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# Siting Is a Constraint to Realize Environmental Benefits from Carbon Capture and Storage

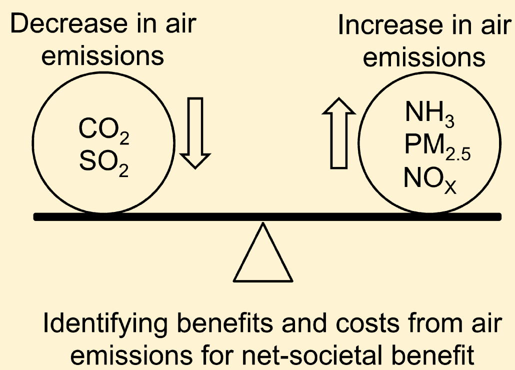
Ashok Sekar,[†] Eric Williams,[*,†] and Mikhail Chester[‡]

[†]Golisano Institute for Sustainability, Rochester Institute of Technology, 111 Lomb Memorial Drive, Rochester, New York 14623, United States

[‡]Civil, Environmental, and Sustainable Engineering, School of Sustainability, Arizona State University, Tempe, Arizona 85287, United States

Supporting Information

**ABSTRACT:** Carbon capture and storage (CCS) for coal power plants reduces onsite carbon dioxide emissions, but affects other air emissions on and offsite. This research assesses the net societal benefits and costs of Monoethanolamine (MEA) CCS, valuing changes in emissions of $CO_2$, $SO_2$, $NO_X$, $NH_3$ and particulate matter (PM), including those in the supply chain. Geographical variability and stochastic uncertainty for 407 coal power plant locations in the U.S. are analyzed. The results show that the net environmental benefits and costs of MEA CCS depend critically on location. For a few favorable sites of both power plant and upstream processes, CCS realizes a net benefit (benefit−cost ratio >1) if the social cost of carbon exceeds \$51/ton. For much of the U.S. however, the social cost of carbon must be much higher to realize net benefits from CCS, up to a maximum of \$910/ton. While the social costs of carbon are uncertain, typical estimates are in the range of \$32−220 per ton, much lower than the breakeven value for many potential CCS locations. Increased impacts upstream from the power plant can dramatically change the social acceptability of CCS and needs further consideration and analysis.




## INTRODUCTION

Carbon capture and storage (CCS) on coal power plants is under development as a candidate to mitigate climate change.[1] There are different technological routes, all are still in pilot or testing phase.[2] $CO_2$ capture using liquid sorbents such as Monoethanolamine (MEA) is one of the most mature options.[3] MEA functions as a regenerative sorbent, first absorbing $CO_2$ from the flue gas and then with high temperatures releasing it. Effective regeneration of MEA necessitates reduction of acidic gases ($SO_2$, $NO_X$, HCl, and HF) and 2.5 $\mu$m of particulate matter ($PM_{2.5}$) in the flue gas below regulatory limits.[4] There are, however, trade-offs. High energy requirements derate the net output of the power plant by 23−30%,[5,6] and the additional fuel requirement leads to increased upstream air emissions from mining, processing and transportation of additional coal. The upstream air emissions are greenhouse gases ($CO_2$, $CH_4$), criteria pollutants ($PM_{2.5}$, $SO_2$, $NO_X$), and ammonia ($NH_3$), which is generated when the flue gas reacts with MEA.[7]

With the goal of understanding if benefits exceed costs, we assess MEA CCS for U.S. coal plants via an integration of life cycle inventory (LCI), risk analysis, and benefit−cost approaches. It is well-known that the environmental impacts of some air pollutants vary significantly by location,[8−10] thus benefits and costs of CCS depend on where power plants and processes in the supply chain are located. Accounting for environmental emissions of supply chains is the domain of life cycle assessment (LCA),[11] or more precisely, LCI. The resulting spatially dependent emissions can be linked to a model describing the geographical heterogeneity of environmental impacts. Health impacts of air pollution are simulated via integrated risk analysis models that combine fate, transport, exposure and dose−response.[12] Translating illness and premature death into economic value is the domain the benefit−cost analysis.[13] To summarize the scope of our study, we (1) perform an LCI to estimate differences in emissions of $PM_{2.5}$, $SO_2$, $NO_X$, $NH_3$, VOC, and $CO_{2\text{-equiv}}$, for a coal power plant with and without MEA CCS, including upstream processes; (2) use risk analysis models to monetarily value the marginal health impacts of air emissions as a function of power plant and upstream process locations; and (3) estimate the social cost of carbon required to make the benefit−cost ratio of CCS exceed one (breakeven carbon cost).

Placing this work in a broader context, mitigation options for $CO_2$ often induce trade-offs for other environmental emissions. There is a general need for methods to account for geographic heterogeneity and supply chain processes. The integration of risk assessment and LCA to address this is under development and

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has been applied to biofuels, electric vehicles, and shale gas production, PV and wind.[14−17] Our approach advances existing methods in three respects, as described in the next section.

There are a number of prior LCA studies of CCS technologies[18−25] and two meta-analyses of those LCA studies.[26,27] In general, the results reveal a tension between benefits from reduced $CO_2$ emissions at the plant and increased emissions elsewhere, for example, from mining additional coal upstream to make up for the efficiency penalty of CCS. No previous studies have assessed the social acceptability of CCS.

## METHODS TO ASSESS GEOGRAPHICALLY VARIABLE BENEFITS AND COSTS OF A TECHNOLOGY

In this section, we overview the challenges in characterizing the geographic heterogeneity and social acceptability of a technology. Methodological approaches and our contributions to these challenges are described.

Figure 1 illustrates the steps in the modeling framework. In the LCI stage, the physical quantities and locations of emissions are estimated. Using the process-sum approach to LCI,[28] the first step is choosing of a set of material flows and emissions to track. Next, a subset of processes in the supply chain is selected to include in the boundary of the analysis. Data describing the material inputs and outputs for included processes are gathered. Finally, calculations are performed to yield the supply chain material flow per unit of functionality (e.g., grams of $CO_2$ emissions per kWh of electricity generated).

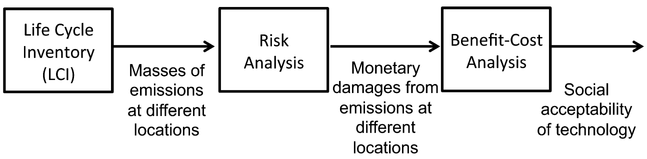


**Figure 1.** Flowchart of a method assessing social acceptability of a technology by combining life cycle inventory, risk analysis, and benefit−cost analysis.

The risk analysis stage translates the physical emissions from the LCI to an integrated impact indicator, such as monetary damage, disability adjusted life years (DALYs),[29] or a damage "index" (e.g., eco-points from Eco-Indicator 99).[30] We focus here on monetary measures of damages, also called social costs, following NRC (2010).[31] Note that social cost is distinct from mitigation cost, the latter being the economic cost to reduce an emission. To summarize the modeling flow for human illness and premature mortality damages, risk analysis starts with physical modeling of fate and transport of emissions from the source to determine concentrations of pollution as experienced by humans.[32] Transport of air emissions, for example, is modeled based on source location, height of release and weather conditions such as wind speed and temperature. The next modeling stage is medical in nature, characterizing exposure and dose−response relationships that relate pollution concentrations to probabilities of developing an illness (e.g., asthma) or premature death.[33] Depending on the situation, direct and indirect exposure pathways may be considered, for example, human inhalation of air pollution or by ingesting exposed animals or plants. The last stage relates numbers of cases of environmentally induced illnesses and premature deaths to monetary value. For illnesses the cost of medical treatment is often used[9] and premature deaths are typically assessed by the value of statistical life (VSL).[34]

In the benefit−cost analysis stage, the social value of net reduced damages (benefits) is compared with the economic cost to implement a technology. The basic principle followed is that benefits must exceed costs to be acceptable to society.[13] A geographically sensitive implementation of this model tracks emissions, valuations and benefits/costs as a function of where a technology is implemented.

There are a number of data and methodological challenges with realizing the model depicted in Figure 1. We address three challenges in this manuscript: scarce data on processing locations in the supply chain, uncertainty in the risk analysis stage, and the question of useful indicators of social acceptability.

**Challenge 1 (LCI Stage): Scarce Data for Locations of Processes in Supply Chain.** A major challenge in the LCI stage is a lack of data describing the geographical location of supply chain processes. In prior studies of other technologies, analysts have addressed data scarcity by using available geographically specific data.[15,31] Coal power, for example, the locations of power plants and coal mines in the U.S. are described in (E-GRID[35]) and (USGS[36]). This approach has three limitations. One limitation is that data detailing locations of production is only available for a subset of processes in a supply chain. A second limitation is that available data, at best, informs the geographical location of production (e.g., tons produced in each U.S. county) but not at what facilities this production is used. There is no public data describing, for example, where limestone is mined for each coal mine. Third, this approach only applies to describe an existing supply chain, in many cases one is interested in a new supply chain for which process locations are as yet unknown.

Our approach to address scarce geographic data is to use a scoping approach that does not detail the impacts of a particular supply chain, but instead characterizes the range of impacts that can arise from geographical variability. This bounding is achieved through treating a supply chain as only having two locations, one location for the coal plant and a second location for all upstream processes for the plant (e.g., coal and limestone mining, MEA production). This is illustrated in Figure 2. For each of 407 power plants, the supply chain is allocated to each of the 3110 counties of the contiguous U.S. to a total of 1,265,770 combinations. From these combinations, we identify the best, median, and the worst supply chain locations and then focus on how damages vary by power plant location for these three cases of upstream process locations.

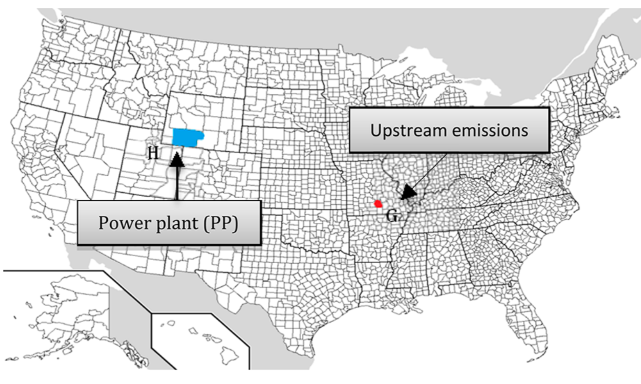


**Figure 2.** Bounding approach to geographic variability: variable location for power plant (index $h$ = 1−407 for current plant locations) and upstream supply chain (index $g$ = 1−3110 for possible counties in U.S.).

Accounting for geographic variability in transportation impacts would require a model that tracks vehicle movements through every county between origin and destination. This is difficult, if not impossible, given our scope to assess all possible locations of power plant and supply chain. Also, since we achieve this scope by locating all supply chain processes in a single county, the results of a detailed transportation model would not be meaningful. A reasonable treatment of transportation requires a list of locations of facilities in the supply chain and is thus only doable when considering specific CCS projects. We thus restrict our model coverage to geographic variability in facility location, treating transportation as taking place in the supply chain county using a fixed distance typical of current coal mine and power plant supply links,[37] that is, replace a variable quantity with its average. We comment on the implications of neglecting transportation variability in the Uncertainty/Caveats section.

**Challenge 2 (Risk Assessment Stage): Uncertainty in Models of Marginal Damages from Air Pollution.** Mapping an emission in a location to monetary damages involves a complicated integration of models, resulting in uncertainty.[9,38] These uncertainties result in assessment models by different analysts giving varying results for the same pollutant and geographical setting. Most pertinent to our case study, there are currently two publicly available models describing county-by-county marginal emission damages for air pollution in the U.S. Levy et al. (2009) is a stochastic model for human health impacts in terms of marginal damage cost ($/ton) for primary $PM_{2.5}$ and secondary $PM_{2.5}$ from $SO_2$ and $NO_X$ emissions.[8] The Air Pollution Emissions Experiments and Policy (APEEP), and its revision APEEP2, is a model of marginal damage cost that evaluates the impacts of $PM_{2.5}$, $SO_2$, $NO_X$, VOC, and $NH_3$ on human health, agricultural and forest yield loss, building materials, and recreation.[9,10] We analyzed differences in results between the APEEP, APEEP2 and Levy et al. (2009) models. For counties with coal power plants, the ratio of Levy et al. and APEEP2 results for marginal damages for $PM_{2.5}$, $SO_2$, and $NO_X$ varies from 0.3−23, depending on the county. The average ratios of the two models for marginal damages are 3 ($\sigma = 1.78$), 1.25 ($\sigma = 0.5$), and 1.5 ($\sigma = 0.6$) for $PM_{2.5}$, $SO_2$, and $NO_X$, respectively. Sufficiently large difference in marginal damage costs could lead to different conclusions as the societal benefit of a technology. There are also differences between multiple versions of APEEP. For example, the ratio of PM damages for APEEP2 and APEEP ranges from 4−235, depending on the county. The large differences between models and their versions present a puzzle as to which is best to use.

How to address the wide variation in results from marginal damage models? In the long term, efforts are needed from the risk analysis community to critically refine models and achieve consensus. Such a task is well beyond the scope of this article. Our approach is to (1) develop a "base case" model combining APEEP2 and Levy et al. models and (2) characterize the range in results arising from model choice. Though modest, our treatment of uncertainty is an advance in the state of the field. Prior uses of marginal damage emissions models pick one model without consideration of alternative choices.[14,15,17]

**Challenge 3 (Benefit−Cost Analysis Stage): Indicator of Social Acceptability Given Uncertain Social Cost of Carbon (SCC).** The output of the risk analysis stage is location-dependent economic damages from the supply chain. To support decision making it is desirable to translate these damages into a measure of social acceptability. Benefit−cost analysis is a widely used to measure acceptability, typically expressed as a benefit−cost ratio, which for our model of CCS takes the form

$$\text{benefit−cost ratio}_{h,g} = \left[\frac{\mathrm{CO_2\ cost} \times \mathrm{CO_2\ reduction} + \sum_i (Q_{h,i} \times \mathrm{MD}_{h,i} + Q_{g,i} \times \mathrm{MD}_{g,i})}{\text{economic cost to implement}}\right] \quad (1)$$

where $h$ is the power plant location and $g$ is the supply chain location. $Q$ is the difference in the CCS versus no-CCS emissions in g/kWh and MD is the marginal damage cost in $/ton. The index $i$ denotes an emission: $PM_{2.5}$, $SO_2$, $NO_X$, $NH_3$, or VOC. A benefit cost ratio larger than one is a necessary (if not sufficient) condition for a technology to be socially desirable.

The primary benefit of CCS is presumably reduction in $CO_2$ emissions. In the previous subsection, we reviewed how damages from criteria air pollutants can be described with risk analysis models,[8,9,39] we have not yet discussed how the social costs of carbon might be monetized. A variety of prior models estimate the monetary damages of climate change including factors such as agricultural productivity, human health impacts, natural disasters, and sea-level rise. The "Social Costs of Carbon" study, authored by a U.S. government multiagency task force,[40] provides a meta-analysis of different models. For a 3% discount rate, the study benchmarks the distribution of 2010 damages from $CO_2$ with a median of $32 per ton and a 95th percentile of $89 per ton. In 2050, the distribution of social cost has a median of $71 per ton and 95th percentile value of $220 per ton.

Herein lies the challenge: The models for social costs of carbon tackle a qualitatively different problem than those for $PM_{2.5}$, $SO_2$, $NO_X$, $NH_3$, or VOC, and in our opinion, are far more uncertain. Three reasons that carbon damages are uncertain are that they (1) depend on uncertain changes in climate, (2) occur further in the future (i.e., decades), and (3) are sensitive to how societies adapt to climate change.[41,42] Also, the damages are much less sensitive to location than for other air pollutants, suggesting that carbon ought to be treated differently.

Our approach to the uncertainty in the SCC: Rather than use current estimates to calculate a benefit−cost ratio, we invert the problem to calculate the SCC *required* to make the benefit−cost ratio larger than one. The result is a breakeven carbon cost necessary for CCS to be socially beneficial.

In a stochastic model, the breakeven carbon cost is the value that satisfies eq 2

$$\begin{aligned}&\{\mathrm{prob.}[(\mathrm{CO_2\ social\ cost}\cdot \mathrm{CO_2\ reduction}\\ &\quad + \text{costs or benefits from other emissions})\\ &\quad /(\text{economic cost to implement})] = 1\} = 90\%\end{aligned} \quad (2)$$

A 90% confidence level is our normative choice, other values could be used. The breakeven carbon cost varies by location according to how damages from non-$CO_2$ pollutants (indirect damages of CCS) affect the numerator of eq 2. If a $CO_2$ mitigating technology reduces non-$CO_2$ emissions, the costs in the numerator fall in (2), requiring a lower SCC to obtain a benefit−cost ratio >1, that is, the breakeven carbon cost will fall. Conversely, an increase in non-$CO_2$ emissions will raise the breakeven carbon cost. Note that if only $CO_2$ is considered and with no stochastic distributions, eq 2 reduces to the requirement that breakeven carbon cost equal to the economic cost of mitigating carbon with MEA CCS, found elsewhere to be $70/ton.[43] We argue that the measure in eq 2 has broad utility because it distills a broad range of systems issues into a single measure

Table 1. Life Cycle Inventory of Coal Power Plant without and with CCS and Marginal Damage Cost from Valuation Model Distinguished Based on the Height of the Source[a]

| emissions | power plant (g/kWh) no CCS | power plant (g/kWh) CCS | supply chain (g/kWh) no CCS | supply chain (g/kWh) CCS | total (g/kWh) no CCS | total (g/kWh) CCS | percent change − CCS vs no CCS | marginal damage cost ($1000/ton) higher level emission | marginal damage cost ($1000/ton) ground level emission |
|---|---|---|---|---|---|---|---|---|---|
| $PM_{2.5}$ | 0.04 | 0.02 | 0.04 | 0.07 | 0.08 | 0.1 | +25% | 30 to 530 | 2.3 to 1600 |
| $SO_2$ | 0.36 | 0.05 | 0.29 | 0.45 | 0.65 | 0.5 | −23% | 5.8 to 1 | 3 to 520 |
| $NO_X$ | 0.36 | 0.45 | 0.19 | 0.29 | 0.54 | 0.73 | +34% | 0.47 to 14 | −2.1 to 47 |
| $NH_3$ | 0 | 0.24 | 0.07 | 0.01 | 0.07 | 0.34 | +364% | 0.65 to 830 | 0.78 to 3100 |
| VOC | 0.01 | 0.01 | 0.19 | 0.25 | 0.19 | 0.26 | +37% | 0.24 to 390 | 0.31 to 150 |
| $CO_{2eq}$ | 720 | 120 | 37 | 48 | 760 | 170 | −78% | assume variable | |

[a]Note: marginal damage costs for higher level $PM_{2.5}$, $SO_2$ and $NO_X$ are taken from Levy et al.,.[8] while the remaining damages are from APEEP2[10].

with a simple interpretation useful in decision-making. To our knowledge, breakeven carbon cost is a new measure.

## MODEL BUILDING TO ASSESS MEA CARBON CAPTURE AND SEQUESTRATION

Following the methodology shown in Figure 1, we build a model to estimate the breakeven carbon cost of MEA CCS applied to a coal power plant as a function of location of the power plant and its upstream processes. We focus only on major air pollutants because previous studies of coal power indicated that air emissions account for about 90% of total damages.[44] For storage, we focus on geological sequestration without enhanced oil recovery (EOR). EOR uses $CO_2$ to increase the yield of oil from reserves. Assessment with EOR is complicated by the question of how to allocate emissions from the extracted oil. If CCS is deemed "responsible" for the oil used, the carbon benefits of CCS are much reduced. We make no attempt to settle this debate, but for informational purposes we analyze EOR in the Supporting Information.

To account for uncertainty, we perform Monte Carlo analysis to find distributions in outcomes given input distributions for marginal damages from air pollutants and economic cost of CCS. Data scarcity prevents us from developing distributions for the LCI stage, and we choose an optimiztic (low) value for energy penalty to give CCS a degree of benefit of doubt. We use both triangular and rectangular distributions, the qualitative results turn out not to be sensitive to this choice. The results in the main text are based on triangular distributions. Results for uniform distributions (shown in the Supporting Information) give qualitatively similar results.

We summarize the modeling for LCI, risk analysis, and benefit−cost analysis stages below and details can be found in the Supporting Information.

**Life Cycle Inventory (LCI).** A cradle-to-grave analysis is performed to estimate the emissions of $CO_2$, $PM_{2.5}$, $SO_2$, $NO_X$, $NH_3$, and VOC emissions per kilowatt-hour generated by a pulverized coal plant with and without MEA CCS. The term $CO_2$-eq in this article refers to both $CO_2$ and methane, using a $CO_2$ equivalency factor of 25 for methane.[45] The LCI for the baseline coal power plant without MEA CCS is drawn from a previous study by Spath et al. (1999).[37] The system boundary includes coal mining, equipment manufacturing, transportation, chemical production for mining and power plant operations, as well extraction of raw materials and the production of intermediate feedstocks (e.g., limestone used in the gas cleanup process at the power plant) and the disposal of wastes. The power plant has a 42% thermal efficiency. The coal used by Spath et al. (1999) is Illinois No.6 coal as it is representative of widely available bituminous coal.[37,46] Previous studies note that the LCI of coal power is sensitive to the type of coal.[19,20,23] The models we use to characterize the combination of coal combustion/desulfurization/MEA CCS do not allow treatment of different coal compositions. We thus focus on typical U.S. coal and hope that future modeling will be able to resolve the issue. The basic dynamic at play of requiring more coal for CCS is true for any type. Coal is assumed to be transported 434 km by rail car and 48 km by barge. The lifetime of the power plant is taken to be 30 years.

MEA CCS is assumed to incur an energy penalty, that is, decrease in electrical output, of 23%, on the low end of the 23−30% range discussed in the literature.[4,7,27] This corresponds to a 31% increase in fuel input per unit of delivered electricity. The MEA technology captures 90% of $CO_2$ leaving the stack. The material requirements and emissions from operation of the capture plant are modeled based on results from IECM model.[7] The LCI for manufacturing of MEA and the infrastructure to install the capture plant is obtained from Koornneef et al. (2008).[18] Storage is assumed to occur via pipeline transport. Most $CO_2$ sources (96%) are located within 160 km from candidate geological formations.[47] For geological sequestration, the LCI from drilling and construction of pipelines to a saline aquifer is assumed.[48] Note that the pipeline distance and type of sequestration contribute to less than 1% of the total emissions do not affect the LCI results.[18,46,49]

The onsite emissions are taken as emitted from the smoke stack while supply chain emissions occur at ground level (mining, transportation and material manufacturing and processing). Classifying the height of emission release is important because it impacts how the emissions are transported in the atmosphere. For quantifying the LCI, we assume that upstream air emissions experience uniform increases due to the need to produce additional coal and inputs to the MEA process.

**Risk Analysis to Obtain Monetary Damages.** In this part, we utilize prior risk analysis models to find marginal damages of emissions ($/ton) and multiply by masses of emissions from the LCI stage to find monetary damages as a function of locations of power plant and upstream supply chains.

The two models to draw from are Levy et al. and APEEP2, discussed in the previous section. A baseline choice of marginal damage model is made and the variability of results to other models is assessed. Our baseline choice (denoted Levy + APEEP2) is to use Levy et al.[8] when possible (smokestack level emissions of $PM_{2.5}$, $SO_2$, and $NO_X$), and APEEP2[10] for emissions not covered by Levy et al. (smokestack level $NH_3$ and VOC and ground level emissions of $PM_{2.5}$, $SO_2$, $NO_X$, $NH_3$, and VOC). The main reason we favor Levy et al. for coal plant emissions is that the model uses a height for emissions that matches the effective heights of power plant smokestacks. APEEP2, in

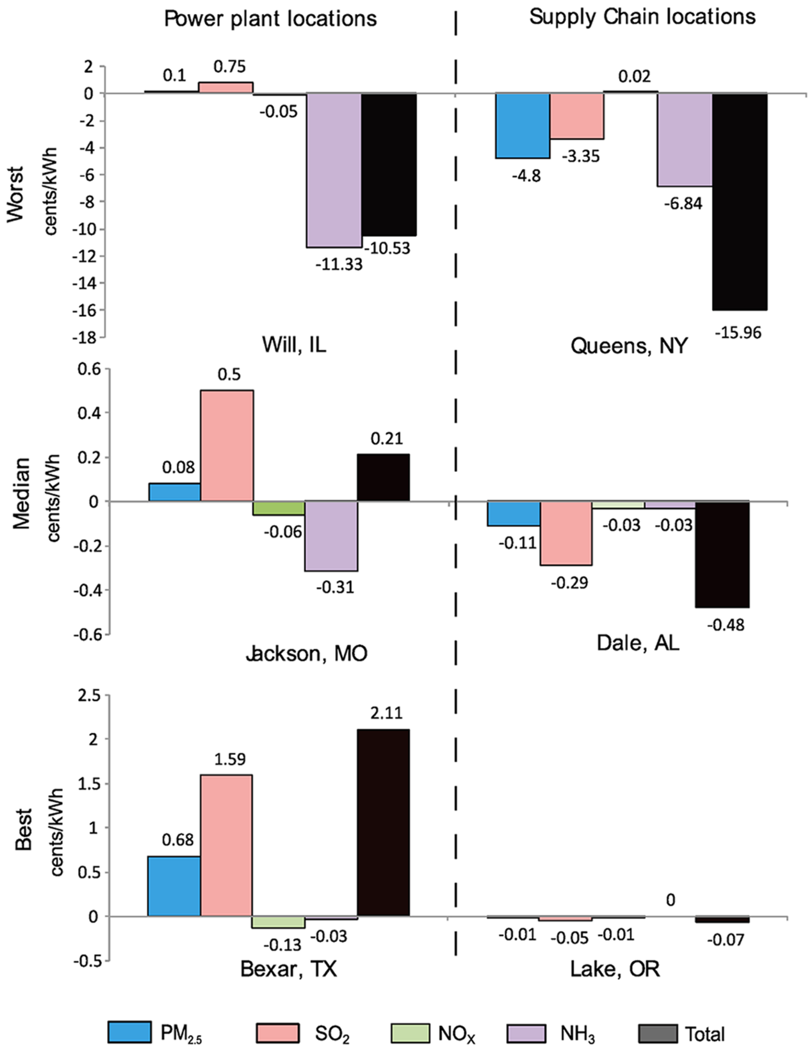


**Figure 3.** Valuation of benefits and costs in in six U.S. counties: Results of multiplying change in emission (CCS − no CCS) by marginal damage factors for $PM_{2.5}$, $SO_2$, $NO_X$, and $NH_3$.

contrast, divides emissions height into ground level and above ground categories only. An aggregated "above ground category" is not suitable for coal power plants, whose effective emission height >500 m significantly reduces damages compared to a lower emission height. We also note that Levy et al. was developed as a stochastic model from the outset, and APEEP started out as a deterministic model, evolving into a stochastic APEEP2 with very different median results from its predecessor.

**Benefit−Cost Analysis.** Damages from the risk analysis stage are combined with economic cost of CCS to find the breakeven carbon cost defined in eq 2. To explain when CCS is a cost or benefit in the numerator of eq 2, a benefit (positive monetary value) corresponds to an emission reduction (e.g., $SO_2$). A cost, or negative benefit, occurs with an emission increase (e.g., $PM_{2.5}$).

The economic cost to implement CCS comes taken from a meta-analysis that reports a levelized cost between 2.6 and 3.6 cents/kWh.[50] This study critically analyzed and reviewed seven independent design and cost studies and estimated the levelized cost of electricity for the U.S. conditions under similar financial assumptions. The levelized cost is comprised of capital charge, operation and maintenance costs, and fuel costs.

## RESULTS

**Life Cycle Inventory.** The LCI of a coal plant with and without CCS is estimated following the discussion in the previous section. Summary results are shown in Table 1, detailed assumptions and results appear in the Supporting Information. CCS results in net reductions of $CO_2$-equiv and $SO_2$ emissions, but net increases for $PM_{2.5}$, $NO_X$, $NH_3$, and VOC. Note that emissions have been divided into two categories, onsite and upstream. As the name implies, onsite emissions are those from the operation of the power plant and MEA CCS. The upstream air emissions are from the supply chain activities like mining of coal, transportation of coal, and production of materials for operation.

**Economic Damages from Non-$CO_2$ Emissions.** Economic damages from non-$CO_2$ emissions are calculated according to the right part of the numerator in eq 1

$$\text{non-CO}_2\ \text{damages}_{h,g} = \sum_i (Q_{h,i} \times \text{MD}_{h,i} + Q_{g,i} \times \text{MD}_{g,i}) \quad (3)$$

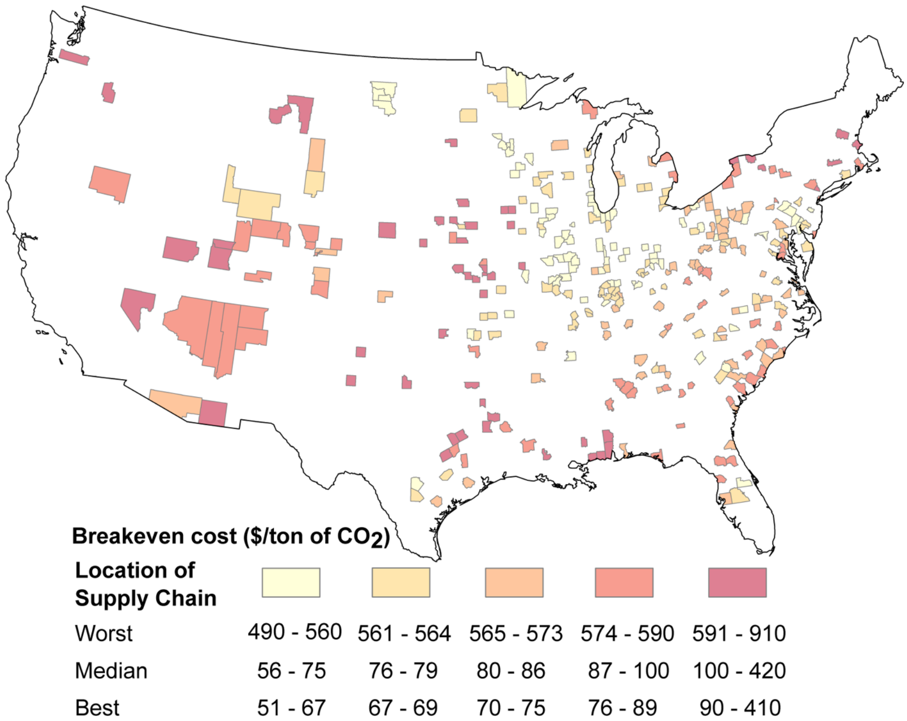


**Figure 4.** Breakeven carbon cost required to yield 90% probability that benefit cost ratio >1 for 407 coal power plants with MEA CCS at worst, median and best locations for supply chain. The legend is divided into quintiles based on the number of power plants. All values are in U.S.$2000. To be socially beneficial, the breakeven carbon cost should less than the social cost of carbon (estimated to range from $32–220/ton).

We combine the LCI results from Table 1 with our baseline marginal damages ($MD_{h,i}$ and $MD_{g,i}$) for all possible combination of locations of power plant *h* and supply chain *g*.

The 1,265,770 combinations of counties for supply chain and power plant are too many to display. In Figure 3, we show an illustrative subset of total monetary damages/benefit in cents per kWh from $PM_{2.5}$, $SO_2$, $NO_X$, $NH_3$ for the worst, median and best power plant and supply chain locations. Positive values indicate benefit and negative values are damages. Damages from VOC are small and not displayed.

Figure 3 shows considerable variation in benefit and damages by county, and in this section, we aim to explain why. In general, siting the power plant in a county has benefits from onsite reduction of $PM_{2.5}$ and $SO_2$ and damages from increased emissions of $NH_3$. Therefore, the best power plant location should have higher marginal damages cost for $PM_{2.5}$ and $SO_2$ and a lower marginal damage cost of $NH_3$. Since CCS increases all emissions from the supply chain, the location with lowest marginal damage cost is the best supply chain location.

To summarize key points on the chemistry of emissions, $NH_3$, $SO_2$, and $NO_X$ are precursors of $PM_{2.5}$. $NH_3$ forms ammonium ions ($NH_4^+$), which first reacts with $SO_2$ forming ammonium sulfate, the remaining $NH_4^+$ reacts with $NO_X$ to form ammonium nitrate. Ammonium sulfate and ammonium nitrate are particulates, contributing to $PM_{2.5}$ concentrations. Also, formation of particulate nitrate is a decreasing function of temperature. In some circumstances, $NO_X$ emissions can result in health benefits by reducing ozone concentrations through a well-documented process called titration.

Factors that lead to variability in marginal damage cost of a county include population, wind speed, wind direction, temperature. Will, IL, is the worst location for a power plant for two reasons. First, the population is low therefore the benefit from reducing $PM_{2.5}$ emissions is low. Second, it takes $NH_3$, $SO_2$, and $NO_X$ time to react, and because of prevailing winds, these are blown into the Chicago area before becoming particulates, causing high damages because of the high population in Chicago. Since the increase in $NH_3$ emissions is greater than the reduction of $SO_2$, $NH_3$ damages outweigh the benefits of $SO_2$ reduction. Bexar, TX, is the best power plant location because the county has well-populated San Antonio; therefore, reductions in $PM_{2.5}$ and $SO_2$ delivers large benefits. The lower damage cost of $NH_3$ can be attributed to relatively warmer temperatures, suppressing particulate formation. Also, southern winds move the $NH_3$ to lower population areas. For supply chain, damages tend to correlate with population, with Queens, NY, being the worst location and Lake, OR, the best location.

**Breakeven Carbon Cost As a Function of Supply Chain and Power Plant Locations.** Next the breakeven carbon costs (eq 2) for 1,265,770 combinations of upstream processes and coal power plant locations are calculated. Given our goal to bound geographical variability, we search these results to identify three locations for the upstream supply chain for each coal plant: best (lowest damages), median, and worst (highest damages). We then show these three values of the breakeven carbon cost for 407 coal power plant locations in the U.S. in Figure 4.

To summarize numerical aspects of the results, depending on the location of the power plant, the breakeven carbon cost varies from $51–410, $56–420, and $490–910 per ton for the best, median and worst supply chain cases respectively, in year 2000 dollars. How to interpret these numbers? Recall from the previous discussion that estimates of the SCC range from $32–220/ton. The breakeven carbon cost must be lower than SCC for carbon capture and storage to be beneficial to society.

In summary, the main points from Figure 4 are as follows: (1) CCS is currently a "no-go" for many locations of power plant and supply chain in the sense that the breakeven carbon cost exceeds the upper range of the expected social cost of carbon (220

\$/ton). Technological improvements are needed for CCS to be socially acceptable in many locations, that is, some combination of reducing the energy penalty below 23% and lowering ammonia emissions. (2) For ideal locations of plant and supply chain, the breakeven carbon cost is as low of \$51/ton, \$19/ton less than if non-$CO_2$ emissions were excluded from the analysis (\$70/ton). Appropriate siting of CCS can thus deliver cobenefits beyond carbon reductions. Ensuring cobenefits is nontrivial, however. For a median supply chain, fewer than 20% of power plant sites yield a breakeven carbon cost less than \$70/ton.

## UNCERTAINTY/CAVEATS

We first discuss consequences of neglecting geographic variability in transportation. In the baseline case, the share of transportation impacts for $CO_2$, $SO_2$, $PM_{2.5}$, and NOx of total supply chain + power plant emissions ranges between 10% and 25% (see Supporting Information, Tables S7 and S8). Large changes in transportation distance could influence results. We simplify the consideration of variability in transportation to two cases: (1) When transport distances are lower than the baseline case, the share of transportation decreases, making the damage function values for supply chain and power plant locations more important. In this case the qualitative conclusions from the Results section remain unchanged. (2) When transportation distances are larger than the baseline case, The breakeven carbon cost for CCS is increased because more ton-km of transport are required with CCS (more coal and MEA). With sufficiently long distances, transportation could dominate total impacts, though as long as the main transportation is within the continental U.S., impacts from supply chain and power locations will still be important. For very long transport distances, the conclusions from the Results section should be modified to read that *locations* and *distances* between supply chain + power plant processes critically affect the breakeven carbon cost.

Considering how the choice of valuation model might influence results, results and discussion for other model choices (Levy et al. only or APEEP2 only) can be found in the Supporting Information. While the numerical results can change considerably, the qualitative conclusions drawn from the results are not sensitive to the choice of marginal damage model.

## DISCUSSION

Non-$CO_2$ supply chain impacts could potentially push the social cost of carbon needed to make CCS socially beneficial into the hundreds of dollars per ton. This result has two implications for the future of CCS.

One implication is that the siting of CCS plants and their supply chains is critical in realizing social benefits. Our bounding approach does not cover specific CCS projects, as this would require a more detailed model accounting for the particulars of locations and transportation. Our results indicate however project level assessment of CCS projects, including non-$CO_2$ emissions, is needed.

The second implication is that technological progress is needed to make CCS beneficial in a wider variety of geographical contexts. Society may invest in a technology with high threshold cost, such investments are done when there is an expectation that technological improvement will lead to e.g. significant cost reductions.[51] Extensions of our model could be used to find target cost and efficiency values that would make CCS socially beneficial.

The bounding model and measure of breakeven carbon cost developed here are applicable to any energy technology. The main virtues of the approach are (1) the range of geography-driven variability in impacts can be found without detailed location data, just specification of a general region (e.g., within the U.S.) and (2) the breakeven carbon cost provides a useful scalar measure of the "distance" a technology is from social acceptability. We see potential for these and related methods to provide insights to support development and deployment of energy technologies.

## ASSOCIATED CONTENT

### Supporting Information

(1) Literature review of MEA CCS and valuation models, (2) detailed description of the life cycle inventory model, and (3) additional results that support the main text such as breakeven carbon cost for other scenarios (APEEP2 only, Levy only, or supply chain scenarios). This material is available free of charge via the Internet at http://pubs.acs.org/.

## AUTHOR INFORMATION

### Corresponding Author

*Phone: 585-475-7211. E-mail: exwgis@rit.edu. Fax: 585-475-5455.

### Notes

The authors declare no competing financial interest.

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