Carbon Capture Co-benefits

Carbon Capture's Role in Removing Pollutants and Reducing Health Impacts

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ABOUT CARBON SOLUTIONS LLC

Carbon Solutions LLC is a low-carbon energy startup using cuttingedge research and development and software and services to address energy challenges, including carbon capture and storage, geothermal energy, wind energy, biofuels, energy storage, and the hydrogen economy. Carbon Solutions aims to accelerate low-carbon energy infrastructure development in the US. The Carbon Solutions business vision is focused on three integrated pillars: research and development that advances low-carbon energy science, software development that generates unique tools and data, and services that apply our research and development and software to address emerging energy challenges for our clients.

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Executive Summary

Carbon capture is a valuable technology for reducing the carbon emissions of point source emitters in various sectors. In addition to carbon dioxide (CO_2), point source emissions are often accompanied by other pollutants, such as nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter (PM). These co-pollutants decrease air quality and have negative health impacts. They can also negatively impact the performance of carbon capture equipment. Though the primary purpose of carbon capture is mitigating the climate impacts of industrial and power processes, retrofitting a facility with a carbon capture system can also provide additional benefits.

One of the primary co-benefits of carbon capture, and the focus of this study, is the improvement of air quality and associated health benefits from the removal of co-pollutants at a facility.

Although the health benefits of reducing NO_x, SO_2, and PM in the atmosphere are well-known, these benefits have yet to be quantified across industries and regions for the United States for carbon capture systems. This study evaluated the health benefits and economic value of capturing the co-pollutants NO_x, SO_2, and PM for 54 representative facilities in seven industries across 10 regions in the contiguous United States.

The industries included in the study are considered primary opportunities for carbon capture technologies due to their large volumes of CO_2 emissions at single facilities, importance to the US economy, and/or for having limited other methods for abating CO_2 emissions at their facilities. The industries in this study include cement, coal power plants, ethanol, fertilizer and ammonia, iron and steel, natural gas power plants, and petroleum refineries. Ten regions were identified to provide representative facilities in each industry throughout the contiguous United States.

This study used emissions data from three sources from the US Environmental Protection Agency (EPA) to identify representative facilities and quantify emissions reductions and associated health impacts. Each source of data provides emissions information at different levels, including individual processes, unit levels, and an entire facility. Because of this, estimates for emissions reductions for NO_x, SO_2, and PM were done at the facility level in this study.

A representative facility was selected for each industry in each region after meeting a series of prerequisite requirements. First, only facilities that are eligible for the 45Q tax credit were considered potential representative facilities. Facilities were also required to have reported annual emissions for NO_x, SO_2, and PM that includes particles 2.5 microns in diameter or smaller ($PM_{2.5}$), though no thresholds were required for any of these emissions.

Facilities were removed if they were not suitable for capture due to retirement or closure based on data from the US Energy Information Administration or public announcements of closure or significant operation reductions. Finally, facilities that already had capture equipment installed at the facility were removed from the study, as well as facilities that had dual characterization (i.e., both natural gas and coal units).

A representative facility was then selected that was closest to the median total annual CO_2 emissions of facilities for each industry in each region. A total of 54 representative facilities were identified for this study, as some industries did not have a representative facility that met all requirements for this study in every region.

This study identified the capture streams and co-pollutants present at each facility type to choose the equipment needed to remove each sector's CO_2, NO_x, SO_2, and $PM_{2.5}$. Co-pollutant removal equipment was chosen and designed to meet EPA's New Source Performance Standards for pulverized coal technology installed post-2011, which provide the most conservative estimates for co-pollutant removal, and thus, health benefits gained.

For this study, low-purity CO_2 streams are fed to a selective catalytic reduction system (SCR), which removes 75.1 percent of NO_x emissions. Streams are then sent to a wet flue gas desulfurization unit (FGD), which removes 98 percent of SO_2 emissions. The stream then enters a direct contact cooler (DCC) with caustic scrubber, which cools the stream, condenses any condensable PM, and removes additional SO_2 quantities. The stream then flows through the Shell Cansolv CO_2 Capture Train, designed to capture 90 percent of CO_2 emissions and prepare the CO_2 for pipeline transportation. Compressed and pure CO_2 exits the system.

The cost of CO_2 capture varied by industry and was calculated using Carbon Solutions' CO_2 National Capture Opportunities and Readiness Data (CO_2NCORD) software or the Carbon Capture Retrofit Database from the National Energy Technology Laboratory (NETL), depending on the industry. The cost of co-pollutant removal was assumed to be around $15, based on a study from NETL.

To calculate the health benefits from removing NO_x, SO_2, and $PM_{2.5}$, this study used the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). COBRA calculates the health impacts of changing air quality associated with changes in emissions of various pollutants, in this study NO_x, SO_2, and $PM_{2.5}$. COBRA estimates the impact at the local level as well as the impact in other regions. Finally, COBRA provides the economic value associated with the changes in health impacts calculated.

Across all industries and regions, we found that co-pollutant removal resulted in positive health benefits. The economic value of these health benefits in each region ranged from $6.8 million to up to $481.2 million per year. The Mid-Atlantic and Appalachia regions saw the highest potential economic value from capture at the representative facilities at up to $481.2 million per year and up to $313.3 million per year, respectively. The Pacific Northwest and New England saw the lowest potential economic value, from $11.5 to $25.9 million per year for the Pacific Northwest and $6.8 to $15.3 million per year for New England.

All industries provided health benefits, ranging from up to $15.3 million per year for ethanol facilities to up to $648.9 million per year for the cement facilities in this study. Coal-fired power plants had the largest average facility benefit of $85.4 million per year and a total health benefit of up to $597.8 million per year for the seven facilities in this study. The lowest health benefits were seen in the ethanol industry and ammonia and fertilizer facilities, though the economic value of the health benefits were still up to $6.8 million per year and $7.2 million per year, respectively.

While installing carbon capture provides annual health benefits at all facilities, the economic feasibility of incorporating capture systems currently depends on the 45Q tax credit. This study found that the credit received from 45Q for permanent storage ($85 per metric ton) was greater than the cost of capture and co-pollutant removal for some industries, including ethanol, fertilizer and ammonia, iron and steel, and some coal and natural gas power plants.

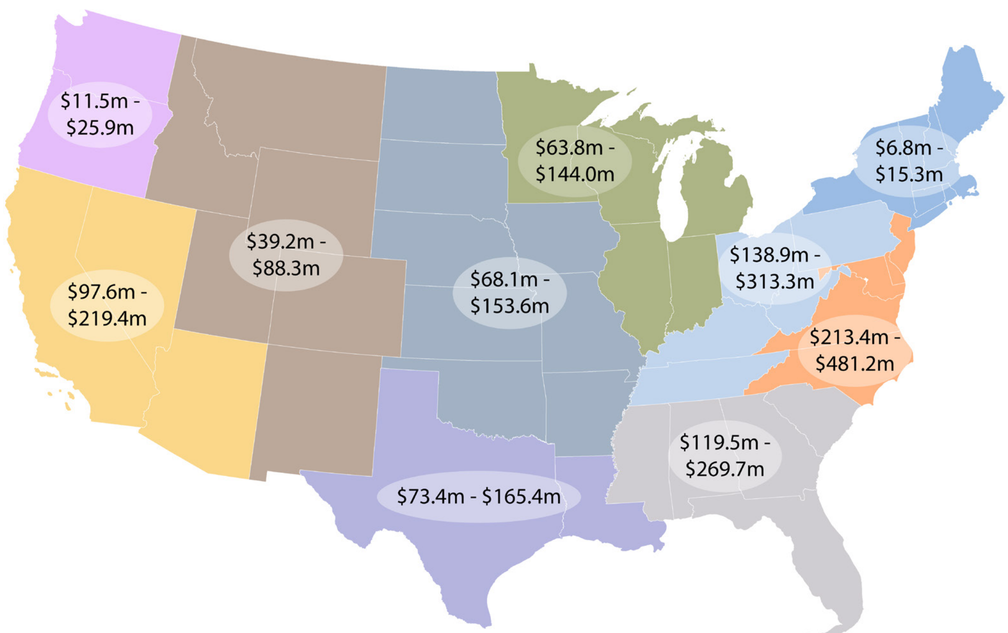
Other sectors, like most cement facilities, most petroleum refineries, and one coal power plant, had a cost of capture that was greater than the 45Q tax credit, but the economic value of the health benefits was greater than the remaining cost of capture.

Finally, most natural gas facilities, some cement facilities and coal power plants, and one petroleum refinery provided health benefits, but the total economic value was less than the remaining cost of capture after the 45Q tax credit for permanent storage.

This study does not consider additional climate benefits from the removal of CO_2 from carbon capture or the additional economic benefits from increased jobs related to carbon capture equipment installment and operations at industrial and power facilities.

While the results from this study indicate substantial health benefits from retrofitting carbon capture systems in various industries, this report only provides health benefit estimates for 54 representative facilities across seven industries. More work is needed to fully evaluate the opportunities available across US industrial and power sectors. Continued advancement of amine-based carbon capture technologies and co-pollutant emissions reduction will also provide further opportunities for carbon capture deployment and realized health benefits.

Annual health benefits (million dollars) for each region after outfitting the 54 representative facilities of this study with carbon capture equipment and pre-treatment.



Note: Dollar amounts indicate the sum of the health benefits from the representative facilities present in each region.

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Nomenclature

Acronyms

CCS – carbon capture and storage
DCC – direct contact cooler
eGRID – Emissions and Generation Resource Integrated Database
EPA – Environmental Protection Agency
FGD – flue gas desulfurization
FLIGHT – Facility Level Information on GreenHouse gases Tool
GHGRP – Greenhouse Gas Reporting Program
NEI – National Emissions Inventory
NETL – National Energy Technology Laboratory
NSCR – non-selective catalytic reduction
SCR – selective catalytic reduction
UV – ultraviolet

Chemistry Nomenclature

CO_2 – carbon dioxide
N_2 – nitrogen
NO_2 – nitrogen dioxide
NO_x – nitrogen oxides
O_2 – oxygen
PM – particulate matter
$PM_{2.5}$ – particulate matter 2.5 microns in diameter or smaller
PM_{10} – particulate matter 10 microns in diameter or smaller
SO_2 – sulfur dioxide
SO_3 – sulfur trioxide
SO_x – sulfur oxides
VOC – volatile organic compound

Units

l – liter
m^3 – cubic meter
mg/Nm^3 – milligrams per normal meter cubed
Mt – million metric tons
M$ – million United States dollars
ng – nanogram
ppm – parts per million
ppmv – parts per million, volume basis
t or ton – metric ton (1000 kg)
yr – year

Background

CARBON MANAGEMENT AND CLIMATE CONTEXT

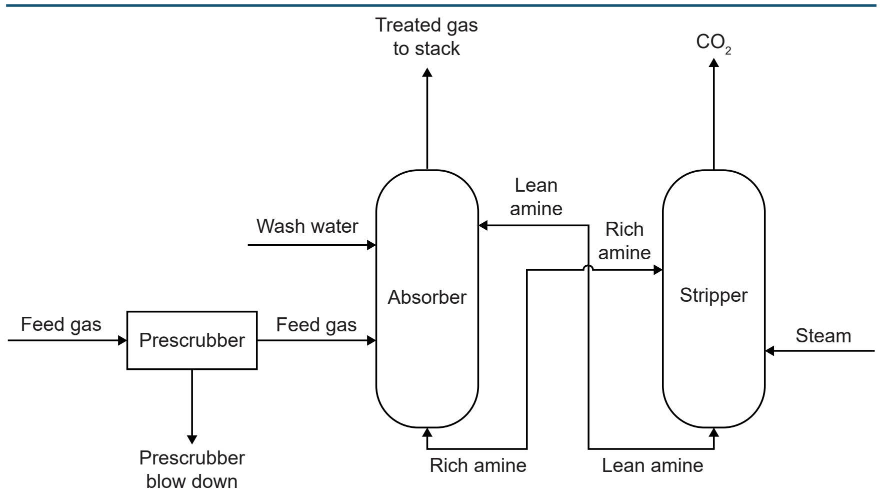
Global greenhouse emissions must be greatly reduced to meet climate goals. Fossil fuel use at power and industrial facilities, as well as process emissions intrinsic to some industrial processes, are some of the primary sources of emissions in the United States. One technology expected to play a major role in reducing these emissions is carbon capture, utilization, and storage, also known as carbon management. Carbon management is the process of capturing carbon dioxide (CO_2) from point sources such as power plants and industry, transporting the CO_2, and storing it in the subsurface or utilizing it for beneficial use.

The Intergovernmental Panel on Climate Change expects that carbon management will be necessary to help mitigate the emissions of industry.[1] Globally, there has been a significant increase in the number of carbon management projects over the last decade. At the end of 2022, there were 30 operational facilities, capturing a total of 42.5 $MtCO_2$/yr, and an additional 153 facilities in early or advanced development, with the potential to capture an additional 189 $MtCO_2$/yr.[2]

Although various carbon capture technologies are in development, the majority that have been deployed are amine-based, post-combustion capture systems.

In these capture systems, a nitrogenous amine-solvent is used to remove CO_2 from exhaust gases and produce a pure stream of CO_2 for utilization or storage. After co-pollutants are removed, the flue gas enters an absorber tower, where the CO_2 is absorbed by the amine solvent. The solvent, which now has a high concentration of CO_2, is then sent to a regeneration tower and heated with steam to release the CO_2. The pure CO_2 stream can then be prepared for pipeline transport and sent to a permanent geologic storage unit or utilized for the creation of various products. Once the amine solvent is rid of the absorbed CO_2, it can then be recycled into the carbon capture system. A simplified amine-based capture process is shown in figure 1[3]. A variety of alternative carbon capture and storage (CCS) technologies are also under development, including calcium-looping, chemical looping, membrane, and oxy-fuel.[4]

Figure 1. Simplified diagram of Shell's Cansolv amine-based carbon capture system



Note: Published with permission from Shell

1 Pathak et al., "Technical Summary."
2 Steyn et al., "Global Status of CCS 2022."
3 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."
4 Bennett et al., "Life Cycle Meta-Analysis of Carbon Capture Pathways in Power Plants: Implications for Bioenergy with Carbon Capture and Storage."

INDUSTRY AND POLLUTANTS OVERVIEW

Exhaust, or flue stack, emissions vary in chemical composition and volume across power plants and industries. For some industries, there are flue stacks that have emissions that are primarily CO_2. In flue stacks with lower CO_2 concentrations, other compounds emitted include criteria air pollutants and hazardous air pollutants. The Clean Air Act requires the US Environmental Protection Agency (EPA) to set national air quality standards for the six criteria air pollutant species, comprising: nitrogen dioxide (NO_2), a component of nitrogen oxides (NO_x); sulfur dioxide (SO_2), a component of sulfur oxides (SO_x); particulate matter (PM); ozone; carbon monoxide; and lead.[5] Capture systems can be affected by levels of NO_x, SO_x, and PM in the exhaust gas.

Nitrogen oxides

Emissions of NO_x are ubiquitous with fossil fuel combustion. NO_x is the collective total of both nitric oxide (NO) and NO_2, a criteria pollutant. Both species of NO_x are generally formed during fossil fuel combustion,[6] caused by a reaction between oxygen and atmospheric nitrogen (N_2) during the combustion process. Small contributions to NO_x totals are made from nitrogenous fuels and a reaction between carbonaceous fuels and atmospheric nitrogen. NO can be further produced when NO_2 breaks down in the atmosphere.[7]

Chronic exposure to NO_x can lead to the development of respiratory diseases and increase the risk of respiratory infections.[8] Further, NO_x is an important precursor to other pollutants formed in the atmosphere such as ozone, acid rain, and nutrient pollution.[9] Each of these can affect both environmental and public health, especially for ecosystems and populations in close proximity to large point-sources.

The quantity of NO_x produced from combustion is dependent on several factors. Two important factors are combustion temperature and the fuel used. Most NO_x is produced from high temperature flames or electric arcs that oxidize atmospheric nitrogen. As nitrogen is the largest component of Earth's atmosphere (78%), NO_x formation is unavoidable when using ambient air for combustion. The fuel type used, and engineering considerations for that fuel, dictate the necessary combustion temperature and chemical components of the fuel that can be oxidized to form NO_x.

Sulfur oxides

Sulfur oxides (SO_x) are composed of SO_2 and sulfur trioxide (SO_3).[10] Most atmospheric SO_2 is the result of fossil fuel combustion.[11] Sulfurous components of these fuels, such as coal, oil, and gaseous fuels, are oxidized during combustion, resulting in SO_x emissions. Most sulfur is extracted from processed fossil fuels (i.e., motor gasoline, diesel, natural gas, etc.) prior to combustion, highlighting the contribution of raw fossil fuel combustion to SO_x emissions. While natural sources of SO_x, such as volcanoes, can represent large single emission events, the total amount emitted is much less than anthropogenic emissions.

Exposure to elevated SO_2 concentrations can have a large effect on public health. SO_2 leads to a variety of harmful lung impacts including wheezing, respiratory symptoms, and increased hospital admissions.[12] SO_3 also has negative impacts. The toxicity of SO_3 is more

5 US EPA, "Criteria Air Pollutants."
6 US EPA, "Basic Information about NO_2."
7 NASA, "Chemistry in the Sunlight."
8 US EPA, "Basic Information about NO_2."
9 US EPA.
10 UCAR, "Sulfur Oxides."
11 US EPA, "Sulfur Dioxide Basics."
12 American Lung Association, "Sulfur Dioxide."

than 10 times that of SO_2.[13] When SO_3 mixes with air it absorbs water and creates sulfuric acid.[14] Sulfuric acid can effectively penetrate deep into the lungs because droplets will grow in size as they pass deeper into the respiratory tract.[15] Both the primary and secondary impacts of SO_2 can have a large impact on human health.

The total quantity of SO_2 emissions depends on the fuels used and engineering parameters within a facility. Nearly all SO_2 emissions are a result of combusting fossil fuels that contain sulfurous compounds. Reduction in SO_2 emissions can be achieved by fuel switching to less sulfurous fuels (for example from coal to natural gas), implementing flue gas desulfurization (FGD) techniques, or novel techniques that remove sulfur before combustion (such as gasification). Elemental sulfur is a valuable consumer good, and many refineries and gas processors are incentivized to recover sulfur before combustion for resale as a chemical feedstock. This study only considers the impacts of direct emissions of SO_2 and considerations regarding that chemical species.

Particulate matter

Particulate matter (PM) refers to very fine particles found in air. Generally, the smaller the particle, the more impactful to environmental and human health it will be. PM is further categorized to particles 10 microns or smaller (PM_{10}) and 2.5 microns or smaller ($PM_{2.5}$). Both $PM_{2.5}$ and PM_{10} can be formed through a variety of processes including natural processes (e.g., dust, bacteria fragments, etc.), from combustion of fossil fuels, and secondary oxidation of NO_x and SO_x.[16] $PM_{2.5}$ and PM_{10} are generally categorized into two groups: filterable and condensable particulate.[17] Filterable particles are particles that are solid or liquid material upon emission. Condensable particulate are particles that are vapor or gas upon emissions and may condense to liquid or solid after cooling. The Capture Performance section of this study provides more information on how different types of PM can be removed.

The particle size determines the impacts on human and environmental health. Smaller particulates can penetrate deep into the lung and can enter the bloodstream, while larger particles are not able to go as deep into the respiratory system. Exposure to PM_{10} and $PM_{2.5}$ can affect the lungs and heart, leading to problems such as diminished lung function, non-fatal heart attacks, and increased respiratory symptoms.[18]

There are many emission sources of PM, driving the wide variation in PM types. The quantity of PM emissions varies by source.[19] Industrial sources often emit larger quantities of PM compared to power sources due to larger contributions from industrial process emissions. For example, a cement plant will have a propensity to generate large quantities of PM because of processing raw materials (which produces fine metal-rich dust), whereas less PM is generated from combustion sources. The quantity of PM produced from combustion depends on the fuel type used.[20] For example, natural gas is primarily combustible material, and thus produces little PM, whereas coal has a high mineral content, and therefore its combustion results in more PM.

13 Kikuchi, "Environmental Management of Sulfur Trioxide Emission: Impact of SO_3 on Human Health."
14 Kikuchi.
15 Kikuchi.
16 California Air Resources Board, "Inhalable Particulate Matter and Health ($PM_{2.5}$ and PM_{10})."
17 US EPA, "How Do the Different Parts of Particulate Matter (PM) Fit Together?"
18 US EPA, "Health and Environmental Effects of Particulate Matter (PM)."
19 US EPA, "Particulate Matter Emissions."
20 US EPA.

IMPACT OF CO-POLLUTANTS ON AMINE-BASED CAPTURE SYSTEMS

Amine-based capture systems require that exhaust gases are pretreated to remove co-pollutants. Failing to pretreat a flue gas prior to carbon capture can affect capture efficacy, contaminate downstream storage operations, and lead to the formation of nitrosamines and nitramines.

Reduce capture system efficacy

While amine-based solvents are highly reactive to CO_2, they will also selectively bond with available NO_x and SO_2 to form heat stable salts.[21] This results in a permanent reduction in the quantity of available solvent, requiring replacement of the reacted solvent. Heat stable salts are also highly corrosive, degrading hot surfaces within a capture system. While most capture systems have built-in solvent purification to prevent these salts from building up in a system, management of the quantity of these salts formed is imperative to increase system life and decrease maintenance costs. Given the high cost of amine-based solvents, maximizing the life of the solvent can also lead to cost savings.

System contamination

In addition to the negative effects of NO_x and SO_2 on capture systems, the presence of PM can physically clog and contaminate a system. Upper limits of allowable PM vary between system and solvent used, but are typically based on an instantaneous, volumetric quantity of PM.[22] As facilities are required to report their pollutants based on weight per year and not required to report information on total exit stream compositions, sufficient data is not available to evaluate if facilities meet instantaneous volumetric requirements for carbon capture equipment.

Nitrosamine and nitramine formation

Amines can react with NO_x (and sometimes SO_x and PM) to create carcinogenic nitrosamines and nitramines.[23] Best practices on how to eliminate these emissions into the surrounding atmosphere are currently being developed. An in-depth review on nitrosamines and nitramines in carbon capture systems is included in Appendix A.

21 Féraud, Marocco, and Howard, "CASTOR Study on Technological Requirements for Flue Gas Clean-Up Prior to CO_2 -Capture"; Adams, "Flue Gas Treatment for CO_2 Capture."

22 "Testing of Cansolv DC-201 CO_2 Capture System At the National Carbon Capture Center Summer 2014."

23 Yu, Mitch, and Dai, "Nitrosamines and Nitramines in Amine-Based Carbon Dioxide Capture Systems: Fundamentals, Engineering Implications, and Knowledge Gaps."

RESEARCH QUESTION AND SCOPE OF STUDY

Although the primary goal of a carbon capture system is to remove CO_2 to support reaching climate goals, amine-based capture systems also offer the opportunity for co-benefits because they require the removal of co-pollutants, particularly NO_x, SO_2, and PM. Reducing the emissions of co-pollutants leads to a variety of human health benefits, including reductions in human mortality and asthma exacerbations.

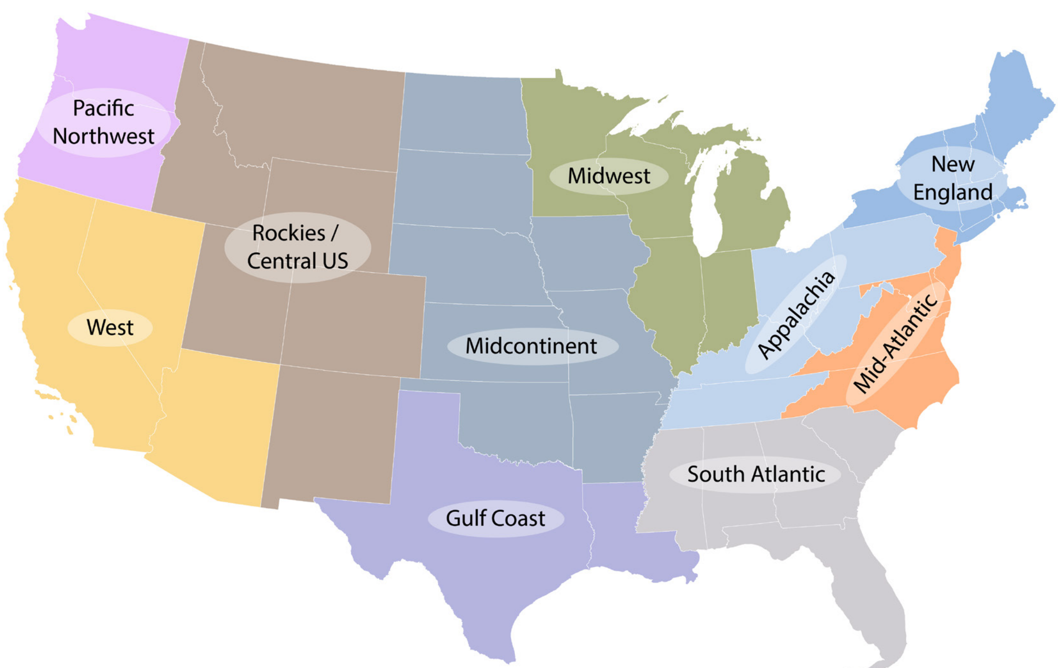
The goal of this report is to address the research gap in quantifying the expected health co-benefits of capturing co-pollutants for carbon capture systems. Specifically, this study performs an assessment of co-benefit opportunities in the contiguous United States for applying carbon capture to seven industries.

To quantify the health co-benefits of carbon capture, we analyzed representative facilities across seven industries and 10 regions in the contiguous United States. Alaska and Hawaii were not analyzed due to the inability of the co-benefits model to simulate these states. The regions selected are shown in figure 2. An overview of the industries is shown below in table 1 and identifies the total number of facilities for each industry type in the entire US.[24]

Table 1. Overview of selected industries for this study based on Carbon Solutions' CO_2NCORD run with 2020 data.

Industry	# of facilities in the US
Cement	96
Coal power plants	160
Ethanol	172
Fertilizer and ammonia	40
Iron and steel	165
Natural gas power plants	1060
Petroleum refineries	153

Figure 2. Regions used in this study

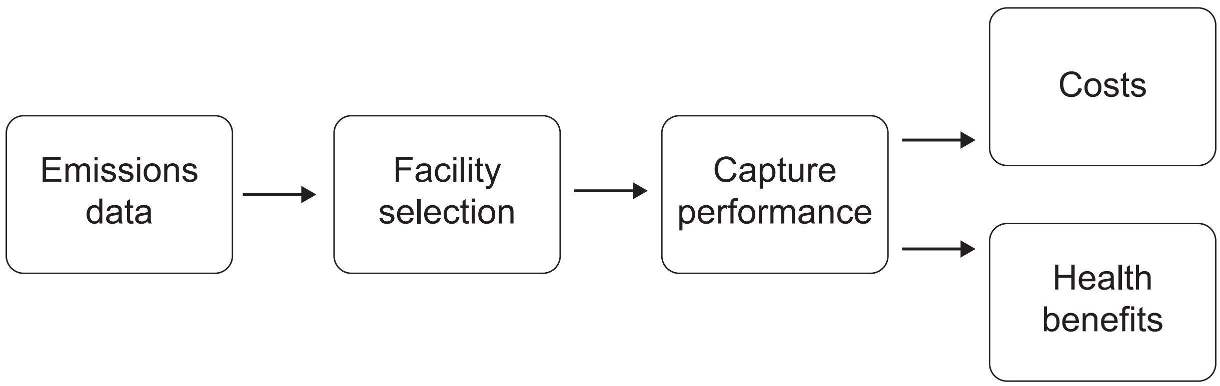


24 US EPA, "GHGRP and the U.S. Inventory of Greenhouse Gas Emissions and Sinks"; US EPA, "The Emissions & Generation Resource Integrated Database."

Methodology

In this study, we developed a five-step approach to quantify the costs and health benefits of capturing CO_2 and co-pollutants for amine-based systems. First, we combined available emissions data. Second, we reviewed data to select representative facilities in each of the 10 regions for analysis. Third, we estimated the effect of the co-pollutant and capture systems on CO_2, NO_x, SO_2, and $PM_{2.5}$. With those results, we estimated the costs and health benefits. An overview of the methodology is presented in figure 3.

Figure 3. Overview of approach to estimate costs and co-benefits of capturing co-pollutants.



EMISSIONS DATA

For this study, we used three sources of emissions data from the US EPA, including the Greenhouse Gas Reporting Program (GHGRP), the Emissions and Generation Resource Integrated Database (eGRID), and the National Emissions Inventory (NEI). GHGRP was used for CO_2 emissions from industry. eGRID was used for CO_2 emissions and performance of coal- and natural gas-fired power plants. NEI was used for information on NO_x, SO_2, and PM levels. Each source of data provides emission information at different levels, including individual processes, unit levels, and an entire facility.

GHGRP and FLIGHT

The US EPA's Facility Level Information on GreenHouse gases Tool (FLIGHT) compiles annually reported CO_2 emissions from the over 8,000 facilities in the United States required to report emissions to GHGRP. The facility threshold for reporting is 25,000 tons of CO_2 equivalent per year, which covers 85-90 percent of total US annual point source emissions.[25] In 2021, this included nearly 6,500 facilities in the "direct emitter" database, which we used to identify facility types and CO_2 emissions for the industries examined in this study.

eGRID

The EPA's Clean Air Markets Division further collects more detailed data on facilities emitting CO_2 for power generation in the Emissions and Generation Resource Integrated Database (eGRID). eGRID includes nearly every power plant facility in the United States, with detailed data on multiple emissions sources at the plant, generator, and unit level.[26] Plant-level data includes key descriptive, locational, and

25 US EPA, "GHGRP and the U.S. Inventory of Greenhouse Gas Emissions and Sinks."
26 US EPA, "The Emissions & Generation Resource Integrated Database."

operational data for 11,393 US power facilities and provides key data on plant ownership and the operational/regulatory markets that they sell power to. Generator-level data provides operational information for 25,031 generating units at these facilities, with important data on generating capacity, planned retirement dates, and power generation. Unit-level data contains key fuel and emissions data for the 24,597 combustion units at these facilities and includes the CO_2 emissions that underlie much of this study's power plant information.

NEI

The EPA's National Emissions Inventory (NEI)[27] includes criteria air pollutants and hazardous air pollutants emissions data from large industrial facilities and point source emitters and is rereleased every three years. This study used 2020 data that was generated by the EPA on January 31, 2023. NEI provides emissions for individual processes at facilities. To make NEI data compatible with data from GHGRP and eGRID, co-pollutant emissions were aggregated at the facility level.

27 US EPA, "National Emissions Inventory (NEI)."

FACILITY SELECTION

Prerequisite requirements

Three prerequisite criteria were used to identify representative facilities for evaluating co-pollutant reduction and subsequent health impacts within each of the 10 regions.

Relevant tax incentives: The first objective was to remove facilities from consideration based on the requirements of the tax credit provided by Section 45Q of the United States Internal Revenue Code (45Q). To be eligible for 45Q, industrial facilities must capture a minimum annual emissions volume of 12,500 tons, while power generation (electric generation) facilities must capture a minimum annual emissions volume of 18,750 tons.[28] For our analysis, we simplified and removed from consideration facilities that had total annual emissions, instead of capture amounts, less than the capture requirements.

Data availability: Next, facilities were evaluated with respect to data availability. Our evaluation of co-pollutant reduction and subsequent health benefits relied on three specific co-pollutants: $PM_{2.5}$, SO_2, and NO_x. To evaluate impacts, it was necessary that a facility have reported emissions for each pollutant in the NEI database. We also needed the facility to be present in EPA's FLIGHT database for evaluation of the type of facility, which is necessary to evaluate capture costs. Facilities that did not have these three pollutants in NEI or were not present in FLIGHT were not considered for this study.

Retirements and existing carbon capture equipment: Third, facilities were removed from consideration if they were not suitable candidates for capture due to retirement or closure or if they already had capture equipment installed. To determine if facilities were due for retirement or closure, we removed all facilities announced to retire based on data from the Energy Information Administration (EIA). We also removed facilities that were publicly announced to be closed or to significantly reduce operations.[29] Facilities that currently capture CO_2 on-site for either use or storage based on FLIGHT were also removed, based on the approach used by National Energy Technology Laboratory (NETL).[30]

Representative facility selection

Finally, of the plants remaining, a representative facility was selected for each industry within each region. We selected representative facilities closest to the median total annual reported CO_2 emissions of facilities in the industry and region. If no facility was equal to the median in that region, the next largest facility was selected. Any facilities that had dual characterization (i.e., both natural gas and coal units) were also not considered.

28 "26 U.S. Code § 45Q - Credit for Carbon Oxide Sequestration."

29 US Energy Information Administration, "Preliminary Monthly Electric Generator Inventory (Based on Form EIA-860M as a Supplement to Form EIA-860)."

30 Hughes et al., "Industrial CO_2 Capture Retrofit Database (IND CCRD)."

CAPTURE PERFORMANCE

The equipment required for a capture system depends on the concentration of CO_2 and which co-pollutants are present in the flue gas. This section provides an overview of the removal process for our selected industries and details the performance of CO_2, SO_2, NO_x, and PM removal systems.

Overview

Flue gas composition varies by industry. Table 2 outlines the individual capture streams by industry type, as well as the pollutants present which must be captured alongside CO_2.

Table 2. Capture streams present by industry

Industry	Capture streams	Pollutants present
Cement	Combustion, rotary kiln	SO_2, NO_x, condensable PM, dilute CO_2
Coal power plants	Combustion	SO_2, NO_x, condensable PM, dilute CO_2
Ethanol	Fermentation	Pure CO_2
	Combustion	SO_2, NO_x, condensable PM, dilute CO_2
Fertilizer and ammonia	Combustion	SO_2, NO_x, condensable PM, dilute CO_2
	CO_2 stripper vent	Pure CO_2
Iron and steel	Combustion, blast furnace gas, blast oven furnace	SO_2, NO_x, condensable PM, dilute CO_2
Natural gas power plants	Combustion	NO_x, condensable PM, dilute CO_2
Petroleum refineries	Stationary combustion and fluid catalytic cracking unit	SO_2, NO_x, condensable PM, dilute CO_2

Equipment to remove SO_2, NO_x, and PM was chosen and designed to meet the EPA's New Source Performance Standards for pulverized coal technology installed post-2011. Among the industries mentioned in these standards, pulverized coal maintains the highest allowable concentrations of released NO_x and SO_2, which allows for a conservative estimate of the quantity of co-pollutants removed and, thus, health benefits gained. Pollutant removal efficiency and costs are based on simulations for implementing an amine-based carbon capture system on pulverized coal plants[31] published by NETL in 2019, and for implementation of the same system on cement plants, published by NETL in 2022.[32]

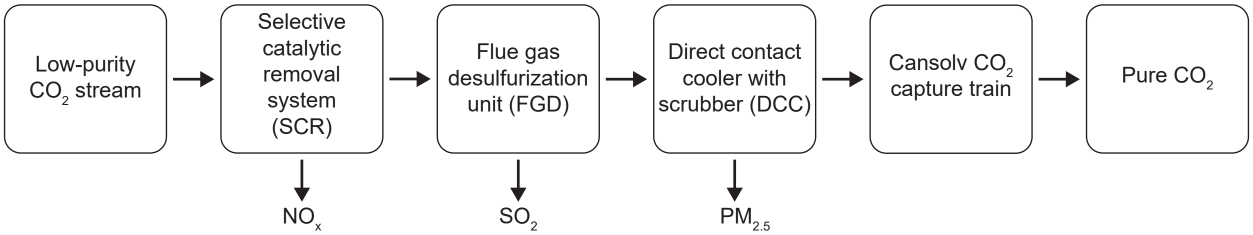
Co-pollutant capture equipment was modeled for all low-purity CO_2 streams. This includes cement, steel, natural gas, and coal facilities, fluid catalytic cracking units at refineries, and combustion streams from ethanol, refineries, and ammonia and fertilizer plants. The fermentation streams from ethanol facilities and CO_2 stripper vent streams from ammonia and fertilizer plants were assumed to be pure CO_2 and thus would not need additional pre-treatment.

Figure 4 shows a block flow diagram of equipment required to remove pollutants on low-purity CO_2 streams. Low-purity CO_2 streams are fed to a selective catalytic reduction system (SCR), which removes 75.1 percent of NO_x emissions. Streams are then sent to a wet FGD unit which removes 98 percent of SO_2 emissions. The stream then enters a direct contact cooler (DCC) with caustic scrubber, which cools the stream, condenses any condensable PM, and removes additional SO_2 quantities. The stream then flows through the Shell Cansolv CO_2 Capture Train, designed to capture 90 percent of CO_2 emissions and prepare the CO_2 for pipeline transportation. Compressed and pure CO_2 exits the system. The overall system performance is summarized in table 3, which provides an overview of the capture equipment by pollutant stream, as well as the estimated removal efficiency, from a combination of

31 James et al., "Cost and Performance Baseline for Fossil Energy Plants Volume 1 : Bituminous Coal And Natural Gas to Electricity."

32 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."

Figure 4. Block diagram of pollutant removal equipment for a CO_2 capture system.



literature and published case studies.[33]

CO_2 emissions

Low-purity CO_2 streams require a CO_2 separation system to purify the CO_2. Most CO_2 capture systems on the market use an amine-based solvent that binds with the CO_2 and then releases it into a separate stream. A variety of amines exist on the market, such as Econ FG+, MDEA, and Cansolv.[34] For this study, we used Shell's Cansolv system, operating at a 90 percent capture rate, due to the availability of literature on the system's design and costs. The amine-based system had a capture rate of 90 percent, similar to other studies.[35] A pure stream of CO_2 exits the captured system, which is then cooled and compressed to meet pipeline standards.

Pure CO_2 streams, such as streams exiting the ethanol fermentation process and the streams exiting from ammonia CO_2 stripper vents, do not require the capture system to isolate CO_2. However, they do still require compression and cooling to bring the CO_2 to within pipeline standards, which is completed by compression trains and heat exchangers.[36]

Table 3. Capture performance by pollutant.

Emission	Capture equipment	Removal efficiency
CO_2	Dilute CO_2 stream: amine	Dilute CO_2 stream: 90%
	High-purity CO_2 stream: none	High-purity CO_2 stream: 100%
NO_x	Selective catalytic reduction system	75.1%
SO_2	Flue gas desulfurization	98%
$PM_{2.5}$	Direct contact cooler	100% of condensable
		0% of filterable

SO_2 emissions

To remove SO_2 emissions, we modeled a wet FGD system designed to decrease SO_2 emissions by 98 percent.[37] The FGD uses a calcium carbonate (limestone) slurry to absorb SO_2 in a reaction that creates gypsum, a nontoxic mineral, which can then be dewatered and either sold as a separate product or responsibly disposed of at the end of the process. Disposal costs or sale credits were not considered in this work. A wet FGD has a higher capital cost but higher operating capacity than its alternative, a dry FGD.[38] While wet FGD allows for a consistent emission reduction approach across facilities, deploying a dry FGD may lead to cost reductions for some facilities.

33 Hughes and Zoelle.; James et al., "Cost and Performance Baseline for Fossil Energy Plants Volume 1 : Bituminous Coal And Natural Gas to Electricity."
34 Bennett et al., "Life Cycle Meta-Analysis of Carbon Capture Pathways in Power Plants: Implications for Bioenergy with Carbon Capture and Storage."
35 Bennett et al.
36 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."
37 James et al., "Cost and Performance Baseline for Fossil Energy Plants Volume 1 : Bituminous Coal And Natural Gas to Electricity."
38 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."

Built into our chosen capture equipment for low-purity CO_2 sources is a pre-scrubber unit modeled as a DCC with caustic scrubber. The caustic scrubber removes additional quantities of SO_2, designed to bring SO_2 content to 2 ppmv.[39] Insufficient data exist to determine, on a facility level, the additional reduction in SO_2 this provides. Thus, we maintained a total removal of 98 percent of SO_2 at this step. Pollutants removed by the DCC exit in a liquid blow-down stream, which is sent to an on-site wastewater treatment system, are included within our balance-of-plant cost estimate. Water is treated to within EPA standards, and remaining solids are disposed of in accordance with EPA guidelines.[40]

NO_x emissions

To remove NO_x emissions, we modeled an SCR designed to remove 75.1 percent of available NO_x.[41] Literature proposes that additional NO_x removal may be attainable by an SCR (around 79 percent) with appropriate system tuning,[42] and up to a 30 percent reduction in NO_x can occur in an FGD system.[43] To retain a conservative estimate, we calculated benefits based on a 75.1 percent reduction.

Removing NO_x using an SCR requires a reducing agent but will produce non-reactive, non-harmful products that can be released into the atmosphere.[44] Flue gas streams containing NO_x, specifically NO_2, are mixed with a reducing agent, often an ammonia or urea solution, before passing through the catalyst bed within the SCR. The reducing agent, in combination with the catalyst, removes the oxygen atoms to produce nitrogen gas (N_2) and water vapor. Research is currently underway to develop high-efficiency, low-temperature, reductant-free systems that would produce N_2 and oxygen gas (O_2).[45]

Particulate matter emissions

Particulate matter (PM) can be separated into filterable and condensable PM. Condensable PM is any PM that is a vapor at stack conditions but a solid or liquid at atmospheric conditions.[46] Removing PM is important for capture system performance, as it can contaminate the solvent. Utilizing an electrostatic precipitator[47] or pulse-jet fabric filter[48] can remove 98-99.9 percent of PM; however, an in-depth review of available literature found that little work has been performed to estimate the cost of additional dust removal technology for capture systems.[49] Thus, we did not include additional dust removal technology in our capture system model. However, to cool the incoming stream and remove residual acidic compounds, such as SO_2 and hydrogen chloride,[50] a DCC with caustic scrubber is implemented before the Cansolv system.

While condensable PM is not typically controlled, a critical review of condensable PM identified that a DCC, which can both cool and entrain condensed particles, could remove a

39 James et al., "Cost and Performance Baseline for Fossil Energy Plants Volume 1 : Bituminous Coal And Natural Gas to Electricity."

40 James et al.; Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."

41 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."

42 James et al., "Cost and Performance Baseline for Fossil Energy Plants Volume 1 : Bituminous Coal And Natural Gas to Electricity."

43 Adams, "Flue Gas Treatment for CO_2 Capture."

44 Koebel, Madia, and Elsener, "Selective Catalytic Reduction of NO and NO_2 at Low Temperatures."

45 Xu et al., "Catalytic Decomposition of NO_2 over a Copper-Decorated Metal – Organic Framework by Non-Thermal Plasma Copper-Decorated Metal – Organic Framework by Non-Thermal Plasma."

46 WV Department of Environmental Protection, "Particulate Matter Overview : Supplement to the Emission Inventory Guidance for Pollutant Reporting CY2013 Particulate Matter."

47 Industrial Quick Search, "Electrostatic Precipitators."

48 James et al., "Cost and Performance Baseline for Fossil Energy Plants Volume 1 : Bituminous Coal And Natural Gas to Electricity."

49 US EPA, "Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire Plate Type."

50 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."

large portion of the pollutant.[51] As the modeled capture train is a closed system, additional quantities of PM will be entrained and removed either within the DCC or the capture system itself through contamination of the solvent, leading to a further reduction in PM. While a simplifying assumption and overestimation, we modeled our system to remove all condensable $PM_{2.5}$, as a DCC would theoretically remove a major portion. To ensure our overall estimations remained conservative, we assumed the removal of no filterable PM, as both types of PM are treated the same within the CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), the software used to estimate overall co-pollutant removal health benefits.

Any $PM_{2.5}$ that is removed or entrained within the DCC exits in a liquid blow-down stream, which is sent to an on-site wastewater treatment system. Water is treated to within EPA standards, and the remaining solids are disposed of in accordance with EPA guidelines.[52] Wastewater treatment occurs on-site and is included in the cost estimates.

51 Feng, Li, and Cui, "Critical Review of Condensable Particulate Matter."
52 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."

COSTS

CO_2 capture at power plants, iron and steel plants, and petroleum refineries

The cost of CO_2 capture at coal and natural gas power plants, as well as iron and steel plants and petroleum refineries, was calculated using Carbon Solutions' CO_2 National Capture Opportunities and Readiness Data (CO_2NCORD) software. CO_2NCORD allows users to identify sources of CO_2 that could be profitably turned into CCS projects. CO_2NCORD is a novel software that utilizes the best available public data, including literature and expert input, to generate insights into point source CO_2 emissions from industrial facilities across the United States for capturable volumes, stream characterization, and associated costs for capture.

For iron and steel facilities and petroleum refineries, we used CO_2NCORD's literature-based estimates across over two dozen published sources into a single database that provides estimated capture efficiency rates, costs, and volumes. Estimates are done for available capturable CO_2 streams and are identified in facilities across multiple industry sectors and subsectors and combined with FLIGHT emissions data at the facility level. Carbon Solutions attributes emissions recorded under GHGRP subparts to capturable streams, providing average cost estimates for project screening. The CO_2NCORD database includes 11 capture cost studies for iron and steel facilities[53] and eight capture cost studies for petroleum refineries.[54]

For coal and natural gas power plants, we used CO_2NCORD's advanced techno-economic analysis to derive cost estimates aggregated from individual cost categories and equipment. This method provides the breakeven CO_2 capture cost of any prospective CCS project by integrating the latest public data and scientific research into a single end-user platform. These bottom-up estimates leverage the NETL Cost and Performance Baseline for Fossil Energy Plants.[55] CO_2NCORD integrates this study's cost estimation formulae with capital equipment with CO_2, SO_2, and NO_x emissions at the boiler unit level from eGRID, as noted above, as well as generation data to calculate per megawatt hour emissions intensity rates by plant. It combines this with US Energy Information Administration EIA-860 data on the presence of co-pollutant reduction equipment at each plant to determine whether additional co-pollutant reduction equipment might need to be installed.[56] For plant operating and maintenance costs, CO_2NCORD further integrates projected gas and electricity prices

53 Naims, "Economics of Carbon Dioxide Capture and Utilization—a Supply and Demand Perspective"; Edwards and Celia, "Infrastructure to Enable Deployment of Carbon Capture, Utilization, and Storage in the United States"; Adams, "Flue Gas Treatment for CO_2 Capture"; IEA, "Technology Roadmap: Carbon Capture and Storage"; IEA, "Transform. Ind. through CCUS"; Abramson, Mcfarlane, and Brown, "Transport Infrastructure for Carbon Capture and Storage - Whitepaper on Regional Infrastructure for Midcentury Decarbonization"; Brown and Ung, "National Petroleum Council Study on Carbon Capture, Use and Storage Supply and Demand Analysis for Capture and Storage of Anthropogenic Carbon Dioxide in the Central U.S"; Psarras et al., "Carbon Capture and Utilization in the Industrial Sector"; Pilorgé et al., "Cost Analysis of Carbon Capture and Sequestration of Process Emissions from the U.S. Industrial Sector"; Bains, Psarras, and Wilcox, "CO_2 Capture from the Industry Sector"; Summers, Herron, and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."

54 Edwards and Celia, "Infrastructure to Enable Deployment of Carbon Capture, Utilization, and Storage in the United States"; Abramson, Mcfarlane, and Brown, "Transport Infrastructure for Carbon Capture and Storage - Whitepaper on Regional Infrastructure for Midcentury Decarbonization"; Leeson et al., "A Techno-Economic Analysis and Systematic Review of Carbon Capture and Storage (CCS) Applied to the Iron and Steel, Cement, Oil Refining and Pulp and Paper Industries, as well as Other High Purity Sources"; Rubin, Davison, and Herzog, "The Cost of CO_2 Capture and Storage"; Summers, Herron, and Zoelle, "Cost of Capturing CO_2 from Industrial Sources"; Pilorgé et al., "Cost Analysis of Carbon Capture and Sequestration of Process Emissions from the U.S. Industrial Sector"; Bains, Psarras, and Wilcox, "CO_2 Capture from the Industry Sector"; Energy Futures Initiative and Stanford University, "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions."

55 James et al., "Cost and Performance Baseline for Fossil Energy Plants Volume 1 : Bituminous Coal And Natural Gas to Electricity."

56 US Energy Information Administration, "Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)."

from the EIA's Annual Energy Outlook[57] and makes inflation adjustments using the reported Gross National Product Implicit Price Deflator reported by the US Bureau of Economic Analysis.[58]

CO_2 capture at cement, ammonia, and ethanol facilities

To model the price of capture at cement, ammonia, and ethanol facilities, we utilized a model for capture pricing generated from the Carbon Capture Retrofit Database, developed and updated by NETL in 2022.[59] This model uses NETL's scaling methodology[60] to determine the cost of capture based on CO_2 available.[61] The model was modified to allow for in-depth stream characterization, individual stream handling, use of the gross domestic product deflator to handle inflation costs, and consistent annualization of costs.

To handle combustion streams, an SCR, FGD, DCC with scrubber, Cansolv Purification Unit,[62] compressors with an intercooler, cooling water unit, and boiler are required to produce a CO_2 stream that meets pipeline standards.[63] The system is designed to capture any emissions generated by the boiler. As most industrial facilities have a cooling water unit and boiler, it is very possible cost reduction could be found by integrating the CO_2 capture train into the existing plant.

To handle high-purity CO_2 streams, only compressors with an intercooler and cooling water unit are required to bring the CO_2 stream within pipeline standards. As aforementioned, most facilities will already have a cooling water unit capable of handling the cooling requirement, thus showing an area of cost reduction. Costs from these streams will be significantly lower than from combustion streams due to their purity and should not be seen as representative of the cost of capture for a stream requiring CO_2 separation.

Ammonia: Ammonia facilities have two major point sources of CO_2: emissions from a primary reformer and emissions from a CO_2 stripper vent. Costing for the ammonia industry assumes individual capture systems for both streams. The primary reformer stream was handled as a combustion stream, and the CO_2 stripper vent was handled as a high-purity CO_2 stream. A water knock-out unit is integrated into the capture train for the high-purity stream, in addition to the units previously mentioned.

Ethanol: Ethanol facilities have one major point source of CO_2 emissions from fermentation, which produces a high-purity CO_2 stream. Ethanol facilities also have emissions from combustion, which were priced using CO_2NCORD.

Cement: Cement production generates emissions from combustion and chemical reactions within its kiln, which can be combined with other process emissions to exit out the facility's stack, or separately released. Streams that originate from the kiln are treated as dilute CO_2 streams, while remaining emissions are treated as generic combustion streams.

Co-pollutant equipment pricing

Coal power plant capture costs from CO_2NCORD include the cost of an FGD and SCR. Similarly, the natural gas power plant capture costs from CO_2NCORD include the cost of an SCR (minimal sulfur is present in natural gas, so FGDs are not used). For the remaining five industries, the FGD and SCR were priced based on a model developed by NETL in 2022, which found that the addition of an FGD and SCR on low-purity CO_2 sources adds about $15 per ton of captured CO_2,

57 US Energy Information Administration, "Annual Energy Outlook."
58 Bureau of Economic Analysis, "GDP Price Index."
59 Hughes et al., "Industrial CO_2 Capture Retrofit Database (IND CCRD)."
60 Turner and Pinkerton, "Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology."
61 Myles and Shirley, "Quality Guidelines for Energy System Studies: CO_2 Impurity Design Parameters."
62 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."
63 Myles and Shirley, "Quality Guidelines for Energy System Studies: CO_2 Impurity Design Parameters."

annualized.[64] This value was added to our cost per ton final value for the low-purity CO_2 streams. As the DCC is included in our chosen capture equipment design, its price is included within our Cansolv CO_2 capture train cost estimate.

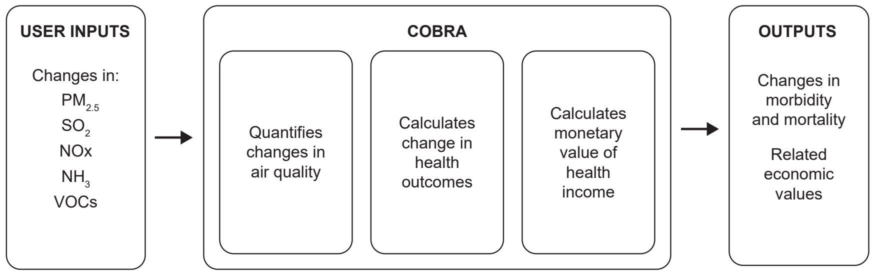
Flue gas cleaning equipment is individually designed for plants based on pollutant concentration, gas flow rate, and desired end concentration.[65] Maximum pollutant concentrations vary between capture systems, and for the Cansolv system, a maximum of 20 mg/Nm^3 is allowable.[66] Specific numbers for SO_2 and NO_x concentrations are not given, but generally, an SO_2 concentration below 10 ppm[67] and an NO_2 concentration below 20 ppmv is a representative target.[68] Despite having these starting limits, publicly available data on facilities' pollutant emissions is given in units of mass, and information on total exiting gas flow from plants is not reported. Since capital costs scale primarily based on the volume of gas that must be treated[69] and final desired concentration[70], we were unable to individually price co-pollutant removal equipment for each facility.

64 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."
65 Sorrels and Walton, "Cost Estimation: Concepts and Methodology."
66 "Testing of Cansolv DC-201 CO_2 Capture System At the National Carbon Capture Center Summer 2014."
67 Adams, "Flue Gas Treatment for CO_2 Capture."
68 Féraud, Marocco, and Howard, "CASTOR Study on Technological Requirements for Flue Gas Clean-Up Prior to CO_2-Capture."
69 Turner and Pinkerton, "Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology."
70 US EPA, "Air Pollution Control Technology Fact Sheet: Flue Gas Desulfurization (FGD) - Wet, Spray Dry, and Dry Scrubbers Type"; EPA, "Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR) Type"; US EPA, "Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire Plate Type."

HEALTH BENEFITS

To calculate the health benefits of removing co-pollutants, we used COBRA, developed by the US EPA.[71] COBRA estimates co-benefits due to changes in pollution emissions.

Figure 5. Flow diagram for COBRA, adapted from EPA (2021).



An overview of how COBRA works is shown in figure 5.[72] Given a set of changes in emissions for a certain location, COBRA first calculates how the emission changes in that location impact the overall air quality in that location and estimates how they propagate to other regions. Next, the model calculates how these changes in air quality impact health outcomes associated with air quality. Finally, economic value is associated with the changes in incidences by health outcome, using EPA's health costs data for analyzing changes in air pollution.

COBRA users can input emission changes for $PM_{2.5}$, SO_2, NO_x, anhydrous ammonia (NH_3), and volatile organic compounds (VOCs). For this study, we modeled emission reductions in tons for $PM_{2.5}$, SO_2, and NO_x because those are the contaminants that we expect the co-pollutant filtration system to remove prior to CO_2 capture.

We ran COBRA for each combination of region and industry considered. By default, COBRA calculates health benefits for all contiguous US states for each input facility because it considers the propagation of emissions across county and state borders. Mailloux et al. found in their study that the majority of benefits occur in the regions where the emissions were reduced.[73] Table 4 presents the match between the industries we simulated and the emission tiers available with COBRA.

Table 4. Match between the industries in this study and COBRA's emission tiers.

Industry	COBRA emission tier 1	COBRA emission tier 2
Cement	Other industrial processes	Mineral products
Coal power plants	Fuel combustion: electric utility	Coal
Ethanol	Other industrial processes	Miscellaneous industrial processes
Fertilizer and ammonia	Chemical & allied product manufacturing	Agricultural chemical manufacturing
Iron and steel	Metals processing	Ferrous metals processing
Natural gas power plants	Fuel combustion: electric utility	Gas
Petroleum refineries	Petroleum & related industries	Petroleum refineries & related industries

71 US EPA, "CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA)."

72 US EPA, "CO-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool: How COBRA Works"

73 Mailloux et al., "Nationwide and Regional $PM_{2.5}$-Related Air Quality Health Benefits From the Removal of Energy-Related Emissions in the United States GeoHealth."

The tool's output consists of changes for 12 different health outcomes and the corresponding total monetary value:

1. Adult mortality
2. Infant mortality
3. Non-fatal heart attacks
4. Respiratory hospital admissions
5. Cardiovascular-related hospital admissions
6. Acute bronchitis
7. Upper respiratory symptoms
8. Lower respiratory symptoms
9. Asthma exacerbations (attacks, shortness of breath, and wheezing)
10. Asthma emergency room visits
11. Minor restricted activity days
12. Work loss days

For this study, we present the results for mortality (adult and infant), asthma exacerbations (attacks, shortness of breath, and wheezing), and the total monetary value of all impacts.

A summary of the inputs used to run COBRA is shown in table 5.[74]

Table 5. COBRA parameter configurations for this study.

Parameter	Value for our study
Analysis year	2023
Location	Reductions modeled on the regional level (the 10 regions are shown in figure 2). Facility coordinates were used to determine in which region the reductions occurred.
Emission tier	Seven industries matched with COBRA tiers (see table 4)
Discount rate	3 percent, recommended by EPA

74 EPA, "CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA)."

Results and discussion

FACILITY SELECTION

Before selecting the representative facilities for the analysis, we reviewed the subset of facilities across the study regions. Figure 6 shows the distribution of CO_2 capture opportunities across the contiguous United States, highlighted by region. The range of capturable volumes is represented by the size of the facility circles in figure 6 and showcases the tremendous range of annual emissions for a given location. Subsequent sections will further break down the prevalence of different industry types across the regional geographies.

Next, we applied the prerequisite selection criteria: 45Q tax credit eligibility, data availability in NEI, not planned to be retired, and not currently capturing or utilizing CO_2 on-site. Table 6 tabulates the number of facilities that met these prerequisite selection criteria by industry type within each of the regions. As shown, there were 661 total facilities identified across all industry types. The distribution of facility counts varied by region, with the greatest number of facilities in the Midcontinent (131) and the least number of facilities in the Pacific Northwest (18). The prevalence of industry types also varied by geographic region. For example, 70 of the 126 ethanol facilities (55 percent) are located in the Midwest.

Finally, we selected the representative facilities based on median CO_2 emissions for each region-industry combination. The selected facilities are shown in figure 7.

Figure 6. Range of facility-level opportunities for capture co-benefits in the contiguous United States.

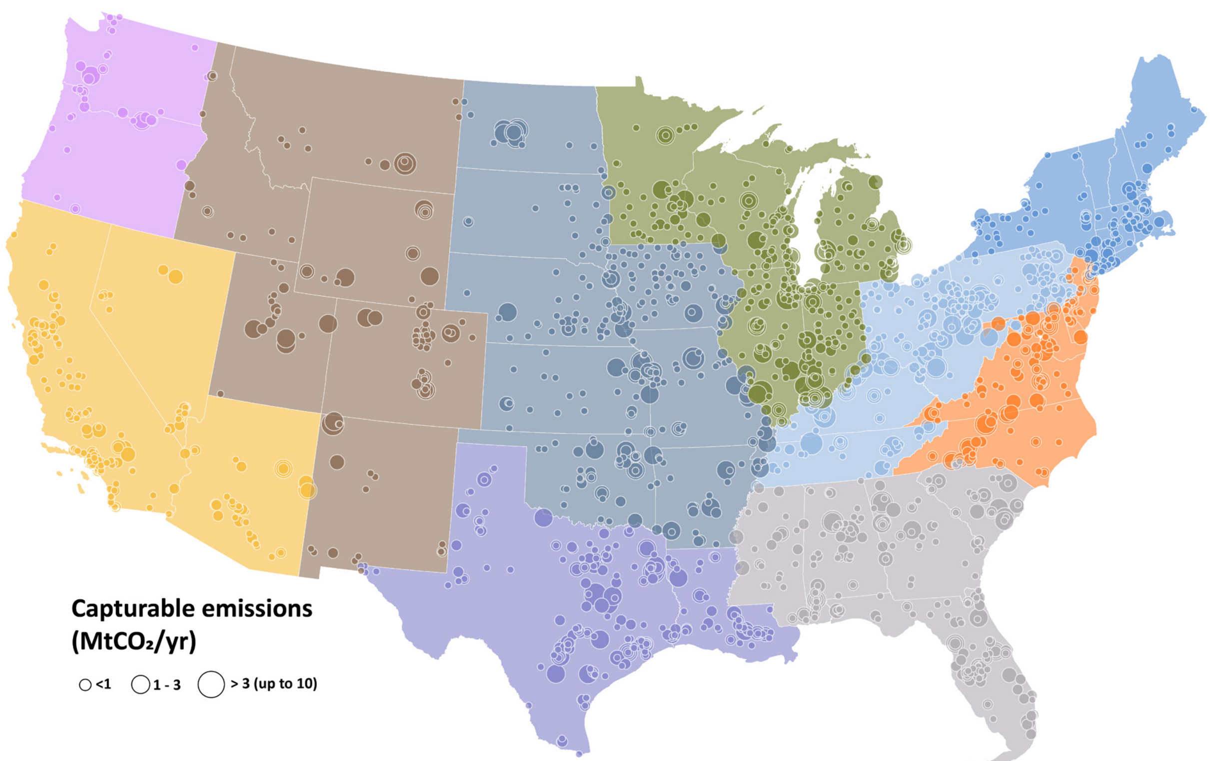
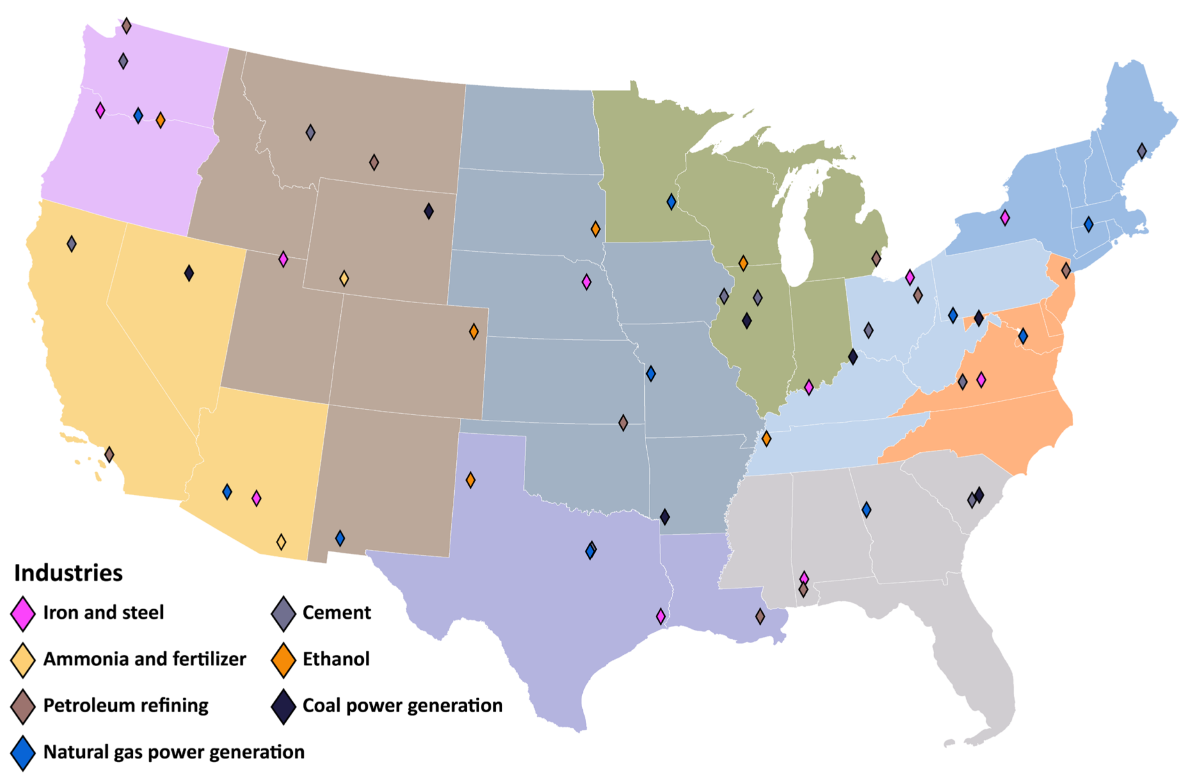


Table 6. Summary of facility counts by industry type and region for the study industries that meet the facility selection requirements.

Region	Industry							
	Cement	Coal power plants	Ethanol	Fertilizer and ammonia	Iron and steel	Natural gas power plants	Petroleum refineries	Total
Appalachia	12	12	7		32	13	14	90
Gulf Coast	5		3		5	30	32	75
Mid-Atlantic	3	3			8	13	1	28
Midcontinent	11	21	70		7	14	8	131
Midwest	8	1	41		26	23	12	111
New England	2		2		1	36		41
Pacific Northwest	1		1		1	12	3	18
Rockies/Central US	5	8	2	2	2	2	11	32
South Atlantic	14	6			16	37	5	78
West	3	1		1	5	34	12	56
Total	64	52	126	3	103	214	99	661

Figure 7. Selected facilities by region.



INTERPRETING THE RESULTS

The following section contains a series of figures and graphics to explain the co-benefits analysis conducted for each of the seven study industries. To help evaluate the wealth of data provided, the figures below provide some guidance on how to interpret the findings throughout this section, within which each of the 10 study regions is analyzed in greater detail.

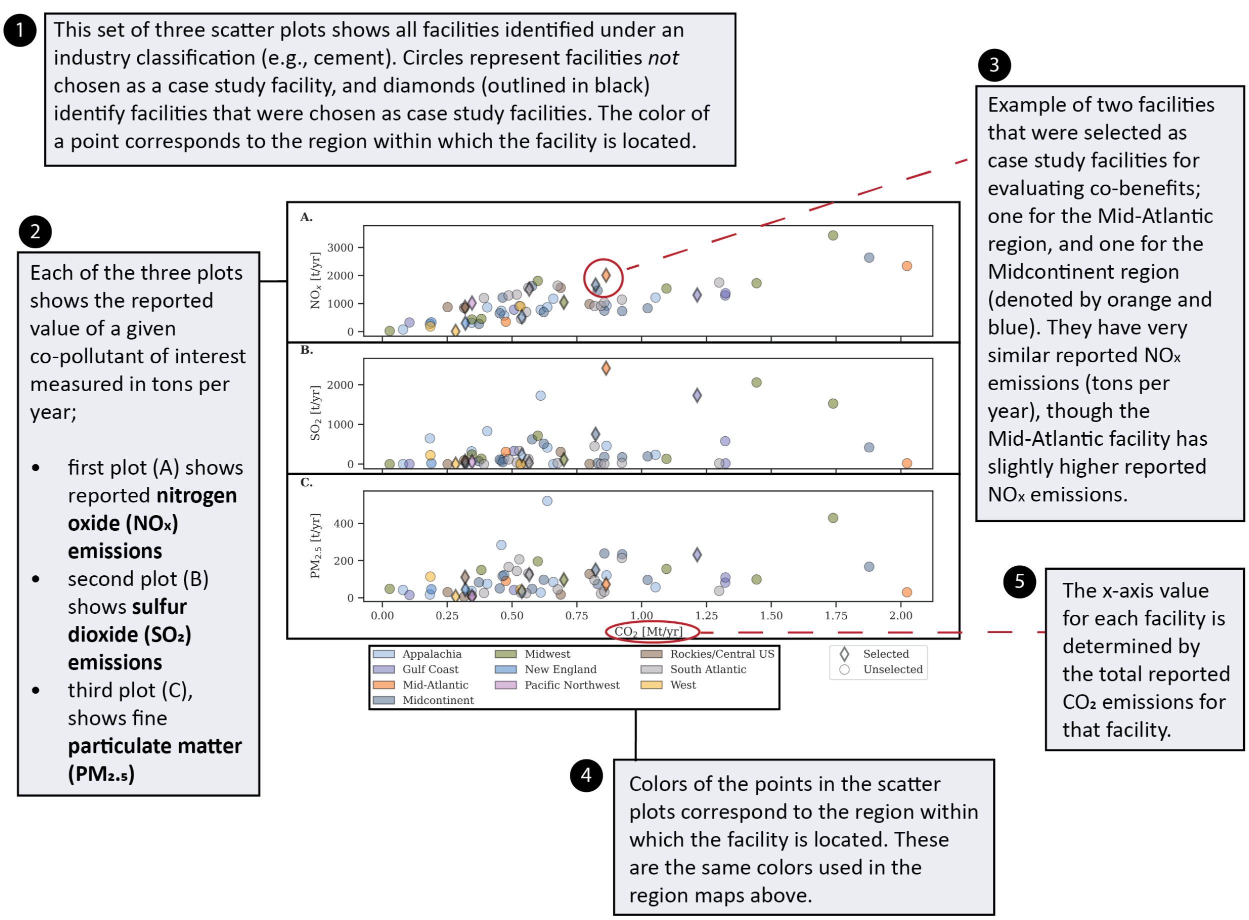
Facility selection

The first step is to understand the range of reported co-pollutant emissions across both the representative facilities, as well as all national facilities of that industry type. Figure 8 highlights important components of a recurring figure across each of the industry sections.

When choosing the representative facility for each industry type within each region, there were instances where a) no example of an industry type was present for a given region, or b) a facility was potentially present but did not satisfy the criteria for evaluation (i.e., all co-pollutants reported, viable for capture equipment installation, minimum emissions requirements for the 45Q federal tax credit incentive).

It is additionally helpful to see where representative facilities fall in the range of all facilities for each industry type when looking at emissions levels for various pollutants. While the case studies chosen aimed to provide a "middle of the road" example based on CO_2 emissions, there were instances when the facility chosen had higher than average emissions for a given co-pollutant type, because the co-pollutants do not directly correlate with CO_2 emissions.

Figure 8. Guidance on how to interpret facility selection for each industry.

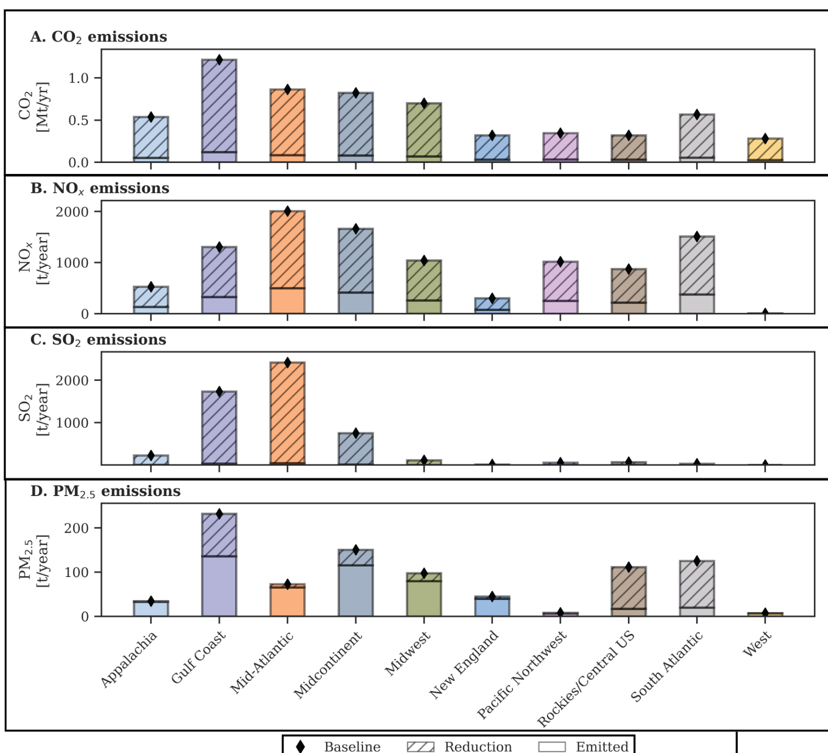


Emission impacts

Emission impacts are evaluated for different emissions:CO_2, NO_x, SO_2, and fine $PM_{2.5}$. The second series of graphs, explained in figure 9, shows the total reported emissions for each representative facility, as well as the successful reduction in each of the four emissions after installation of capture equipment and pre-treatment.

Figure 9. Guidance on how to interpret emission impacts for each representative facility.

1 The second series of graphs provides insights into the total reported value for each of the four emissions of interest—CO_2, NO_x, SO_2, and $PM_{2.5}$—equal to the entirety of the bar shown for each region. The series also provides information on the reduction achieved after installation of capture equipment; the amount of emissions reduced at each facility are shown as the hatched portion of each bar. Any emissions remaining after installation of capture equipment are shown as non-hatched portion.



2 The first graph shows the total annual CO_2 volumes (in million tons per year). Total reported emissions are shown as the bar for each region. The hatched portion is equal to the amount reduced after installation of capture equipment.

3 The second graph highlights NO_x emissions (in tons per year) and estimated reduction for each facility.

4 The third graph highlights SO_2 emissions (in tons per year) and estimated reduction for each facility.

5 The fourth graph highlights $PM_{2.5}$ emissions (in tons per year) and estimated reduction for each facility.

6 The x-axis labels indicate the region. The regions continue in the same position on the x-axis for each graph.

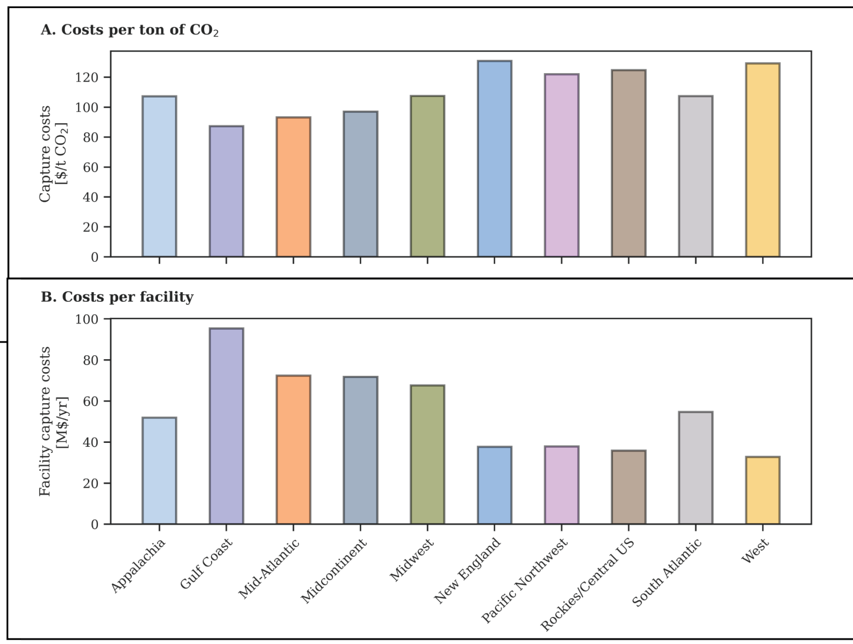
7 The black diamond represents the baseline total reported volumes. The reduction achieved through installation of capture equipment is shown as hatched, while any remaining emissions are shown without hatching.

Capture costs

Figure 10 provides guidance on how to interpret the capture costs provided for each of the industries analyzed. Costs include both capital and operation and maintenance costs but do not include 45Q tax credits.

Figure 10. Guidance on how to interpret capture costs at representative facilities.

1 The third series of graphs provides two important economic results—the cost per ton of CO_2 captured at each case study facility (in dollars per ton of CO_2 captured)—and as the total cost of capture at each case study facility (in million dollars per ton of CO_2). Note, if a region is not included, that is because there was not a satisfactory, representative facility of the industry type to use as a case study.



2 The first graph shows the cost per ton (in dollars per ton of CO_2) for all CO_2 captured at each representative facility.

3 The second graph in the figure provides the total cost to capture all four emissions (CO_2, NO_x, SO_2, and $PM_{2.5}$) per facility on an annual basis for capture.

4 The x-axis labels indicate the region. The regions continue in the same position on the x-axis for each graph.

Health co-benefits

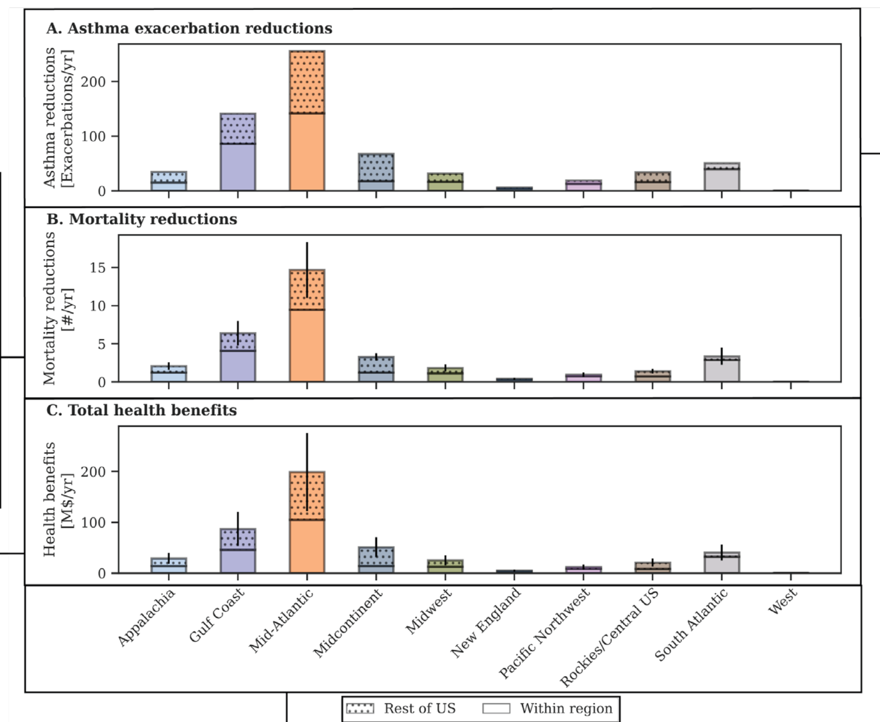
As shown in figure 11, the final set of figures for each of the industry sections provides an overview of the health benefits resulting from the impact of emissions reductions in each of the study regions. Note that COBRA evaluates 12 dimensions of health impacts. Two of the 12 dimensions are presented for each of the industry results sections below: asthma exacerbations and mortality reductions. The final health metric, total health benefits, provides a dollar-equivalent, cumulative estimate of all 12 benefits associated with capturing co-pollutants at the representative facility in that region.

Figure 11. Guidance on how to interpret health benefits at representative facilities.

1 The final series of three bar graphs provides insights into the health benefits associated with the facility-level emissions impacts (from the second series of graphs). Health impacts are assessed across three metrics: asthma exacerbations, mortality reductions, and total health benefits (in million dollars per year).

2 The first graph (**Asthma exacerbation reductions**) shows reductions in asthma exacerbations. Exacerbations are measured by count of asthma-related hospital visits per year. The estimated reduction is the number of incidents mitigated by capture equipment installed at the individual representative facility in each region represented.

3 The second graph (**Mortality reductions**) provides the estimated count of human deaths prevented by installation of the capture equipment at the individual representative facility in each region represented. The error bar shows the potential range of reductions (low to high).



4 The final graph (**Total health benefits**) provides an overview of the cumulative estimated health impacts of capture in each region from capture equipment installed at each representative facility. Total health benefits are given as the million dollar-equivalent of health impacts. The error bar shows the potential range of benefits (low to high).

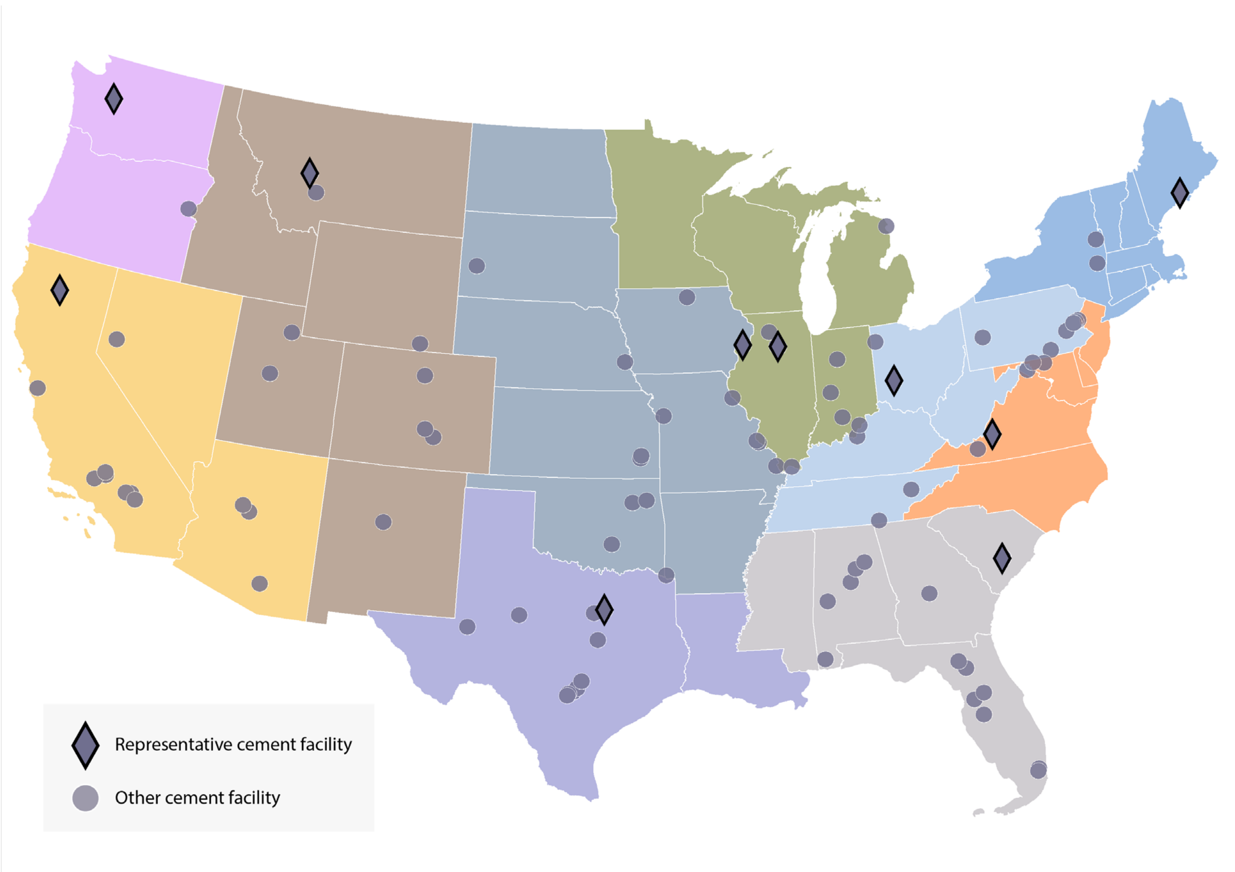
5 The x-axis labels indicate the region. The regions continue in the same position on the x-axis for each graph.

6 Results for each type of health benefit for each representative facility are further broken out by the impacts within the region, shown as the non-dotted portion of each bar, and the impacts outside of the region (from capture at the representative facility within the region), shown in the dotted portion of each bar.

CEMENT

Cement production generates over 7 percent of global CO_2 emissions,[75] most of which is a result of extended periods of high-temperature heat. The heat is used to instigate a calcination reaction, which releases additional CO_2 from limestone. Combustion accounts for around 40 percent of cement facility emissions, while calcination accounts for the remaining 60 percent.[76] Nearly all emissions are generated within a plant's kiln, where fuel is burned and CO_2 is liberated concurrently. CO_2-rich flue gas can be used as a heat source at the plant and is ideally conditioned and treated to remove PM and pollutants before exiting a plant's stack.[77] However, the cement industry is the third-largest industrial polluter, indicating a lack of proper air pollution control measures.[78] Thus, it is necessary to account for additional SO_2, NO_x, and $PM_{2.5}$ control measures to ensure carbon capture system efficiency.Cement facilities generate dilute CO_2 exiting from a plant's stack, ranging between 14 and

Figure 12. Cement facilities in the United States.



Note: Representative facilities for each region are diamonds and outlined in black. Facilities that were not selected are circles and outlined in white.

75 Stashwick, "With Carbon Capture, Concrete Could One Day Be a Carbon Sink."
76 Portland Cement Association, "Carbon Footprint."
77 SINTEF-ER, "CO_2 Capture from Cement Production."
78 US EPA, "Cement Manufacturing Enforcement Initiative."

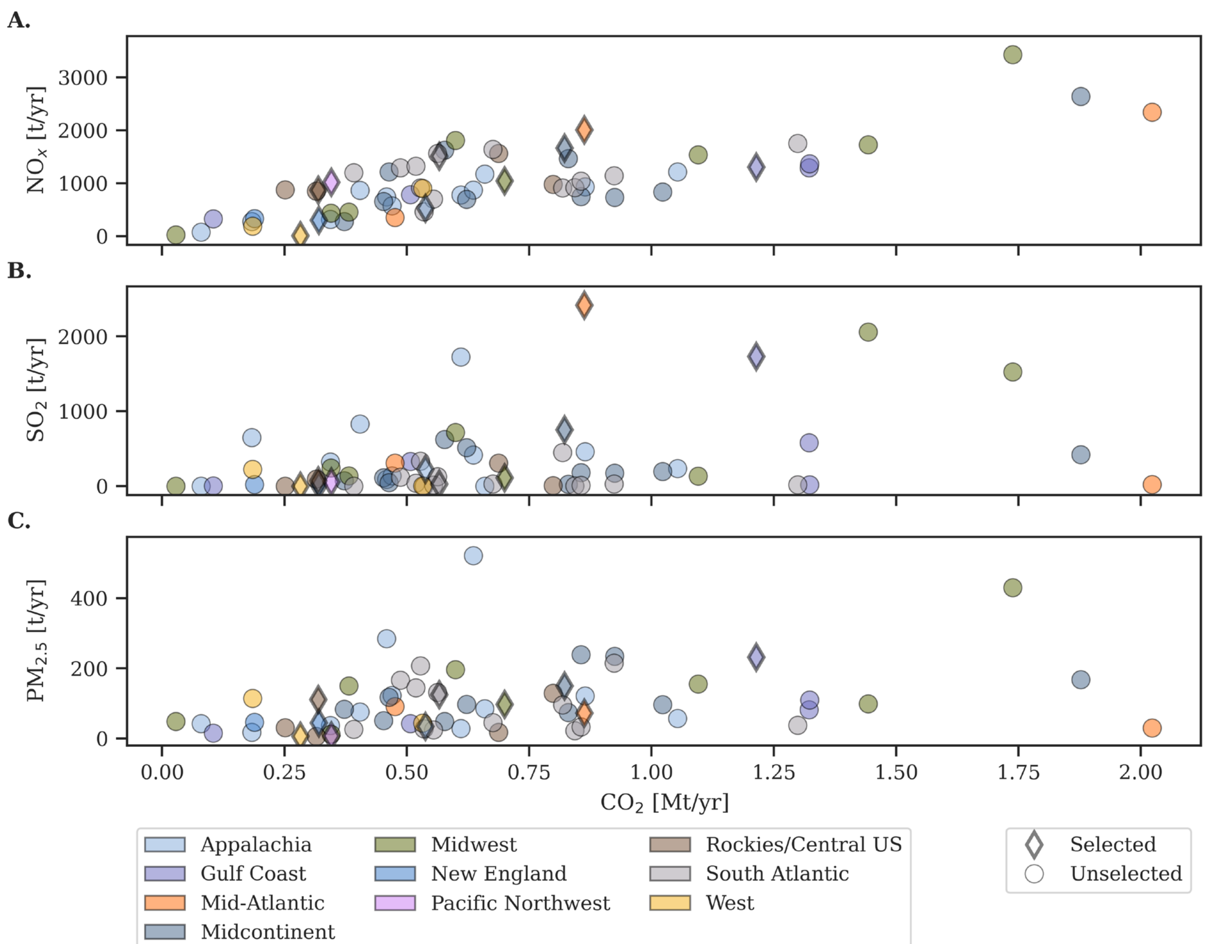
33 percent CO_2 by weight.[79] System design and costs were determined using published flue gas characteristics for St Mary's Cement Plant, at 32 weight percent (22 mole percent) CO_2.[80] To capture this CO_2, we modeled a retrofit capture system, which would route flue gas through an SCR, FGD, then DCC with scrubber to reduce pollutants that could otherwise negatively impact the capture unit, then route the treated gas through a CO_2 capture train. The resulting high-purity CO_2 is compressed and cooled to pipeline standards.

As shown in figure 12, the distribution of cement facilities across the lower 48 is regular, with at least one cement facility in every region modeled. At least one facility for each region also satisfied the evaluation criteria for use in this study. However, the greatest number of cement facilities are in the South Atlantic, Midcontinent, and Appalachia regions, respectively.

Cement: Facility selection

Figure 13 shows the distribution of reported co-pollutant emissions (NO_x, SO_2, and $PM_{2.5}$) for all cement facilities across the US that fit the evaluation criteria, highlighting (as diamonds with a thick outline) the facilities chosen as a representative facility for each of the regions.

Figure 13. Cement representative facility selection.



79 Bosoaga, Masek, and Oakey, "CO_2 Capture Technologies for Cement Industry."
80 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."

Cement: Emission impacts

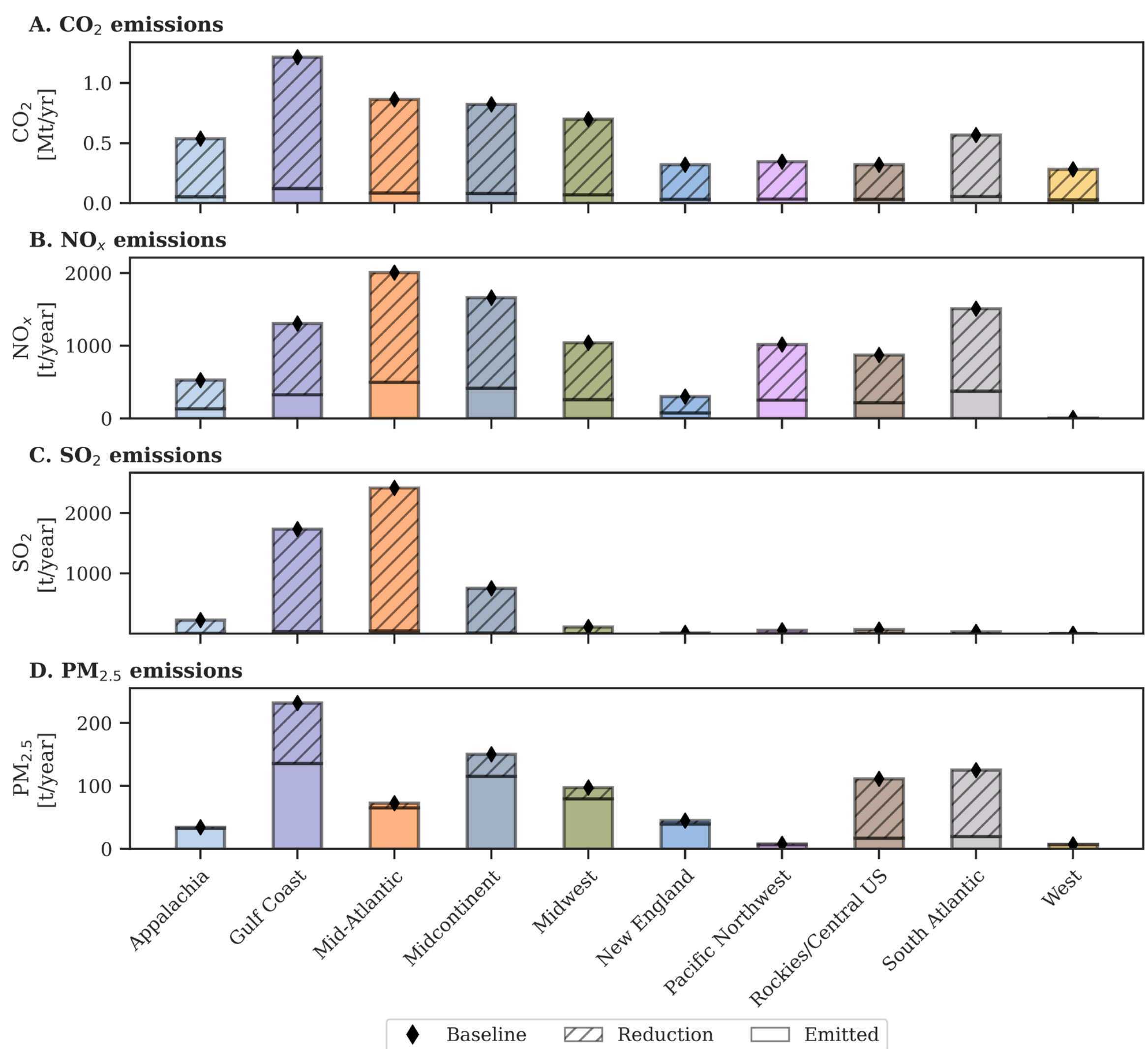
Figure 14 breaks down the impact on emissions for the representative cement facilities when outfitted with capture equipment and pre-treatment.

CO_2 emissions: Capturable CO_2 emissions ranged from 0.25 to 1.09 Mt. The streams at each facility were simulated with a 90 percent CO_2 capture rate.

NO_x emissions: There was greater variation in the reported NO_x emissions at the study facilities. In general, facilities with higher total reported NO_x emissions saw the greatest volumetric reductions associated with the introduction of capture equipment, because the SCR is simulated to capture 75.1 percent of NO_x.

SO_2 emissions: Generally, the facilities with the highest overall NO_x and CO_2 emissions also had the highest SO_2 emissions. These were the facilities in the Mid-Atlantic, Gulf Coast, and Midcontinent. SO_2 emissions in all other regions were small by comparison. However, regardless of initial emissions volumes, 98 percent of SO_2 emissions were simulated to be captured with the introduction of capture equipment.

Figure 14. Emission impacts at representative cement facilities by region.



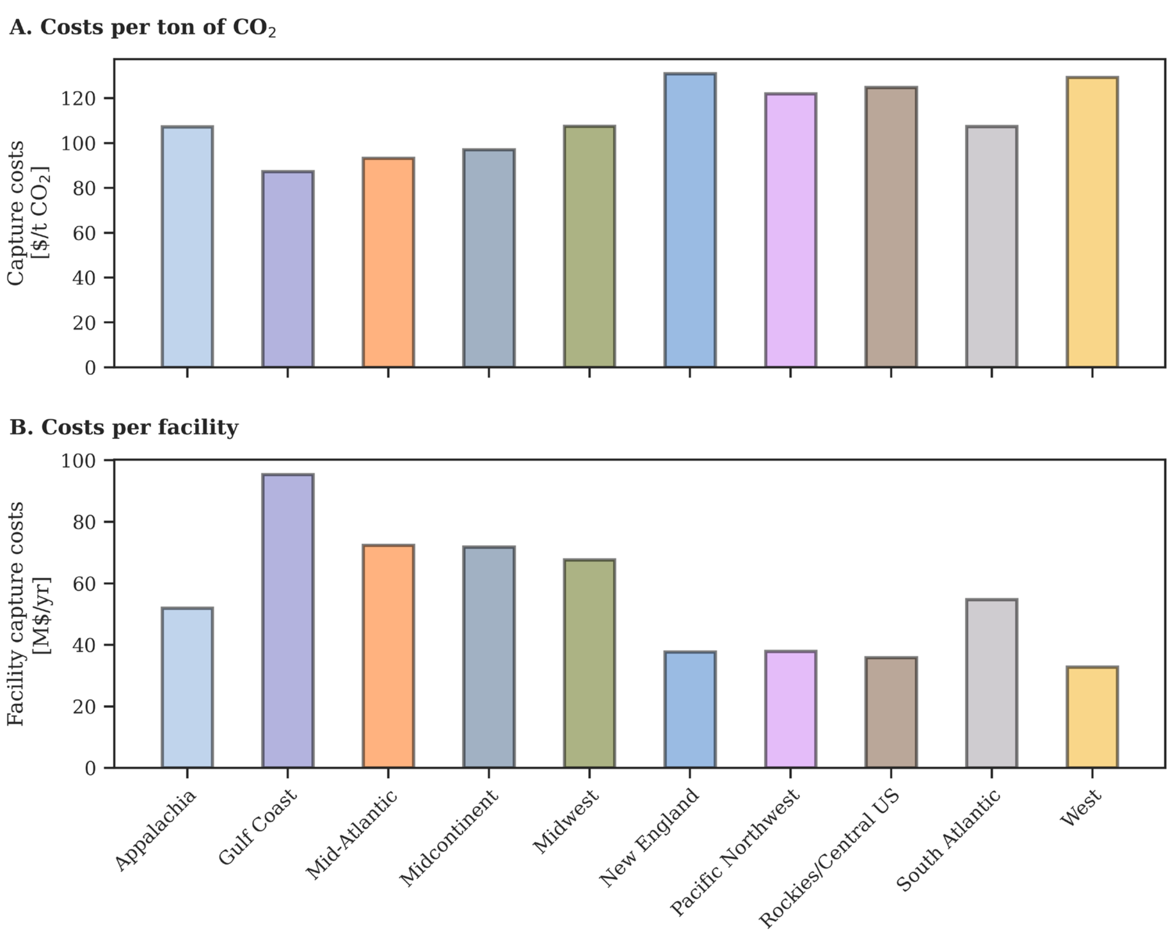
$PM_{2.5}$ emissions: There was little correlation between $PM_{2.5}$ emissions and other co-pollutant emissions. For example, the Mid-Atlantic region was identified as having high CO_2, NO_x, and SO_2 emissions but average $PM_{2.5}$ emissions. Meanwhile, the Rockies/Central US facility had no remarkable CO_2 or NO_x emissions and almost no SO_2 emissions but considerably higher $PM_{2.5}$ emissions. In instances (like the Rockies/Central US facility) where $PM_{2.5}$ had an unexpectedly higher emissions volume, the abatement associated with introducing capture equipment was proportionally higher. The results showed the highest percent reduction in total reported $PM_{2.5}$ emissions in the Rockies/Central US and South Atlantic facilities at 93 percent. The proportional reductions of $PM_{2.5}$ in Appalachia, the Mid-Atlantic, the Midcontinent, the Midwest, New England, and the West were in the 5 to 20 percent range. This is because these regions did not have much condensable PM, which the simulated capture equipment would have captured.

Cement: Capture costs

Figure 15 provides an overview of the cost for capture for the cement facilities studied, both for the average costs per ton of CO_2 as well as the total facility costs (in million dollars per year). The capture costs for all study facilities were between $87 per ton (at the representative Gulf Coast facility) and just over $130 per ton (at the New England and West representative facilities).

Total annual facility capture costs varied slightly across the representative cement facilities,

Figure 15. Capture costs at representative cement facilities by region for capturing CO_2 from all streams, including co-pollutant equipment, as applicable.



ranging from the lowest at $33 million per year in the West to the highest at just under $100 million per year in the Gulf Coast. The total facility costs are largely a function of the size of the facility, with facilities with higher CO_2 emissions typically having the largest total facility costs. The Mid-Atlantic, Midcontinent, and Midwest all saw similar reported capture costs, around $70 million per year, while the South Atlantic and Appalachia were slightly less at ~$52 and ~$55 million per year, respectively. Capture costs were lower in the Rockies/Central US, Pacific Northwest, and New England regions, between $35 and $40 million per year, only slightly higher than the representative facility in the West.

In general, cement facilities evaluated showcased some of the opportunities for economies of scale; facilities with higher overall costs per facility (e.g., the cement facility in the Gulf Coast, in particular, as well as the cement facilities in the Mid-Atlantic and the Midcontinent) also had the lowest average capture costs in dollars per ton of CO_2 captured.

Table 7 provides an overview of the cement facilities chosen as representative facilities, along with the individual stream-level economics and estimated capturable CO_2 volumes.

Cement: Health co-benefits

Finally, the modeling evaluated the impact of capture at each representative cement facility on health in the region through the lens of reductions in asthma exacerbations, mortality reductions, and health benefits (in millions of dollars per year), as shown in figure 16.

Asthma exacerbations: All regions experienced a reduction in asthma exacerbations. The greatest volume of reductions occurred in the Mid-Atlantic (the highest reported reduction at 256 fewer asthma exacerbations), followed by the Gulf Coast and the Midcontinent (141 and 67, respectively).

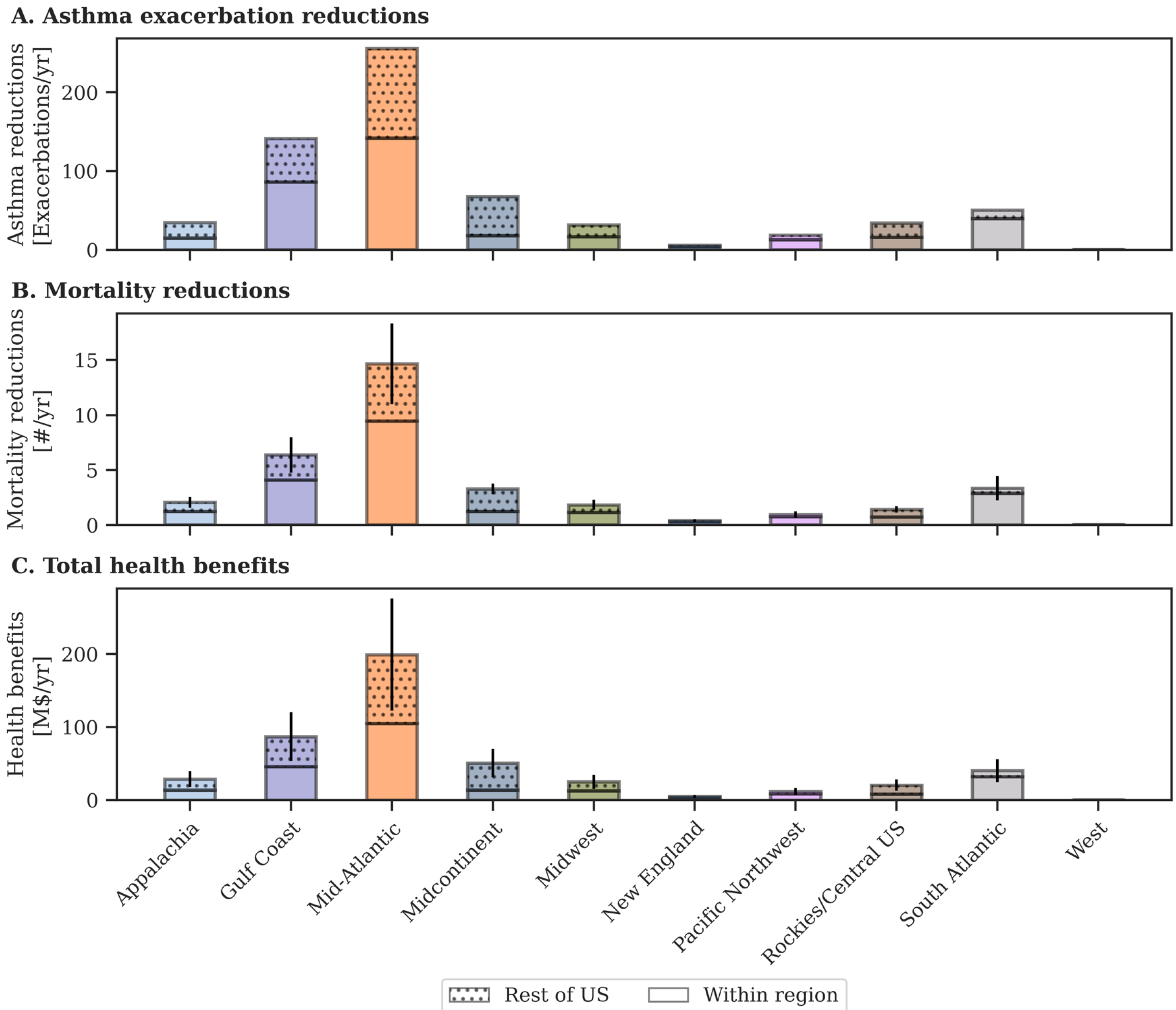
Mortality: All regions also experienced a reduction in mortality per year. The distribution of in-region benefits varied from 40 to 86 percent for all regions. The West was a notable outlier in experiencing a near-zero reduction in mortality.

Dollar-equivalent health benefits: All regions experienced health benefits, measured as million dollars per year equivalent, from installing capture equipment on the representative cement facility. Most of these benefits are due to mortality reductions. The greatest health benefit was found in the Mid-Atlantic region, which experienced significantly higher health benefits than other regions ($199 million per year), though other regions also experienced significant health benefits, chiefly the Gulf Coast ($87 million per year). The West was a notable outlier in experiencing near-zero-dollar savings in health benefits, an intuitive result given the West began with the lowest co-pollutant emissions.

Table 7. Overview of CO_2 capture stream costs at representative cement facilities.

Steam type (-)	Capturable CO_2 (t/yr)		Capture costs ($/t CO_2)		
			Co-pollutant costs	Combined capture costs	
	Minimum	Maximum		Minimum	Maximum
Rotary kiln	253,337	1,092,639	$15.30	$87.32	$131.06
Stationary Combustion	3	243,175	$15.30	$95.73	$95.73
Total facility	254,056	1,092,642	-	$87.32	$130.88

Figure 16. Health co-benefits at representative cement facilities by region.

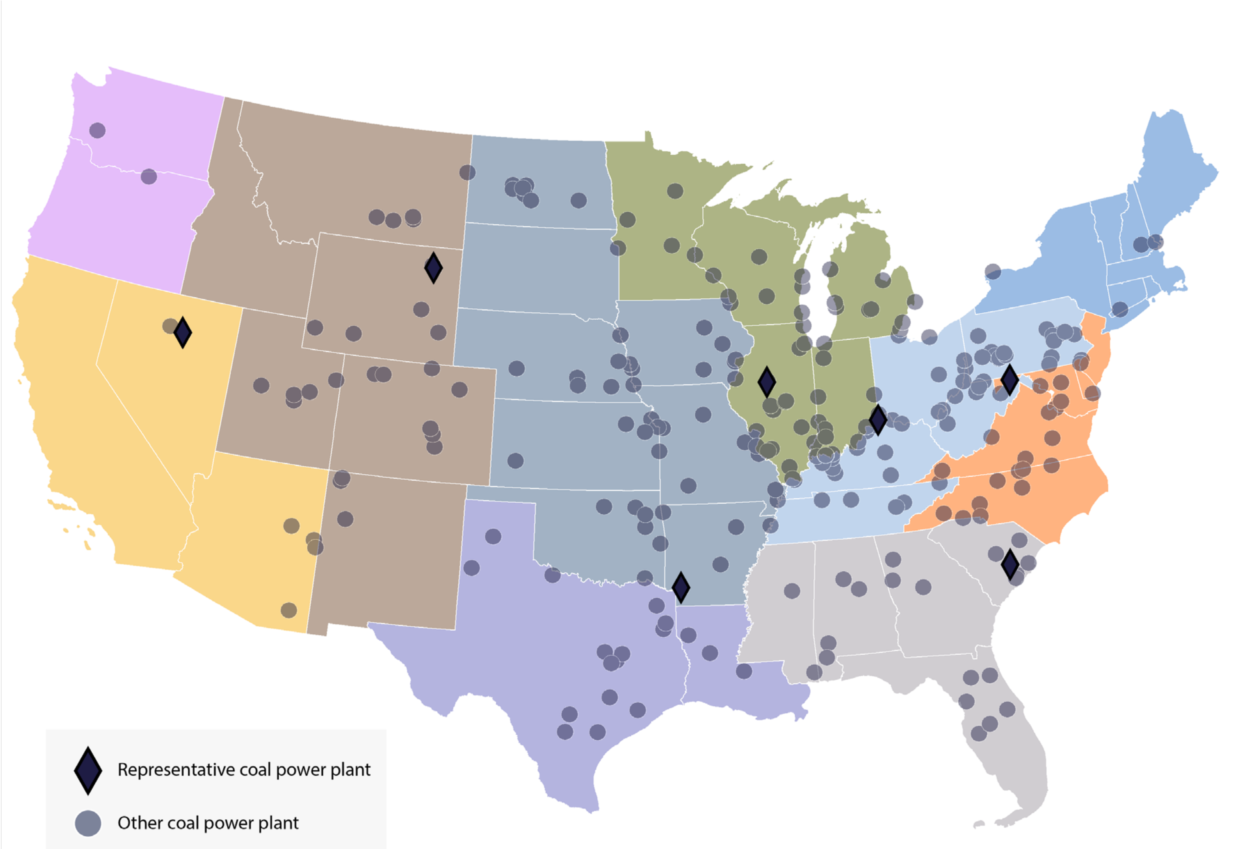


COAL POWER PLANTS

Electricity generation globally is primarily provided by fossil fuel combustion. Among these combustion power plants, coal accounts for the majority of energy produced, as well as the majority of emissions.[81] In 2019, coal-fired power plants produced 36.8 percent of energy globally.[82] Coal-fired power plants accounted for approximately 20 percent of energy-related CO_2 emissions and nearly 60 percent of total CO_2 emissions from electric generation in 2021.[83] Coal-fired power plants use coal to heat water within a boiler, converting the liquid water into high-pressure steam. This steam turns the blades of a turbine, which drives a generator and produces electricity. The chemical composition of coal varies between coal deposits, and rates of pollutant emissions vary similarly. Coal is a major source of atmospheric SO_2 emissions, as well as NO_x, PM, mercury, and other trace metals.[84] Controlling emissions of these pollutants, especially SO_2, is critical for mitigating the environmental and public health impacts of power generation from coal-fired facilities.

Flue gases from coal-fired power plants will generally be dilute. Typical coal-combustion

Figure 17. Coal power plants in the United States.



Note: Representative facilities for each region are diamonds and outlined in black. Facilities that were not selected are circles and outlined in white.

81 IEA. "World Energy Balances."
82 IEA.
83 US Energy Information Administration, "Coal Explained: Coal and the Environment."
84 US Energy Information Administration.

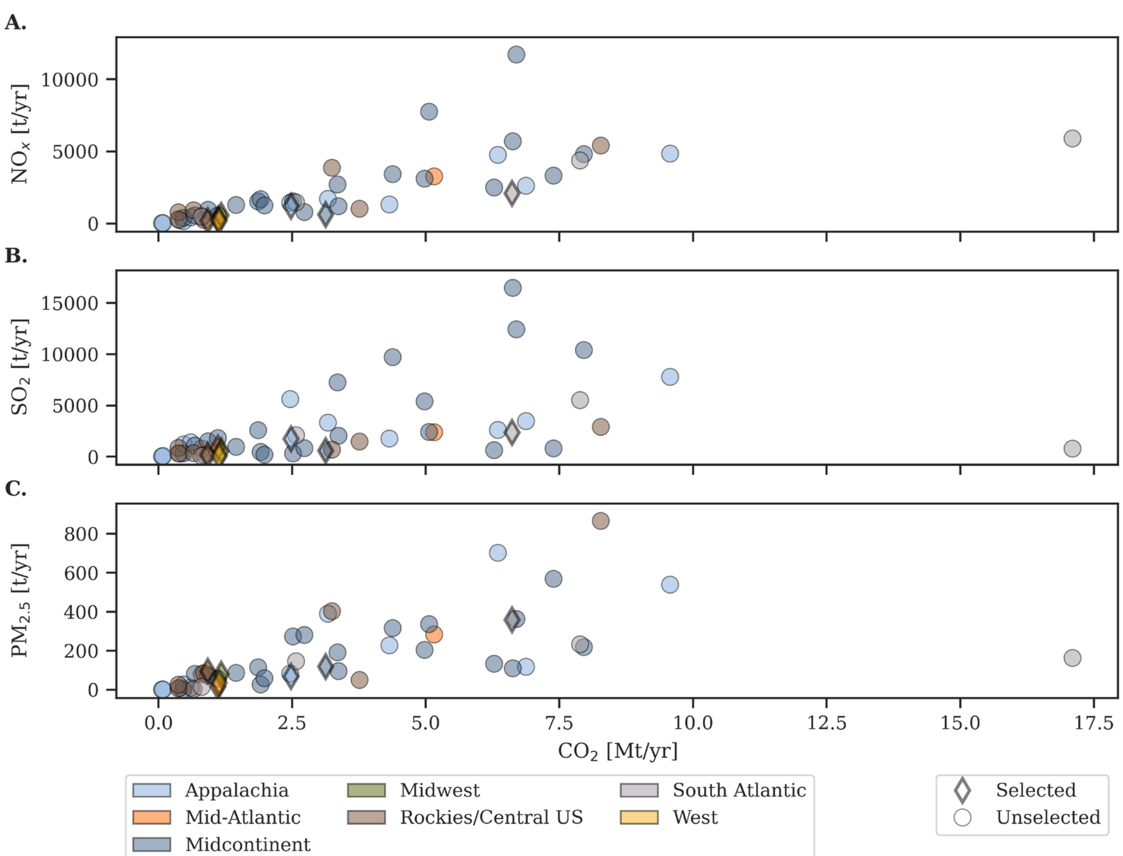
flue gases will be composed of about 3-15 percent CO_2 by volume, with many exemplar plants ranging from 10-14 percent.[85] The remaining gases will be N_2 (60-70 percent), water vapor (20-23 percent), O_2 (4-5 percent), and trace gases, such as SO_2 and NO_x.[86] To evaluate CO_2 capture at these facilities, we modeled a retrofit amine-based capture system equipped with an SCR, FGD, and DCC with scrubber to mitigate pollutants that could negatively impact the capture unit. These treated flue gases would then be routed through an amine-based CO_2 capture train. Recovered CO_2 is compressed and cooled to pipeline standards.

As shown in figure 17, the distribution of coal power plants across the lower 48 is fairly ubiquitous, with the highest concentrations in the Midwest, Midcontinent, Appalachia, and Mid-Atlantic. Many states and utilities have published planned retirement dates for coal-fired power plants, which precluded them from consideration in the analysis.

Coal Power Plants: Facility selection

Figure 18 shows the distribution of reported co-pollutant emissions (NO_x, SO_2, and $PM_{2.5}$) for all coal power plants across the US that met the prerequisite conditions, highlighting (as diamonds with a thick outline) the facilities chosen as the representative facility for each of the regions. There was notable similarity across the three co-pollutants for all coal power plants. Many reported very consistent co-pollutant volumes to one another, as well as across the co-pollutant streams (e.g., similar concentrations of NO_x and SO_2), which was unique to coal power plants.

Figure 18. Coal power plant representative facility selection.



85 Artanto et al., "Performance of MEA and Amine-Blends in the CSIRO PCC Pilot Plant at Loy Yang Power in Australia."
86 Artanto et al.

Coal Power Plants: Emission impacts

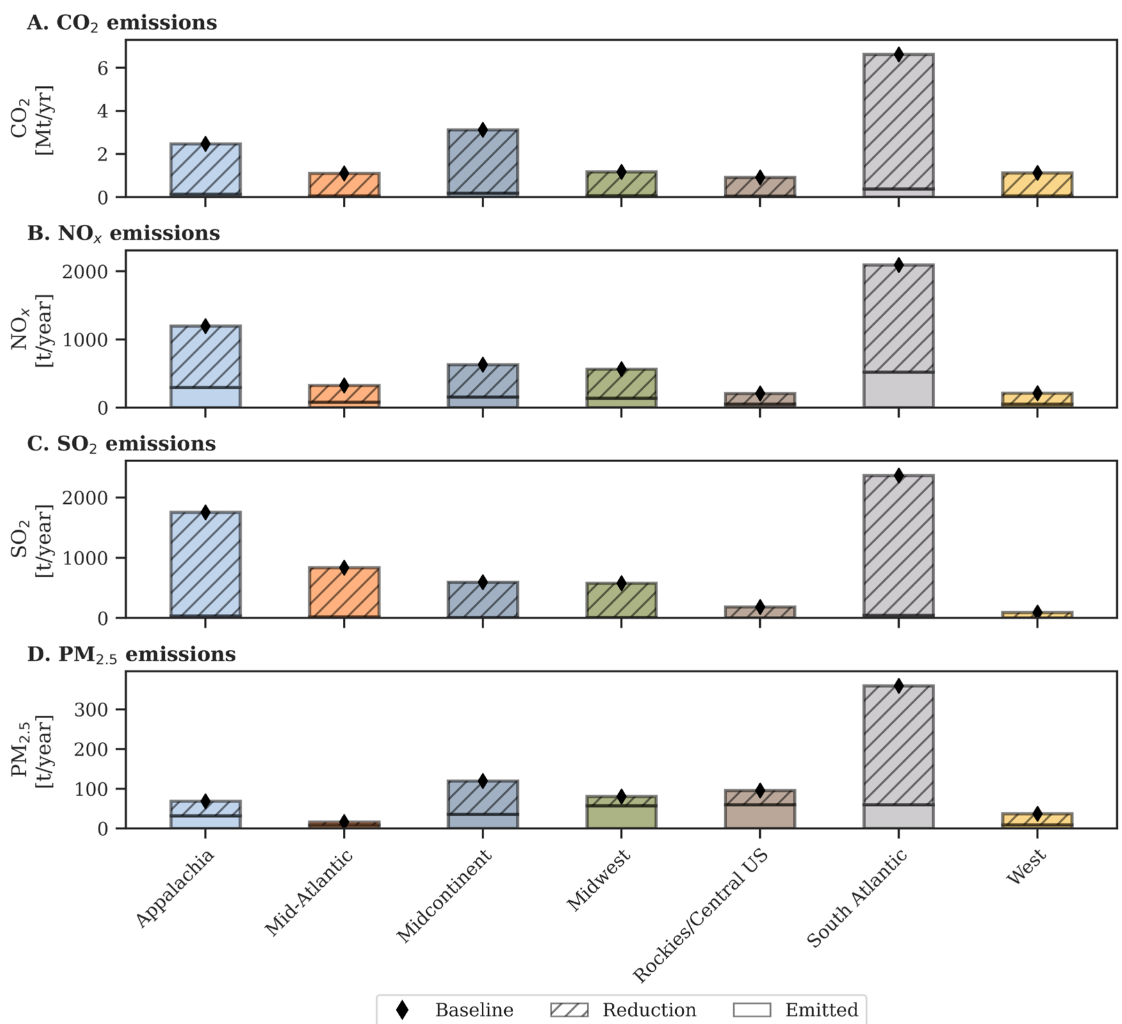
Figure 19 breaks down the impact on emissions for coal power plants when outfitted with capture equipment and pre-treatment. Estimated emissions impacts are broken out by the representative facility within each region, as well as by the reduction (shown as hatched) and the remaining (shown as not hatched) compared to the baseline (the entire extent of the bar, denoted by a black diamond).

CO_2 emissions: Coal power plants showed a large range of total reported CO_2 emissions per year, ranging from just over one million tons to over six million tons of CO_2 per year. All plants were modeled to have 90 percent of CO_2 captured.

NO_x emissions: Consistent with other industries, there was a fairly strong association between high reported CO_2 emissions and an equal proportion of reported NO_x emissions. As with CO_2, facilities with the highest reported total NO_x emissions (both the South Atlantic and Appalachia facilities) had the highest remaining volumes because 75.1 percent of NO_x was assumed captured.

SO_2 emissions: The distribution of SO_2 emissions is also variable across the representative facilities, and the proportion of reported volumes is consistent with other reported co-pollutants across coal power plants—specifically CO_2 and NO_x. In every instance, 98 percent of SO_2 emissions were

Figure 19. Emission impacts at representative coal power plants by region.



simulated to be captured with the co-pollutant equipment, with the South Atlantic facility having the largest removal by volume at 2,300 tons of SO_2 per year.

$PM_{2.5}$ emissions: The reported $PM_{2.5}$ emissions were largely consistent with proportional reported volumes of other co-pollutants across coal power plants, with the exception of the representative facility in Appalachia, which had significantly lower $PM_{2.5}$ emissions than would have been expected based on the relatively higher total volumes of other co-pollutants. $PM_{2.5}$ reductions varied from 31 percent at the Midwest facility to 92 percent at the South Atlantic facility.

Coal Power Plants: Capture costs

Capture costs varied slightly across the representative cement facilities, and the average cost per ton of CO_2 captured as well as the estimated total facility-level costs for capture are shown in figure 20.

The average cost per ton of captured CO_2 varied by facility depending on region. The highest per ton cost occurred at the Midwest facility, at $167 per ton. The lowest cost occurred at the Midcontinent facility, at $74 per ton.

However, when we look at total facility costs, economies of scale become noticeable. The lowest total costs for facility-wide capture occur in the Mid-Atlantic, Rockies/Central US, and West regions, between $91 and $112 million per year. In Appalachia, the Midcontinent, and the Midwest, facilities spent

Figure 20. Capture costs at representative coal power plants by region for capturing CO_2 from all streams with co-pollutant equipment, as applicable.

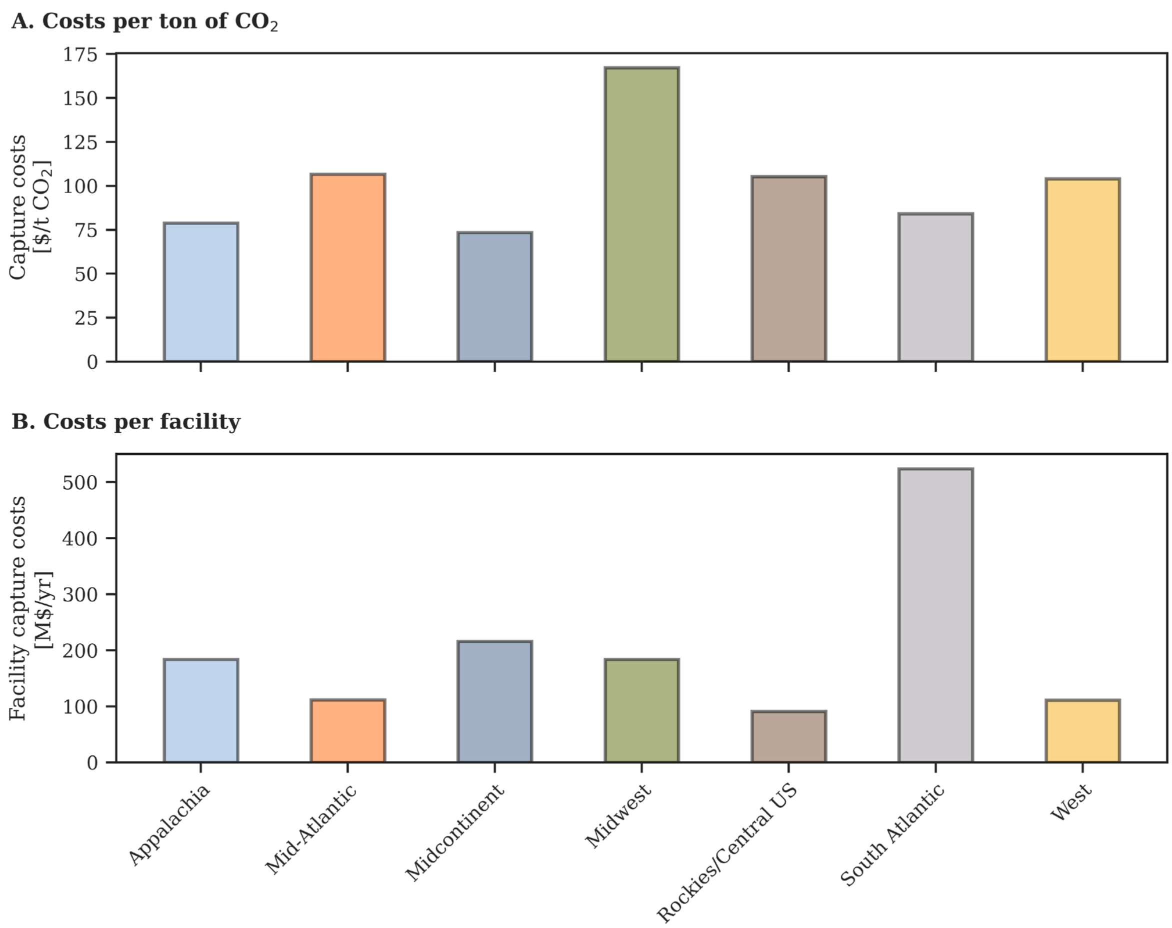


Table 8. Overview of CO_2 capture stream costs at representative coal power plants.

Steam type (-)	Capturable CO_2 (t/yr)		Capture costs ($/t CO_2)		
			Co-pollutant costs	Combined capture costs	
	Minimum	Maximum		Minimum	Maximum
Combustion from a single boiler	158,924	3,181,804	(included)	$73.41	$208.47
Total facility	866,971	6,232,451	-	$73.41	$167.16

between $183 and $217 million for capture. The South Atlantic facility was significantly higher, consistent with total reported volumes of CO_2 and other co-pollutant emissions, at $524 million per year.

Table 8 provides an overview of the coal power plants chosen as representative facilities, along with the individual stream-level economics and estimated capturable CO_2 volumes.

Coal Power Plants: Health co-benefits

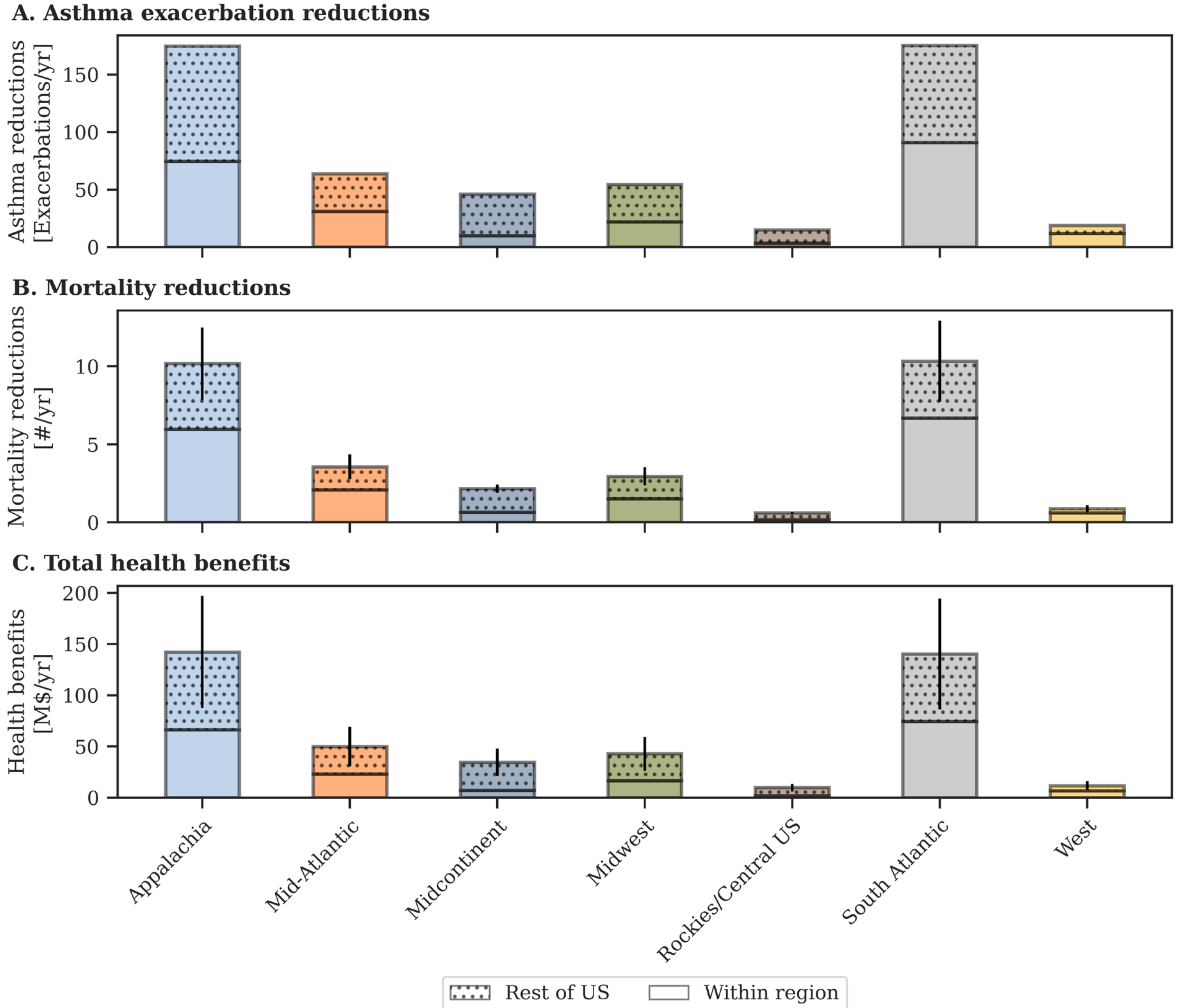
Finally, shown in figure 21, the modeling evaluated the impact of capture at each representative coal power plant on health in the region through the lens of reductions in asthma exacerbations, mortality reductions, and health benefits (in millions of dollars per year).

Asthma exacerbations: Impacts on reductions in asthma exacerbations varied by region, but three trends emerged. Asthma reductions were lowest in the Rockies/Central US and West at between 15 and 19 exacerbations prevented from installing capture equipment. In the Mid-Atlantic, Midcontinent, and Midwest, the reduction in asthma exacerbations was slightly higher, between 46 and 64 exacerbations prevented. Impacts on asthma exacerbations were greatest in Appalachia and the South Atlantic, reaching a reduction of 175 exacerbations per year. When looking at the breakdown of in-region reductions versus reductions outside of the region, the results were consistent across Appalachia, the Mid-Atlantic, the Midwest, the South Atlantic, and the West—where reductions were between 40 and 63 percent in-region. In the remaining regions—the Midcontinent and Rockies/Central US—between 21 and 24 percent of reductions occurred inside the region.

Mortality: Impacts on reductions in mortality, measured as count per year, saw similar proportional impact across the study regions. The greatest reduction in annual mortality counts was in Appalachia and the South Atlantic, both of which saw a reduction of 12 deaths per year. About half of these reductions were projected reductions in the region. The Mid-Atlantic, Midcontinent, and Midwest saw similar estimated reductions, between three and five reductions per year. Both the Rockies/Central US and West saw the lowest reductions in mortality, on the order of one per year.

Dollar-equivalent health benefits: All regions experienced a positive estimated total health benefit from the installation of capture equipment at each of the representative facilities. Consistent with reductions in asthma exacerbations and mortality, the total health benefits were estimated to be highest in Appalachia and the South Atlantic, on the order of $140 million in health benefits per year. Benefits in the Mid-Atlantic, Midcontinent, and Midwest were also high and estimated to be around $35 to $50 million per year. The Rockies/Central US and West also saw health benefits of around $10 million per year.

Figure 21. Health co-benefits at representative coal power plants by region.



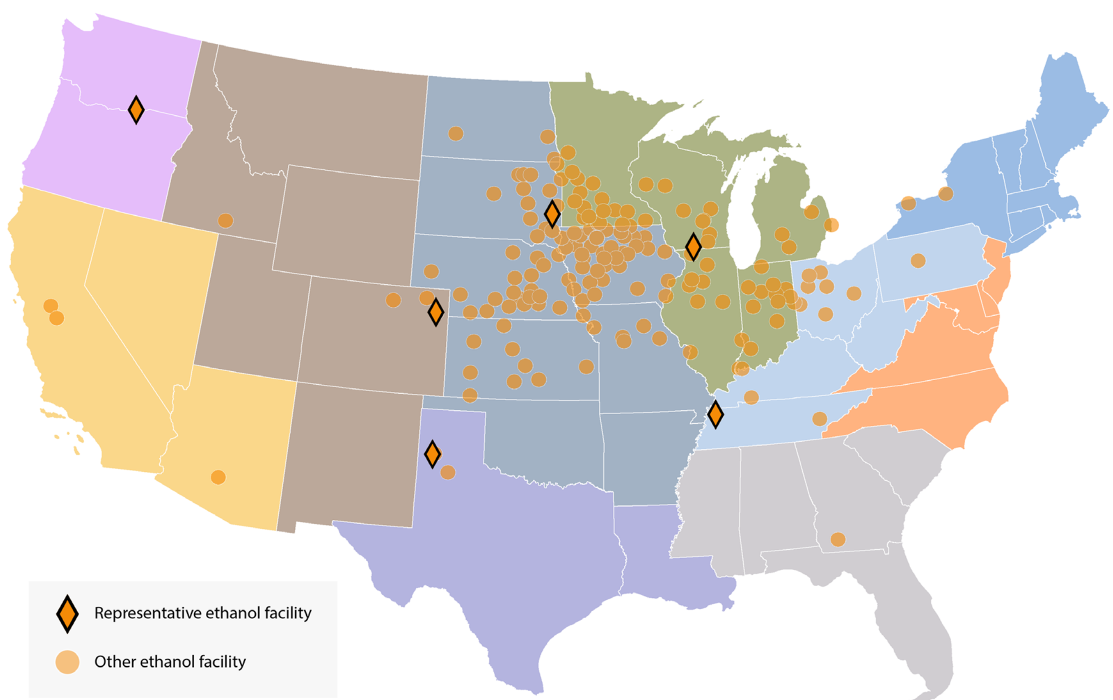
ETHANOL

Ethanol facilities are primarily located in the Midwest, co-located with corn production.[87] Most facilities use first-generation feedstock, such as corn, due to the accessibility of sugars and starches which are fermented into ethanol.[88] Second-generation feedstocks include non-edible plant parts, such as corn husk, cob, and even species of grass. Recovering sugars and starches from second-generation feedstocks is significantly more energy intensive and is thus rarely used.

Regardless of feedstock choice, CO_2 is generated at ethanol facilities when sugars are fermented into alcohol. As a result, ethanol facilities have extremely high-purity CO_2 streams from the fermentation process.[89] Additional streams of CO_2 are generated from process heat production required to run the fermentation process and the electricity required to run the equipment; however, these streams are small in magnitude in comparison to biologically produced CO_2.

Due to the high purity of capturable CO_2, CO_2 capture equipment is not necessary to separate ethanol's CO_2 generated from fermentation, only from the combustion processes. To evaluate CO_2 capture for the process heat production, we modeled a retrofit amine-based capture system equipped with an SCR, FGD, and DCC with scrubber to mitigate pollutants that could negatively impact the capture unit. These treated flue gases would then be routed through an amine-based CO_2 capture train. For the fermentation processes,

Figure 22. Ethanol facilities in the United States.



Note: Representative facilities for each region are diamonds and outlined in black. Facilities that were not selected are circles and outlined in white.

87 US Department of Energy, "Ethanol Fuel Basics."
88 US Energy Information Administration, "Biofuels Explained: Ethanol."
89 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."

only compressors and coolers are required to bring the CO_2 to pipeline-ready conditions.

As shown in figure 22, the distribution of ethanol facilities across the lower 48 is very concentrated in the upper Midwest and Midcontinent, though there are some facilities in other regions. A representative facility was identified for six of the 10 study regions: Appalachia, the Gulf Coast, the Midcontinent, the Midwest, the Pacific Northwest, and the Rockies/Central US.

Ethanol: Facility selection

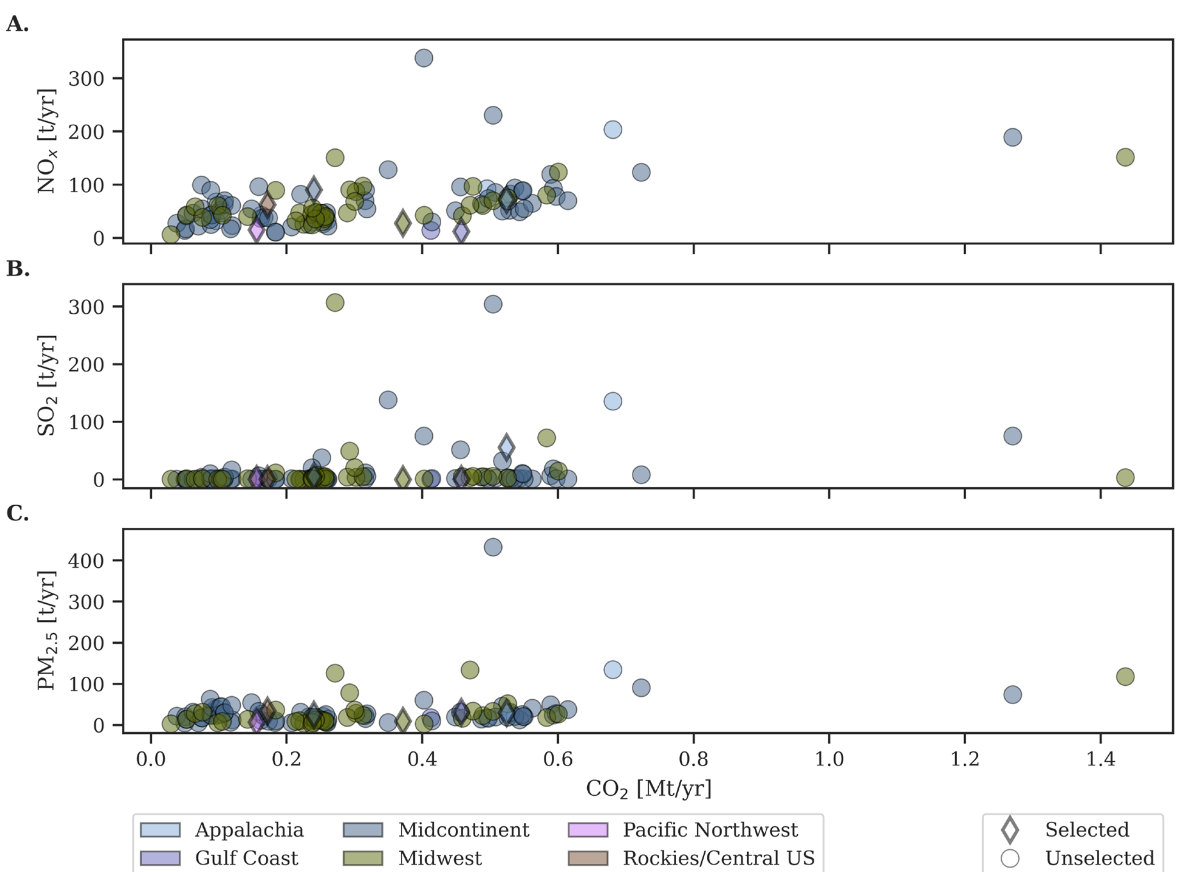
Figure 23 shows the distribution of reported co-pollutant emissions (NO_x, SO_2, and $PM_{2.5}$) for all ethanol facilities that met prerequisite conditions for our analysis, highlighting (as diamonds with a thick outline) the facilities that were chosen as representative for each of the regions.

There was some variation across the three co-pollutants for all ethanol facilities. Instances of ethanol facilities in the same or adjacent regions (geographically) tended to report similar total co-pollutant volumes to one another.

Ethanol: Emission impacts

Figure 24 breaks down the impact on emissions for ethanol facilities when outfitted with CO_2 and co-pollutant capture equipment and pre-treatment. Estimated emission impacts are broken out by the representative facility within each region, as well as by

Figure 23. Ethanol representative facility selection.



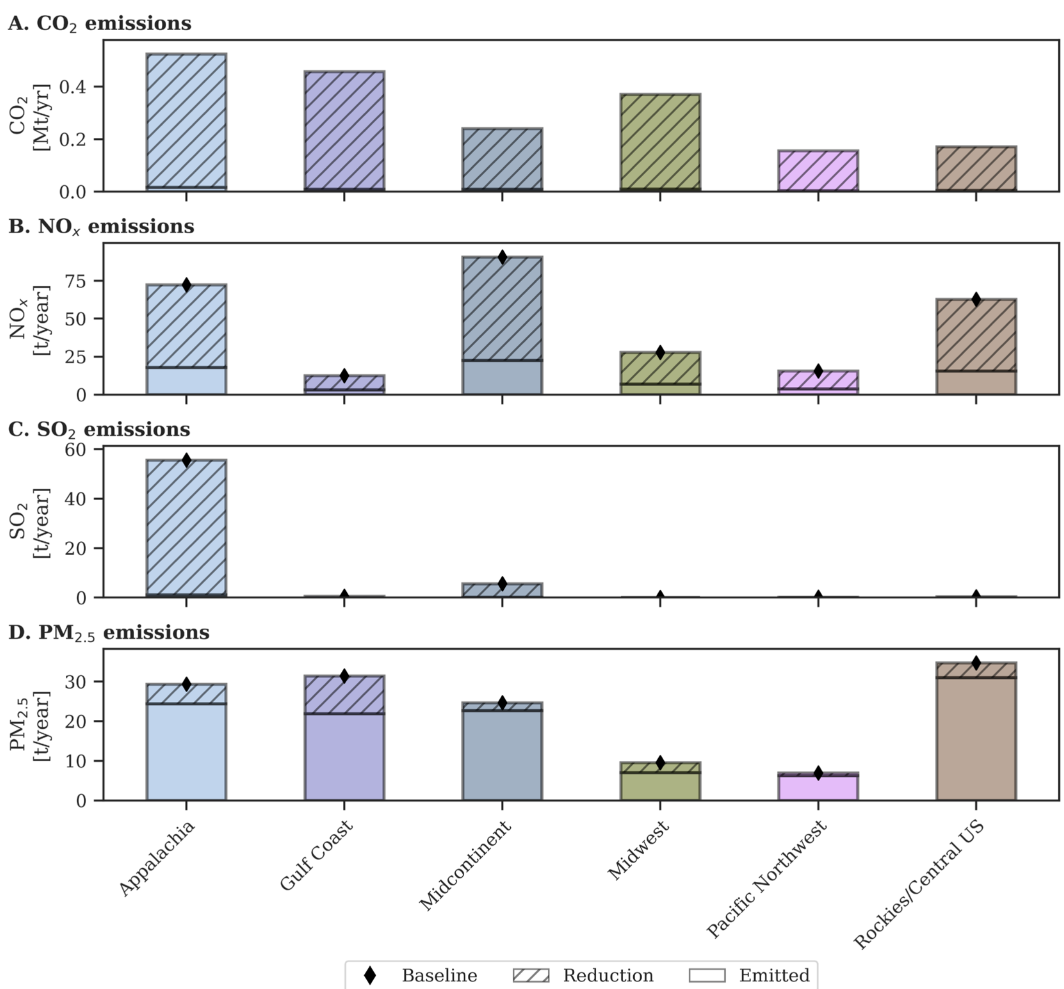
the reduction (shown as hatched) and the remaining (shown as not hatched) compared to the baseline (the entire extent of the bar, denoted by a black diamond).

CO_2 emissions: Compared to some of the other study industries, ethanol facilities have much lower total reported annual CO_2 emissions. The largest representative facility reported just over 500,000 tons per year (in Appalachia). The second largest facilities were in the Gulf Coast (450,000 tons per year) and the Midwest (around 380,000 tons per year). The major CO_2 stream at ethanol plants is pure CO_2, which leads to more than 90 percent of CO_2 being captured.

NO_x emissions: Total reported volumes of annual NO_x emissions varied across the six regions, with two distinct groups emerging. Appalachia, the Midcontinent, and the facility in the Rockies/Central US all reported significantly higher NO_x emissions than the other three ethanol representative facilities. These facilities reported between 60 and 90 tons per year. The other three facilities, in the Gulf Coast, Midwest, and Pacific Northwest, reported between 10 and 30 tons per year. These are already very low total reported NO_x emissions volumes compared to other industries. After installation, all facilities were simulated with a reduction of 75.1 percent of reported NO_x emissions.

SO_2 emissions: SO_2 emissions across four of the six representative facilities were near zero. The Appalachia facility uniquely reported around 55 tons of SO_2 per year, suggesting

Figure 24. Emission impacts at representative ethanol facilities by region.



that coal is used as the fuel for the Appalachia region. Regardless of total reported emissions volumes, installation of capture equipment was able to abate 98 percent of reported SO_2 emissions. As a result, the reduction in SO_2 emissions was greatest in Appalachia.

$PM_{2.5}$ emissions: The representative facilities in Appalachia, the Gulf Coast, Midcontinent, and Rockies/Central US all reported higher and similar total annual $PM_{2.5}$ emissions, ranging from around 25 to 35 tons per year. The two remaining facilities, in the Midwest and Pacific Northwest, reported much lower total $PM_{2.5}$ emissions, between seven and 10 tons per year. There was variable mitigation of $PM_{2.5}$ emissions at each of the representative facilities, varying from 9 to 33 percent. This shows that the majority of $PM_{2.5}$ emissions were from filterable PM, which would not be captured by the system we simulated.

Ethanol: Capture costs

Capture costs were similar across the representative ethanol facilities. The average cost per ton of CO_2 captured, as well as the estimated total facility-level costs for capture, are both shown in figure 25.

The estimated capture cost per ton of CO_2 captured was very similar across all six ethanol facilities. The lowest-cost facility was in the Gulf Coast at $42 per ton, while the most expensive facility on a per ton basis was in the Midcontinent at just under $60 per ton.

For total facility costs of capture, the most expensive facility was in Appalachia at $24

Figure 25. Capture costs at representative ethanol facilities by region for capturing CO_2 from all streams with co-pollutant equipment, as applicable.

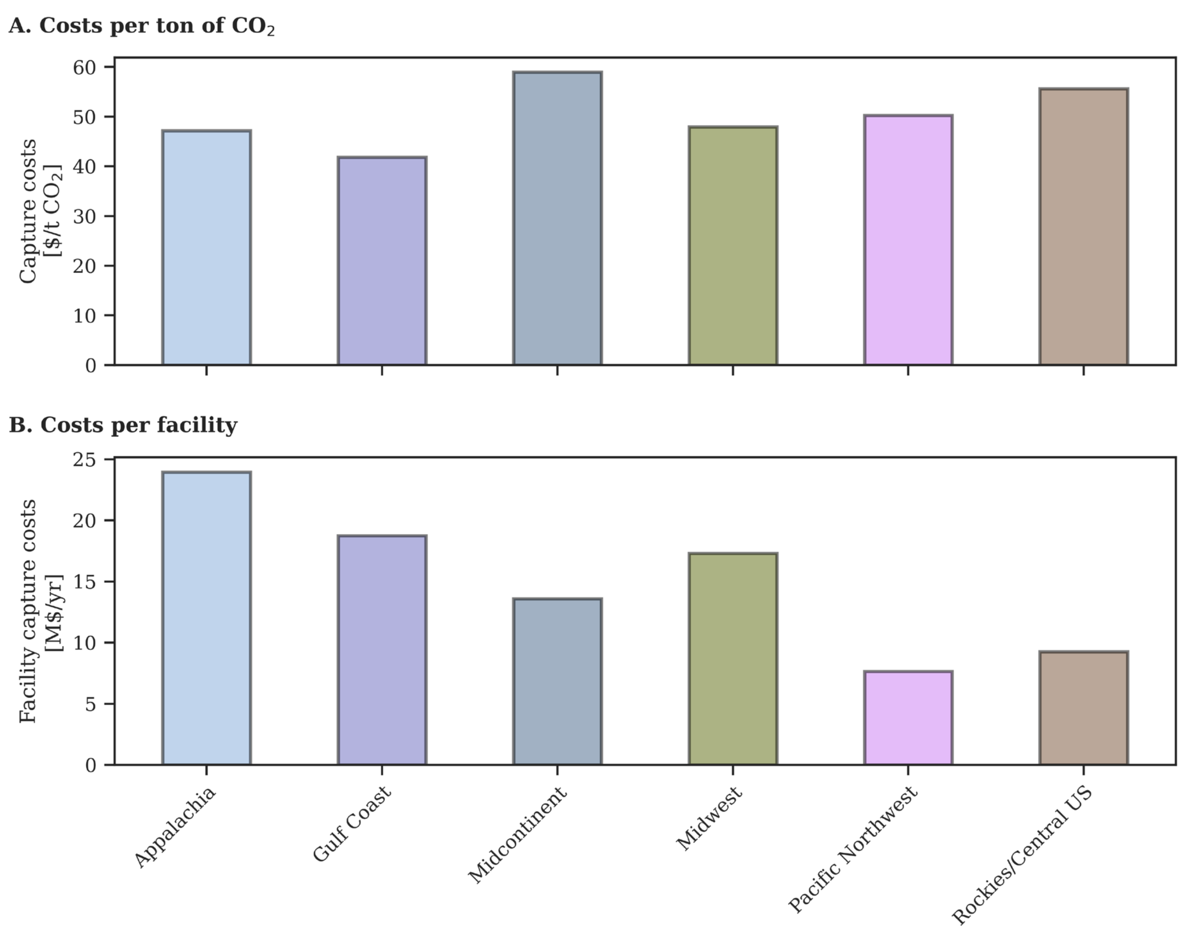


Table 9. Overview of CO_2 capture stream costs at representative ethanol facilities.

Steam type (-)	Capturable CO_2 (t/yr)		Capture costs ($/t CO_2)		
			Co-pollutant costs	Combined capture costs	
	Minimum	Maximum		Minimum	Maximum
Fermentation off-gas	120,163	360,490	N/A	$27.32	$40.15
Stationary combustion	31,969	147,341	$15.30	$95.73	$95.73
Total facility	152,132	507,831	-	$41.86	$58.95

million per year, followed by the facility in the Gulf Coast at $19 million per year (though the Gulf Coast facility had the lowest per ton cost). The representative facility in the Midwest was estimated at $17 million per year, while the two lowest-cost facilities were in the Rockies/Central US region ($9 million per year) and the Pacific Northwest ($8 million per year).

Table 9 provides an overview of the ethanol facilities chosen as representative facilities, along with the individual stream-level economics and estimated capturable CO_2 volumes.

Ethanol: Health co-benefits

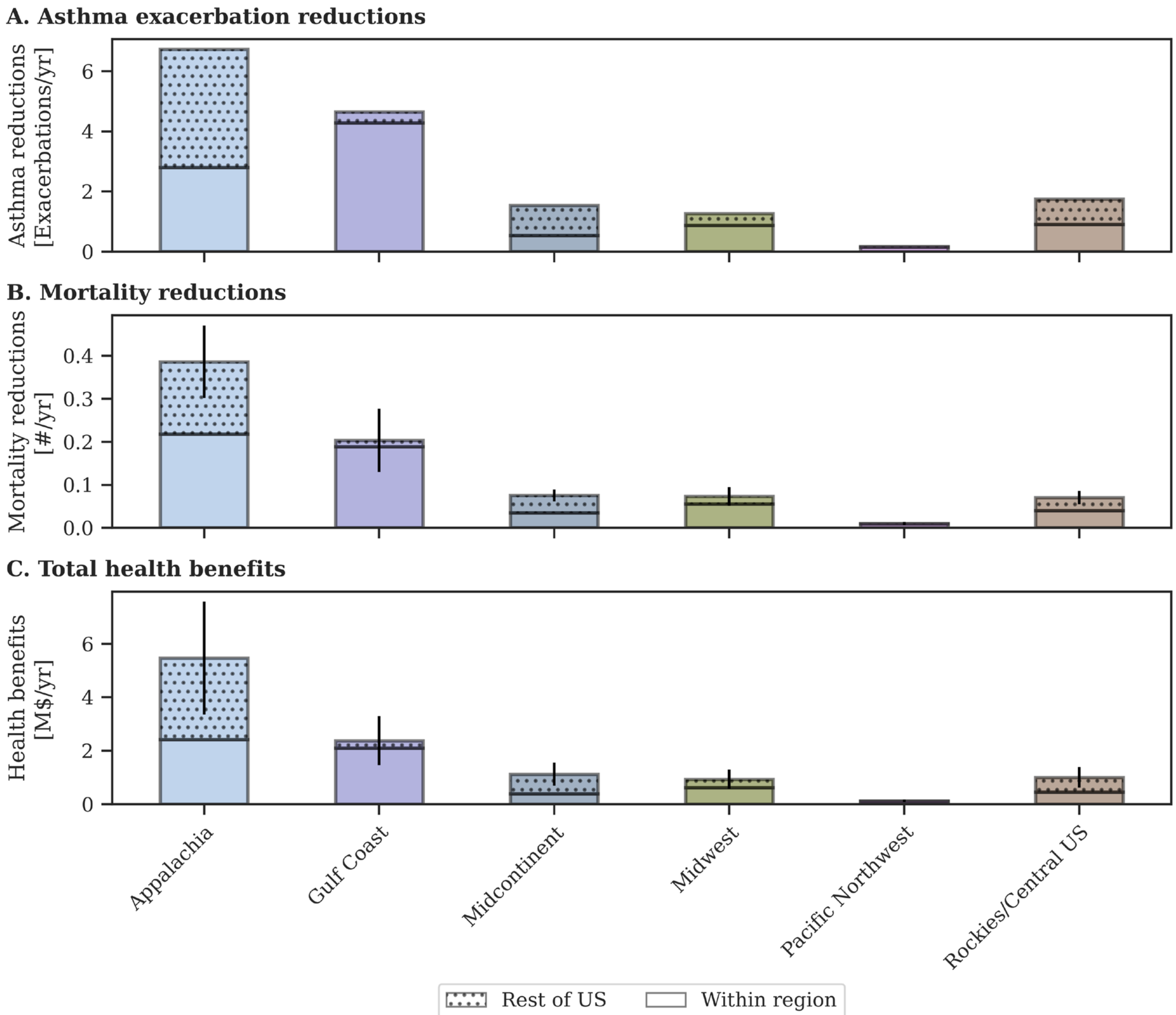
Finally, the modeling evaluated the impact of capture at each representative cement facility on health in the region through the lens of health benefits (in millions of dollars per year), mortality reductions, and reductions in asthma exacerbations. The results are shown in figure 26.

Asthma exacerbations: The first measure of health outcomes is measured as reduction in asthma exacerbations. Overall reductions across all regions with a representative ethanol facility were relatively low. However, the facilities in Appalachia and the Gulf Coast showed the highest estimated reduction in asthma exacerbations, at seven and five reductions, respectively. The remaining regions all saw a reduction in asthma exacerbations, but fewer than two per region. The distribution of impacts within versus outside of the region varied, with 92 percent of benefits occurring in-region for the Gulf Coast and Pacific Northwest regions, while 35 percent in-region for the Midcontinent.

Mortality: The second metric of health outcomes is measured as mortality reductions or count of deaths prevented each year. All representative ethanol facilities saw exceptionally low reductions in mortality. The greatest reduction was estimated for the representative facility in Appalachia (at a reduction in annual mortality count of 0.5). The Appalachia facility did not have the highest NO_x or $PM_{2.5}$ reductions; however, it did have 10 times higher SO_2 emissions than the second-highest facility.

Dollar-equivalent health benefits: These insights allow estimates for the total cumulative health benefits in dollar equivalents across each region from capture equipment installed at the representative facility. The total health benefits are much lower for each region than the health benefits from some of the other study industries, although every region did experience a positive health benefit. The greatest health benefit was in Appalachia, with an average estimated health benefit of $5.5 million per year, with 44 percent of those benefits occurring within the region. The Gulf Coast experienced the second-highest estimated total health benefit at just over $2.4 million per year and 89 percent of this benefit within the region. The remaining regions all experienced $1.1 million per year or less in health benefits.

Figure 26. Health co-benefits at representative ethanol facilities by region.

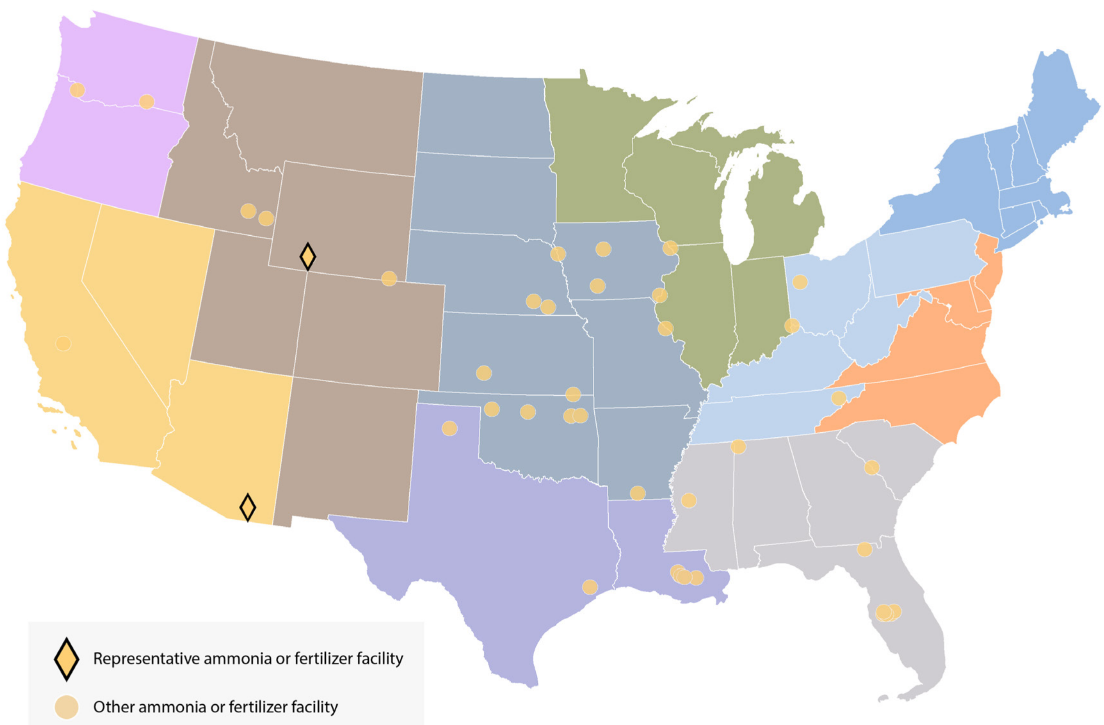


FERTILIZER AND AMMONIA

Around 88 percent of ammonia produced is consumed in the production of mineral fertilizer, which is relied on for 50 percent of the world's crop production.[90] Ammonia production involves isolating hydrogen through a reaction that generates a nearly pure stream of CO_2[91] and accounts for about 66 percent of total ammonia emissions.[92] This CO_2 can be used in conjunction with ammonia to make urea and urea ammonium nitrate, both forms of fertilizer.[93] Additional CO_2 is generated from combustion during the production of hydrogen, which exits at reformer units.[94] This stream is dilute, at 12 to 20 mole percent, and more difficult to capture.[95]

Additional components of fertilizer are potassium and phosphorous, both made from mined ores.[96] Fertilizer production plants may either chemically treat phosphate and potash rock to make these components, or they may receive the components in bulk and granulate them to make them more bioavailable.[97] Ammonia production is the most CO_2-intensive chemical produced, and around 60 percent of consumed fertilizer is nitrogen-

Figure 27. Fertilizer and ammonia facilities in the United States.



Note: Representative facilities for each region are diamonds and outlined in black. Facilities that were not selected are circles and outlined in white.

90 Pattabathula and Richardson, "Introduction to Ammonia Production."
91 Boerner, "Industrial Ammonia Production Emits More CO_2 than Any Other Chemical-Making Reaction. Chemists Want to Change That."
92 Hughes et al., "Industrial CO_2 Capture Retrofit Database (IND CCRD)."
93 Fertilizers Europe, "How Fertilizers Are Made."
94 Hughes and Zoelle, "Cost of Capturing CO_2 from Industrial Sources."
95 Voss, "CO_2 Removal by PSA: An Industrial View on Opportunities and Challenges."
96 Fertilizers Europe, "How Fertilizers Are Made."
97 Romanowski, "Fertilizer."

based, made from ammonia.[98] As ammonia is such an important component of fertilizer, and fertilizer production has no standard plant configurations, we grouped ammonia and fertilizer production together and analyzed them using costs based on ammonia plants.

To capture CO_2 at ammonia facilities, two separate systems must be considered to handle the dilute and non-dilute streams. The dilute stream is handled as a typical combustion stream, with SCR, FGD, DCC with scrubber, and a CO_2 capture unit. In comparison, the pure stream is compressed and cooled to reach CO_2 pipeline standards.

A map of fertilizer and ammonia facilities in the contiguous United States is shown in figure 27.

Fertilizer and ammonia: Facility selection

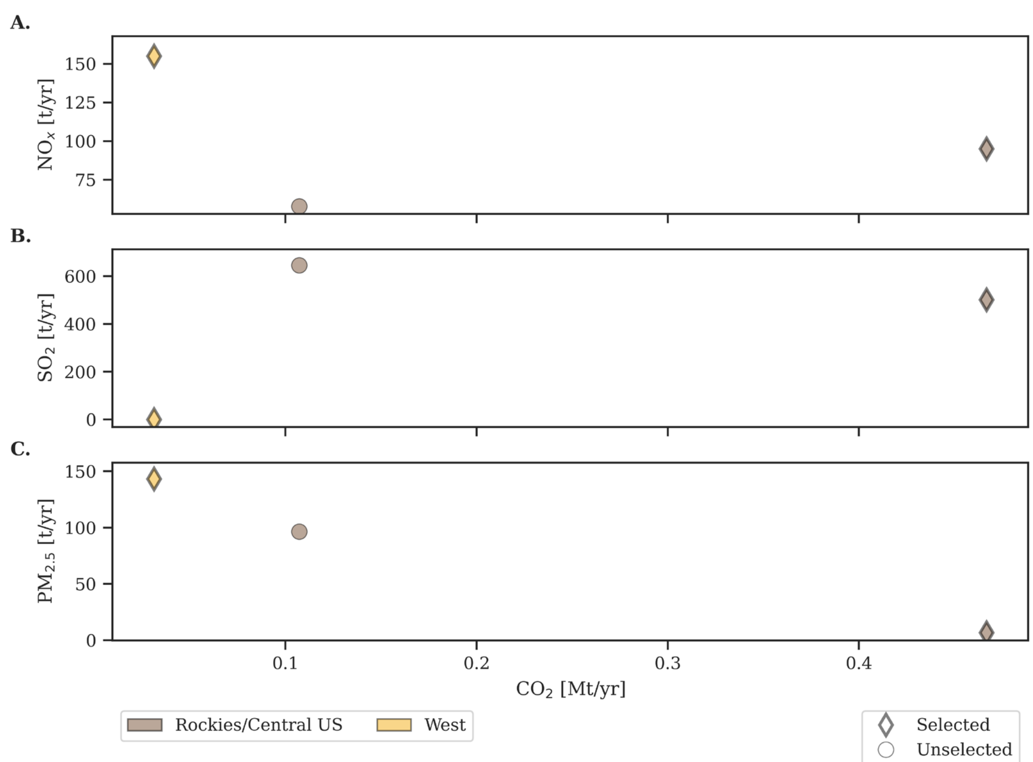
Figure 28 shows the distribution of reported co-pollutant emissions (NO_x, SO_2, and $PM_{2.5}$) for all fertilizer and ammonia facilities that met prerequisite conditions across the contiguous US. It also highlights (as diamonds with a thick outline) the facilities chosen as the representative facility for each of the regions. There were only three qualifying facilities to use as options for a representative facility, distributed across two study regions. The majority of fertilizer and ammonia facilities are using CO_2 on-site, so they were excluded from the analysis. Both of the representative facilities are fertilizer facilities.

In terms of co-pollutants, there was moderate variation across the three co-pollutants for the fertilizer and ammonia facilities. In addition to the variation in total reported volumes of co-pollutants, there was also a variation in the total reported annual CO_2 emissions.

Fertilizer and ammonia: Emission impacts

Figure 29 breaks down the impact on

Figure 28. Fertilizer and ammonia representative facility selection



98 Fertilizers Europe, "Facts & Figures."

emissions for fertilizer and ammonia facilities when outfitted with capture equipment and pre-treatment. Estimated emission impacts are broken out by the representative facility within each region, as well as by the reduction (hatched) and the remaining (not hatched) compared to the baseline (the entire extent of the bar, denoted by a black diamond).

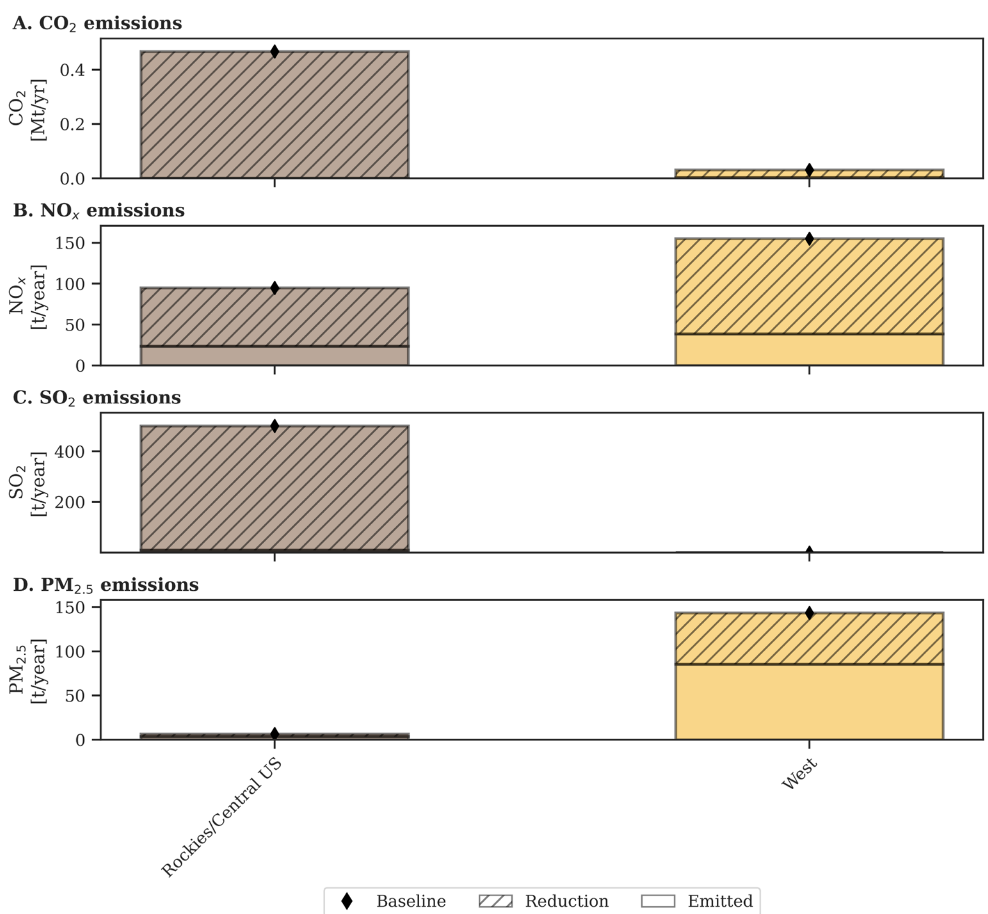
CO_2 emissions: Total reported annual CO_2 emissions from both facilities were relatively low compared to other industries; the facility in the Rockies/Central US had around 450,000 tons per year, and the facility in the West had around 34,000 tons per year. Since a large portion of the CO_2 emissions at a facility are a high-purity CO_2 stream, the CO_2 emissions reduction was greater than 90 percent for both facilities.

NO_x emissions: The facility in the Rockies/Central US region had just under 100 tons per year of NO_x, and the facility in the West had just over 150 tons per year. NO_x was reduced by 75.1 percent at both facilities.

SO_2 emissions: The Rockies/Central US reported significantly higher SO_2 emissions (500 tons per year) than the facility in the West (nearly zero). Installation of capture and abatement equipment reduced reported SO_2 emissions by 98 percent.

$PM_{2.5}$ emissions: $PM_{2.5}$ emissions at the two facilities mirrored trends in NO_x emissions in that the facility in the West reported much higher $PM_{2.5}$ emissions (under 150 tons per year) than the facility in the Rockies/Central US (around 8 tons per year). Installation of abatement equipment was moderately successful, reducing 48 percent of $PM_{2.5}$ emissions at the facility in the Rockies/Central US (bringing the total near zero) and 44 percent of total reported $PM_{2.5}$ emissions at the facility in the West (bringing the remaining total emissions to 85 tons per year).

Figure 29. Emission impacts at representative fertilizer and ammonia facilities by region.



Fertilizer and ammonia: Capture costs

Capture costs varied greatly between the representative fertilizer and ammonia facilities. The average cost per ton of CO_2, as well as the estimated total facility-level costs for capture, are shown in figure 30. The per ton cost of capture at the facility in the Rockies/Central US region was $27 per ton, while the cost per ton at the facility in the West was $96 per ton. Total costs at the facility in the Rockies/Central US, however, were much higher, estimated at $13 million per year, while the total costs for the facility in the West were $3 million per year. The difference can be largely attributed to economies of scale, due to the much higher total CO_2 emissions at the facility in the Rockies/Central US region.

Table 10 provides an overview of the ammonia and fertilizer facilities chosen as representative facilities, along with the individual stream-level economics and estimated capturable CO_2 volumes.

Figure 30. Capture costs at representative fertilizer and ammonia facilities by region for capturing CO_2 from all streams and with co-pollutant equipment, as applicable.

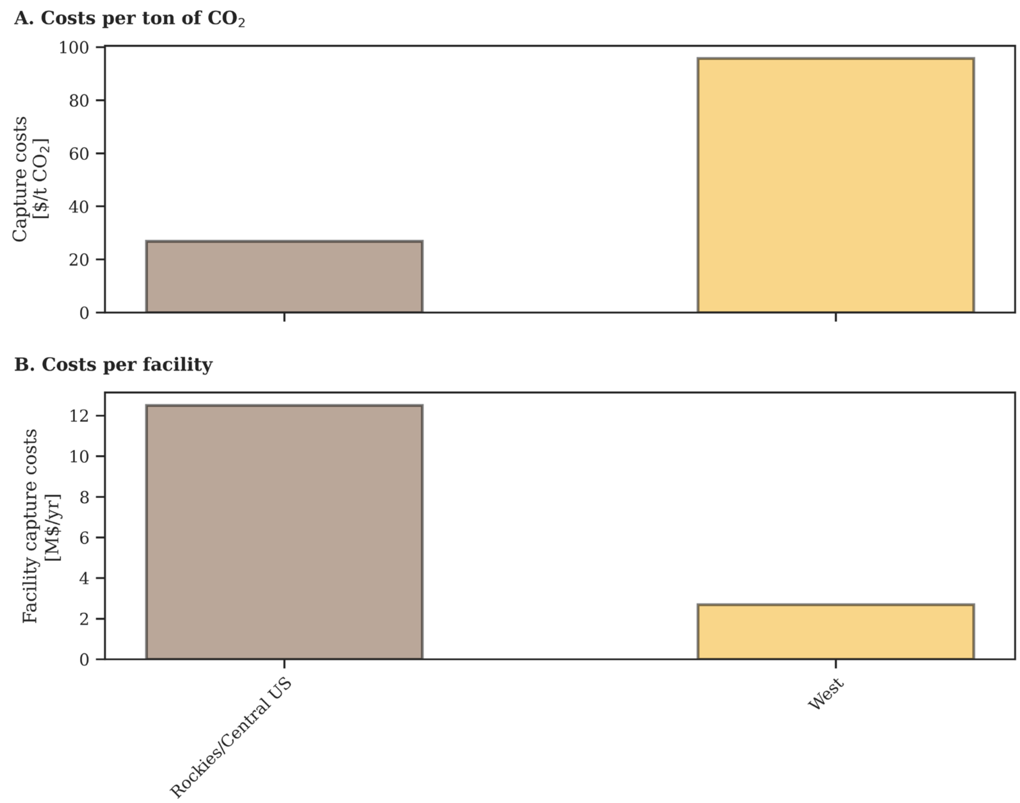


Table 10. Overview of CO_2 capture stream costs at representative fertilizer and ammonia facilities.

Steam type (-)	Capturable CO_2 (t/yr)		Capture costs ($/t CO_2)		
			Co-pollutant costs	Combined capture costs	
	Minimum	Maximum		Minimum	Maximum
Urea surplus gas	455,178	455,178	N/A	$25.29	$25.29
Stationary combustion	10,430	28,132	$15.30	$95.73	$95.73
Total facility	28,132	465,608	-	$26.87	$95.73

Note: The urea surplus gas stream was only present at one of the facilities.

Fertilizer and ammonia: Health co-benefits

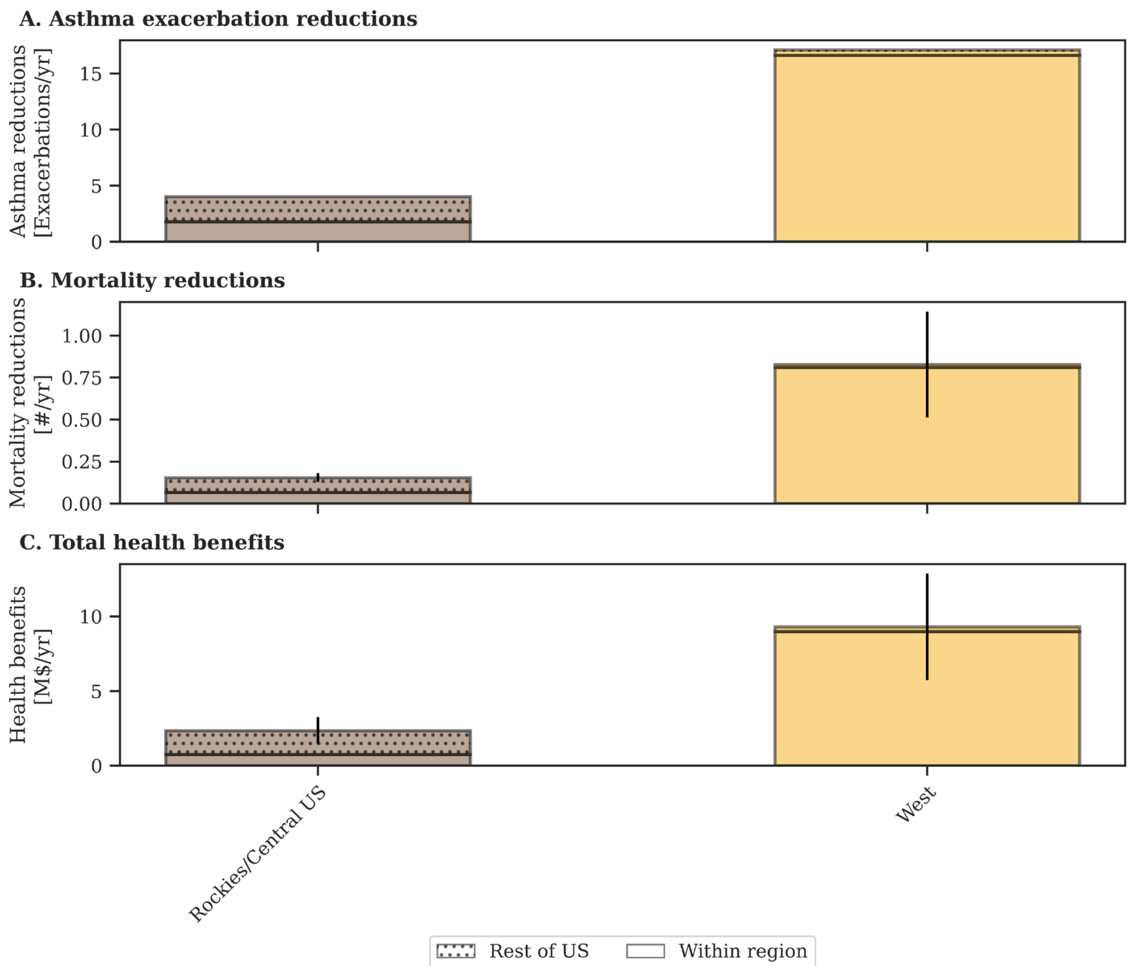
Finally, the modeling evaluated the impact of capture at each representative cement facility on health in the region through the lens of total health benefits (in millions of dollars per year), mortality reductions, and reductions in asthma exacerbations, shown in figure 31.

Asthma exacerbations: There were four asthma exacerbations reduced in the Rockies/Central US region, and 17 exacerbations prevented in the West. In the Rockies/Central US, about half of the exacerbation reductions were within region, while in the West, the reductions were almost entirely estimated to be within region.

Mortality: Estimates for a reduction in mortality (in count of deaths prevented) were below one for each region, estimated at 0.2 for the Rockies/Central US and 0.8 for the West. As with asthma exacerbations, the mortality reductions in the Rockies/Central US were split within the region and outside, while in the West, the reductions stayed almost entirely within the region.

Dollar-equivalent health benefits: The cumulative impact of total health benefits associated with capture equipment at the facilities was positive in both regions, around $2.3 million per year in the Rockies/Central US, though most of those benefits were estimated for outside of the region, while just under $9.3 million in health benefits was estimated for the West, almost the entirety of which occurred within the region.

Figure 31. Health co-benefits at representative fertilizer and ammonia facilities by region.

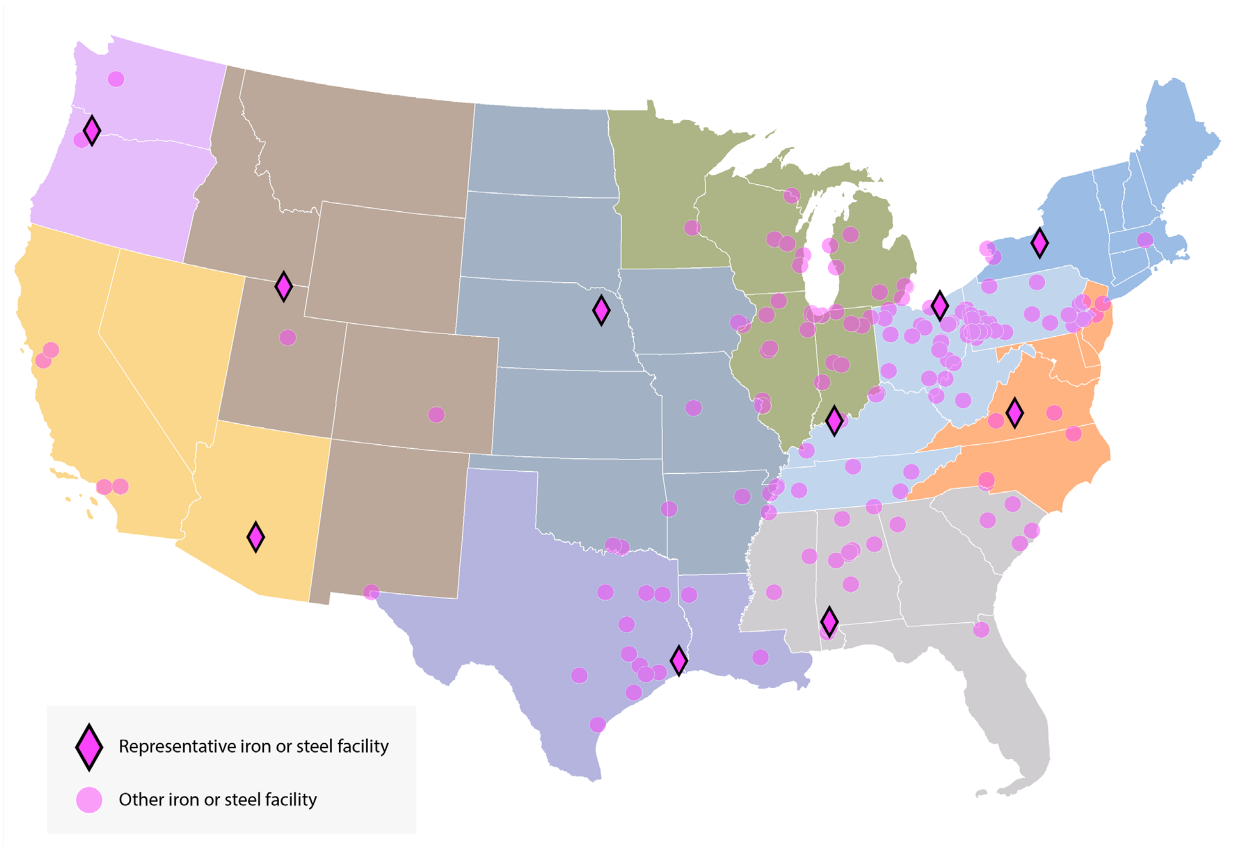


IRON AND STEEL

The iron and steel industry produces 7 percent of energy sector CO_2 emissions and consume 8 percent of global energy.[99] Iron and steel facilities are considered a hard-to-abate industry because the process emissions require sustained, high-temperature heat.[100] There are three main ways to produce iron: blast furnace, direct reduction, and smelting reduction.[101] Iron can then be processed to produce steel via a basic oxygen furnace or electric arc furnace.[102] In 2019, 70 percent of steel was produced via a combination of using a blast furnace and basic oxygen furnace, 7 percent with a combination of direct reduction and electric arc furnace, and 22 percent via recycling scrap.[103]

To evaluate CO_2 capture at these facilities, we modeled a retrofit amine-based capture system equipped with an SCR, FGD, and DCC with scrubber to mitigate pollutants that could negatively impact the capture unit. These treated flue gases would then be routed through an amine-based CO_2 capture train. Recovered CO_2 is compressed and cooled to pipeline standards.

Figure 32. Iron and steel facilities in the United States.



Note: Representative facilities for each region are diamonds and outlined in black. Facilities that were not selected are circles and outlined in white.

99 IEA, "Iron and Steel Technology Roadmap."
100 Kim et al., "Decarbonizing the Iron and Steel Industry: A Systematic Review of Sociotechnical Systems, Technological Innovations, and Policy Options."
101 Kim et al.
102 Kim et al.
103 IEA, "Iron and Steel Technology Roadmap."

An overview of iron and steel facilities is shown in figure 32. Iron and steel facilities are concentrated in the Midwest and Appalachia, though present in all regions. A representative facility was found for all study regions.

Iron and steel: Facility selection

Figure 33 shows the distribution of reported co-pollutant emissions (NO_x, SO_2, and $PM_{2.5}$) for all iron and steel facilities across the US, highlighting (as diamonds with a thick outline) the facilities chosen as a representative facility for each of the regions. There was moderate variation across the three co-pollutants for all iron and steel facilities, as well as in the total reported annual CO_2 emissions.

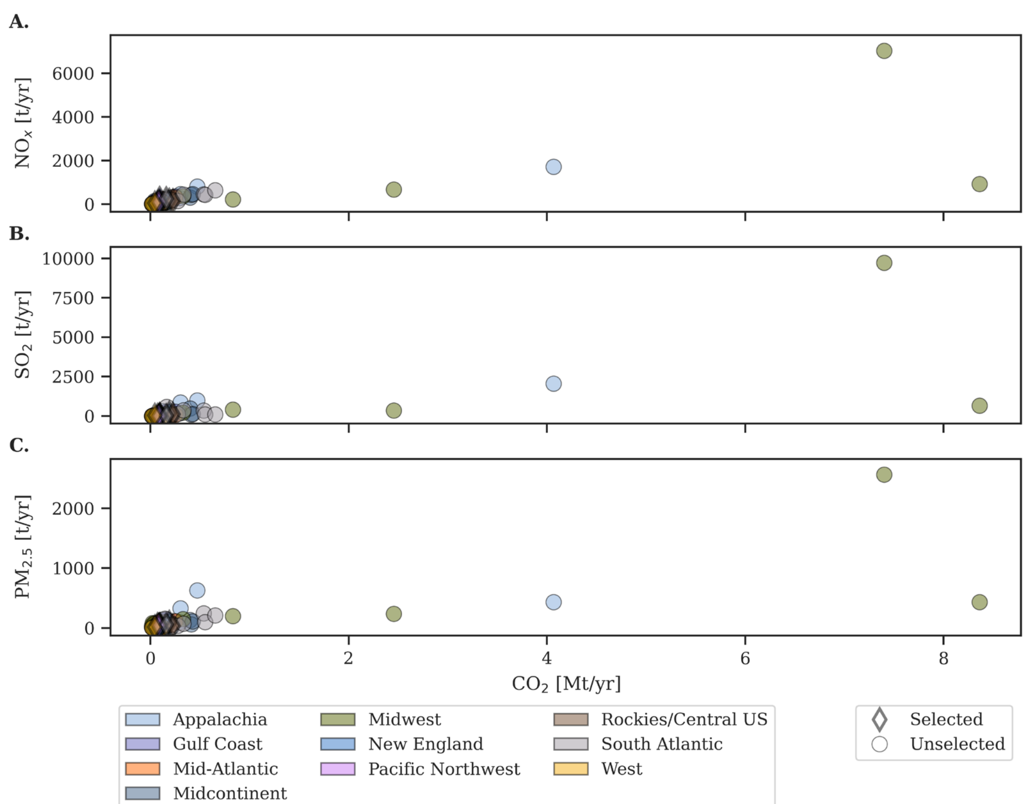
When considering reported co-pollutant emissions, iron and steel facilities have very similar total volumes reported for each co-pollutant, regardless of region. The instances of notable variation occur at a few facilities, primarily located in the Midwest, which also stand out for significantly higher total annual CO_2 emissions than other iron and steel facilities.

Iron and steel: Emission impacts

Figure 34 breaks down the impact on emissions for iron and steel facilities when outfitted with capture equipment and pre-treatment. Estimated emissions impacts are broken out by the representative facility within each region, as well as by the reduction (shown as hatched) and the remaining (shown as not hatched) compared to the baseline (the entire extent of the bar, denoted by a black diamond).

CO_2 emissions: CO_2 emissions were low for all representative facilities compared to other study industries but still varied across each of the 10 regions. The total reported CO_2 emissions were highest at the facilities in the Midcontinent, Rockies/Central US, and South Atlantic, between 150,000 and 220,000 tons

Figure 33. Iron and steel facility selection.

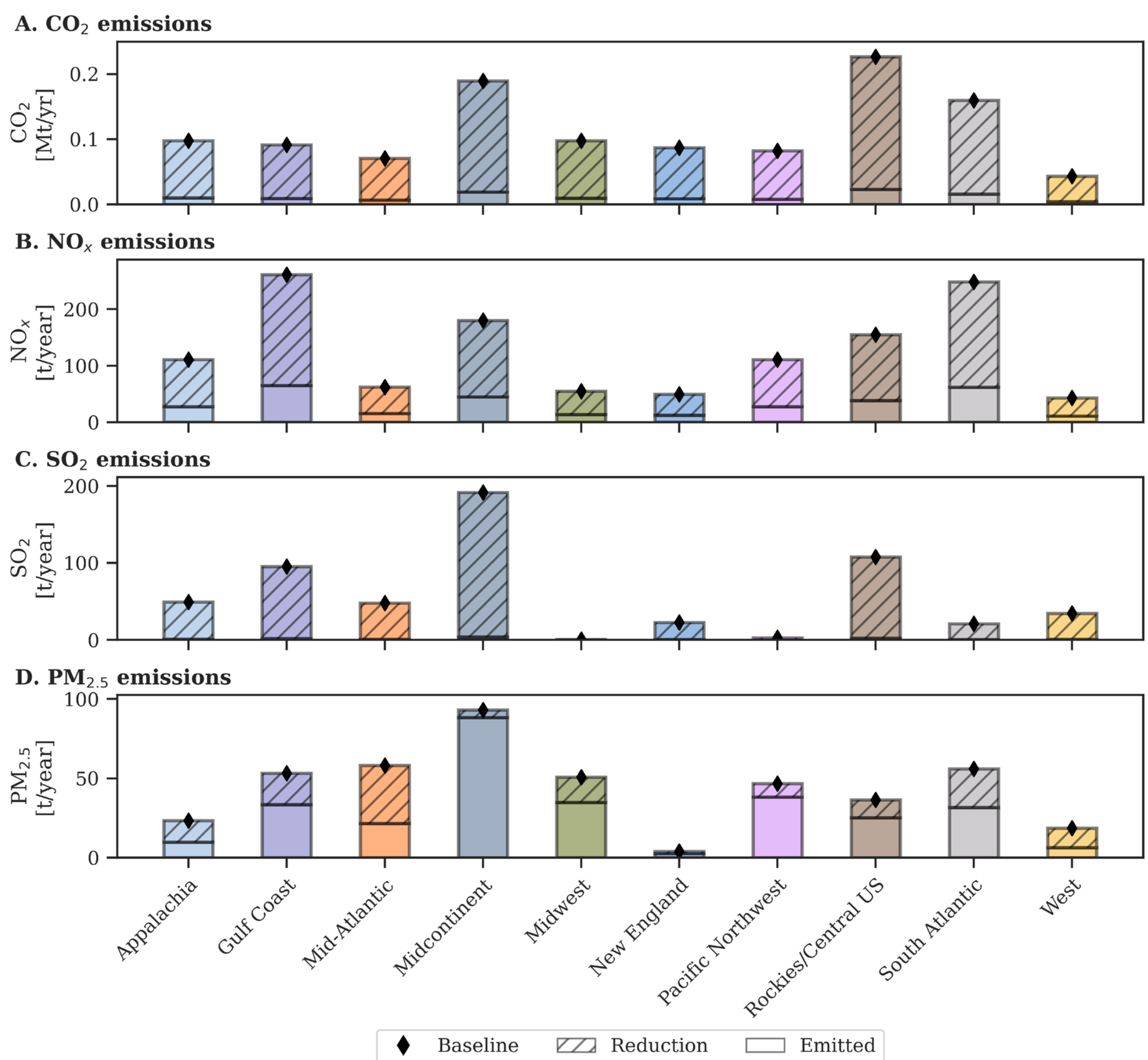


per year. The remaining facilities all reported total annual CO_2 emissions below 100,000 tons per year.

NO_x emissions: Total reported NO_x emissions were slightly more varied. The representative facility in the Gulf Coast had the highest reported NO_x emissions, followed by the facility in the South Atlantic, both around 250 tons per year. The facilities in the Midcontinent and Rockies/Central US regions reported between 150 and 180 tons per year, while the facilities in Appalachia and the Pacific Northwest both reported around 110 tons per year. The remaining facilities in the Mid-Atlantic, Midwest, New England, and West all reported around 50 tons per year. NO_x emissions were simulated to be reduced by 75.1 percent by the installation of SCR equipment.

SO_2 emissions: SO_2 emissions varied greatly across the 10 iron and steel facilities. The facility in the Midcontinent had the highest total reported SO_2 emissions at nearly 200 tons per year, almost double the reported SO_2 emissions from the next highest facility. The iron and steel facility in the Rockies/Central US had just over 100 tons per year, and the facility in the Gulf Coast reported just under 100 tons per year total. The facilities in Appalachia and the Mid-Atlantic both reported 50 tons per year, while the facilities in New England,

Figure 34. Emission impacts at representative iron and steel facilities by region.



the South Atlantic, and the West all reported between 25 and 35 tons per year. The two remaining representative facilities, in the Midwest and Pacific Northwest, both reported near-zero SO_2 emissions. SO_2 emissions were simulated to be reduced by 98 percent by the installation of FGD equipment.

$PM_{2.5}$ emissions: Total reported baseline volumes of $PM_{2.5}$ varied across the facilities. They were highest at the facility in the Midcontinent (around 90 tons per year), consistent at the facilities in the Gulf Coast, Mid-Atlantic, Midwest, Pacific Northwest, Rockies/Central US, and South Atlantic, between 35 and 60 tons per year, around 20 tons per year at the facility in Appalachia and the West, and roughly 5 tons at the facility in New England. $PM_{2.5}$ reductions varied from a 6 percent reduction for the Midcontinent facility to 69 percent at the Mid-Atlantic facility.

Iron and steel: Capture costs

The cost of capture, detailed in figure 35, was similar on a per ton basis across all 10 regions. The cost was estimated to be lowest at the facility in the West, at $54 per ton of CO_2 captured, and highest at the facilities in the Mid-Atlantic, Midwest, and Pacific Northwest, at $69 per ton captured.

Regarding total facility costs, the iron and steel facility in the Rockies/Central US was the most expensive, estimated at $12 million per year to capture, followed by the facility in the Midcontinent ($10 million per year) and the facility in the South Atlantic ($9 million per year). The facility in the West was the least expensive, at $2 million per year, and the remaining facilities were estimated to cost between $4 and $6 million per year for capture.

Figure 35. Capture costs at representative iron and steel facilities by region for capturing CO_2 from all streams with co-pollutant equipment, as applicable.

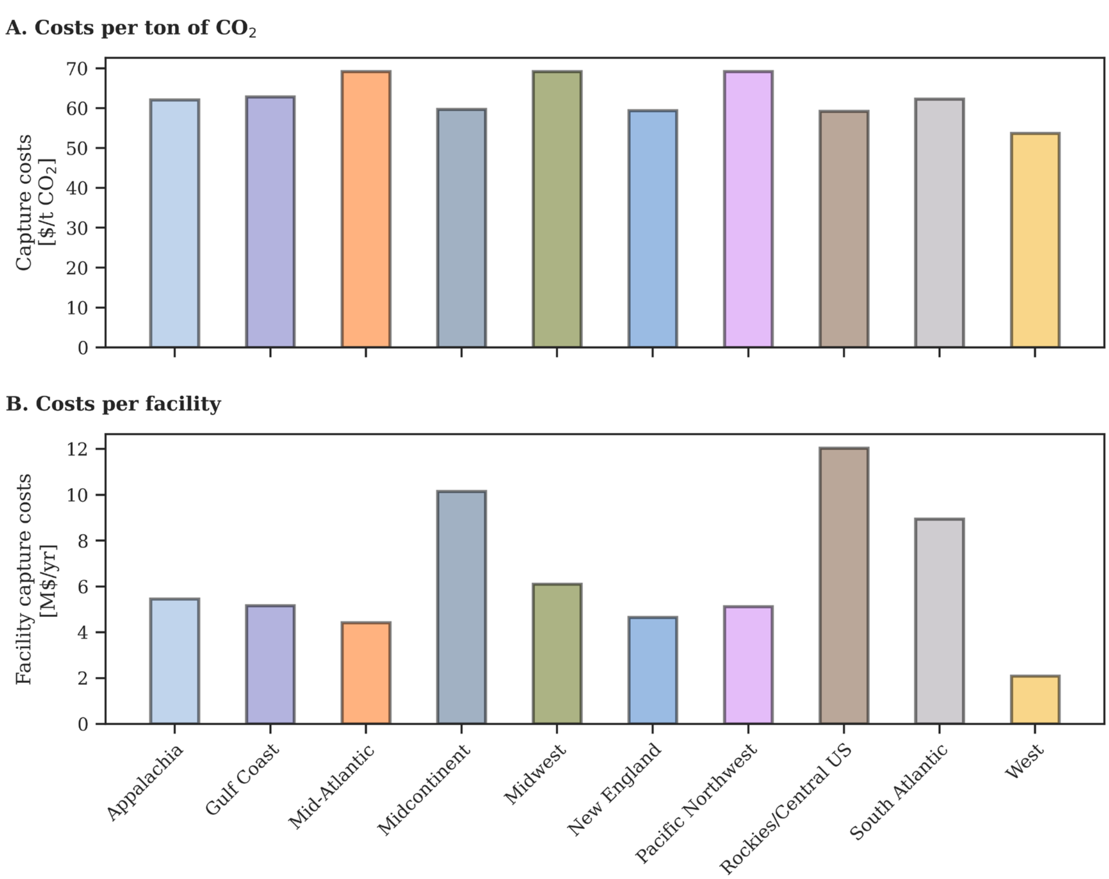


Table 11. Overview of CO_2 capture stream costs at representative iron and steel facilities.

Steam type (-)	Capturable CO_2 (t/yr)		Capture costs ($/t CO_2)		
			Co-pollutant costs	Combined capture costs	
	Minimum	Maximum		Minimum	Maximum
Stationary combustion	1,586	88,260	$15.30	$69.15	$69.15
Blast furnace gas (BFG)	21,658	84,039	$15.30	$63.34	$63.34
Blast oven furnace (BOF)	10,578	41,046	$15.30	$31.83	$31.83
Total facility	38,972	203,288	-	$53.66	$69.15

Table 11 provides an overview of the estimated capturable CO_2 emissions by stream type, as well as the estimated cost to capture associated with each stream, for the representative iron and steel facilities.

Iron and steel: Health co-benefits

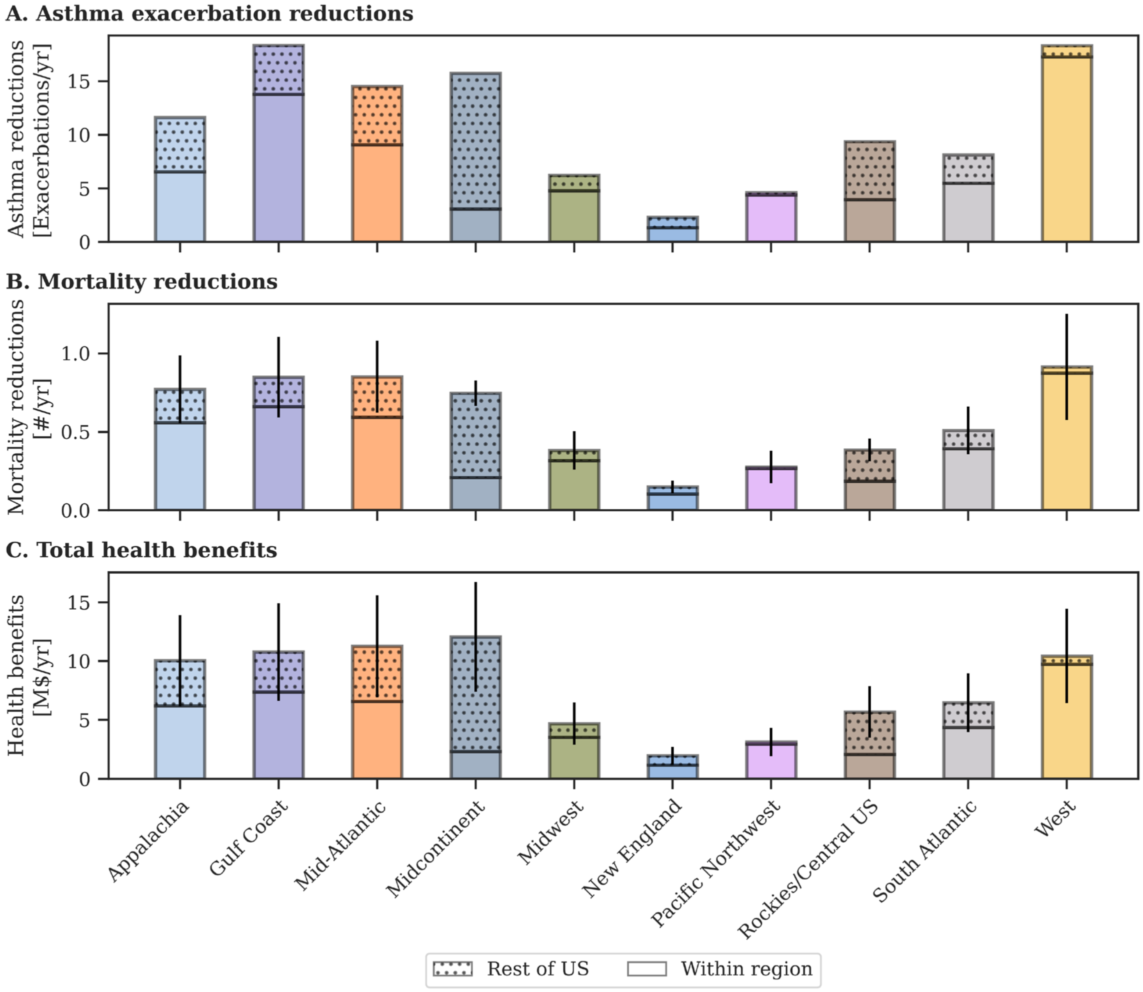
An overview of the health benefits for capturing co-pollutants at iron and steel facilities are shown in figure 36.

Asthma exacerbations: All regions experienced a reduction in asthma exacerbations. The highest reductions were seen from the facilities in the Gulf Coast and in the West, both of which resulted in 18 total reductions in exacerbations. The majority of the reductions for both study facilities occurred within their respective regions. The facilities in Appalachia, the Mid-Atlantic, and the Midcontinent also saw similar reductions, ranging from 11 (in Appalachia) to 16 (in the Midcontinent). In both Appalachia and the Mid-Atlantic, over half of the reductions occurred within the region, while in the Midcontinent, most reductions occurred outside of the region. All remaining facilities resulted in fewer than 10 reductions in asthma exacerbations. The distribution of reductions varied for these facilities as well, with just under half of reductions staying within the region for the Rockies/Central US representative facilities, while in the other four regions—the Midwest, New England, Pacific Northwest, and South Atlantic—the majority of reductions were estimated within each facility's respective region.

Mortality: Mortality reductions in each region were low compared to other study industries. The facilities where installation of capture equipment resulted in the highest estimated reduction in total annual mortality were in the Gulf Coast, Mid-Atlantic, Midcontinent, and the West (0.9 to 1.0 per year). In all cases, except the Midcontinent and Rockies/Central US, the majority of estimated reductions occurred within the region where the representative facility was located.

Dollar-equivalent health benefits: All regions experienced positive health benefits (expressed as total dollar equivalent). The highest total health benefits were estimated in Appalachia, the Gulf Coast, the Mid-Atlantic, the Midcontinent, and the West, between $10 and $12 million per year. The distribution of health benefits for each region varied. For example, the majority of the health benefits for the facility in the Midcontinent occurred outside the region, with only 19 percent of the health benefits occurring within the region. In Appalachia, the Gulf Coast, and the West, 95 percent of benefits occurred within the region. The total health benefits for New England, the Midwest, the Rockies/Central US, Pacific Northwest, and South Atlantic were all between $1 and $7 million per year.

Figure 36. Health co-benefits at representative iron and steel facilities by region.



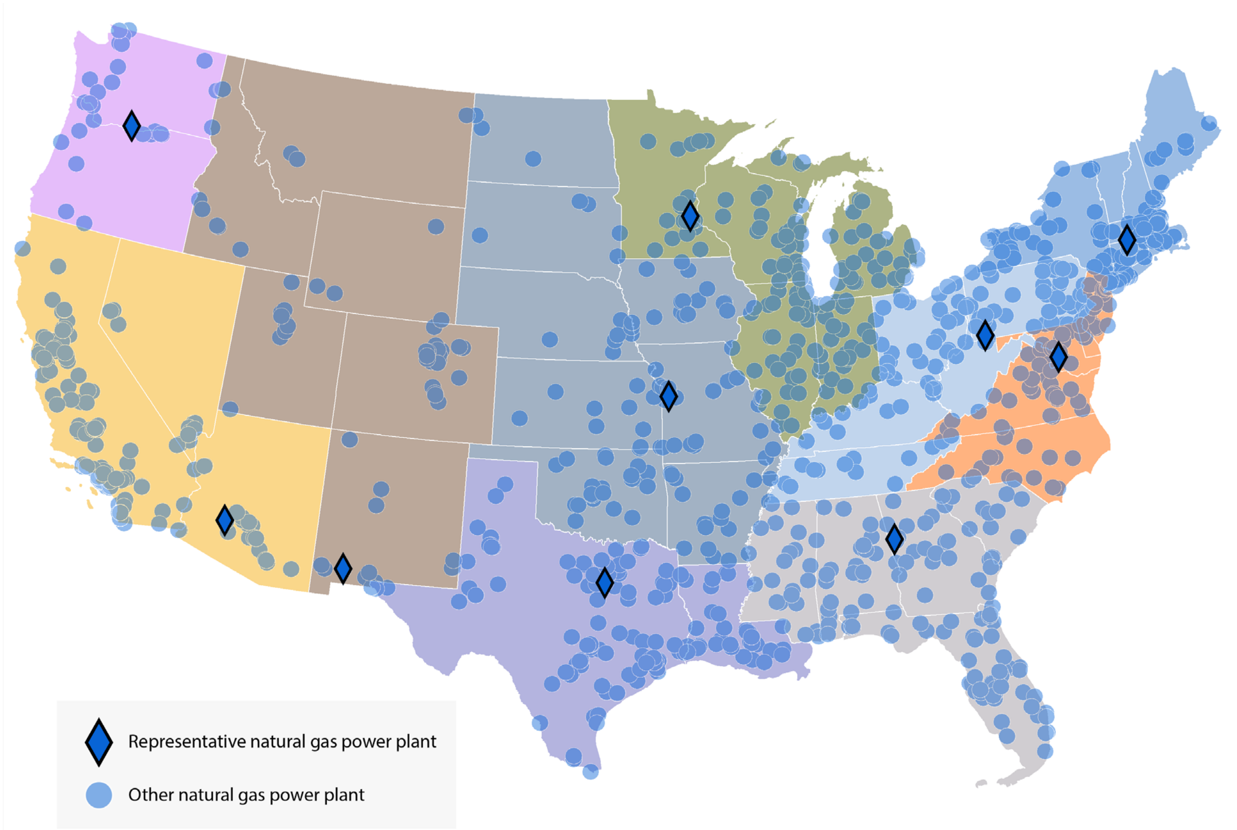
NATURAL GAS POWER PLANTS

Natural gas power plants are ubiquitous across the domestic United States, with the highest densities of facilities east of the Mississippi River and along the West Coast, as shown in figure 37. Natural gas power plants provide electricity generation to power a broad range of end uses, across the residential, commercial, and industrial sectors for a variety of processes.

The EIA projects that the United States will remain reliant on natural gas power plants, with 19 percent of power generation coming from natural gas in 2050.[104] Flue gases from a natural gas combined-cycle power plant are approximately 5 percent CO_2, 11 percent water vapor, 8 percent O_2, and 75 percent N_2 (on a molar basis).[105]

In our analysis, we simulated natural gas power plants with SCR to reduce NO_x, a DCC with scrubber for removing condensable $PM_{2.5}$, and with a carbon capture system. FGD was not included because the sulfur content of natural gas is relatively low.

Figure 37. Natural gas power plants in the United States.



Note: Representative facilities for each region are diamonds and outlined in black. Facilities that were not selected are cir-cles and outlined in white.

104 US Energy Information Administration, "Table: Table 9. Electricity Generating Capacity."

105 Amann and Bouallou, "CO_2 Capture from Power Stations Running with Natural Gas (NGCC) and Pulverized Coal (PC): Assessment of a New Chemical Solvent Based on Aqueous Solutions of N-Methyldiethanolamine + Triethylene Tetramine."

Natural gas: Facility selection

Figure 38 shows the distribution of reported co-pollutant emissions (NO_x, SO_2, and $PM_{2.5}$) for all natural gas power plants across the US, highlighting (as diamonds with a thick outline) the facilities chosen as a representative case study for each of the regions. Due to the extent of natural gas facilities, it was possible to identify a representative facility for each of the 10 regions.

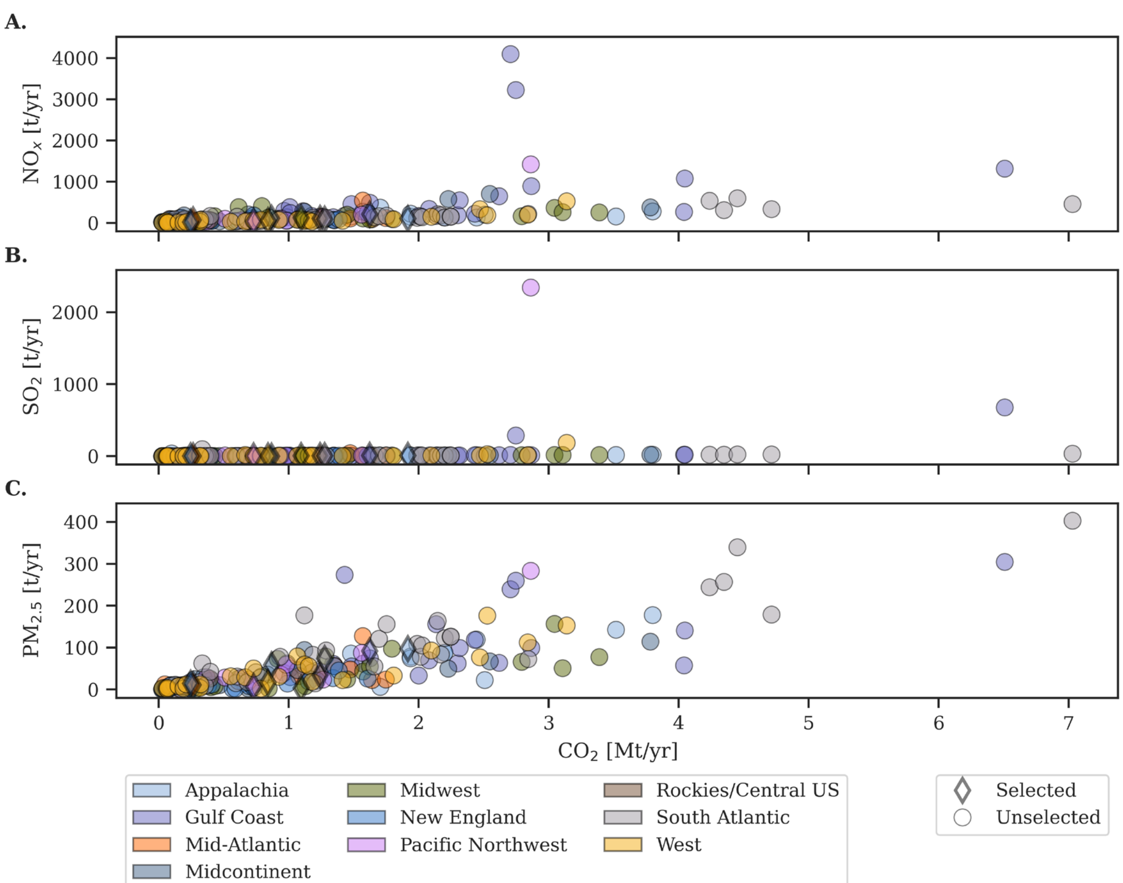
When considering co-pollutant emissions, natural gas power plants have relatively low co-pollutant emissions (particularly for NO_x and SO_2), and there is little variation in total emissions for a given co-pollutant across all natural gas power plants, regardless of region. The instances of notable variation occur primarily in the Gulf Coast, where some facilities report significantly higher NO_x emissions, and in the South Atlantic, where some facilities report significantly higher $PM_{2.5}$ emissions.

Natural gas: Emission impacts

Figure 39 breaks down the impact on emissions for natural gas power plants when outfitted with capture equipment and pre-treatment. Estimated emissions impacts are broken out by the representative facility within each region, as well as by the reduction (shown as hatched) and the remaining (shown as not hatched) compared to the baseline (the entire extent of the bar, denoted by a black diamond).

CO_2 emissions: Total reported CO_2 emissions varied by facility for the 10 representative facilities. The total highest reported CO_2 emissions were in Appalachia (1.9 million tons per year) and the Gulf Coast (just over 1.6 million tons per year). Total reported

Figure 38. Natural gas power plant facility selection.

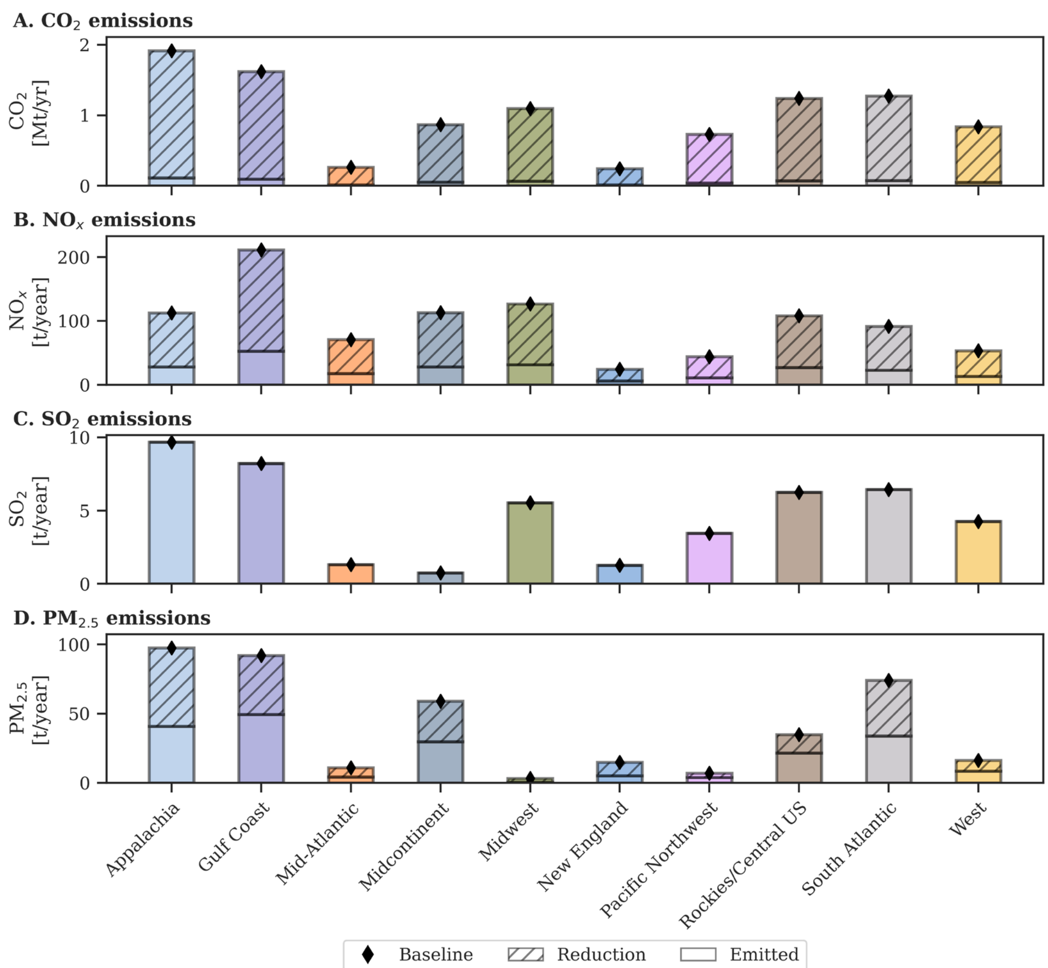


annual CO_2 emissions were moderate for the representative natural gas power plants in the Midwest, the Rockies/Central US, and the South Atlantic, ranging from just over 1 million to around 1.3 million tons per year. Total annual CO_2 emissions were slightly less for the facilities in the Midcontinent, Pacific Northwest, and the West, between 0.7 and 0.9 million tons per year, and emissions were lowest at the facilities in the Mid-Atlantic and New England, under 0.3 million tons per year.

NO_x emissions: The facility with the highest total reported NO_x was in the Gulf Coast, at over 200 tons per year. The facilities in Appalachia, the Midcontinent, the Midwest, the Rockies/Central US, and South Atlantic all reported similar annual NO_x emissions, around 100 tons per year. The facilities in the Mid-Atlantic and West reported just over 50 tons each, while the facility in the Pacific Northwest reported 44 tons. The facility in New England reported the lowest total volume of annual NO_x emissions, 24 tons per year. NO_x emissions were reduced by 75.1 percent with the addition of the SCR.

SO_2 emissions: SO_2 emissions profiles largely matched total reported CO_2 emissions at natural gas power plants. However, all natural gas power plants reported relatively low total annual SO_2 emissions compared to other study industries. The facilities with the highest total reported SO_2 emissions were in Appalachia (just under 10 tons per year) and the Gulf Coast (around 8 tons per year). The facilities in the Midwest, Pacific Northwest, Rockies/Central US, South Atlantic, and West

Figure 39. Emission impacts at representative natural gas power plants by region.



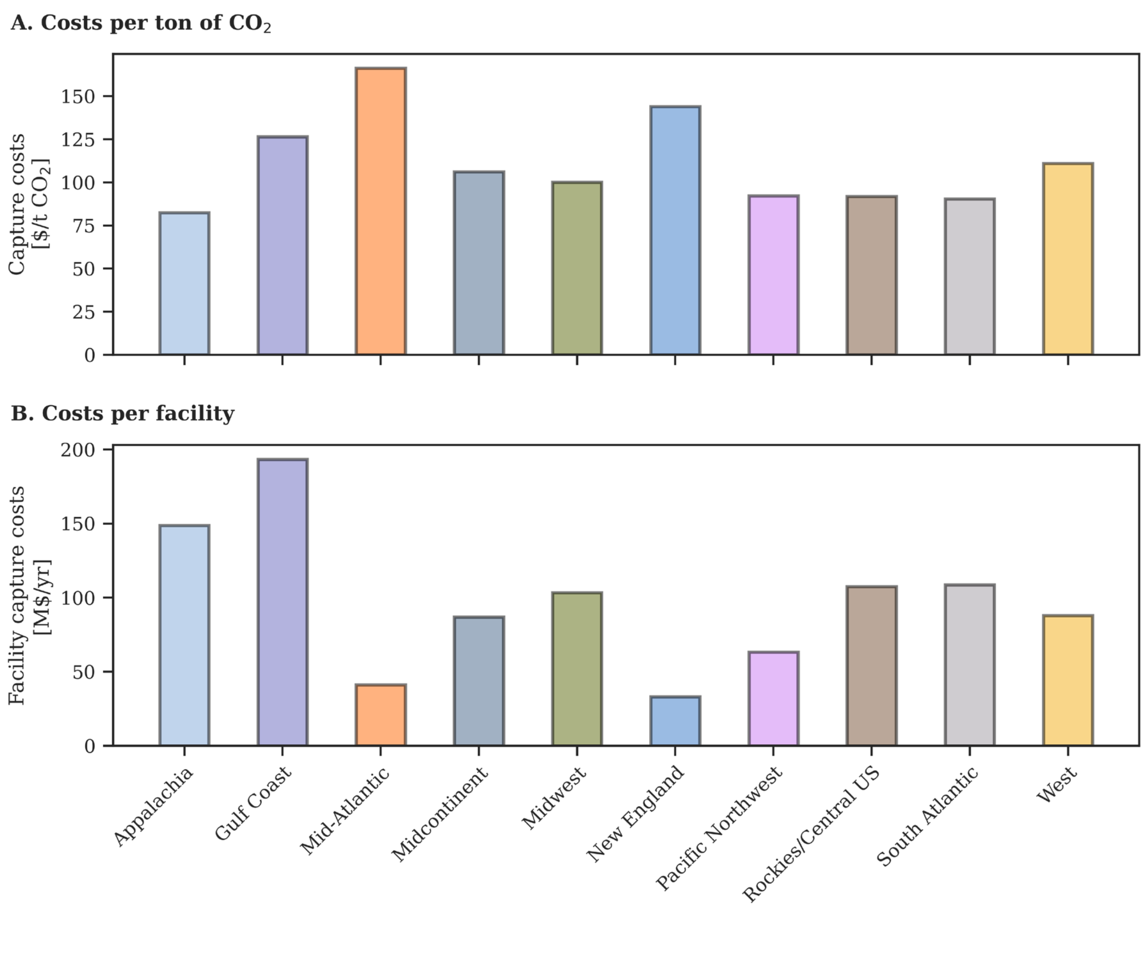
all reported between three and seven tons per year, while the remaining three facilities in the Mid-Atlantic, Midcontinent, and New England all reported less than two tons per year. Given the low SO_2 emissions across all plants studied, capture equipment for SO_2 was not applied for natural gas power plants.

$PM_{2.5}$ emissions: Total annual reported $PM_{2.5}$ emissions were highest at the facilities in Appalachia and the Gulf Coast, with 95 to 100 tons per year. The facility with the next highest total $PM_{2.5}$ emissions was in the South Atlantic (75 tons per year), followed by the natural gas power plant in the Midcontinent (60 tons per year). The facility in the Rockies/Central US reported 35 tons per year, while the five remaining facilities in the Mid-Atlantic, Midwest, New England, Pacific Northwest, and West all reported under 20 tons per year (and as low as 5 tons per year in the Midwest). Reduction in $PM_{2.5}$ emissions was variable across the representative facilities, ranging from 51 percent removed at the Appalachia facility to 93 percent at the Midwest facility. This is due to the variation in the amount of $PM_{2.5}$ that was condensable and thus capturable by the DCC system utilized in this study.

Natural gas: Capture costs

The cost of capture, detailed in figure 40, varied across representative facilities. The facility in Appalachia achieved the lowest per ton cost for CO_2 captured at $82 per ton. The facilities in the Pacific Northwest, Rockies/Central US, and South Atlantic reported slightly higher per ton capture costs, around $90-$93 per ton, and the facilities in the Midcontinent, Midwest, and West reported costs of $100 to $111 per ton of CO_2 captured. The facility with

Figure 40. Capture costs at representative natural gas power plants by region for capturing CO_2 from all streams and with co-pollutant equipment, as applicable.



the highest reported per ton cost for capture was the Mid-Atlantic facility, at $166 per ton. The variation can be attributed to economies of scale, with facilities with lower CO_2 emissions being more expensive to capture than facilities with higher CO_2 emissions on a per ton basis.

The facilities in the Gulf Coast and Appalachia had the highest cost for capture at $193 million per year, and $149 million per year, respectively. The next most expensive facilities were in the Midwest, Rockies/Central US, and South Atlantic—all of which were estimated to cost $103 to $109 million per year on capture. The facilities in the Midcontinent and West were estimated at around $90 million per year, and the facility in the Pacific Northwest at $63 million per year. The least expensive facilities were the Mid-Atlantic (though most expensive on a per ton basis due to its smaller size), and the facility in New England. Both were estimated to cost under $50 million per year.

Table 12 provides an overview of the estimated capturable CO_2 emissions by stream type, as well as the estimated cost of capture associated with each stream, for the representative natural gas power plants.

Natural gas: Health co-benefits

The results of estimated reductions in asthma exacerbations, total annual mortality, and cumulative health benefits in dollar equivalence are shown in figure 41.

Asthma exacerbations: Estimated impact on the reduction in asthma exacerbations varied by region. The greatest reduction in asthma exacerbations was found in Appalachia, with 20 fewer exacerbations per year, where 45 percent of the total reductions were estimated to occur within the region. The Gulf Coast and West also had high asthma reductions from the reduction of co-pollutants at natural gas power plants (around 15 and 16, respectively), and most of the benefits stayed within the region for both facilities (88 to 97 percent). The other seven representative facilities resulted in fewer reductions, between four and six reductions per year in all regions, except the Pacific Northwest, which experienced no reduction in asthma exacerbations.

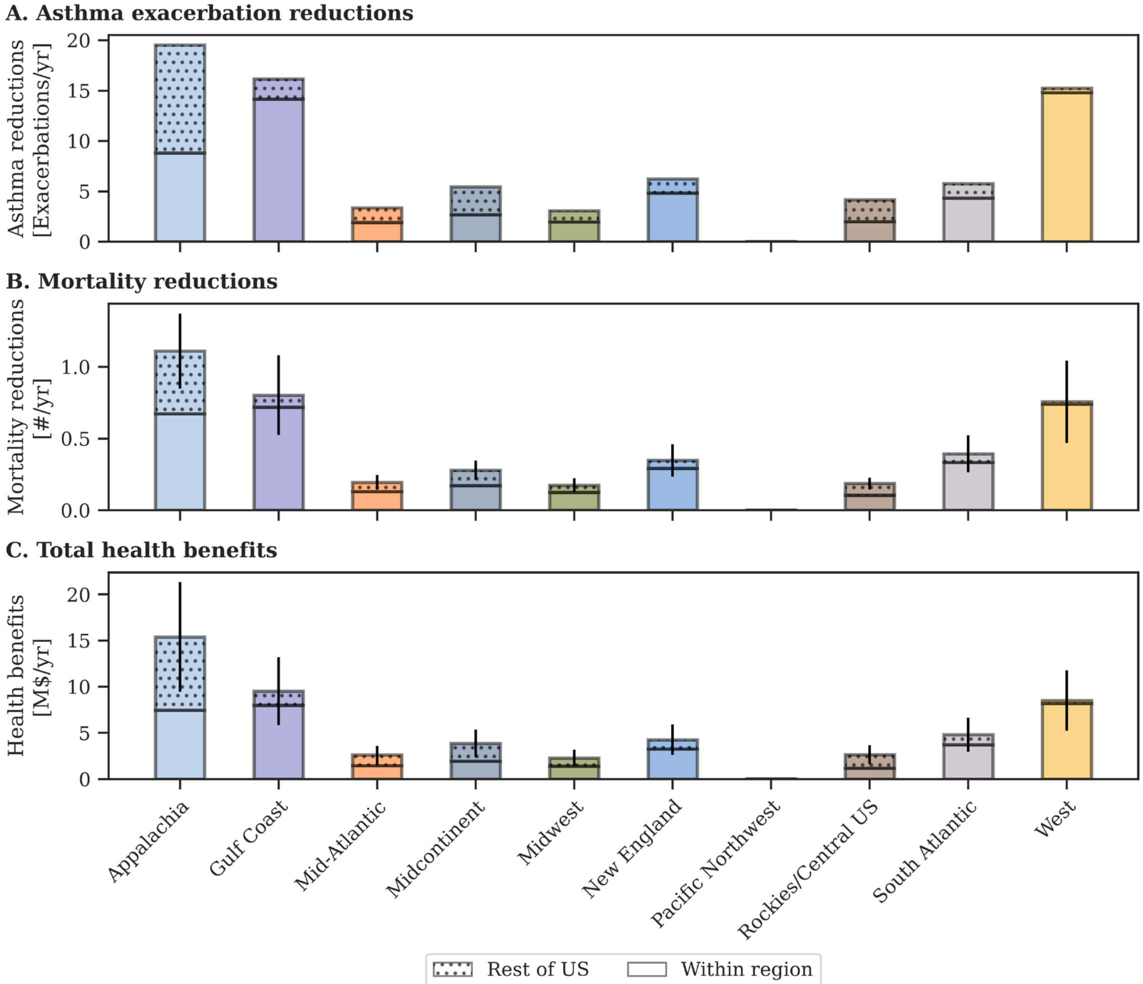
Mortality: Estimated reductions in mortality in each region were found to be consistent with estimates on asthma reductions when comparing the impact from installing capture equipment at the representative facility for each region. The highest reductions occurred again in Appalachia, the Gulf Coast, and the West. The remaining regions all experienced a reduction in mortality, though the reduction was between 0.2 and 0.5, and zero for the Pacific Northwest.

Dollar-equivalent health benefits: When translated to dollar-equivalent health benefits, the extent of benefits also matched reductions in both asthma exacerbations and mortality when comparing regions. The greatest health benefit was estimated to occur in Appalachia ($15.3 million per year), with about half of the benefit occurring within the region and half outside of the region. The Gulf Coast and West both achieved $8.5 to $9.5 million per year in health benefits, the majority of which stayed within the respective regions. The remaining regions also all experienced a positive dollar-equivalent health benefit. The Pacific Northwest had health benefits of $30,000 per year.

Table 12. Overview of CO_2 capture stream costs at natural gas power plants.

Steam type (-)	Capturable CO_2 (t/yr)		Capture costs ($/t CO_2)		
			Co-pollutant costs	Combined capture costs	
	Minimum	Maximum		Minimum	Maximum
Combustion from a single turbine	123,665	912,672	(included)	$82.07	$166.35
Total facility	229,970	1,804,721	-	$82.40	$166.18

Figure 41. Health co-benefits at representative natural gas power plants by region.



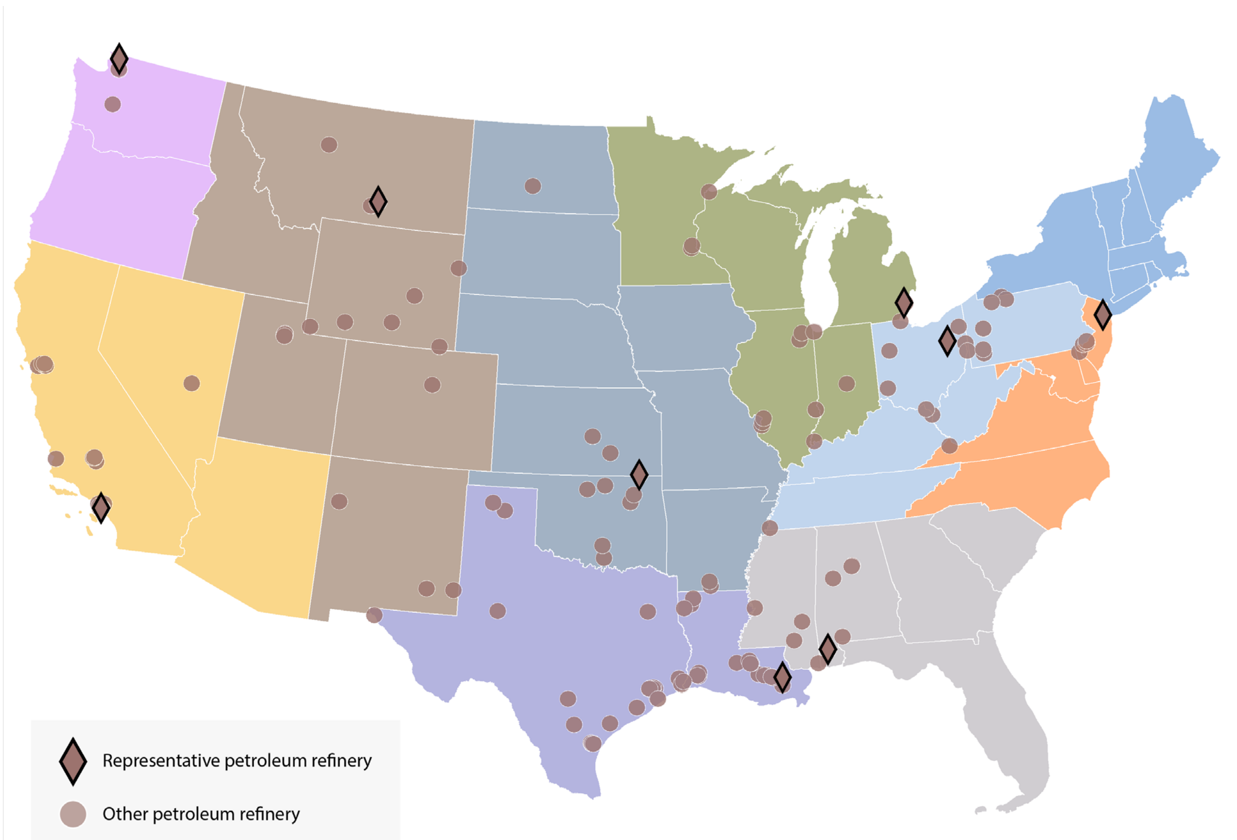
PETROLEUM REFINERIES

Petroleum refineries take raw, unrefined crude oil and convert it to consumer goods, liquid fuels, and a variety of other materials. Refineries account for 4-6 percent of global CO_2 emissions, with a large contribution (25-35 percent) from the fluid catalytic cracking units (FCCUs).[106] FCCUs convert heavy fuels into gasoline and fuel products.[107] Refineries also have other sources of emissions, including process heaters, flares, process vents, sulfur recovery, and catalytic reforming.[108]

For this analysis, FGD, SCR, and DCC with scrubber co-pollutant capture equipment was applied to both the FCCU and combustion emission streams before going through the carbon capture system. Co-pollutant capture was modeled at the facility level; therefore, it was assumed that all co-pollutant emissions could also be captured at these sources.

An overview of petroleum refineries in the United States is shown in figure 42. The majority are located along the Gulf of Mexico.

Figure 42. Petroleum refineries in the United States.



Note: Representative facilities for each region are diamonds and outlined in black. Facilities that were not selected are cir-cles and outlined in white.

106 Güleç, Meredith, and Snape, "Progress in the CO_2 Capture Technologies for Fluid Catalytic Cracking (FCC) Units — A Review."
107 Güleç, Meredith, and Snape.
108 Bains, Psarras, and Wilcox, "CO_2 Capture from the Industry Sector."

Petroleum refineries: Facility selection

Based on the evaluation criteria, there was a satisfactory facility to serve as a representative facility for every study region except New England. The range of emissions for each region is shown in figure 43.

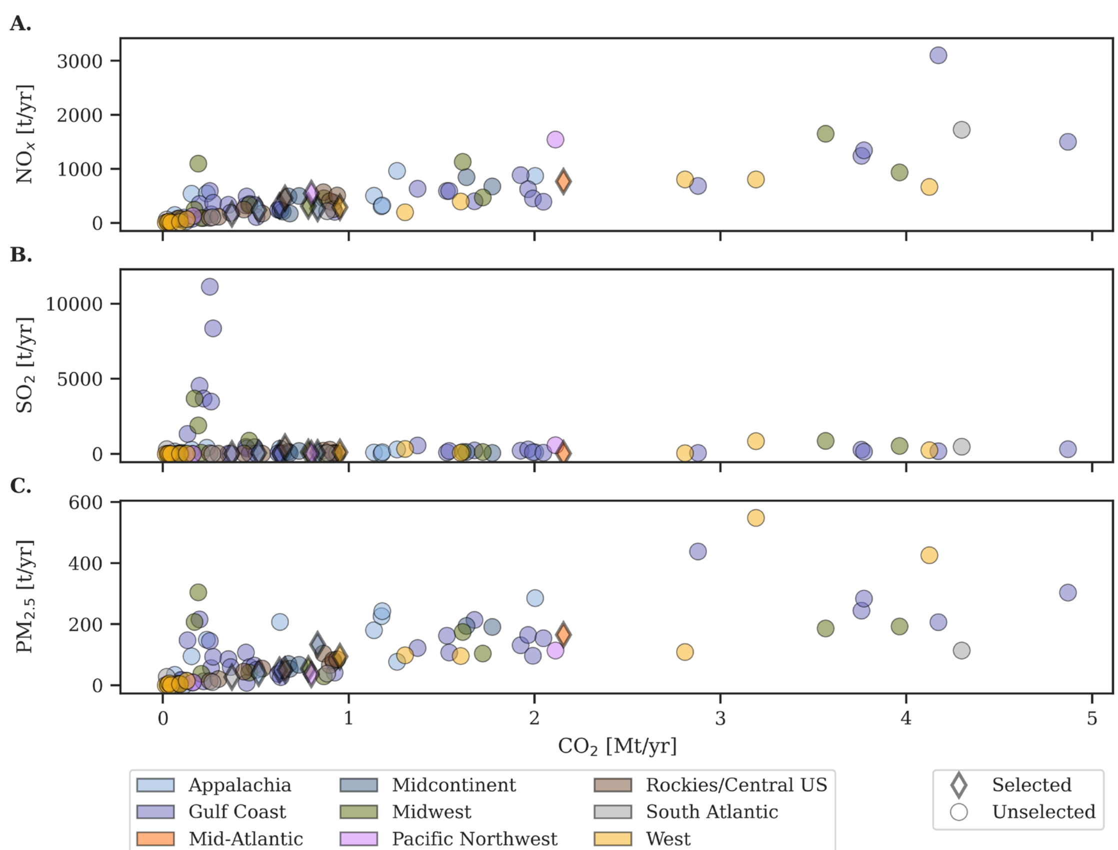
Petroleum refineries: Emission impacts

Figure 44 breaks down the impact on emissions for petroleum refineries when outfitted with capture equipment and pre-treatment. Estimated emissions impacts are shown for each representative facility within each region, as well as by the reduction (shown as hatched) and the remaining (shown as not hatched) compared to the baseline (the entire extent of the bar, denoted by a black diamond).

CO_2 emissions: The CO_2 emissions across the 10 representative facilities had similar reported total volumes, except for the Mid-Atlantic, which reported significantly higher total CO_2 emissions at over two million tons per year. The next highest facility, in the West, had one million tons per year. The remaining facilities all reported between 0.5 and around 0.8 million tons of CO_2 emissions per year. Overall capture rates varied from 65 percent to 89 percent. The variation in total capture rates is based on the proportion of emissions coming from the FCCU and stationary combustion, where CO_2 was being captured, against other streams that were not identified as capturable.

NO_x emissions: Trends in NO_x emissions across the representative petroleum refineries mostly correlated with total reported CO_2 emissions in that facility. The Mid-Atlantic representative facility had significantly higher total NO_x emissions than the other study facilities (770 tons per year). The facility with the next highest total reported NO_x emissions

Figure 43. Petroleum refinery facility selection.

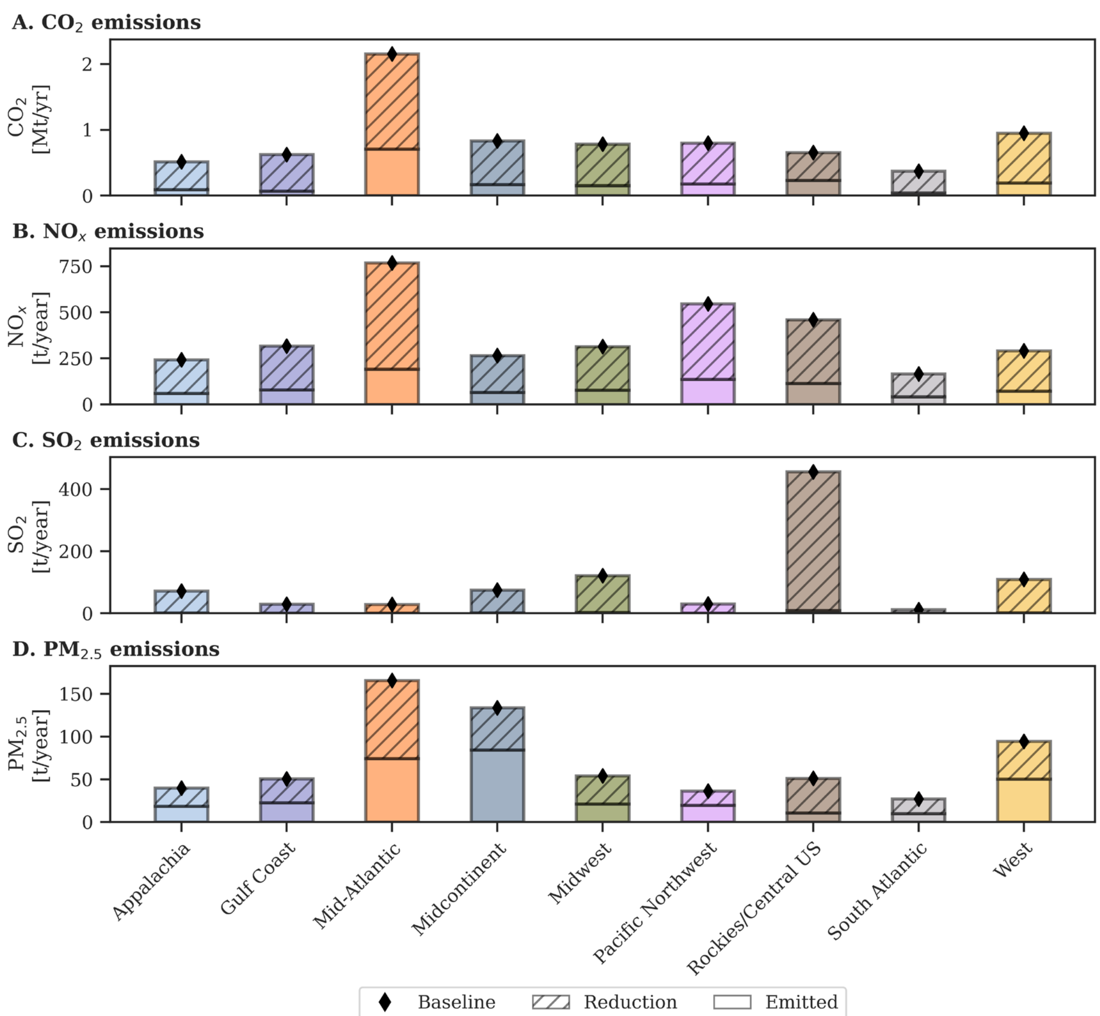


was in the Pacific Northwest (around 550 tons per year), followed by the Rockies/Central US (around 450 tons per year). The remaining facilities all reported total annual NO_x emissions of around 240 to 320 tons per year, except for the facility in the South Atlantic, which reported the lowest total annual NO_x emissions at 170 tons per year. By installing capture equipment, all facilities reduced NO_x emissions by 75.1 percent.

SO_2 emissions: All facilities reported relatively low total annual SO_2 emissions (near or below 100 tons per year) with the notable exception of the facility in the Rockies/Central US region, which reported over 460 tons per year. The Appalachia, Midcontinent, Midwest, and West facilities had emissions in the 70 to 125 tons per year range. The remaining facilities reported 20 tons or less. With the installation of capture equipment, all facilities reduced their SO_2 emissions by 98 percent.

$PM_{2.5}$ emissions: The facility in the Mid-Atlantic reported the largest volume overall of $PM_{2.5}$ emissions, around 165 tons per year. The second largest volume of $PM_{2.5}$ emissions was reported at the facility in the Midcontinent, with just over 130 tons per year, followed by the West, with around 100 tons per year. The remaining facilities all reported 60 tons per year or less. Installation of capture equipment had variable success at reducing $PM_{2.5}$ emissions, varying from 51 percent at the West facility to 87 percent at the Rockies/Central US facility.

Figure 44. Emission impacts at representative petroleum refineries by region.



Petroleum refineries: Capture costs

As shown in figure 45, the cost of capture was between \$85 and \$95 per ton for each representative facility. The most expensive per ton cost to capture CO_2 was estimated at the facility in the Gulf Coast (\$93 per ton of CO_2) and the least expensive at the facility in the Mid-Atlantic (\$87 dollars per ton of CO_2).

When looking at total facility costs for capture, the facility in the Mid-Atlantic was significantly more expensive than the other facilities, estimated at \$125 million per year. There was less variation among the remaining facilities. The petroleum refineries in the Gulf Coast, Midcontinent, Midwest, Pacific Northwest, and West were all between \$50 and \$70 million per year, the facilities in Appalachia and the Rockies/Central US at \$38 million per year, and the facility in the South Atlantic was the least expensive at \$30 million per year.

Table 13 provides an overview of the estimated capturable CO_2 emissions by stream type, as well as the estimated cost to capture associated with each stream at the representative petroleum refineries.

Figure 45. Capture costs at representative petroleum refineries by region for capturing CO_2 from all streams with co-pollutant equipment, as applicable.

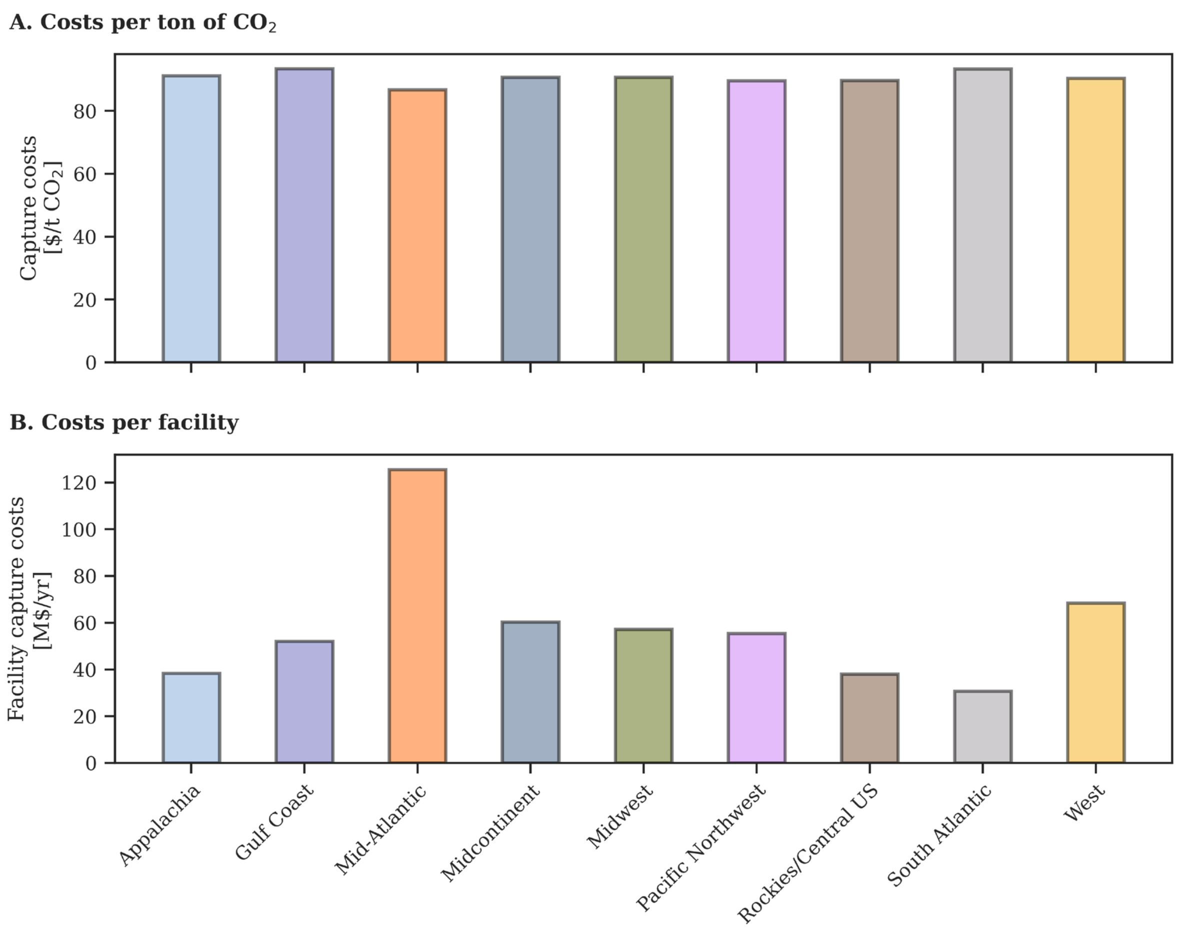


Table 13. Overview of CO_2 capture stream costs at representative petroleum refineries.

Steam type (-)	Capturable CO_2 (t/yr)		Capture costs (\$/t CO_2)		
			Co-pollutant costs	Combined capture costs	
	Minimum	Maximum		Minimum	Maximum
Stationary combustion	300,142	705,831	\$15.30	\$93.76	\$93.76
FCCU	2,503	741,231	\$15.30	\$80.10	\$80.10
Total facility	329,060	1,447,063	-	\$86.76	\$93.66

Petroleum refineries: Health co-benefits

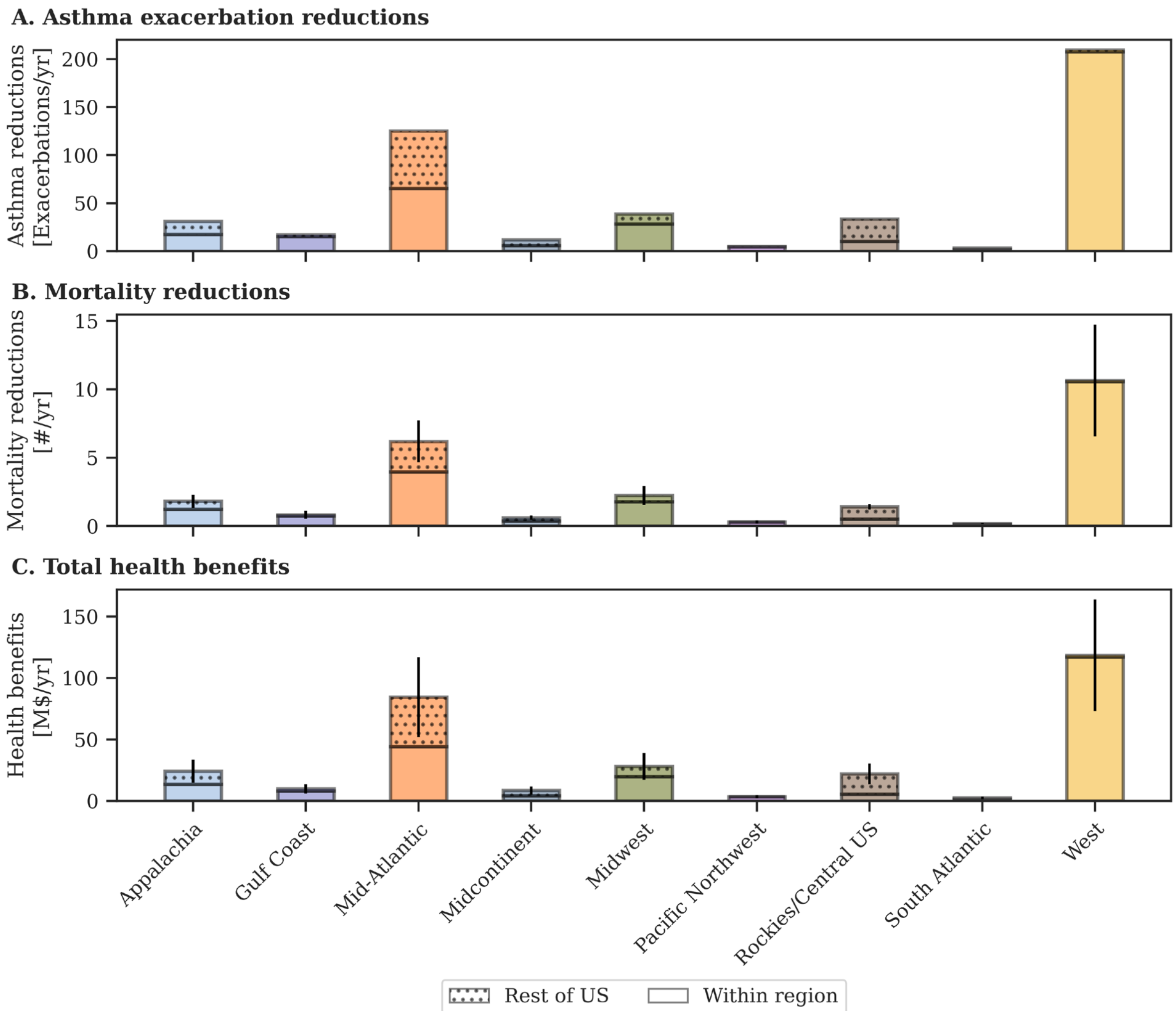
The results of estimated reductions in asthma exacerbations, total annual mortality, and cumulative health benefits in dollar equivalence are shown in figure 46.

Asthma exacerbations: Reported reductions in asthma exacerbations from petroleum refineries in two of the regions were responsible for some of the highest reductions in asthma exacerbations across all facilities in all study industries. The facilities in the West and the Mid-Atlantic were estimated to have the greatest reduction in asthma exacerbations, with a reduction of 210 exacerbations in the West, and around 125 fewer exacerbations in the Mid-Atlantic. In the West, 99 percent of reductions were estimated to occur within the region, while in the Mid-Atlantic the reductions were 52 percent within the region. The remaining facilities reported significantly fewer reductions. The facilities in Appalachia, the Midwest, and the Rockies/Central US resulted in 30 to 40 reductions each, with variable in-region versus outside-region impacts. The Gulf Coast, Midcontinent, Pacific Northwest, and South Atlantic facilities resulted in fewer than 20 reductions each.

Mortality: Mortality reductions mirrored the impact seen in asthma reductions. The greatest reductions in mortality occurred with the facility in the West (11) and Mid-Atlantic (8). The remaining facilities had an estimated reduction in mortality of less than three per year. In all regions except the Rockies/Central US, the majority of mortality reductions occurred within each respective region.

Dollar-equivalent health benefits: The dollar-equivalent health benefit was consistent with reductions in both asthma exacerbations and mortality reductions. The greatest total health benefits were experienced in the West (where 99 percent of benefits stayed within the region), estimated at \$118 million per year. The next highest was the Mid-Atlantic at \$84 million per year, where benefits were 52 percent in-region. In Appalachia, the Midwest, and the Rockies/Central US, health benefits were equivalent to an estimated \$20 to \$30 million per year. The remaining four facilities all experienced health benefits of less than \$10 million per year.

Figure 46. Health co-benefits at representative petroleum refineries by region.



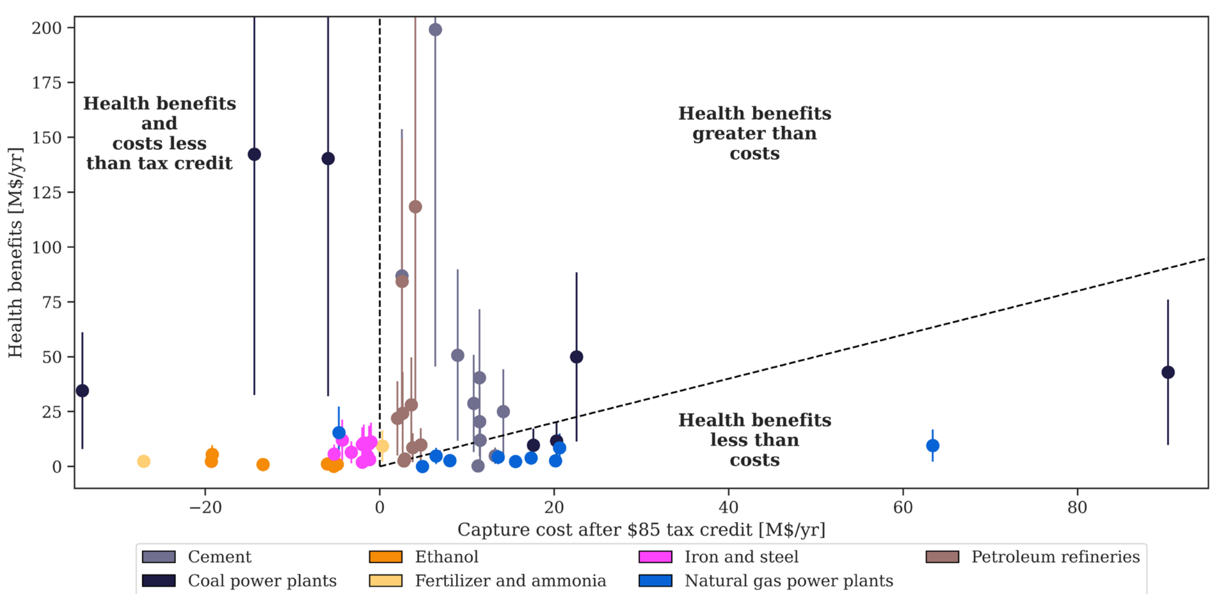
CROSS INDUSTRY TRENDS

Next, we evaluated trends across the industries by comparing the total facility benefits of each representative facility against the costs of capturing CO_2 and the co-pollutants. Our analysis was based in the contiguous United States, so we applied the 45Q tax credit of $85/ton of CO_2 for geologic saline storage. An overview is shown in figure 47. The analysis groups industries into three categories. The first group includes facilities where the cost to capture CO_2 with pre-treatment for NO_x, SO_2, and $PM_{2.5}$ is less than the credit received from 45Q. These facilities also saw health benefits associated with capture. This group includes many ethanol and iron and steel plants. The second group includes facilities where the tax credit does not fully cover the cost of capture and pre-treatment, but the health benefits are greater than the costs. This includes many cement plants and petroleum refineries. The final group has health benefits, but their economic value is less than the costs of capture. This includes the majority of natural gas plants. Some industries are scattered across the groups, including coal power plants and fertilizer and ammonia plants.

Next, in figure 48, we show the aggregate health benefits by each region for the 54 representative facilities analyzed in this study. Not every region had a representative facility for each industry type. Additionally, the reductions in health impacts quantified by COBRA are directly impacted by the population density around a representative facility, meaning that the same level of reductions will likely have a greater health benefit in a location near large populations.

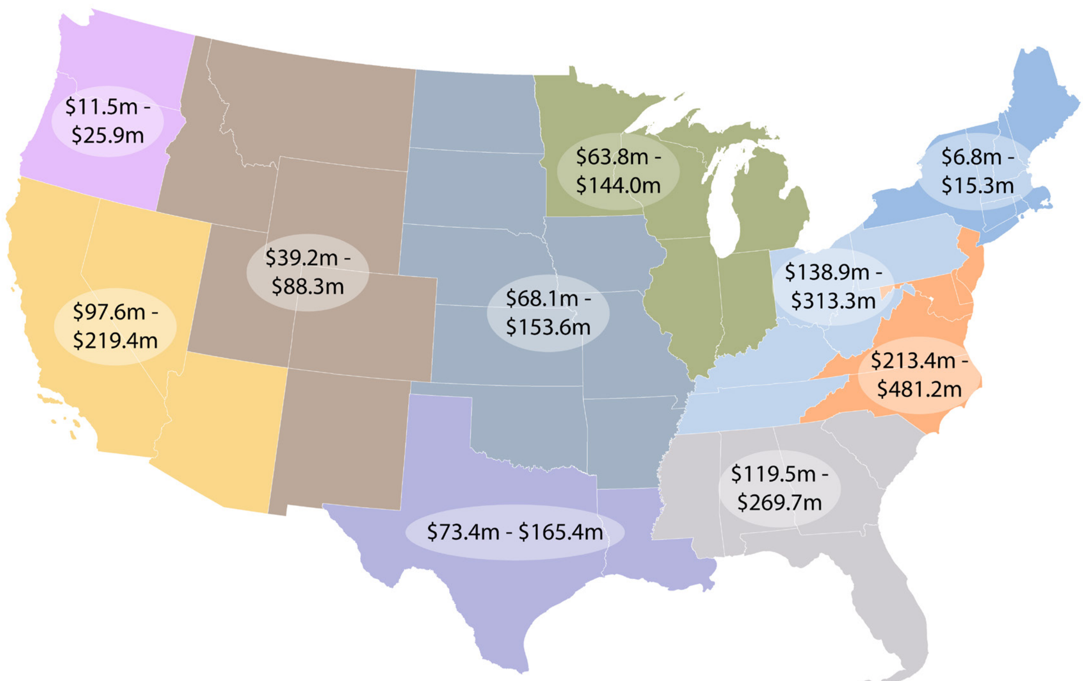
The opportunity for air quality and subsequent health benefits is evident across the contiguous US. There are many additional facilities to consider beyond what was analyzed in this study for every region, highlighted by figure 49, which shows all point source emitters across the contiguous US, scaled by reported CO_2 emissions.

Figure 47. Comparison of health benefits and capture costs.



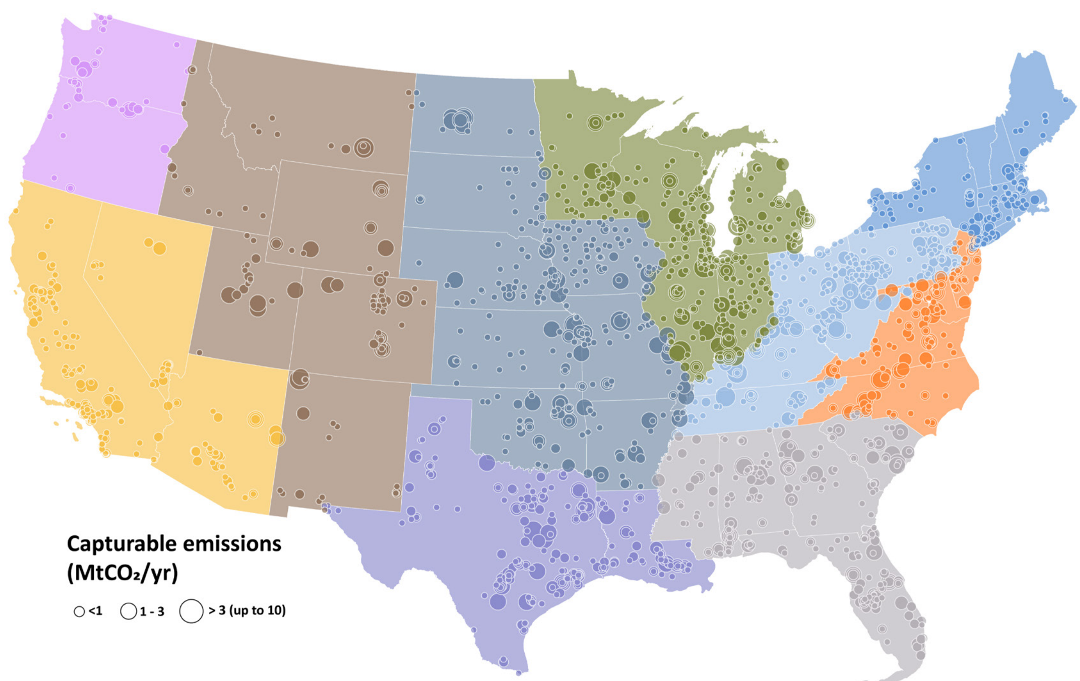
Note: Costs are after an $85/ton of CO_2 tax credit has been applied.

Figure 48. Annual health benefits (million dollars) for each region after outfitting the 54 representative facilities of this study with carbon capture equipment and pre-treatment.



Note: Dollar amounts indicate the sum of the health benefits from the representative facilities present in each region.

Figure 49. Extent of industrial facilities in the US (by region) with potential to consider for capture and pre-treatment equipment, inclusive of all industry types and scaled by reported annual CO_2 emissions volumes.



Conclusions

As we continue to evaluate and study the benefits of carbon capture, it's essential to recognize the additional health benefits from co-pollutant reduction. Most commercial-scale carbon capture technologies use an amine-based solvent to separate CO_2 from flue gases released by industrial plants and thermal power plants, which require the removal of NO_x, SO_2, and $PM_{2.5}$ for optimal performance. In this study, we developed a methodology to evaluate the co-benefits of applying pre-treatment for NO_x, SO_2, and $PM_{2.5}$ to amine-based carbon capture for seven industries: cement, coal power plants, ethanol, fertilizer and ammonia, iron and steel, natural gas power plants, and petroleum refineries. The analysis was performed for 54 representative facilities across seven industries and 10 contiguous US regions.

Across all industries and regions, we found that co-pollutant removal resulted in health benefits, with the largest benefits seen in cement, coal, and petroleum refineries. The economic value of these health benefits in each region ranged from $6.8 million to $481.2 million per year. This means that, in addition to reducing CO_2 emissions at industrial and thermal power facilities, amine-based carbon capture equipment with pre-treatment to remove these co-pollutants has a positive effect on air quality for both nearby communities and in regions across the contiguous United States.

As this study outlines, carbon capture in industrial applications has additional benefits beyond carbon reduction, such as increased air quality and health benefits for those in the community surrounding a facility and throughout the United States. This study represented the results for reductions in adult and infant mortality, asthma exacerbations, and the overall economic value from lowering risks of all health categories in the EPA COBRA tool.

While carbon capture with removal of co-pollutants yields annual health benefits at all facilities in this study, the economic feasibility of incorporating capture systems currently depends on the 45Q tax credit for storing CO_2 (currently $85 per metric ton for saline geologic storage). For most ethanol, ammonia and fertilizer, and iron and steel plants, the 45Q tax credit was greater than the cost of carbon capture with pre-treatment in this study. Other industries, like many cement plants and petroleum refineries, have a cost of capture that is greater than the tax credit, but offer health benefits that, when quantified as an annual economic value, exceed the remaining cost of capture. For most natural gas power plants, the cost of capture is greater than the 45Q tax credit and the economic value of the modeled health benefits are less than the remaining cost of capture.

More work is needed to fully realize the opportunities for increased air quality from carbon capture systems in many industries. Carbon capture remains a vital opportunity for reducing the carbon emissions for many industries. With further research, we are confident that amine-based carbon capture technologies will continue to improve the efficiency and efficacy in removing CO_2 and other co-pollutants, which will increase the health benefits beyond what is estimated in this study and decrease cost. An analysis of sector-wide carbon capture deployment (beyond the 54 facilities in this study) would also be valuable to show the significant health benefits from decarbonizing an entire industry with carbon capture.

Appendix A. Review of nitrosamines and nitramines

Although amine-based carbon capture is effective at capturing CO_2, an unintended potential byproduct is the formation and emission of nitrosamines and nitramines. These substances are known to be carcinogenic, and while their direct study in carbon capture systems is limited, they have been studied at lab and pilot scale for carbon capture and in other industries at commercial scale (such as water treatment). The goal of this section is to review what nitrosamines and nitramines are, how they are formed, how they accumulate, and what can be done to prevent their emission into the ambient air and groundwater in carbon capture operations.

WHAT ARE NITROSAMINES AND NITRAMINES?

Nitrosamines are a common byproduct of operating amine solvent carbon capture systems. Nitrosamines, and related nitramines, are formed when the nitrogen-rich amine solvent is oxidized, often by excess oxygen gas or nitrogen oxides (NO_x). Both nitrosamines and nitramines are environmental toxins that can significantly impact marine and riparian ecosystems.[109] Nitrosamines have drawn particular attention due to their carcinogenic potential and lack of investigation regarding their emissions from amine solvent capture systems.

Nitrosamines and nitramines are categorized as VOCs known to increase cancer risk. Both are nitrogen-containing species that contain various subfamilies of specific molecules, but nitrosamines have an additional oxygen ion on one end of the molecule that is not present in nitramines. Nitrosamines also have a 15 times stronger mutation potential than nitramines.[110] However, nitramines are more chemically stable and can survive longer in the atmosphere.[111]

FORMATION PROCESSES/PATHWAYS

The formation of nitrosamines and nitramines in industrial applications is not a new concept. For example, the chlorination of water containing nitrite can create nitrosating species, which could eventually form nitrosamines, and is a challenge for the water treatment industry.[112] In typical combustion processes, the flue gas that leaves the combustion chamber contains NO_x. NO_x can react with the amine solvent of a carbon capture system, forming nitrosamines and nitramines. A diagram of how this process might occur is shown in figure 50.[113]

In an ideal combustion process, only CO_2 must be removed from the flue gas. Within the absorber, CO_2 will bind to the amine, then flow into the desorber, where the combined CO_2 and amine will be heated to high temperatures (about 900 °C), releasing the CO_2 in a concentrated stream.

However, NO_x and other co-pollutants often

109 Beard and Swager, “An Organic Chemist’s Guide to N-Nitrosamines: Their Structure, Reactivity, and Role as Contaminants”; Wagner et al., “Comparative in Vitro Toxicity of Nitrosamines and Nitramines Associated with Amine-Based Carbon Capture and Storage.”

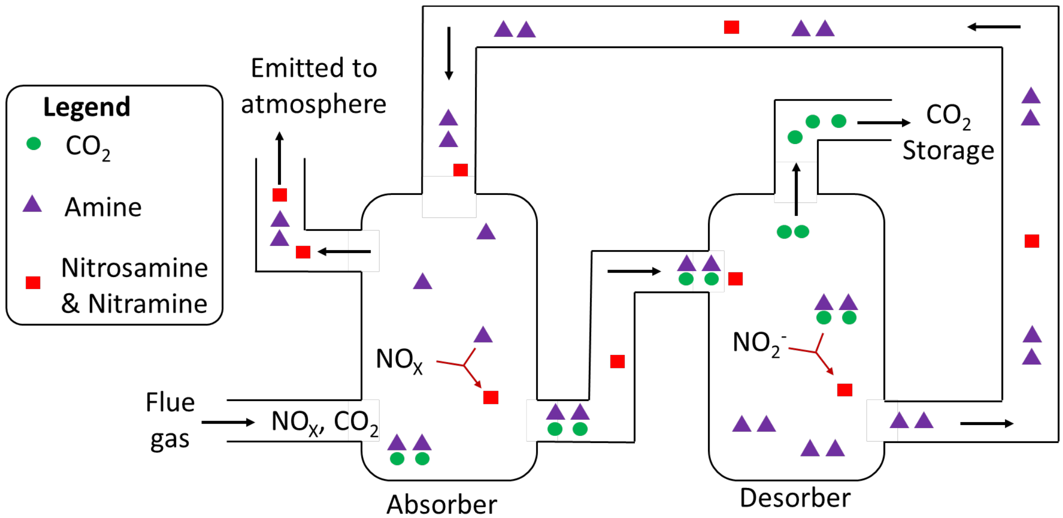
110 Mazari, Alaba, and Saeed, “Formation and Elimination of Nitrosamines and Nitramines in Freshwaters Involved in Post-Combustion Carbon Capture Process.”

111 Gelowitz et al., “Part 8: Post-Combustion CO_2 Capture: Pilot Plant Operation Issues.”

112 Beard and Swager, “An Organic Chemist’s Guide to N-Nitrosamines: Their Structure, Reactivity, and Role as Contaminants.”

113 Yu, Mitch, and Dai, “Nitrosamines and Nitramines in Amine-Based Carbon Dioxide Capture Systems: Fundamentals, Engineering Implications, and Knowledge Gaps.”

Figure 50. Nitrosamine and nitramine formation in a simplified amine-based carbon capture system.



Note: Image adapted from Yu, Mitch, and Dai.

form within the combustion chamber in addition to CO_2. NO_x is created when the high temperatures within the combustion chamber cause the N_2 and O_2 in ambient air to react and form NO and NO_2. Most flue gas NO_x contains about 5-10 percent NO, and the rest is typically NO_2.[114] However, facilities such as coal-fired power plants can also have SO_x, PM, and chlorine-based pollutants, all of which can form nitrosamines and nitramines.[115] The most common locations for this nitration are the absorber and desorber, but it can also occur within a wash water unit if the system has one (not shown in figure 50) or even in the atmosphere after release since they can also form through the photo-degradation of amines.[116] Within the desorber, nitrosamines will form between the amines and aqueous nitrite, which is a hydrolysis product of NO_x.

ACCUMULATION POST EMISSION

Nitrosamines and nitramines can be found in ambient air, the atmosphere, and groundwater. Airborne nitrosamines typically do not pose a risk to human health since sunlight photolysis breaks nitrosamines into secondary byproducts fairly quickly (the characteristic time for nitrosamine removal by photolysis is 30 minutes in the atmosphere[117]). Photolysis can also remove nitrosamines and nitramines from water, but only if the water is exposed to sunlight.[118]

Amine solvents and their degradation products emitted from the carbon capture system can adsorb into the soil and groundwater and contaminate sources of drinking water.[119] According to Spietz et al., safe levels of nitrosamines and nitramines are around 0.3 ng/m^3 in air and 4 ng/l in drinking water.[120]

114 Yu, Mitch, and Dai.
115 Mazari, Alaba, and Saeed, "Formation and Elimination of Nitrosamines and Nitramines in Freshwaters Involved in Post-Combustion Carbon Capture Process."
116 Mazari, Alaba, and Saeed.
117 Nielsen, Herrmann, and Weller, "Atmospheric Chemistry and Environmental Impact of the Use of Amines in Carbon Capture and Storage (CCS)."
118 Beard and Swager, "An Organic Chemist's Guide to N-Nitrosamines: Their Structure, Reactivity, and Role as Contaminants."
119 Spietz et al., "Nitrosamines and Nitramines in Carbon Capture Plants."
120 Spietz et al.

CONSEQUENCES OF EMISSION

While nitrosamines and nitramines are primarily emitted in gaseous form into the atmosphere, both species quickly react in the presence of sunlight, forming secondary products. When photochemistry is inactive, these directly emitted species can have longer atmospheric lifetimes and may directly contaminate local environments and ecosystems.

The secondary products of nitrosamine photochemistry vary, with various pathways for nitrosamines to degrade into VOCs (e.g., formaldehyde), reactive nitrogen species (e.g., NO_x, methylamine), acids (formic and nitric acids), and potent greenhouse gases (N_2O).[121] The propensity of each formation pathway will vary, and all pathways may contribute equally, or one pathway may have a larger impact, depending on the atmospheric and chemical regimes.

Each of these secondary products may impact local air quality in isolation or may interact synergistically to impact local air quality. Many of the secondary products from nitrosamine degradation can directly impact environmental and public health. Formaldehyde, a hazardous air pollutant, is known to cause respiratory disease from acute and chronic exposure and is an important component of cancer risks in 99 percent of US census tracts.[122] Reactive nitrogen species can increase smog and can further degrade into other hazardous substances, such as peroxyacetyl nitrate.[123] Increased quantities of acids in the atmosphere can lead to acid rain and impact cloud formation within the greater region.[124]

Beyond direct impacts, these compounds can influence other chemical regimes within the atmosphere. VOCs can interact with atmospheric NO_x species to aid in the formation of surface ozone, a criteria air pollutant and major contributor to air quality impacts on environmental and public health.[125]

The relationship between VOC/NO_x mixing ratios and ozone formation is not linear, and an excess of one precursor species (either VOCs or NO_x) will lead to considerably more ozone formation than equal amounts of both precursors.[126] Ozone, and many other atmospheric pollutants, are removed from the atmosphere by the reaction with hydroxyl radicals (OH). This reaction is determined by the quantity of OH in the atmosphere, as well as the reactivity of the pollutant. Reactive compounds, such as VOCs and acids, can react with OH before OH can remove pollutants from the air, prolonging the atmospheric lifetime of those pollutants.[127] Further, many of these reactive compounds can influence the formation of secondary organic aerosols, which will further impact local air quality.[128]

Other pollutants that may form are acetaldehyde, ethylamine diethylamine, acetone, and acetic acid.[129]

121 Beard and Swager, "An Organic Chemist's Guide to N-Nitrosamines: Their Structure, Reactivity, and Role as Contaminants."

122 Luecken et al., "Sensitivity of Ambient Atmospheric Formaldehyde and Ozone to Precursor Species and Source Types Across the United States."

123 EPA SA, "Photochemical Smog - What It Means for Us."

124 Pye et al., The Acidity of Atmospheric Particles and Clouds.

125 US EPA, "Ground-Level Ozone Basics."

126 US EPA.

127 Permar et al., "Atmospheric OH Reactivity in the Western United States Determined from Comprehensive Gas-Phase Measurements during WE-CAN."

128 Yang et al., "Atmospheric Reactivity and Oxidation Capacity during Summer at a Suburban Site between Beijing and Tianjin.""ISSN":"16807324","abstract":"Hydroxyl (OH

129 Spietz et al., "Nitrosamines and Nitramines in Carbon Capture Plants."

REMOVAL OF NITROSAMINES AND NITRAMINES

The two mainstream methods of eliminating nitrosamine and nitramine emissions are by preventing their precursors, such as NO_x, from entering the post-combustion carbon capture system or by eliminating the nitrosamines and nitramines before they are released into the atmosphere from the carbon capture system.

Precursor prevention

There are multiple methods that can be used to prevent nitrosamine and nitramine precursors from entering the carbon capture system. Two of these methods involve preventing NO_x formation in the combustion chamber. One way to do this involves recirculating flue gas to reduce flame temperatures, resulting in lower-temperature combustion. This prevents NO_x from forming since NO_x needs a high temperature to form.[130] Another approach is to use oxyfuel combustion, where pure O_2 replaces ambient air in the combustion chamber. This also means that no NO_x forms because there is no N_2 in the input stream.

Other methods include removing NO_x after it has formed in the combustion chamber but before it enters the carbon capture system. A common way to do this is by using selective catalytic reduction (SCR) or non-selective catalytic reduction (NSCR). SCRs perform very well at removing one specific compound (such as NO_2, as done for this study) but have poor performance when removing other chemicals.[131] NSCRs perform moderately well at removing many different chemicals from a flue gas stream; an example of an NSCR is the catalytic converter on most automobiles.[132] The choice to use either an SCR or NSCR can vary depending on the specific conditions of the system being treated and the concentrations of chemicals within the flue gas.

Technologies that remove NO_x and other nitrosamine and nitramine precursors include ultraviolet (UV) irradiation, bio-treatment, polymerization, and activated carbon.[133] Activated carbon is ineffective at removing nitrosamines, but precursors can be removed. For bio-treatment, activated sludge can reduce nitrosamines, up to 60 percent, when concentrations are 15 ng/l or above.[134] It is worth noting that there is no single solution that will remove all nitrosamines and nitramines at present.

Yu et al. claim that NO_x removal is the best strategy since it would prevent the nitrosamines and nitramines from forming in the first place, which overall keeps them out of the system. However, NO_x removal technologies will add to the cost of CO_2 capture.[135]

Nitrosamine and nitramine elimination

There are a variety of ways nitrosamines and nitramines can be eliminated, including peroxidation, bio-treatment, photolysis, UV treatment, and ozonation.[136] Some of the best systems are either UV treatment or ozonation.

Certain carbon capture systems include wash-water units to prevent amine loss in the carbon capture system. However, NO_x and nitrosamines can also accumulate within the wash-water systems. Yu et al. discuss methods of treating these nitrosamines,

130 Mazari, Alaba, and Saeed, “Formation and Elimination of Nitrosamines and Nitramines in Freshwaters Involved in Post-Combustion Carbon Capture Process.”
131 US EPA, “Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR) Type.”
132 US EPA, “Nonselective Catalytic Reduction.”
133 Mazari, Alaba, and Saeed, “Formation and Elimination of Nitrosamines and Nitramines in Freshwaters Involved in Post-Combustion Carbon Capture Process.”
134 Mazari, Alaba, and Saeed.
135 Yu, Mitch, and Dai, “Nitrosamines and Nitramines in Amine-Based Carbon Dioxide Capture Systems: Fundamentals, Engineering Implications, and Knowledge Gaps.”
136 Mazari, Alaba, and Saeed, “Formation and Elimination of Nitrosamines and Nitramines in Freshwaters Involved in Post-Combustion Carbon Capture Process.”

nitramines, and NO_x using proposed in-line washer treatment systems, UV treatment, and ozone. Nitrosamines break down in the presence of UV light, a process known as photolysis,[137] which happens naturally when nitrosamines and nitramines are exposed to sunlight. According to Beard & Swager, artificial UV exposure and photolysis are effective,[138] but they can be expensive due to the high UV flux it requires to be effective. It also does not deal with nitrosamine precursors like NO_x; however, including ozone in this treatment can help to remediate this issue. Researchers are investigating the improvement of photolysis efficiency by including peroxydisulfate.[139]

Ozonation is best used as a post-UV treatment for any remaining amines that may be present in the final exhaust.[140] Overall, the best treatment system would be a combination of UV radiation and ozone since this can lead to 90 percent nitrosamine reduction.[141]

In addition to UV treatment and ozonation, there are other niche solutions to lower nitrosamine and nitramine emissions. One of these methods includes increasing the temperature of the desorber from 120°C to 140°C. A SINTEF Materials and Chemistry test showed a reduction in nitrosamine concentrations by 50 percent and nitramine concentrations by 75 percent with this method.[142]

Other proposed solutions include designing a different carbon capture solvent that prevents nitrosamine and nitramine formation within the carbon capture system. One alternative solvent, piperazine, has a sorption rate 2.6 times faster than traditional amine solvents, has a low heat of absorption, and has good thermal stability.[143] It can react to form nitrosamines but can be heated to 150 °C to degrade them.[144] As of 2019, piperazine was still under development.[145] Other potential solvents that are still being developed include amino acid salts, phase change solvents (e.g., Alstom chilled ammonia process), and ionic liquids.[146]

As mentioned above, sunlight photolysis can also break down nitrosamines and nitramines. Nitrosamines can also be rapidly degraded because of the OH radicals present within the atmosphere, which is a separate process from photolysis.[147] Water wash units and mist eliminators could be used to treat amines that are emitted, reducing the formation of nitrosamines and nitramines.[148] These systems prevent amine loss within the carbon capture system and prevent nitrosamines and nitramines, as well as amines, from being emitted into the atmosphere.[149]

137 Yu, Mitch, and Dai, "Nitrosamines and Nitramines in Amine-Based Carbon Dioxide Capture Systems: Fundamentals, Engineering Implications, and Knowledge Gaps."
138 Beard and Swager, "An Organic Chemist's Guide to N-Nitrosamines: Their Structure, Reactivity, and Role as Contaminants."
139 Beard and Swager.
140 Yu, Mitch, and Dai, "Nitrosamines and Nitramines in Amine-Based Carbon Dioxide Capture Systems: Fundamentals, Engineering Implications, and Knowledge Gaps."
141 Spietz et al., "Nitrosamines and Nitramines in Carbon Capture Plants."
142 Yu, Mitch, and Dai, "Nitrosamines and Nitramines in Amine-Based Carbon Dioxide Capture Systems: Fundamentals, Engineering Implications, and Knowledge Gaps."
143 National Petroleum Council, "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage."
144 National Petroleum Council.
145 Chen et al., "Evaluation of Concentrated Piperazine for CO_2 Capture from Coal-Fired Flue Gas (Final Report, REV0)."
146 Liang et al., "Recent Progress and New Developments in Post-Combustion Carbon-Capture Technology with Amine Based Solvents."
147 Spietz et al., "Nitrosamines and Nitramines in Carbon Capture Plants."
148 Gelowitz et al., "Part 8: Post-Combustion CO_2 Capture: Pilot Plant Operation Issues."
149 Gelowitz et al.

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