and the 90th percentile of costs for the high (Shawhan et al. 2021). For the high-cost case, we also assume a 12-year economic lifetime for fossil-gas CCUS—instead of a standard 30-year economic life—to reflect that CCUS may only be viable to operate with the 45Q tax credit, which only extends for 12 years for a given plant.

For retrofit coal CCUS, to calculate cost in the high- and low-cost cases, we apply cost multipliers to the costs in the central cost case. Those multipliers are based on the ratio of costs in the high-, medium-, and low-cost projections for retrofit coal CCUS in the 2023 Annual Technology Baseline (ATB) (Mirletz et al. 2023). Because the retrofit costs from the ATB do not depend on plant characteristics, using the relative cost ratios from the ATB in our modeling requires this multiplier approach.

For the high-cost case, we add an additional storage cost per ton of CO_2 to represent constraints on the rate at which the infrastructure for CO_2 capture, transportation, and sequestration can be built. This cost adder is calibrated to reduce the total stored CO_2 from power generation to roughly 140 million metric tons per year, which comes from the assumptions in Jenkins et al (2023). This amount is that source's assumed upper limit on annual CO_2 sequestration (400 million metric tons) minus that source's projection of non-electric-sector CO_2 capture (260 million metric tons) in 2035. This cost adder is given as part of the variable cost in Table A. 3.

Table A. 3. Typical Cost and Performance Assumptions for CCUS Units for the Year 2035: Low-Cost and High-Cost Sensitivities

Generation type	Total cost to build (million $/MW)	Annual fixed costs ($/MW)	Variable costs ($/MWh)	Heat rate (MMBtu/	Capital recovery factor	Levelized cost of energy ($/MWh)
Fossil Gas with CCUS	1.37	58,971	31.41	6.88	0.068	51.96
Low-Cost Fossil Gas with CCUS	1.29	44,660	30.1	6.42	0.068	47.94
High-Cost Fossil Gas with CCUS	2.4	70,000	40.87	8	0.116	83.85
Coal	N/A	57,953	26.41	10.12	N/A	N/A
Coal CCUS Retrofit Incremental Costs	1.67	45,260	10.34	4.29	0.068	N/A
Low-Cost Coal CCUS Retrofit Incremental Costs	1.39	38,077	9.68	4.3	0.068	N/A
High-Cost Coal CCUS Retrofit Incremental Costs	1.81	45,240	21.12	3.23	0.068	N/A

Note: The given costs of retrofitted coal CCUS are the average additional costs on top of the original costs of the coal plant. The same is true for heat rate. These averages depend on which specific coal plants are retrofitted, which explains how the average effect of retrofitting with CCUS can be smallest in the high-cost case. Capital recovery factor is higher for high-cost fossil gas with CCUS because we assume a 12-year economic lifetime instead of 30-year one.

The high-cost assumption leads to considerably less generation with CCUS, as shown in Figure A. 1. Therefore, in this case, the incremental effect of CCUS is relatively small in either policy scenario. Even with significantly less CCUS deployment, almost all the monetized impacts have the same signs as in our central case, as shown in Figure A. 2, Figure A. 3, and Figure A. 4, and compared with Figure 4, Figure 6, and Figure 9 in the paper, respectively. There are just two exceptions. The first is that producer profits under the Cap are positive in the low- and central-cost cases, but negative—albeit very close to zero—in the high-cost case. The second is that aggregate effect for non-Hispanic White people is positive in the low- and central-cost cases and negative in the high-cost case, but it is extremely close to zero in all three cases.

In the low-cost case, the directions of all effects are the same as in the central-cost case.

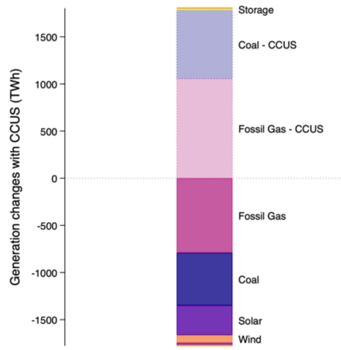
The low-cost assumption leads to a small increase in retrofit-coal CCUS and a large increase in fossil-gas CCUS generation compared to our central scenario. This change is due to the incremental cost differences for additional CCUS generation. In our central case, the most ideal coal plant candidates for retrofit are already chosen by the model to be retrofitted. Thus, building new fossil-gas CCUS is now more economically viable than retrofitting additional existing coal plants, leading to a relatively higher deployment of additional fossil-gas CCUS in the low-cost case than in the central case.

With low-cost CCUS, under Current Policies, the averted mortality due to CCUS deployment is only slightly higher than in the central cost case because the additional CCUS generation is primarily displacing additional fossil-gas generation without CCUS, which has a smaller impact on mortality than displacing coal generation. The increases in averted mortality and energy cost savings are balanced by the increase in government spending, so the aggregate benefits are roughly the same in the low-cost case as the central case. This result suggests again that, under Current Policies, displacement of coal without CCUS produces larger net benefits per MWh than does displacement of gas without CCUS.

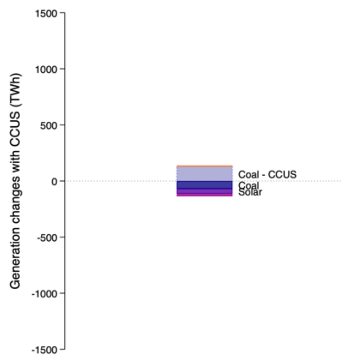
Under the Cap as well, low-cost CCUS produces approximately the same estimated net benefits as central-cost CCUS, but the reason is different. Low-cost CCUS is built to a larger extent, requiring more government incentives (a cost) and causing a larger increase in air pollution in light of the relatively clean mix of other generation it displaces in the presence of the Cap. However, these higher costs are almost exactly offset by the larger electricity bill savings it causes.

Figure A. 1. CCUS Cost Sensitivity – Changes in Generation Mix with CCUS

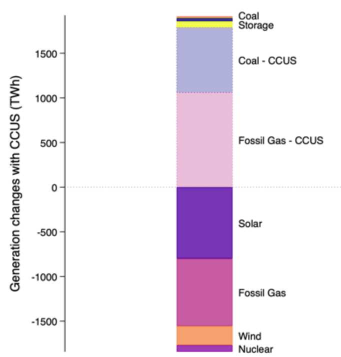
Panel A. Current Policies – Low-Cost CCUS



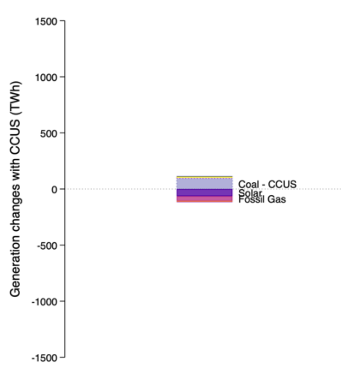
Panel B. Current Policies – High-Cost CCUS



Panel C. Additional Cap – Low-Cost CCUS



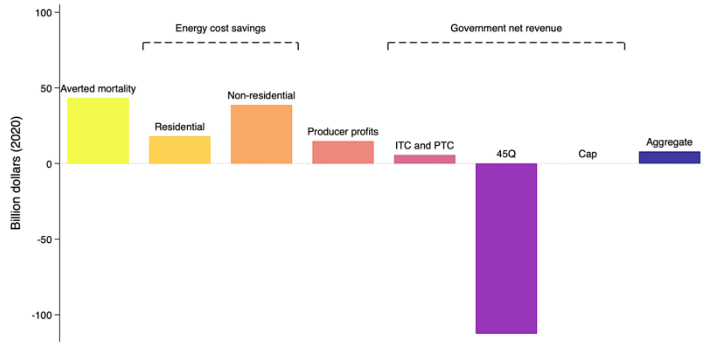
Panel D. Additional Cap – High-Cost CCUS



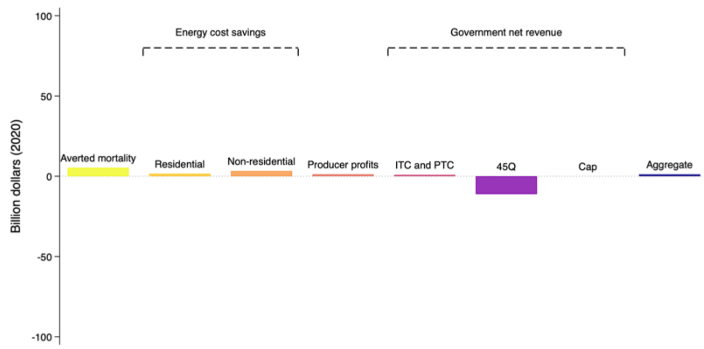
Note: Figures show changes in generation sources resulting from allowing CCUS. Positive values represent increases with CCUS, whereas negative values indicate that these generation sources decrease with CCUS.

Figure A. 2. CCUS Cost Sensitivity – Monetized Impacts of CCUS

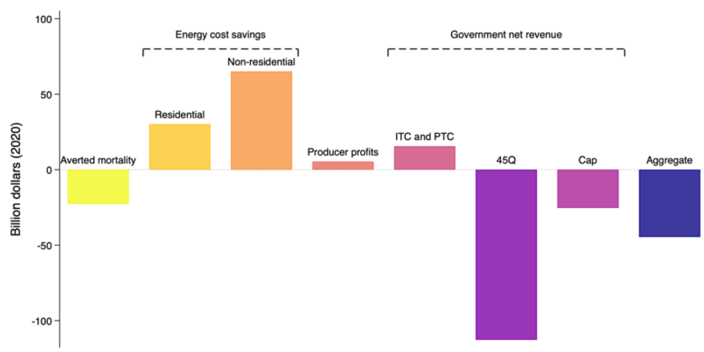
Panel A. Current Policies – Low-Cost CCUS



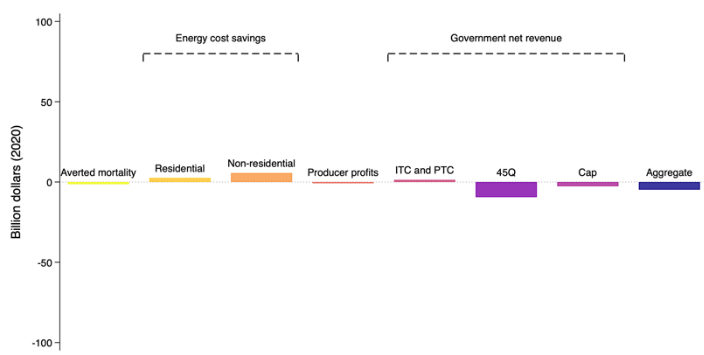
Panel B. Current Policies – High-Cost CCUS



Panel C. Additional Cap – Low-Cost CCUS



Panel D. Additional Cap – High-Cost CCUS



Note: Monetized impacts of allowing CCUS on U.S. households. Positive values represent net benefits relative to the case in which CCUS is not allowed, while negative values are net costs.

Figure A. 3. CCUS Cost Sensitivity – Income Quintile: Impacts of CCUS as Percentage of Group Total Income

Panel A. Current Policies – Low-Cost CCUS

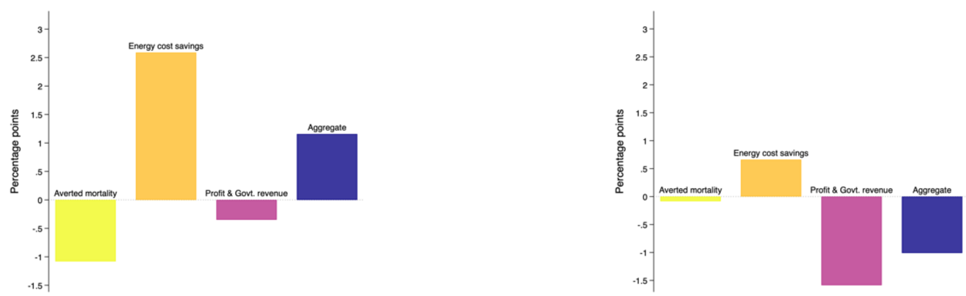
Bottom quintile | Top quintile

Panel B. Current Policies – High-Cost CCUS

Bottom quintile | Top quintile

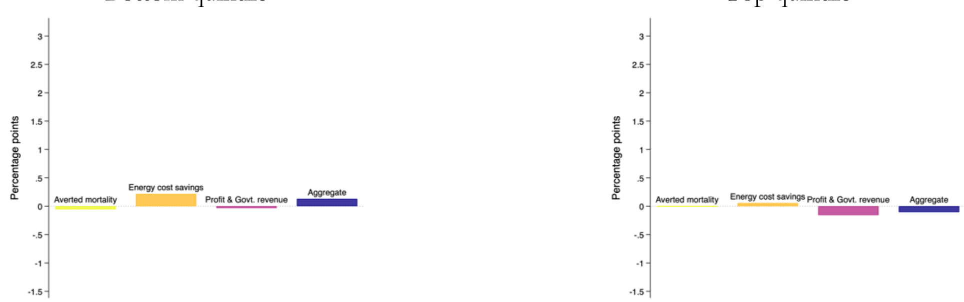
Panel C. Additional Cap – Low-Cost CCUS

Bottom quintile | Top quintile



Panel D. Additional Cap – High-Cost CCUS

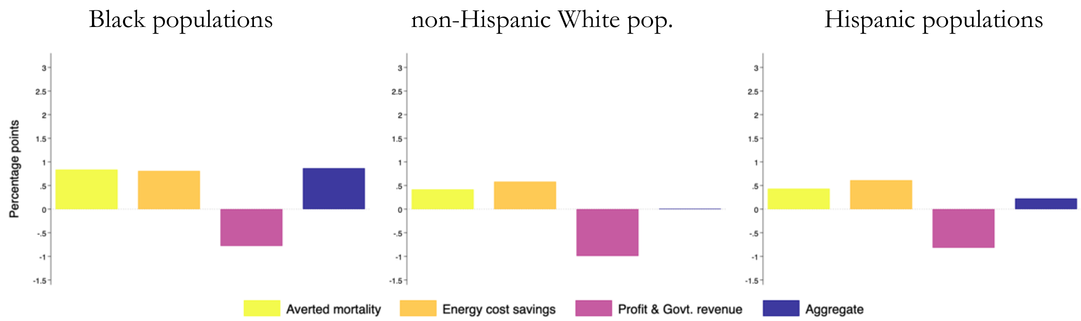
Bottom quintile | Top quintile



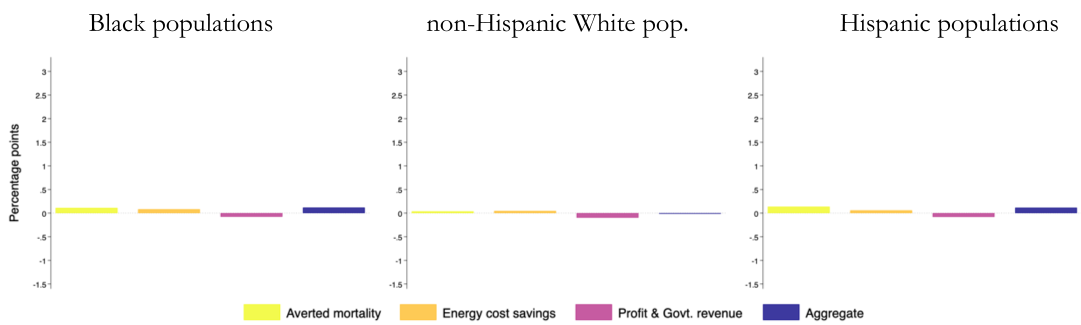
Note: Figures show monetized impacts of allowing CCUS for the populations in the bottom quintile of the income distribution (left) and top quintile (right). Positive values represent net benefits relative to the case in which CCUS is not allowed, while negative values are net costs. Values are expressed as a percentage of the group's total income.

Figure A. 4. CCUS Cost Sensitivity – Race & Ethnicity: Impacts of CCUS as Percentage of Group Total Income

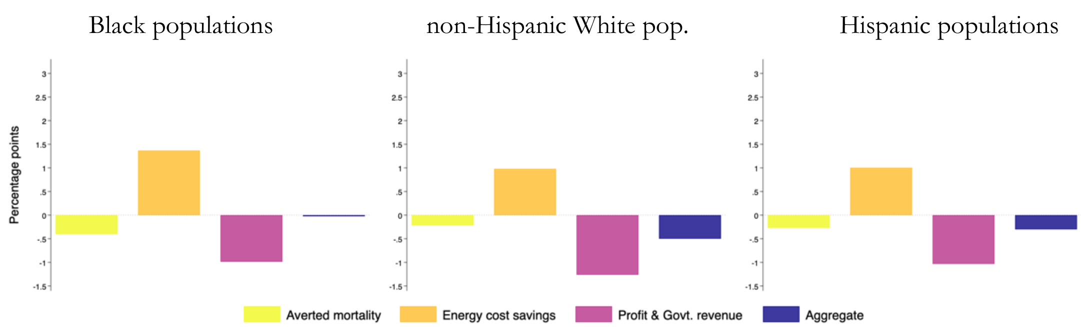
Panel A. Current Policies – Low-Cost CCUS



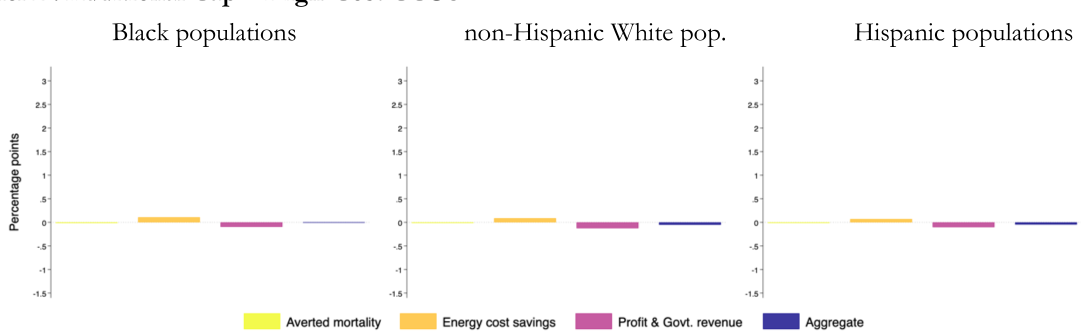
Panel B. Current Policies – High-Cost CCUS



Panel C. Additional Cap – Low-Cost CCUS



Panel D. Additional Cap – High-Cost CCUS



Note: Figures show monetized impacts for different race/ethnicity groups of allowing CCUS. The race/ethnicity groups are Black populations (left), non-Hispanic White populations (center), and Hispanic populations of any race (right). Positive values represent net benefits relative to the case in which CCUS is not allowed, while negative values are net costs. Figures are expressed as a percentage of the group's total income.

H. Impacts of Allowing Just Coal CCUS or Just Fossil-gas CCUS

It is helpful to have estimates of the effects of coal CCUS alone and gas CCUS alone for two reasons. First, a given proposed power plant CCUS project will generally be for just a coal-fueled or just a gas-fueled generating unit. Second, the anticipated mix of coal- and gas-fueled power plant CCUS projects that would be enabled or prevented by any given action, such as a change in federal regulations, might be different from the mix in our main results, or unknown. The effects could therefore be any combination of the effects of changing the amount of coal CCUS and changing the amount of gas CCUS. In this section, we use our central emissions rate estimates for generation with CCUS.

Coal CCUS and fossil-gas CCUS displace markedly different mixes of other types of generation, as shown in Figure A. 5 below. However, remarkably, the signs of almost all effects that we have compared are the same, including the signs of all effects on income and race/ethnicity groups. Figure A. 6, Figure A. 7, and Figure A. 8 show these effects. The signs of the effects of allowing coal CCUS only or gas CCUS only are the same, and they are the same as the signs of allowing both (Figure 4, Figure 6, and Figure 9 in the paper), with very few exceptions. We discuss this more below.

i. Effects of Allowing Just Coal CCUS or Just Gas CCUS, Under Current Policies

Under Current Policies, the generation with CO_2 capture is 885 TWh in the case with both coal and gas CCUS allowed, 719 TWh in the coal-CCUS-only case, and 445 TWh in the gas-CCUS-only case. Under Current Policies, 27 of the 29 effects compared in the figures below have the same sign across the gas-only, coal-only, and both-gas-and-coal cases.[4] For example, allowing CCUS, whether from coal, from gas, or from both, has the following effects: it reduces emissions, reduces electricity bills, increases producer profits, and increases government subsidies (a cost). It also disproportionately helps low-income, Black, and Hispanic populations.

a. Effects of allowing CO_2 capture only by coal-fueled power plants, under current policies

Seventy-two percent of the generation displaced by allowing coal CCUS retrofits is coal generation without CCUS, in our modeling results, as shown in Figure A. 5. In approximately 85% of cases, the coal generating unit that adopts CCUS would still operate in 2035, even without the CCUS, in our modeling results.[5] This result reflects the fact that coal-fueled capacity that is most likely to add CO_2 capture also tends to be the most likely to keep operating if CO_2 capture is not allowed, according to

---

[4] Figure A. 6 shows global welfare effects, like Figure 10 in the main paper does. Figure A. 7 and Figure A. 8, like Figures 4, 6, and 9 in the main paper, show effects for U.S. households only. Aside from including change in climate damages, the other quantities included in global welfare effects that are not included in U.S. household welfare effects are non-U.S. investors' share of U.S. power plant profits and non-U.S. investors' shares of increased (or decreased) U.S. tax liability to pay for the 45Q and ITC/PTC incentives. These non-climate differences are relatively small and do not affect the signs of any of the effects of allowing CCUS that are reported in Figure A. 6.

[5] If EPA finalizes its 111(d) regulations in their form as of early 2024, in 2035 coal plants planning to retire by 2040 will have to be retrofitted to co-fire with gas and those planning to exist beyond 2040 will have to be retrofitted with CCS.

our modeling results. Consequently, a large portion of the non-CCUS coal-fueled generation displaced is the generation that the same coal units would produce if they did not adopt CCUS. This increases the emissions reductions and health benefits from allowing coal CCUS. Another eight percent of the generation displaced is from fossil gas without CCUS. The net emissions effects are reductions of 0.6 short tons of CO_2e, 1.44 lbs of SO_2, and increases of 0.50 lbs of NO_X, 0.03 lbs of $PM_{2.5}$, and 0.11 lbs of ammonia, per MWh of coal CCUS generation.

The effects of allowing coal CCUS only are similar to the effects of allowing both coal and gas CCUS. Under Current Policies, the 29 effects all have the same signs and are almost identical. This reflects the fact that, under Current Policies, coal CCUS has larger benefits and costs than gas CCUS, per MWh, and the fact that there is more generation from coal CCUS than from gas CCUS when both are allowed, in our results.

b. Effects of allowing CO_2 capture only by gas-fueled power plants, under current policies

In contrast to coal CCUS, which displaces mostly coal generation without CCUS, gas CCUS displaces mostly gas without CCUS. With only gas CCUS allowed, only six percent of the generation displaced by gas generation with CCUS is from coal. However, 83% of the generation displaced is from gas without CCUS, even though the gas CCUS generating units are new, not retrofits. The net non-GHG emissions effects are reductions of 0.27 short tons of CO_2e, 0.13 lbs of SO_2, 0.09 lbs of NO_X, 0.02 lbs of $PM_{2.5}$, and an increase of 0.03 lbs of ammonia, per MWh of coal CCUS generation.

The effects of allowing only gas CCUS almost all have the same signs as the effects of allowing only coal CCUS or both coal and gas CCUS, but are much smaller in magnitude. This is true even on a per-MWh basis. Per MWh, gas CCUS earns 70% less subsidy than coal CCUS does and reduces electricity rates and pollution much less. Of the 29 effects we estimate, the two that do not have the same sign are the net benefits for the overall U.S. population and the net benefits for non-Hispanic White people (again, before counting climate benefits). Those net benefits are both slightly negative in the gas-CCUS-only case but positive in the coal-and-gas-CCUS case. Panels B of Figure A. 6, Figure A. 7, and Figure A. 8, and Panels A of Figure 4 and Figure 9 show this.

ii. Effects of Allowing Just Coal CCUS or Just Gas CCUS, Under a CO_2 Cap

With the Cap accompanying the Current Policies, the generation with CO_2 capture is 1218 TWh in the case with both coal and gas CCUS allowed, 709 TWh in the coal-CCUS-only case, and 1022 TWh in the gas-CCUS-only case. The binding cap causes CCUS to have less effect on emissions but to reduce costs more since the cap is costly to meet and CCUS helps to meet it at lower cost.

Of the 29 effects shown in the figures, only one does not have the same sign across all three CCUS cases (allowing coal CCUS only, allowing gas CCUS only, and allowing both). For example, allowing CCUS in the presence of a Cap, whether from coal, from gas, or from both, has the following effects for the U.S. population in the aggregate: it increases mortality, reduces electricity bills, increases government subsidies (a cost), and produces a net estimated cost (i.e. estimated costs are greater than estimated benefits) for the U.S. and global populations. Its estimated net cost per household, as a percentage of income, is smaller for Black and Hispanic people than for White non-Hispanic people. For U.S. households in the bottom income quintile, it produces a net benefit because that group has a lower tax rate and pays for a disproportionately small portion of the government incentives for CCUS, allowing the energy cost savings to dominate the other effects for that group.

a. Effects of allowing CO_2 capture only by coal-fueled power plants, under a CO_2 cap

The binding Cap greatly changes the types of generation displaced by CCUS. Without the cap, coal with CCUS mostly displaces coal without CCUS, as reported above. With the cap, coal with CCUS must displace a blend of generation types that has the same net average CO_2e emissions rate it has. That blend is composed of 53% gas without CCUS, 31% solar, and 15% wind, as shown in Figure A. 5.

This change in generation increases emissions because the assumed emissions rates from the generation with CCUS are greater than the average emissions rates of the displaced generation. The net non-GHG emissions effects are increases of 0.02 lbs of SO_2, 1.48 lbs of NO_X, 0.14 lbs of $PM_{2.5}$ and 0.11 lbs of ammonia per MWh of coal CCUS generation.

Under a Cap, most of the benefits and costs of allowing coal CCUS only are smaller than the effects of allowing both coal and gas CCUS, reflecting the nearly 40% reduction in total generation with CCUS when only coal CCUS is allowed. The only exception is producer profits, which increase more when only coal CCUS is allowed. The overall sum of estimated benefits and costs is approximately the same when allowing only coal CCUS as when allowing both.

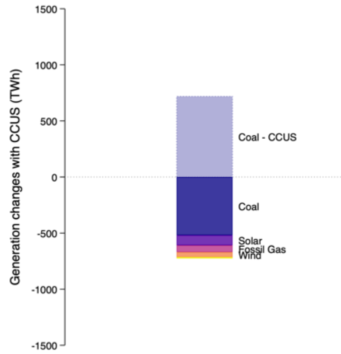
b. Effects of allowing CO_2 capture only by gas-fueled power plants, under a CO_2 cap

With only gas CCUS allowed, the displaced generation must be even cleaner than in the case with only coal CCUS allowed. The displaced generation is composed of 51% gas without CCUS, 40% solar, and 9% wind. Moreover, the gas CCUS reduces the national CO_2 price enough to slightly increase the amount of coal-fueled generation. The net non-GHG emissions effects are increases of 0.20 lbs of SO_2, 0.13 lbs of NO_X, 0.01 lbs of $PM_{2.5}$, and 0.04 lbs of ammonia per MWh of coal CCUS generation.

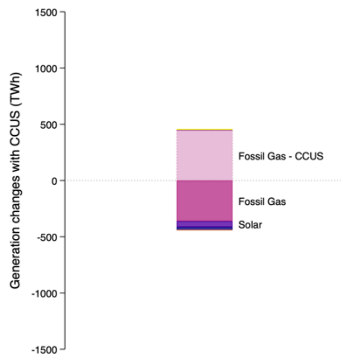
Allowing only gas CCUS, like allowing only coal CCUS, produces smaller benefits and costs than allowing both, reflecting less overall generation with CCUS. It also produces smaller net costs. In the presence of the CO_2 cap, the only one of the effects in the figures that does not have the same sign when CCUS is allowed for generation with coal only, gas only, and both, is the effect on producer profits: allowing CCUS only for gas-fueled generation reduces it while allowing CCUS for coal-fueled or both kinds of generation increases it.

Figure A. 5. Just Coal or Fossil-gas CCUS – Changes in Generation Mix with CCUS

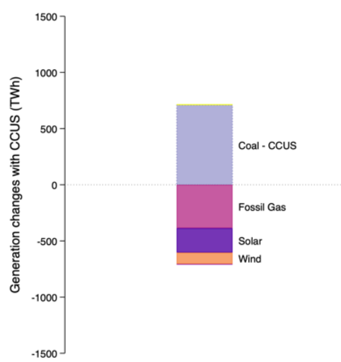
Panel A. Current Policies – Just coal CCUS



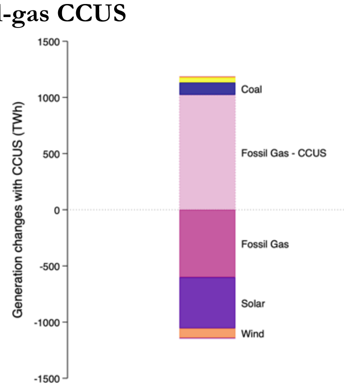
Panel B. Current Policies – Just fossil-gas CCUS



Panel C. Additional Cap – Just coal CCUS



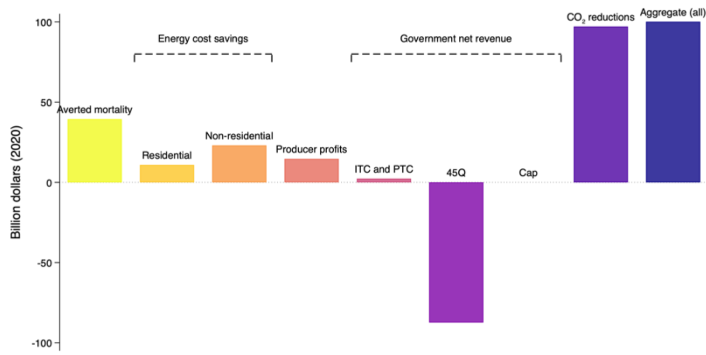
Panel D. Additional Cap – Just fossil-gas CCUS



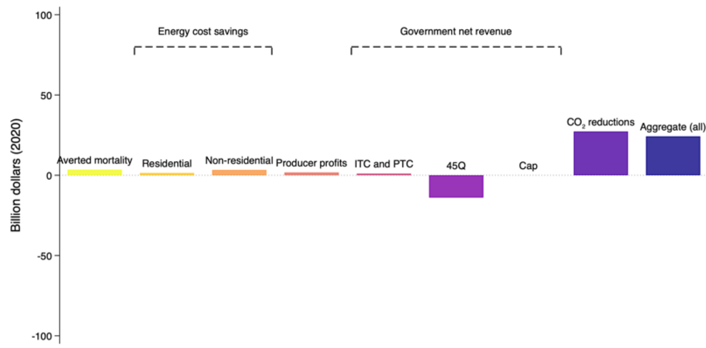
Note: Figures show changes in generation sources resulting from allowing CCUS. Positive values represent increases resulting from allowing CCUS, whereas negative values indicate that these generation sources decrease as a result of allowing CCUS.

Figure A. 6. Just Coal or Fossil-gas CCUS – Monetized Global Benefits and Costs of CCUS

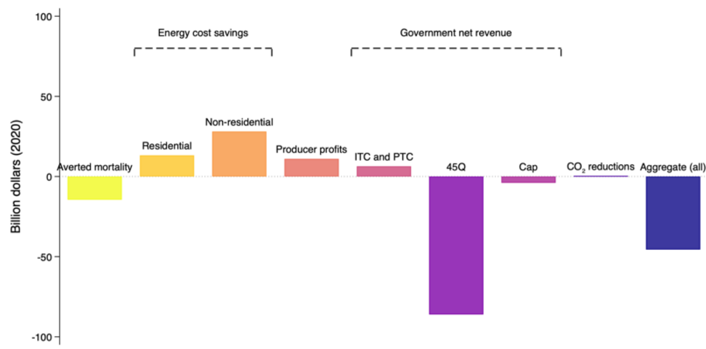
Panel A. Current Policies – Just coal CCUS



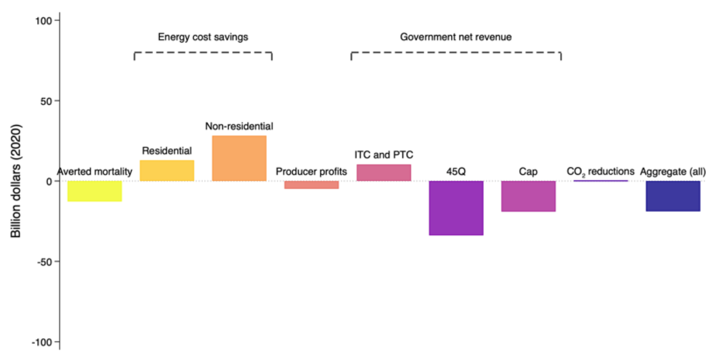
Panel B. Current Policies – Just fossil-gas CCUS



Panel C. Additional Cap – Just coal CCUS



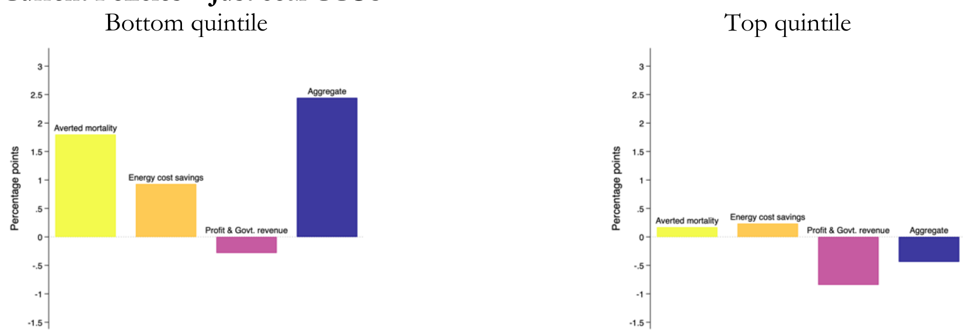
Panel D. Additional Cap – Just fossil-gas CCUS



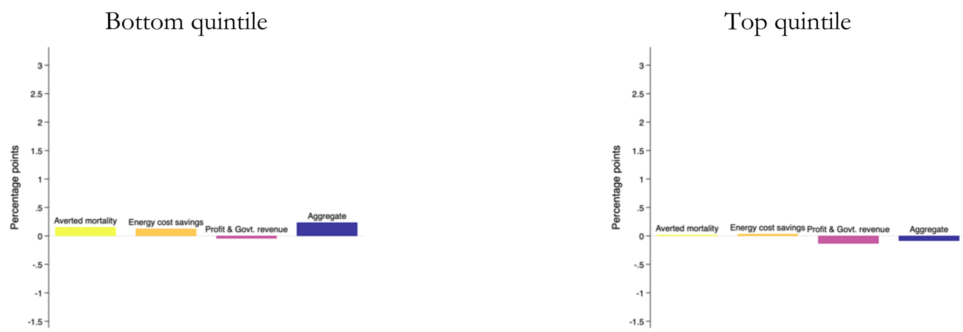
Note: Monetized impacts of allowing CCUS, including the effects on CO_2 emissions and on revenues for non-US generator owners. Positive values represent net benefits relative to the case in which CCUS is not allowed, while negative values are net costs.

Figure A. 7. Just Coal or Fossil-gas CCUS – Welfare Effects by Income Quintile, as Percentage of Group Total Income

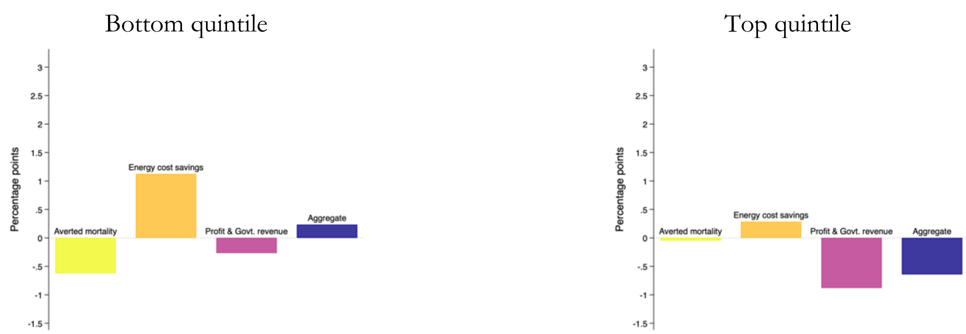
Panel A. Current Policies – Just coal CCUS



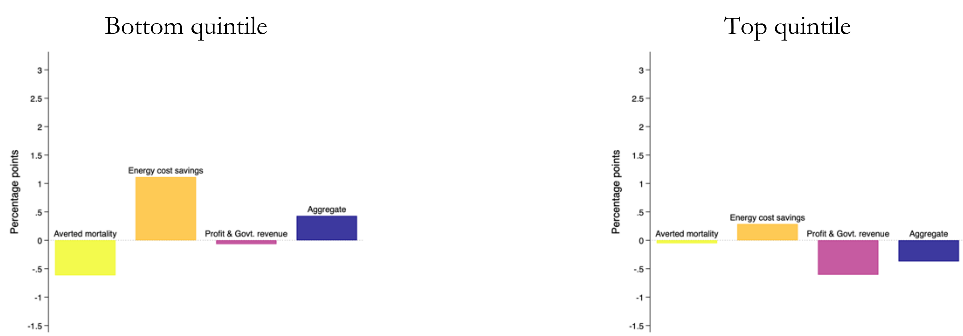
Panel B. Current Policies – Just fossil-gas CCUS



Panel C. Additional Cap – Just coal CCUS



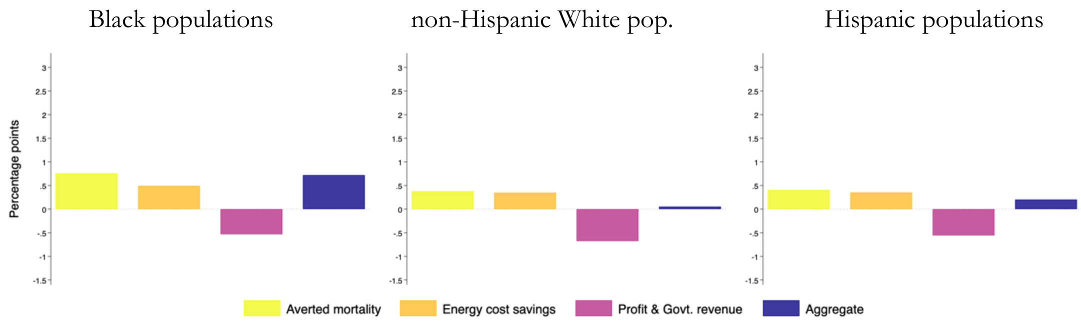
Panel D. Additional Cap – Just fossil-gas CCUS



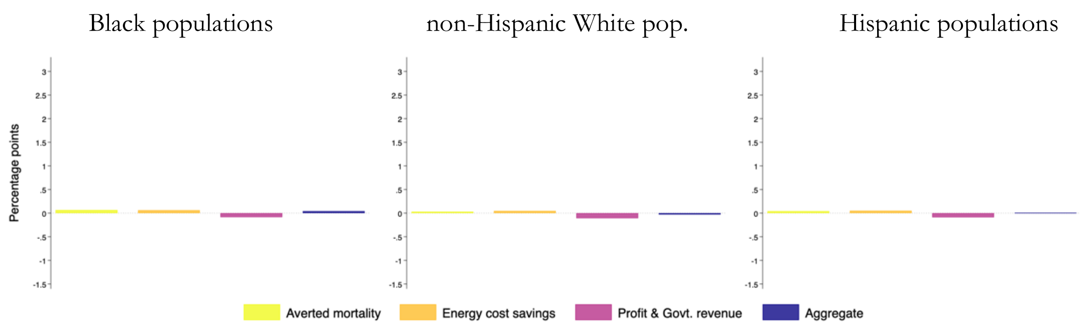
Note: Figures show monetized impacts of allowing CCUS for the U.S. populations in the bottom quintile of the income distribution (left) and top quintile (right). Positive values represent net benefits relative to the case in which CCUS is not allowed, while negative values are net costs. Values are expressed as a percentage of the group's total income.

Figure A. 8. Just Coal or Fossil-gas CCUS – Welfare Effects by Race & Ethnicity Group, as Percentage of Group Total Income

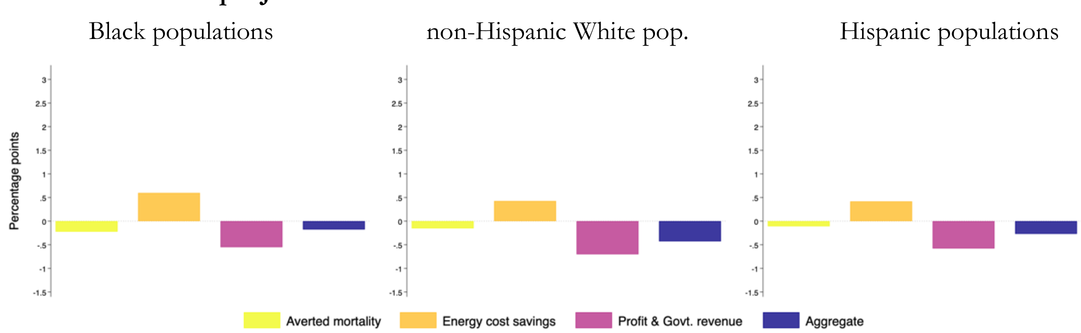
Panel A. Current Policies – Just coal CCUS



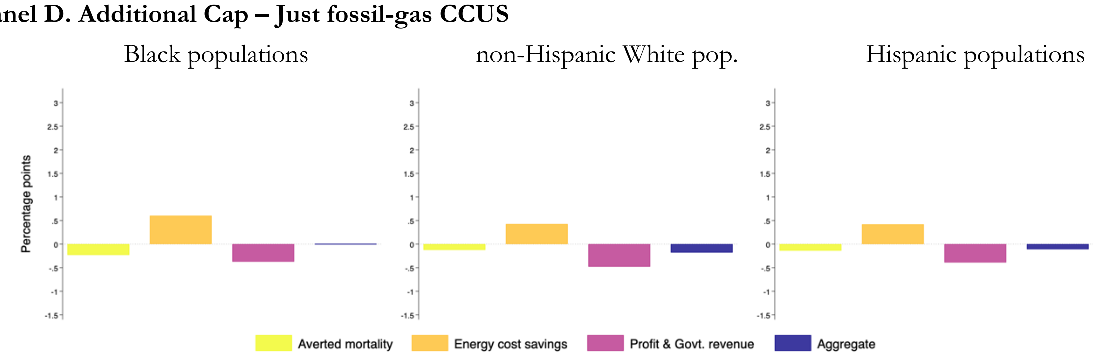
Panel B. Current Policies – Just fossil-gas CCUS



Panel C. Additional Cap – Just coal CCUS



Panel D. Additional Cap – Just fossil-gas CCUS



Note: Figures show monetized impacts for different U.S. race/ethnicity groups of allowing CCUS. The race/ethnicity groups are Black populations (left), non-Hispanic White populations (center), and Hispanic populations of any race (right). Positive values represent net benefits relative to the case in which CCUS is not allowed, while negative values are net costs. Figures are expressed as a percentage of the group's total income.

I. Other Figures

Figure A. 9. Spatial Distribution of Changes in Total $PM_{2.5}$ Concentration ($\mu g/m^3$)

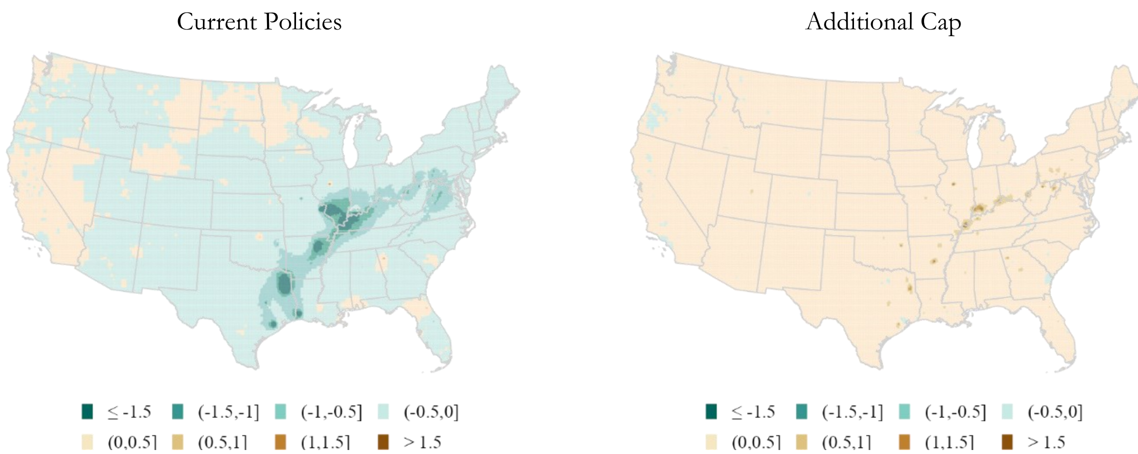
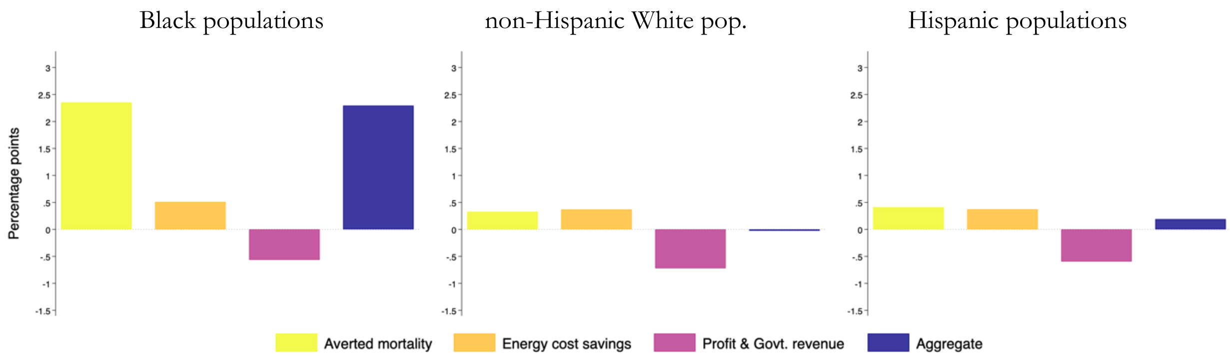


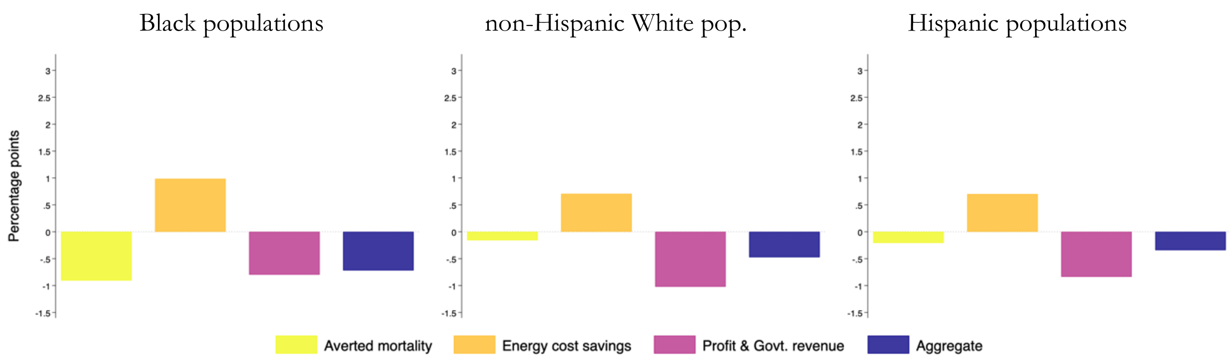
Figure maps the change in total $PM_{2.5}$ concentration when CCUS is allowed. Units are $\mu g/m^3$. Positive values represent increases in $PM_{2.5}$ concentration when CCUS is included in the choice set of generation sources, whereas negative values represent a decrease. Output for the Current Policies scenario is shown on the left, and for the Cap scenario on the right.

Figure A. 10. Monetized Impacts of CCUS by Race and Ethnicity as Percentage of Group Total Income, Using Group-Specific Concentration-Response Estimators and Mortality Rates

Panel A. Current Policies

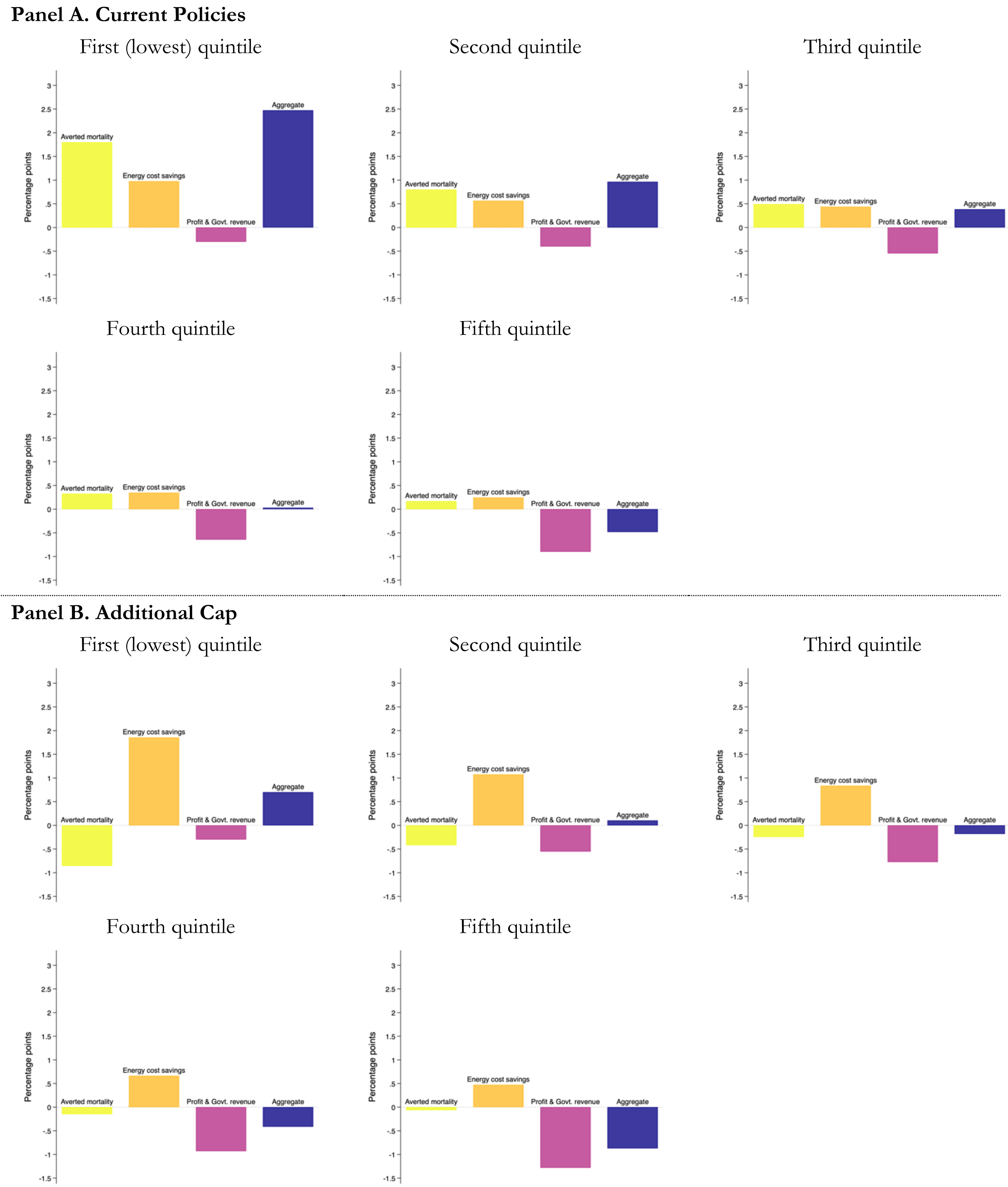


Panel B. Additional Cap



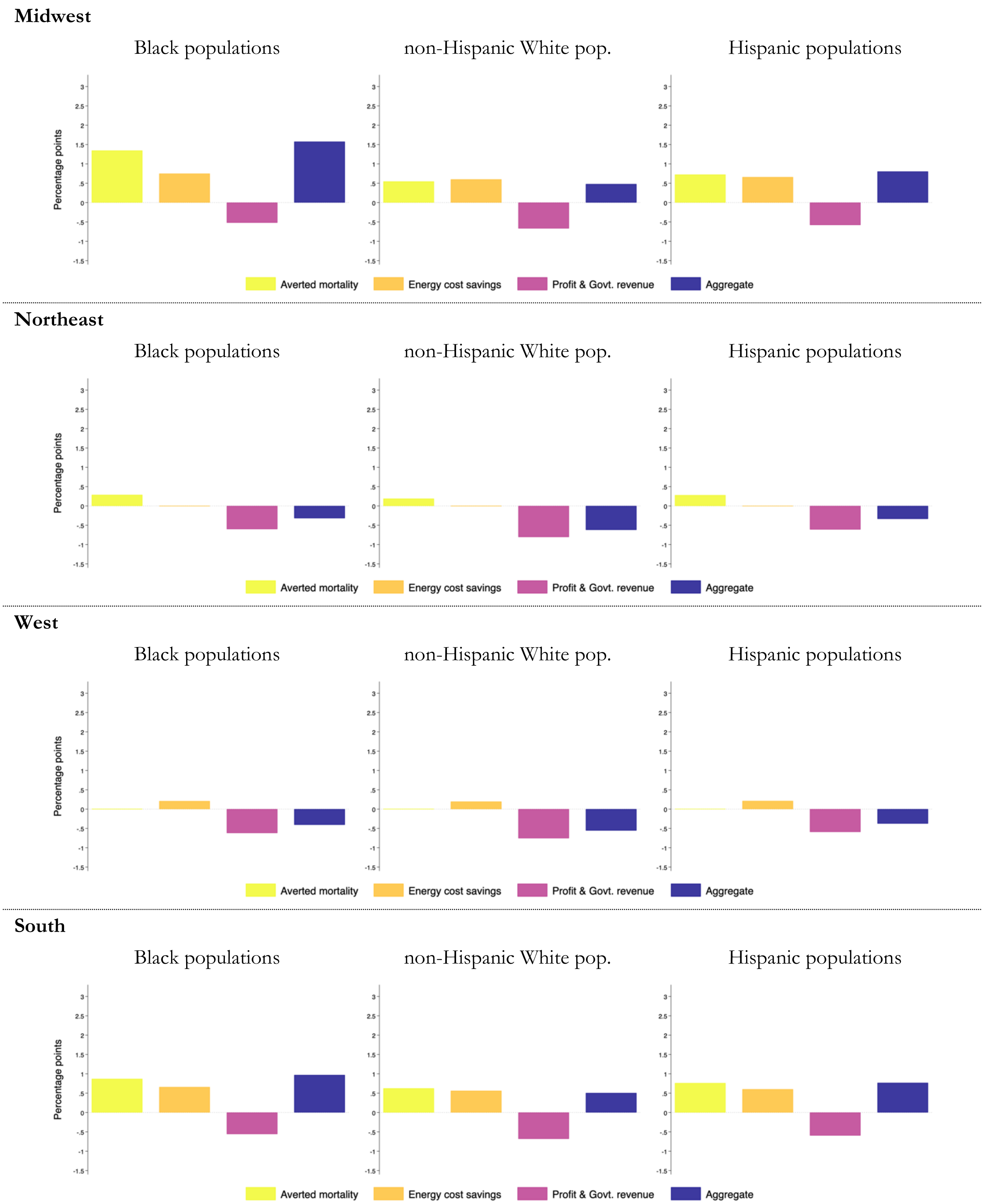
Note: Figure shows monetized impacts for different race/ethnicity groups of allowing CCUS. The groups are Black populations (left), non-Hispanic White populations (center), and Hispanic populations of any race (right). Pollution-related mortality is computed using group-specific mortality rates and concentration-response estimates. Positive values represent net benefits relative to the case when CCUS is not in the choice set, while negative values are net costs. Figures are expressed as a percentage of the group's total income. Panel A shows the output for the Current Policies scenario, and Panel B for the Current Policies Plus a Cap scenario.

Figure A. 11. All Income Quintiles: Impacts of CCUS as Percentage of Group Total Income



Note: Figure shows monetized impacts of allowing CCUS by income quintile. Positive values represent net benefits relative to the case when CCUS is not in the choice set, while negative values are net costs. Figures are expressed as a percentage of the group's total income.

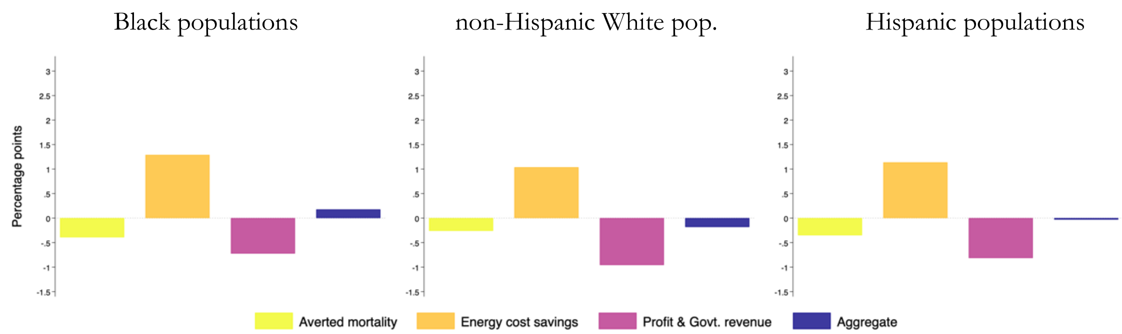
Figure A. 12. Race & Ethnicity by Region Under Current Policies: Impacts of CCUS as Percentage of Group Total Income



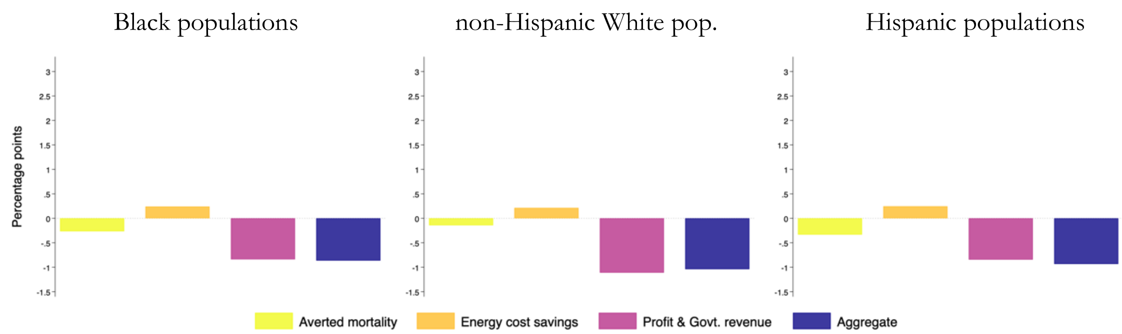
Note: Figure shows monetized impacts of allowing CCUS on populations of different races and ethnicities across census regions. Positive values represent net benefits relative to the case when CCUS is not in the choice set, while negative values are net costs. Figures are expressed as a percentage of the group's total income.

Figure A. 13. Race & Ethnicity by Region Under Additional Cap: Impacts of CCUS as Percentage of Group Total Income

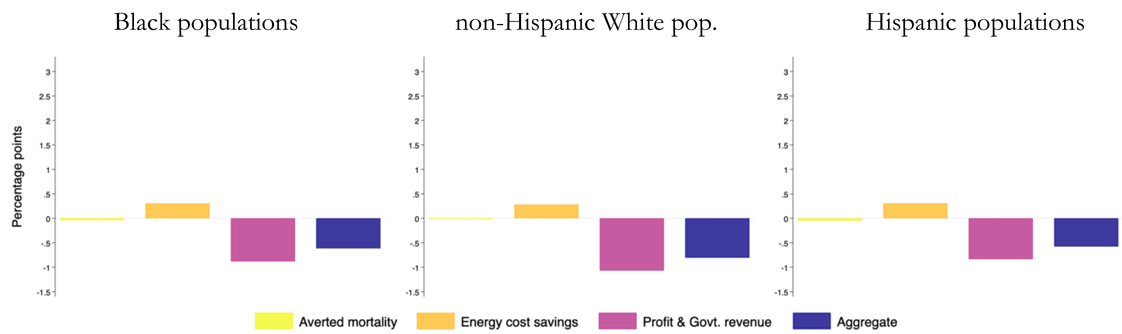
Midwest



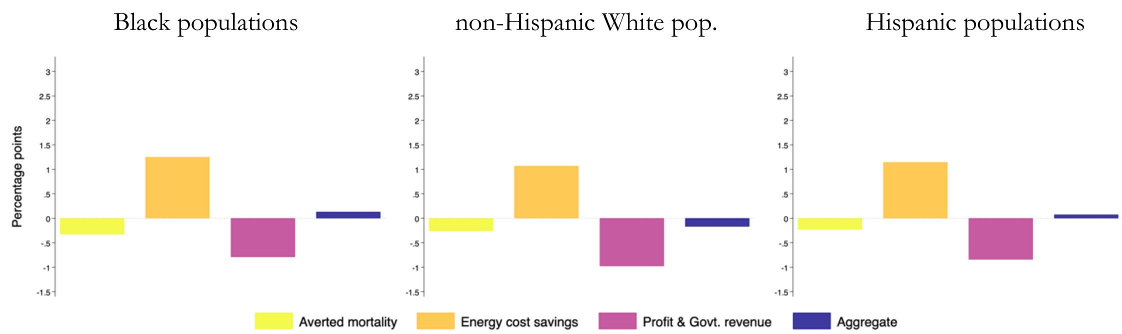
Northeast



West



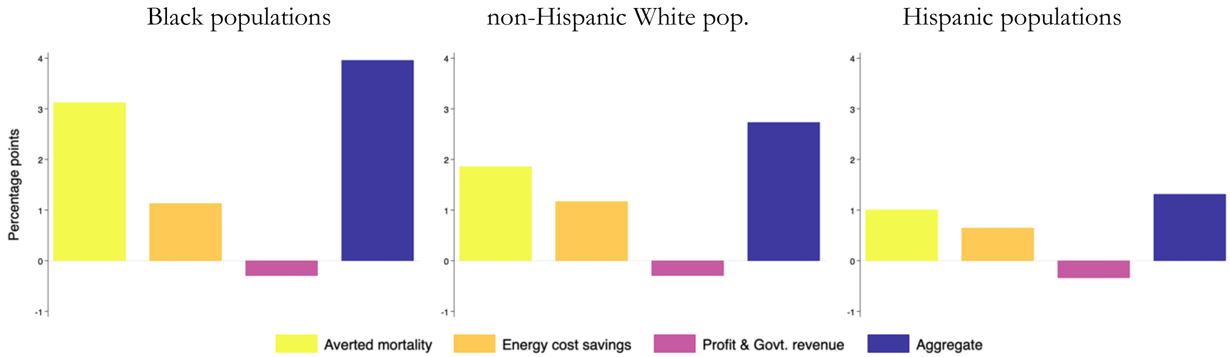
South



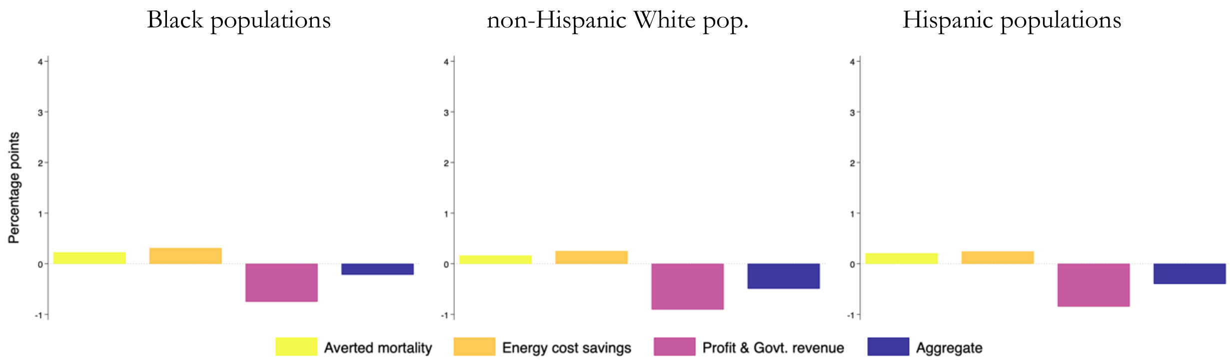
Note: Figure shows monetized impacts of allowing CCUS on populations of different races and ethnicities across census regions. Positive values represent net benefits when CCUS is allowed, while negative values are net costs. Figures are expressed as a percentage of the group's total income.

Figure A. 14. Race & Ethnicity by Income Quintile Under Current Policies: Impacts of CCUS as Percentage of Group Total Income

Bottom quintile



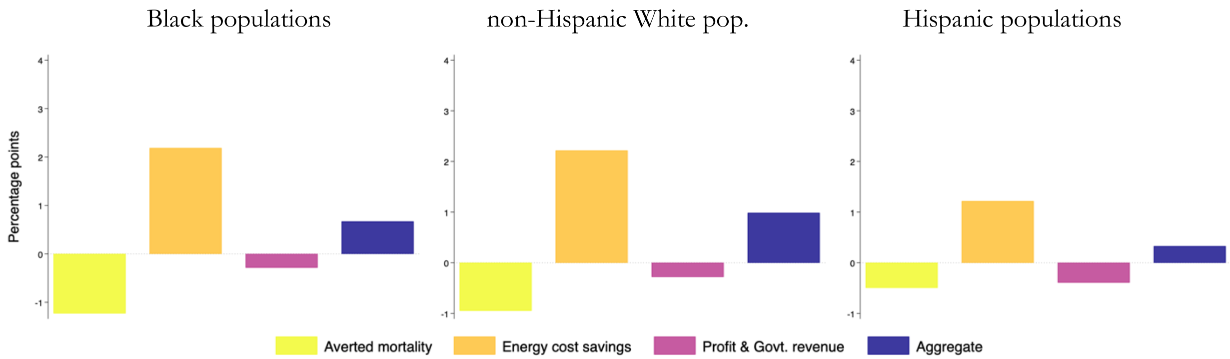
Top quintile



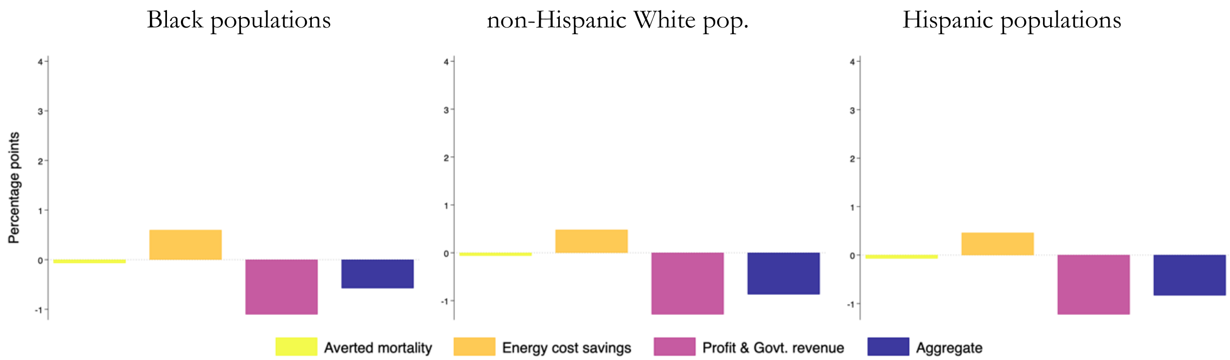
Note: Figure shows monetized impacts of allowing CCUS on populations of different races and ethnicities in the top and bottom income quintiles. Positive values represent net benefits when CCUS is allowed, while negative values are net costs. Figures are expressed as a percentage of the group's total income.

Figure A. 15. Race & Ethnicity by Income Quintile Under Additional Cap: Impacts of CCUS as Percentage of Group Total Income

Bottom quintile



Top quintile



Note: Figure shows monetized impacts of allowing CCUS on populations of different races and ethnicities in the top and bottom income quintiles. Positive values represent net benefits when CCUS is allowed, while negative values are net costs. Figures are expressed as a percentage of the group's total income.

J. Other Tables

Table A. 4. Hazard Ratio for $PM_{2.5}$ Increases and Mortality Rates by Race and Ethnicity

	Hazard ratio	Mortality rates
All	1.073	744
Black populations	1.208	890
Hispanic populations	1.116	532
White non-Hispanic populations	1.063	761

Note: Hazard ratios refer to mortality risk associated every 10 $\mu g/m^3$ increase in $PM_{2.5}$ concentration, as in Di et al (2017) and reported by Spiller et al (2021). Mortality rates are deaths by 100,000 people. We use data on age-adjusted mortality from all causes by county from the Centers for Disease Control and Prevention (data from 2007-2016). The table shows averages weighted by population.

Table A. 5. Average Annual Capacity Factor by Technology and Scenario

	Current Policies		Additional Cap	
	Without CCS	With CCS	Without CCS	With CCS
Coal	67%	50%	14%	26%
Fossil-gas Combined Cycle	41%	37%	36%	26%
Coal CCUS Retrofit	-	85%	-	84%
Fossil-gas CCUS	-	79%	-	76%
Solar	23%	23%	21%	23%
Wind	40%	40%	38%	39%
Nuclear	92%	92%	92%	92%
Hydro	31%	31%	31%	31%

Note: Average annual capacity factors calculated as (yearly generation)/(total capacity * 8760 hours/year).

Appendix references

Barbose, Galen. 2021. U.S. Renewables Portfolio Standards 2021 Status Update: Early Release.

Bhown, Abhoyjit S. 2022. *Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant*. Electric Power Research Inst. (EPRI), Palo Alto, CA (United States).

Bistline, John, Maxwell Brown, Maya Domeshek, Cara Marcy, Nicholas Roy, Geoffrey Blanford, Dallas Burtraw, Jamil Farbes, Allen Fawcett, Anne Hamilton, Jesse Jenkins, Ryan Jones, Ben King, Hannah Kolus, John Larsen, Amanda Levin, Megan Mahajan, Erin Mayfield, James McFarland, Haewon McJeon, Robbie Orvis, Neha Patankar, Kevin Rennert, Sally Robson, Christopher Roney, Ethan Russell, Greg Schivley, Daniel Shawhan, Daniel Steinberg, Nadejda Victor, Shelley Wenzel, John Weyant, Ryan Wiser, Mei Yuan, and Alicia Zhao. 2024. Power sector impacts of the Inflation Reduction Act of 2022. *Environmental Research Letters* 19 (1): 014013.

California EPA. 2023. CalEnviroScreen. https://oehha.ca.gov/calenviroscreen.

Campa, Pamela, and Lucija Muehlenbachs. 2024. Addressing Environmental Justice through In-Kind Court Settlements. *American Economic Journal: Economic Policy* 16 (1): 415–46.

Crane, Cindy A. 2022. *Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station*. Enchant Energy, LLC, Farmington, NM (United States); City of Farmington, NM (United States); Sargent & Lundy, Chicago, IL (United States); Mitsubishi Heavy Industries America, Inc., Huston, TX (United States); Kiewit Energy Group, Inc., Lenexa, KS (United States).

Cusano, David M. 2021. Zero-Emissions Supercritical Carbon Dioxide Syngas Oxy-Combustor Development & Testing Program presented at the US D.O.E. Award DE-FE0031922, November 9.

Di, Qian, Yan Wang, Antonella Zanobetti, Yun Wang, Petros Koutrakis, Christine Choirat, Francesca Dominici, and Joel D Schwartz. 2017. Air Pollution and Mortality in the Medicare Population. *New England Journal of Medicine* 376 (26): 2513–22.

EEA. 2020. Carbon capture and storage could also impact air pollution. https://www.eea.europa.eu/highlights/carbon-capture-and-storage-could.

Elliott, William R. 2021. *Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant (2x2x1 Duct-Fired 758-MWe Facility with F Class Turbines)*. Bechtel National, Inc., Reston, VA (United States).

Goodkind, Andrew L, Christopher W Tessum, Jay S Coggins, Jason D Hill, and Julian D Marshall. 2019. Fine-scale damage estimates of particulate matter air pollution reveal opportunities for location-specific mitigation of emissions. *Proceedings of the National Academy of Sciences* 116 (18): 8775–80.

Heo, Jinhyok, Sean T McCoy, and Peter J Adams. 2015. Implications of Ammonia Emissions from Post-Combustion Carbon Capture for Airborne Particulate Matter. *Environmental Science & Technology* 49 (8): 5142–50.

Hernandez-Cortes, Danae, and Kyle C Meng. 2023. Do environmental markets cause environmental injustice? Evidence from California's carbon market. *Journal of Public Economics* 217: 104786.

Jenkins, Jesse D, Erin N Mayfield, Jamil Farbes, Greg Schivley, Neha Patankar, and Ryan Jones. 2023. *Climate Progress and the 117th Congress: The Impacts of the Inflation Reduction Act and Infrastructure Investment and Jobs Act*. Rapid Energy Policy Evaluation and Analysis Toolkit. Princeton ZERO Lab.

Kennedy, Greg. 2020. *W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)*. Petra Nova Power Holdings LLC.

Krewski, Daniel, Michael Jerrett, Richard T Burnett, Renjun Ma, Edward Hughes, Yuanli Shi, Michelle C Turner, C Arden Pope, George Thurston, Eugenia E Calle, Michael J Thun, Bernie Beckerman, Pat DeLuca, Norm Finkelstein, Kaz Ito, DK Moore, K Bruce Newbold, Tim Ramsay, Zev Ross, Hwashin Shin, and Barbara Tempalski. 2009. Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. *Research Report (Health Effects Institute)* (140): 5–114; discussion 115-136.

Lepeule, Johanna, Francine Laden, Douglas Dockery, and Joel Schwartz. 2012. Chronic exposure to fine particles and mortality: an extended follow-up of the Harvard Six Cities study from 1974 to 2009. *Environmental Health Perspectives* 120 (7): 965–70.

Majewski, W Addy. 2022. *Selective Catalytic Reduction*.

Merkel, Tim, Brice Freeman, Richard Baker, Alicia Breen, Pingjiao Hao, Thomas Hofmann, and Paul St-Martin. 2022. *Commercial-Scale Front-End Engineering Design (Feed) Study for MTR's Membrane CO2 Capture Process*. Membrane Technology and Research, Inc., Newark, CA (United States).

Mirletz, Brian, Laura Vimmerstedt, Tyler Stehly, Sertac Akar, Dana Stright, Chad Augustine, Philipp Beiter, Stuart Cohen, Wesley Cole, and Patrick Duffy. 2023. *2023 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies*. DOE Open Energy Data Initiative (OEDI); National Renewable Energy Laboratory ….

Purswani, Sanjay, and Daniel Shawhan. 2023. *How Clean Is Your Capture? Co-Emissions from Planned US Power Plant Carbon Capture Projects*. Resources for the Future.

Resources for the Future. 2023. Engineering, Economic, and Environmental Electricity Simulation Tool (E4ST). *Resources for the Future*. https://www.rff.org/topics/data-and-decision-tools/e4st/.

Santa Barbara County, Pollution Control District. 2023. CONVERT PPMV TO LB/MMBTU (Ver. 1.0). https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fdec.alaska.gov%2Fmedia%2F21928%2Fppmv-to-lb-per-mmbtu-turbine.xlsx&wdOrigin=BROWSELINK.

Sargent & Lundy. 2020. *Capital Costs and Performance Characteristics for Utility Scale Power Generating Technologies*. U.S. EIA.

SaskPower. 2018. Boundary Dam 3 CCS Facility: Pioneering Lessons for the World - Factsheet. *International CCS Knowledge Centre*. https://ccsknowledge.com/resources/factsheets.

Schrader, R. 2005. *The 15% O2 Correction Factor requirement: Correcting Bridge Analyzers Exhaust Gas Readings for Stationary Source Emission Regulation Agency Requirement*. Bridge Analyzers.

Shawhan, Daniel, Kathryne Cleary, Christoph Funke, and Steven Witkin. 2021. *The Value of Advanced Energy Funding: Projected Effects of Proposed US Funding for Advanced Energy Technologies*. Resources for the Future Working Paper.

Shawhan, Daniel, Christoph Funke, and Steven Witkin. 2020. *Benefits of Energy Technology Innovation Part 1: Power Sector Modeling Results*. RFF Working Paper Series. Resources for the Future.

Sorrels, John L, David D Randall, Karen S Schaffner, and Carrie Richardson Fry. 2019. *Chapter 2: Selective Catalytic Reduction*.

Spiller, Elisheba, Jeremy Proville, Ananya Roy, and Nicholas Z Muller. 2021. Mortality Risk from PM2.5: A Comparison of Modeling Approaches to Identify Disparities across Racial/Ethnic Groups in Policy Outcomes. *Environmental Health Perspectives* 129 (12): 127004.

U.S. EIA. 2022. Electricity Market Module of the National Energy Modeling System: Model Documentation 2022.

------. 2023. Summary Statistics for the United States 2011-2021. https://www.eia.gov/electricity/annual/html/epa_01_02.html.

U.S. EPA. 2003. *Air Pollution Control Technology Fact Sheet*.

------. 2020. eGRID Related Materials. https://www.epa.gov/egrid/egrid-related-materials.

------. 2021. Documentation for EPA's Power Sector Modeling Platform v6 - Summer 2021 Reference Case. https://www.epa.gov/power-sector-modeling/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference.

------. 2022. *EJSCREEN Environmental Justice Mapping and Screening Tool. Technical documentation.*

------. 2023a. *Method 19 - Determination Of Sulfur Dioxide Removal Efficiency And Particulate Matter, Sulfur Dioxide, And Nitrogen Oxide Emission Rates*.

------. 2023b. Environmental Justice. *US EPA*. https://www.epa.gov/environmentaljustice.

------. 2023c. 2020 NEI Supporting Data and Summaries. https://www.epa.gov/air-emissions-inventories/2020-nei-supporting-data-and-summaries.

Vimmerstedt, Laura, Tyler Stehly, Sertac Akar, Ashok Sekar, Brian Mirletz, Dana Stright, Chad Augustine, Philipp Beiter, Parangat Bhaskar, Nate Blair, Stuart Cohen, Wesley Cole, Patrick Duffy, David Feldman, Pieter Gagnon, Parthiv Kurup, Caitlin Murphy, Vignesh Ramasamy, Jody Robins, Jarett Zuboy, Debo Oladosu, and Jeffrey Hoffmann. 2022. 2022 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies. DOE Open Energy Data Initiative (OEDI); National Renewable Energy Laboratory (NREL).

Yang, Zhifang, Haiwang Zhong, Qing Xia, and Chongqing Kang. 2017. Solving OPF using linear approximations: fundamental analysis and numerical demonstration. *IET Generation, Transmission & Distribution* 11 (17): 4115–25.