

A Technical, Economic, and Environmental Assessment of Amine-Based CO₂ Capture Technology for Power Plant Greenhouse Gas Control

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Capture and sequestration of CO₂ from fossil fuel power plants is gaining widespread interest as a potential method of controlling greenhouse gas emissions. Performance and cost models of an amine (MEA)-based CO₂ absorption system for postcombustion flue gas applications have been developed and integrated with an existing power plant modeling framework that includes multipollutant control technologies for other regulated emissions. The integrated model has been applied to study the feasibility and cost of carbon capture and sequestration at both new and existing coal-burning power plants. The cost of carbon avoidance was shown to depend strongly on assumptions about the reference plant design, details of the CO₂ capture system design, interactions with other pollution control systems, and method of CO₂ storage. The CO₂ avoidance cost for retrofit systems was found to be generally higher than for new plants, mainly because of the higher energy penalty resulting from less efficient heat integration as well as site-specific difficulties typically encountered in retrofit applications. For all cases, a small reduction in CO₂ capture cost was afforded by the SO₂ emission trading credits generated by amine-based capture systems. Efforts are underway to model a broader suite of carbon capture and sequestration technologies for more comprehensive assessments in the context of multipollutant environmental management.

Introduction

The control of greenhouse gases is arguably the most challenging environmental policy issue facing the U.S. and other countries. An approach that is gaining widespread interest is to control CO₂ emissions by capturing and sequestering CO₂ from fossil-fuel combustion sources (1, 2). The key attraction of this option is that it can allow fossil fuels to continue to be used without contributing significantly to greenhouse warming. This would be a radical departure from conventional thinking about climate mitigation, which would require eliminating or severely limiting the use of fossil fuels. Given our high degree of reliance on fossil fuels (roughly 85% of commercial energy use domestically and globally) and the difficulties—technical, economic, and social—of large-scale use of alternative options (like nuclear and renewables), the ability to use fossil energy while avoiding greenhouse gas

emissions is a potentially attractive alternative that needs to be carefully studied. Coal-based power plants, which contribute about 30% of total U.S. CO₂ emissions, are the principal targets for this type of CO₂ control technology (3–5).

Technology Options for CO₂ Capture. A wide range of technologies currently exist for separation and capture of CO₂ from gas streams (Figure 1), although they have not been designed for power-plant-scale operations (6). They are based on different physical and chemical processes including absorption, adsorption, membranes, and cryogenics (7–11). The choice of a suitable technology depends on the characteristics of the flue gas stream, which depend mainly on the power plant technology. Future coal-based power plants may be designed to capture CO₂ before combustion (using coal gasification systems), or they may employ pure oxygen combustion instead of air to obtain a concentrated CO₂ stream for treatment. Figure 2 shows the variety of power plant fuels and technologies that affect the choice of CO₂ capture systems.

Options for CO₂ Sequestration. Once the CO₂ is captured, it needs to be securely stored (sequestered). Again, there are a range of options potentially available. Geologic formations including deep saline reservoirs, depleted oil and gas wells, and unmineable coal seams are some of the potentially attractive disposal sites (12–14). Ocean disposal is another option being studied (15, 16). The distance to a secure storage site and the availability and cost of transportation infrastructure also affect the choice of disposal option. In general, studies indicate that geologic formations are the most plentiful and attractive option for U.S. power plants (17). While the economic costs of CO₂ storage appear to be low, its social and political acceptability are not yet clear, especially with regard to ocean sequestration.

Scope of This Study

This research is motivated by a desire to better understand the technological options for CO₂ capture and sequestration and their possible role in climate mitigation policy. Because the topic is fairly new, some of the key research questions that need to be addressed include the following: What kind of technologies may be used for capture and storage of CO₂? What are the key parameters that affect the performance, cost and environmental acceptability of different options? How do the alternative options compare in terms of these considerations? What are the uncertainties associated with different options? What are the benefits of R&D to reduce key uncertainties?

To begin addressing such questions, this paper focuses on current coal combustion systems. Today the 300 GW of coal-fired power generation capacity in the U.S. provides 51% of all power generation and accounts for 79% of carbon emissions coming from electric utilities. Even with the expected growth in natural gas for new generating capacity, coal's share of the electricity supply is still projected to be about 44% in 2020 and higher in absolute capacity compared to today (18). Thus, any new policies to significantly reduce CO₂ emissions during the next two or three decades must consider not only the technology options for new power plants (which is the case typically discussed in the literature) but also the retrofitting of existing coal plants which will continue to operate for several decades to come. Such medium-term intervention to reduce CO₂ emissions has received relatively little attention to date. Hence, the present study examines the feasibility of postcombustion carbon capture at existing power plants as well as new facilities.

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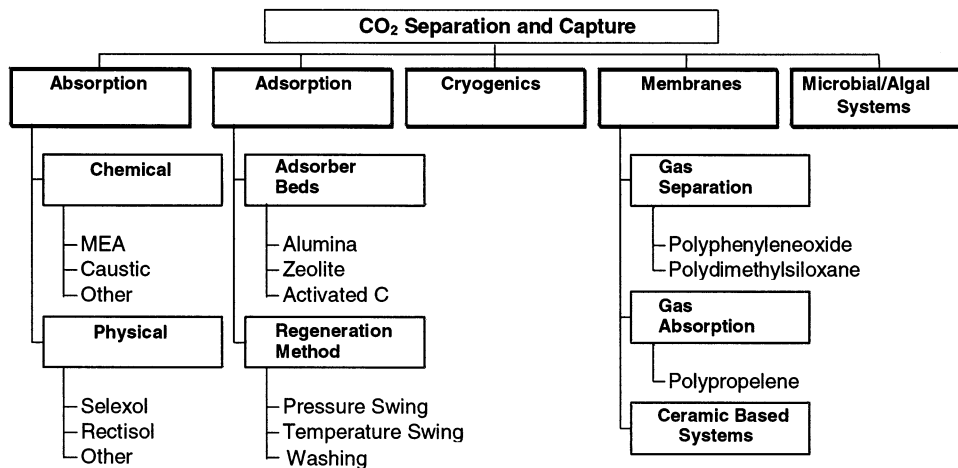


FIGURE 1. Technology options for CO₂ separation and capture.

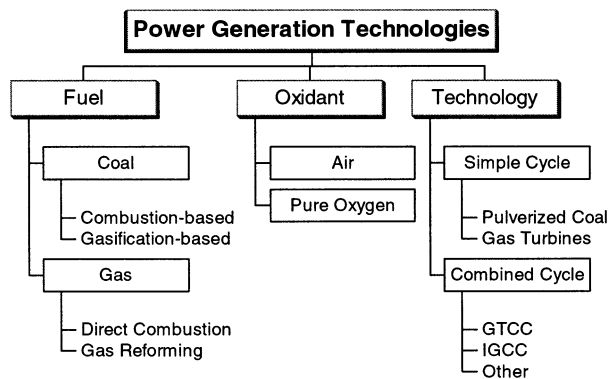


FIGURE 2. Technology options for fossil-fuel based power generation.

In this context, past studies have shown that amine-based CO₂ absorption systems are the most suitable for combustion-based power plants for the following reasons: (1) These systems are effective for dilute CO₂ streams, such as coal combustion flue gases, which typically contain only about 10%–12% CO₂ by volume. (2) Amine-based CO₂ capture systems are a proven technology that is commercially available and in use today. (3) Amine-based systems are similar to other end-of-pipe environmental control systems used at power plants. These units are operated at ordinary temperature and pressure. (4) A major effort is being made worldwide to improve this process in the light of its potential role in CO₂ abatement. Thus, one can anticipate future technology advances.

A number of previous studies have reported some cost and/or performance data for specific amine-based systems, including hypothetical applications to coal-fired power plants (19–23). However, detailed models of such processes are not generally available. Cost data reported in different studies also tend to be limited and often incomplete. Therefore the first objective of this study has been to develop a preliminary model of performance and cost of amine-based systems based on available information, including a characterization of key uncertainties, as reflected in the current literature.

The second objective is to apply the model to study the feasibility and cost of carbon capture and sequestration at both new and existing coal-based power plants. This analysis incorporates multipollutant interactions between CO₂ control, criteria air pollutants (especially SO₂ and NO_x), and air toxics (especially mercury). These aspects of CO₂ mitigation policy analysis are seldom addressed in other studies.

Finally, a third objective is to examine the impact of possible process improvements resulting from R&D. This

will help to characterize the role of technological change in looking at future options and costs for CO₂ control.

Overview of Amine-Based CO₂ Capture Systems

The idea of separating CO₂ from flue gas streams started in the 1970s, not with concern about the greenhouse effect, but as a potentially economic source of CO₂, mainly for enhanced oil recovery (EOR) operations. Several commercial CO₂ capture plants were constructed in the U.S. in the late 1970s and early 1980s (24, 25). CO₂ was also produced for other industrial applications such as carbonation of brine and production of products such as dry ice, urea, and beverages. Some of these CO₂ capture plants are still in operation today, but all these plants are much smaller than a typical power plant. The first commercial CO₂ sequestration facility started in Norway in September 1996 in response to a Norwegian carbon tax. Since then, Statoil has been storing CO₂ from the Sleipner West gas field in a sandstone aquifer 1000 m beneath the North Sea (1). The international research community is closely monitoring this facility.

All these plants capture CO₂ with processes based on chemical absorption using a monoethanolamine (MEA)-based solvent. MEA is an organic chemical belonging to the family of compounds known as amines. It was developed over 60 years ago as a general, nonselective solvent to remove acidic gas impurities (e.g. H₂S, CO₂) from natural gas streams (21). The process was then adapted to treat flue gas streams for CO₂ capture. Fluor Daniel Inc., Dow Chemical Co., Kerr-McGee Chemical Corp., and ABB Lummus Crest Inc. were some of the initial developers of MEA-based technology for CO₂ capture. Typically, about 75–90% of the CO₂ is captured using this technology, producing a nearly pure (>99%) CO₂ product stream.

Process Description. A continuous scrubbing system is used to separate CO₂ from the flue gas stream. As illustrated in Figure 3, the system consists of two main elements: an absorber where CO₂ is removed and a regenerator (or stripper), where CO₂ is released (in concentrated form) and the original solvent is recovered. The Supporting Information contains additional details of the process chemistry and design of this system (26–32).

A key feature of amine systems is the large amount of heat required to regenerate the solvent. This heat is typically drawn from the steam cycle and significantly reduces the net efficiency of the power plant. Substantial electrical energy also is needed to compress the captured CO₂ for pipeline transport to a storage site. As shown later in this paper, the overall energy penalty of this process has a major impact on system performance as well as cost.

TABLE 1. Amine System Performance Model Parameters and Uncertainties

performance parameter	units	data (range)	nominal value	unc. representation (distribution function)
CO ₂ removal efficiency	%	mostly 90	90	
SO ₂ removal efficiency	%	almost 100	99.5	uniform (99,100)
NO ₂ removal efficiency	%	20–30	25	uniform (20,30)
HCl removal efficiency	%	90–95	95	uniform (90,95)
particulate removal eff.	%	50	50	uniform (40,60)
MEA concentration	wt %	15–50	30	
lean solvent CO ₂ loading	mol CO ₂ /mol MEA	0.15–0.30	0.22	triangular (0.17,0.22,0.25)
nominal MEA makeup	kg MEA/tonne CO ₂	0.5–3.1	1.5	triangular (0.5,1.5,3.1)
MEA loss (SO ₂)	mol MEA/mol SO ₂	2	2	
MEA loss (NO ₂)	mol MEA/mol NO ₂	2	2	
MEA loss (HCl)	mol MEA/mol HCl	1	1	
MEA loss (exhaust gas)	ppm	1–4	2	uniform (1,4)
NH ₃ generation	mol NH ₃ /mol MEA oxidized	1	1	
caustic consumption in MEA reclaimer	kg NaOH/tonneCO ₂	0.13	0.13	
activated carbon use	kg C/tonne CO ₂	0.075	0.075	
cooling water makeup	m ³ /tonne CO ₂	0.5–1.8	0.8	triangular (0.5,0.8,1.8)
solvent pumping head	kPa	35–250	207	triangular (150,207,250)
pump efficiency	%	70–75	75	uniform (70,75)
gas-phase pressure drop	kPa	14–30	26	triangular (14,26,30)
fan efficiency	%	70–75	75	uniform (70,75)
equiv. elec. requirement	% regeneration heat	9–19	14 ^a	uniform (9,19)
CO ₂ product purity	wt %	99–99.8	99.5	uniform (99,99.8)
CO ₂ product pressure	MPa	5.86–15.16	13.79	triangular (5.86,13.79,15.16)
compressor efficiency	%	75–85	80	uniform (75,85)

^a For retrofit applications, nominal value is 25, and the range is 22–30 (uniform distribution).

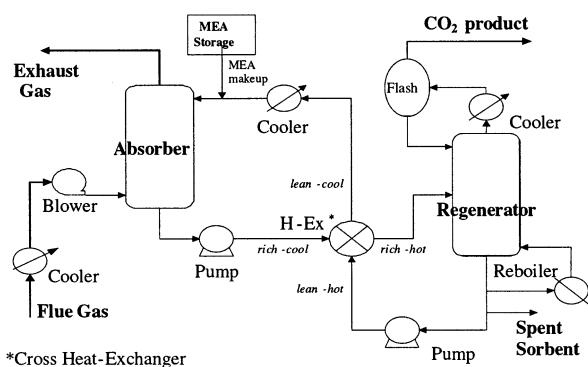


FIGURE 3. Flowsheet for CO₂ capture from flue gases using amine-based system.

From a multipollutant perspective, there are also important interactions between the CO₂ capture system and the control of other air pollutants, especially SO₂ and NO_x emissions. Acid gases such as SO₂ and NO₂ react with MEA to form heat-stable salts that reduce the CO₂ absorption capacity of the solvent. Thus, very low concentrations of these gases (on the order of 10 ppm) are desirable to avoid excessive loss of (costly) solvent. The problem is especially acute for SO₂ because its concentration in flue gases is typically 700–2500 ppm at coal-fired plants. NO_x is less of a problem because most of the NO_x is nitric oxide (NO), whereas only NO₂ (typically about 5% of total NO_x) is reactive (see Supporting Information for additional details).

Process Performance Model

The removal of CO₂ from flue gases using an amine scrubber depends on the gas–liquid mass transfer process. The chemical reactions that permit diffusion of CO₂ in the liquid film at the gas–liquid interface enhance the overall rate of mass transfer. Thus, the CO₂ removal efficiency in the absorber is a function of various parameters that affect the gas–liquid equilibrium (e.g., flow rates, temperature, pressure, flue gas composition, CO₂ concentration, MEA con-

centration, and absorber design). Similarly, the conditions and detailed design of the regenerator affect the energy requirements and overall performance of the system.

Performance Parameters. A mathematical model was developed to simulate the performance of a CO₂ capture and storage system based on amine (MEA) scrubbing. This CO₂ module was then added to an existing coal-based power plant simulation model, described later in this paper. Basically, there are two types of input parameters to the CO₂ performance model: (1) *Parameters from the “base plant”*: These include the flow rate, temperature, pressure, and composition of the inlet flue gas to the CO₂ absorber and the gross power generation capacity of the power plant. (2) *Parameters of the CO₂ system*: The CO₂ module specifies parameters of the CO₂ capture technology, CO₂ compression system, CO₂ product transport, and CO₂ storage (sequestration) method. The basic configuration is an MEA-based absorption system with pipeline transport of liquefied CO₂ to a geologic sequestration site. Table 1 lists the model input parameters that affect overall process performance. These parameters, along with those from the base plant, are used to calculate the solvent flow rate, MEA requirement, regeneration heat requirement, and electrical energy needs of the CO₂ system. Functional relationships and default values for all model parameters were developed for a typical system design based on a detailed review of the literature, discussions with process developers and other experts, and the use of detailed process simulation models (33, 34). The resulting model employs fundamental mass and energy balance relationships together with empirical relationships for some key parameters. Details of the performance model are presented elsewhere (35). All of the performance parameters also affect the cost of the system.

Characterization of Uncertainties. This modeling effort also incorporates a stochastic simulation capability that allows any or all model inputs to be represented by a probability distribution rather than a single deterministic value. In general, such distributions may reflect uncertainty and/or variability in system design parameters. Table 1 shows the distributions used in this paper to characterize the performance parameters of the CO₂ capture system. These

TABLE 2. MEA Cost Model Parameters

capital cost elements	nom. value*	O&M cost elements	nom. value*
process area costs (nine areas) ^a		fixed O&M costs (FOM)	
total process facilities cost	PFC ^{a,b}	total maintenance cost	2.5% TPC ^j
engineering and home office	7% PFC ^c	maintenance cost allocated to labor	40% of total maint. cost
general facilities	10% PFC ^d	admin & support labor cost	30% of total labor cost
project contingency	15% PFC ^e	operating labor	2 jobs/shift ^k
process contingency	5% PFC ^f	variable O&M costs (VOM)	
total plant cost (TPC) = sum of above		reagent (MEA)	\$1250/tonne MEA ^l
interest during construction	calculated	water cost	\$0.2/m ³
royalty fees	0.5% PFC ^g	CO ₂ transport cost	\$0.02/tonne CO ₂ /km ^m
preproduction costs	1 month ^h VOM & FOM	CO ₂ storage/disposal cost	\$5/tonne CO ₂ ⁿ
inventory (startup) cost	0.5% TPC ⁱ	solid waste disposal cost	\$175/tonne waste ^b
total capital reqmt (TCR) = sum of above			

* Uncertainty distributions are given below. ^a The individual process areas modeled are as follows: flue gas blower, absorber, regenerator, solvent processing area, MEA reclaimer, steam extractor, heat exchanger, pumps, CO₂ compressor. The sum of these is the total process facilities cost (PFC). ^b Uncertainty distribution: normal (1.0,0.1). ^c Uncertainty distribution: triangular (5,7,15). ^d Uncertainty distribution: triangular (5,10,15). ^e Uncertainty distribution: triangular (10,15,20). ^f Uncertainty distribution: triangular (2,5,10). ^g Uncertainty distribution: triangular (0,0.5,0.5). ^h Uncertainty distribution: triangular (0.5,1,1). ⁱ Uncertainty distribution: triangular (0.4,0.5,0.6). ^j Uncertainty distribution: triangular (1,2,5,5). ^k Uncertainty distribution: triangular (1,2,3). ^l Uncertainty distribution: uniform (1150,1300). ^m Uncertainty distribution: triangular (0.004,0.02,0.06). ⁿ Uncertainty distribution: triangular (-10,5,8).

distributions reflect the current literature on amine-based (MEA) systems and (in a few cases) data and judgments provided by process developers (36). Detailed descriptions of these distributions are provided in ref 35.

Model Outputs. The key outputs of the amine system performance model include the following: (1) *MEA requirement.* This depends mainly on the mass flow rate of CO₂ in the flue gas, the desired CO₂ capture efficiency, the MEA concentration, and CO₂ loadings in the solvent. Depending on the level of impurities in the flue gas, there is additional loss of solvent associated with removal of other acid gases such as SO_x and NO₂. (2) *Energy requirements.* Heat requirements for solvent regeneration depend mainly on the lean sorbent loading and other system parameters. This heat is provided by low-pressure steam within the power plant, thus decreasing the net power generation efficiency. In addition, electrical energy is required for CO₂ product compression, solvent circulation, and other system requirements. The total amine system energy requirement is one of the most important model results, as it dictates the net power plant output, and hence the net cost of power generation and CO₂ avoidance. (3) *Environmental emissions.* The CO₂ control system generates several new waste products that are accounted for in the model, principally ammonia gas (generated by degradation of MEA) and reclaimer bottoms (a potentially hazardous solid waste generated during recovery of spent sorbent from the process). On the other hand, the CO₂ capture system also reduces emissions of particulate matter and acid gases such as SO₂, HCl, and NO₂. Removal of trace metals such as mercury and other air toxics is not well-characterized for these systems but is anticipated to be similar to other wet scrubber systems. A complete accounting of multipollutant emissions is provided by the IECM framework in which the CO₂ module is embedded, as discussed below.

The IECM Framework. The Integrated Environmental Control Model (IECM) is a power plant simulation model developed by Carnegie Mellon University for the U.S. Department of Energy (USDOE) (37, 38). It includes a menu of technological options for controlling criteria air pollutants (SO₂, NO_x, and particulates), mercury (an air toxic), and solid wastes. The new CO₂ module has been integrated into the existing IECM modeling framework, allowing the analysis of alternative CO₂ capture and sequestration technologies in complex plants involving multipollutant emission controls. (This newly integrated version is designated IECM-CS.)

Process Cost Model

The CO₂ capture and sequestration system cost model is directly linked to the process performance model described earlier. The cost model follows the framework used in the IECM to ensure consistency in plant-level economic calculations (35). There are four types of cost calculated by this model based on available data (8, 19, 23, 26, 30, 39–42).

Capital Cost. The total capital requirement (TCR) of a system is the sum of direct equipment costs (which depend on one or more performance variables that determine the size or capacity of a component), plus various indirect costs that are calculated as fractions of the total process facilities cost (PFC), following the EPRI cost estimating guidelines (43). Table 2 lists the elements of capital cost, showing the nominal parameter values plus the uncertainties used later for probabilistic analyses. For the MEA system, the absorber capital cost depends mainly on the flue gas flow rate. The cost of the regenerator section and the CO₂ compressor scale mainly with the mass flow rate of CO₂ captured. Indirect cost factors are estimated based on available data for amine systems and similar technologies.

O&M Costs. Operating and maintenance (O&M) cost elements are also listed in Table 2. Major variable cost items include the cost of sorbent (MEA) and the costs of CO₂ transport and storage. Fixed costs include the costs of maintenance and labor. Energy costs are handled internally in the model by derating the overall power plant based on the calculated energy requirement. This increases the cost per net kilowatt-hour delivered by the plant.

Cost of Electricity. The IECM framework calculates the cost of electricity (COE) for the overall power plant by dividing the total annualized plant cost (\$/yr) by the net electricity generated (kWh/yr). Results are expressed in units of \$/MWh (equivalent to mills/kWh). Two key parameters in this calculation are the levelized fixed charge factor (used to amortize capital expenses) and the plant capacity factor. The fixed charge factor is based on the plant lifetime (book life) and after-tax discount rate (or interest rate, or rate of return), while the capacity factor reflects the average annual hours of plant operation. The incremental cost of electricity attributed to CO₂ control is then the difference in COE between plants with and without the CO₂ capture and storage system.

Cost of CO₂ Avoided. Analysts commonly express the cost of an environmental control system in terms of either the

TABLE 3. Design Parameters for Case Study of New Pulverized Coal Plant

parameter	value	parameter	value
gross plant size (MW)	500	emission standards	2000 NSPS ^d
gross plant heat rate (kJ/kWh)	9600 ^a	NO _x controls	LNB ^e + SCR ^f
plant capacity factor (%)	75 ^b	particulate control	ESP ^g
coal characteristics			
rank	sub-bit.	SO ₂ control	FGD ^h
HHV (kJ/kg)	19346	CO ₂ control	MEA ⁱ
% S	0.48	CO ₂ capture efficiency (%)	90
% C	47.85	CO ₂ product pressure (kPa)	13790 ^j
mine-mouth cost (\$/tonne)	13.73	distance to storage (km)	165
delivered cost (\$/tonne)	23.19 ^c	cost year basis (constant dollars)	2000
		fixed charge factor	0.15 ^k

^a Nominal case is a subcritical unit. Uncertainty case includes supercritical unit. Uncertainty distribution: Unc = uniform (9230,9600). ^b Unc = triangular (65,75,85). ^c Unc = triangular (15.94,23.19,26.81). ^d NO_x = 65 ng/J, PM = 13 ng/J, SO₂ = 70% removal (upgraded to 99% with MEA systems). ^e LNB = low- NO_x burner. ^f SCR = selective catalytic reduction. ^g ESP = electrostatic precipitator. ^h FGD = flue gas desulfurization. ⁱ MEA = monoethanolamine system. ^j See Table 1 for uncertainty. ^k Corresponds to a 30-year plant lifetime with a 14.8% real interest rate (or, a 20-year life with 13.9% interest); Unc = uniform (0.10,0.20).

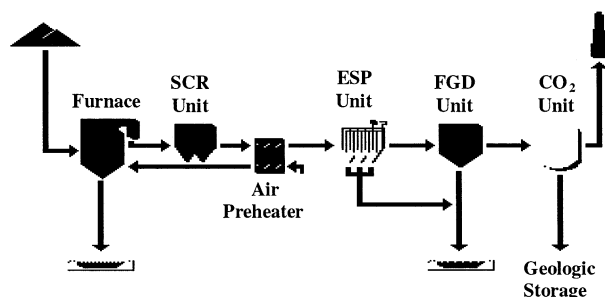


FIGURE 4. Schematic of an NSPS plant including CO₂ capture unit.

cost per tonne of pollutant removed or the cost per tonne “avoided”. For an energy-intensive system like amine scrubbers there is a big difference between the cost per tonne CO₂ removed and the cost per tonne CO₂ avoided based on net plant capacity. Since the purpose of adding a capture unit is to reduce the CO₂ emissions per net kWh delivered, the cost of CO₂ avoidance (relative to a reference plant with no CO₂ control) is the economic indicator most widely used. It can be calculated as

$$\text{cost of CO}_2 \text{ avoided (\$/tonne)} = \frac{(\$/\text{kWh})_{\text{capture}} - (\$/\text{kWh})_{\text{reference}}}{(\text{tonne CO}_2/\text{kWh})_{\text{reference}} - (\text{tonne CO}_2/\text{kWh})_{\text{capture}}}$$

Case Study Results for a New Plant

The IECM-CS simulation framework models a complete coal-fired power plant with multipollutant environmental controls, including CO₂ capture and sequestration. The reference case is assumed to be a new 500 MW unit (gross) burning low-sulfur western U.S. coal and meets current federal New Source Performance Standards (NSPS) for SO₂, NO_x, and particulates (44). The CO₂ capture case adds an MEA scrubber. Figure 4 shows a schematic of the plant and its environmental control systems, including the CO₂ capture unit. Table 3 lists key plant design parameters and the uncertainties assumed for probabilistic analysis.

Deterministic Results. We run the model first for the reference power plant (without CO₂ capture) and then for the same plant including CO₂ capture. Table 4 quantifies the impact of the CO₂ unit on plant performance, plant discharges, and plant costs. Figure 5 shows graphically the relationship of electricity cost to CO₂ emissions for the two cases; the slope of the line connecting the two points represents the cost of CO₂ avoided, which is \$59/tonne for this case. Most of this cost (79%) is associated with the CO₂

TABLE 4. Deterministic Results for a New 500 MW Plant

parameter	units	reference plant	w/CO ₂ control
net plant capacity	MW (net)	462	326
CO ₂ emission rate	g CO ₂ /kWh (net)	941	133
SO ₂ emission rate	g SO ₂ /kWh (net)	2.45	0.0003
NO _x emission rate	g NO _x /kWh (net)	0.45	0.58
CO ₂ sequestered	10 ⁶ tonne CO ₂ /yr		2.58
cost of electricity	\$/MWh (net)	49.2	97.0
CO ₂ mitigation cost	\$/tonne CO ₂ avoided		59.1

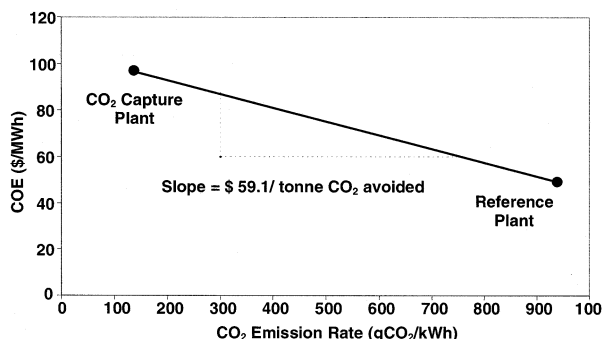


FIGURE 5. Nominal CO₂ avoidance cost for the case study coal plant (new 500 MW, low-S coal, 75% CF).

capture process (including gas compression). CO₂ transport (8%) and storage (13%) account for the remainder.

Addition of the CO₂ capture system increases the total plant capital cost from \$571M (for the reference plant) to \$705M. Energy requirements consume about 27% of gross plant capacity, mostly for solvent regeneration (49% of total) and CO₂ product compression (34% of total). Solvent circulation and fan power account for the remaining share (17% of total). MEA makeup requirements contribute about 10% to the cost of CO₂ capture. The presence of SO₂ impurities can substantially increase these reagent costs, so the cost of CO₂ avoidance is sensitive to the SO₂ removal efficiency of the FGD unit located upstream of the MEA system. Tradeoff studies showed that overall plant costs were minimized by reducing the SO₂ concentration to about 10 ppm inlet to the MEA absorber. Therefore, in this case study the SO₂ removal system was upgraded to 99% removal with CO₂ controls, as against only 70% SO₂ removal in the reference case. The costs of this upgrade were charged to the CO₂ unit.

Probabilistic Results. Different assumptions about power plant design, coal properties, plant operation, and CO₂ control system design can have a significant effect on CO₂ mitigation

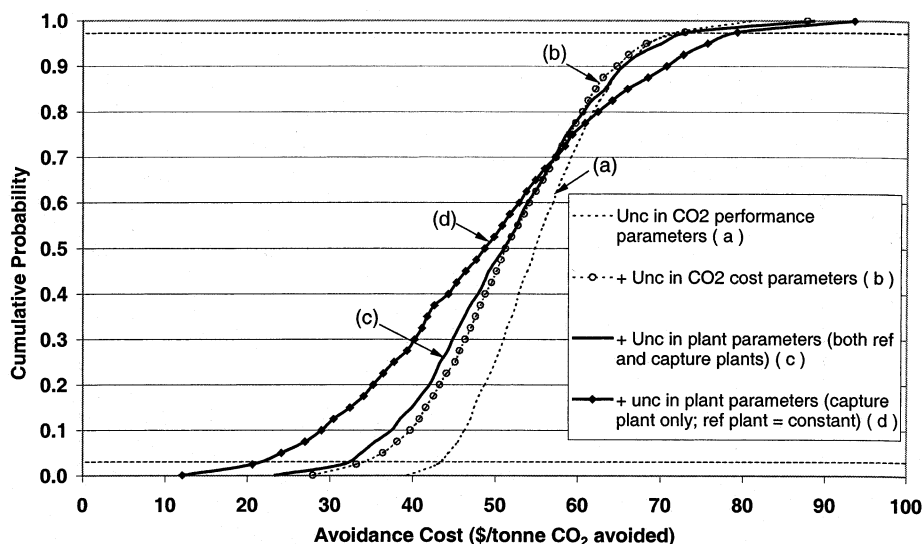


FIGURE 6. Uncertainty in the cost of CO₂ avoided, decomposed into four parameter categories. The dotted lines at the top and bottom of the graph demarcate the 95% probability interval.

TABLE 5. Scenarios for Retrofit Studies of a 500 MW Plant

case	A	B	C	D
coal type	low-S	low-S	low-S	high-S
existing SO _x control	none	none	FGD (70% removal)	FGD (~90% removal)
existing NO _x control	LNB	LNB	LNB	LNB
CO ₂ retrofit option	MEA system	MEA system plus new FGD	MEA system plus FGD upgrade	MEA system plus FGD upgrade

costs and are responsible for many of the cost differences found in the literature. To systematically characterize the effects of different assumptions, parameters that vary across design studies are represented here by probability distributions, with values selected based on the current literature (35) and (in some cases) the authors' judgment. Note that the term "uncertainty" is used loosely here to include parameter variability.

Figure 6a first shows the effect of considering uncertainties and design variability only in the performance parameters of the MEA system (from Table 1). The resulting distribution for cost of CO₂ avoidance has a 95-percentile range of \$43–72/tonne. The main contributors to this range are lean solvent CO₂ loading (which determines the reboiler duty), and equivalent electrical penalty of the regeneration steam requirement. Figure 6b shows the additional uncertainty contributed by CO₂ cost model parameters, including the costs of the CO₂ capture unit, pipeline transport, and geologic storage (see Table 2). Now the overall cost of CO₂ avoided shows a much wider range of \$33–73/tonne (95% probability interval). The dominant factor here is the assumed cost of CO₂ storage. The high end of the distribution corresponds to a disposal cost of up to \$8/tonne CO₂ stored, while the low end reflects a cost credit (revenue) of up to \$10/tonne when CO₂ is used for enhanced oil recovery (EOR).

Figures 6c,d show the effect of additional uncertainties (or variability) for the assumed power plant efficiency (heat rate), capacity factor, coal price, and fixed charge factor (see Table 3). If these parameter values are identical for the reference plant and capture plant (Figure 6c), the 95% probability range in the CO₂ avoidance cost increases slightly (\$32–73/tonne), although the COE of each plant is strongly affected. However, if the capture plant values differ from the reference plant (Figure 6d) the CO₂ mitigation cost now broadens to a much wider range of \$21–79/tonne CO₂ avoided (95% probability interval). The dominant factors here are the fixed charge rate and plant capacity factor, which

strongly influence the COE for the overall plant, and thus the cost of CO₂ avoided.

Note that the tails of the overall distribution can span up to nearly an order of magnitude in the cost of CO₂ avoided. Note too that the distributions in Figure 6 are not symmetric about the deterministic value of avoided cost shown in Figure 5. This is a consequence of the distributions assumed for key model parameters like lean sorbent loading, CO₂ transportation, disposal cost, and power plant heat rate. The mean cost in Figure 6c is \$51/tonne CO₂ avoided.

Applications to CO₂ Retrofits

As discussed earlier, a large number of existing coal-fired power plants may be candidates for CO₂ retrofits under a sufficiently stringent climate policy. Because of multipollutant interactions, the cost of CO₂ mitigation will be affected by policies for other pollutants, especially SO₂. Considering that most (~70%) of the current coal-based capacity in the U.S. does not have SO₂ scrubbers, several cases were modeled to analyze the impacts of adding postcombustion CO₂ capture systems to existing coal plants (see Table 5).

Cases A and B are for a plant burning low-sulfur western coal (0.48% S, as in Table 3) with no other SO₂ emission controls. It complies with federal standards for plants constructed before July 1978. To reduce CO₂ emissions the plant can either retrofit an MEA system (case A) or install both MEA plus a new FGD system (case B) to reduce the input of sulfur impurities to the MEA unit. In case C the low-sulfur coal plant is already equipped with an FGD system that meets federal New Source Performance Standards (NSPS), which in this case is 70% SO₂ removal. This plant has the option of upgrading the existing SO₂ scrubber (to 99% removal) in addition to installing an MEA system. Case D is similar to case C except that the plant burns high-sulfur (3.25% S) eastern bituminous coal. Federal standards in this case require about 90% reduction in potential SO₂ emissions, achieved with a wet FGD system.

TABLE 6. Effect of SO₂ Controls on Carbon Mitigation Costs for the Low-Sulfur Retrofit Scenarios

quantity	reference plant (no CO ₂ control)	case A (MEA only)	case B (MEA + FGD)	case C (MEA + FGD upgrade)
net power (MW)	470	288	275	275
COE (\$/MWh)	18.0	111.8	70.4	66.7
SO ₂ emission rate (g/kWh)	4.51	0.04	0.0004	0.0004
total SO ₂ emission (tonne/yr)	13916	69	0.7	0.7
new SO ₂ capture in FGD (tonne/yr)	0	0	13777	7451
new SO ₂ capture in MEA (tonne/yr)	0	13847	138	138
total new SO ₂ capture (tonne/yr)	0	13847	13915	7589
mitigation cost (\$/tonne CO ₂ avoided)				
no SO ₂ credit	-	118.8	67.0	59.2
\$150/tonne SO ₂ credit	-	117.4	65.5	58.4
no SO ₂ credit, retrofit factor = 1.25	-	123.2	70.5	62.7

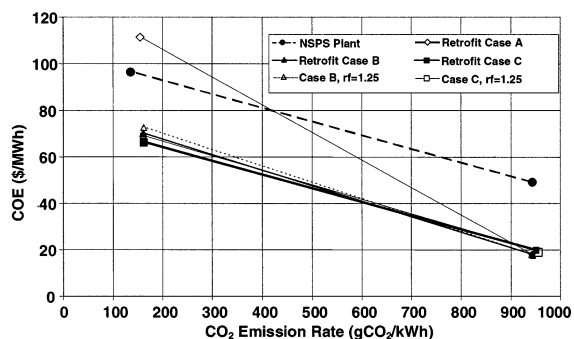


FIGURE 7. Estimation of CO₂ avoidance cost for low-S coal plants.

In contrast to the new plant analysis presented earlier, the retrofit scenarios assume, as a bounding case, that all existing capital equipment has been fully amortized. The cost of electricity is then determined only by plant O&M costs, plus any new capital expenditures for CO₂ control. The latter includes the costs of any new sulfur removal systems that are installed to minimize the cost of CO₂ avoidance. We also credit the CO₂ unit for the market value of additional SO₂ allowances that are generated and traded under the national acid rain control program. The remaining plant life is assumed to be at least 15 years. The base capital cost of the CO₂ capture unit is the same as for a greenfield site, but we then consider an additional retrofit cost premium to account for site-specific retrofit difficulties. We also assume higher plant heat rates and energy penalties in providing steam to the MEA system (see Table 1).

Results for Low-Sulfur Coal Plants. Figure 7 shows the deterministic results for the cost of electricity versus CO₂ emission rate for the three low-sulfur coal plant retrofit cases (A, B, C), plus the new plant case shown earlier. Without CO₂ capture, the fully amortized reference plant produces electricity at a cost that is 60–65% lower than the new plant. This lower COE reduces the cost of CO₂ capture when the energy-intensive MEA unit is added to the plant. The analysis also shows that for an existing facility without SO₂ control (cases A and B), the addition of an SO₂ scrubber along with the CO₂ scrubber significantly reduces the cost of carbon mitigation. For a plant that already has FGD (case C), upgrading the existing system to achieve higher sulfur removal efficiency further reduces the cost of carbon capture. These results are consistent with the design premises of other studies (26, 39, 40) that include SO₂ removal prior to an amine scrubber.

In all cases, retrofitting the power plant with an MEA system results in substantial added reductions in SO₂ emissions, which is an additional environmental benefit. The interaction between SO₂ and CO₂ controls is shown in Table 6. If credits for SO₂ reductions at recent market prices are taken into account, the carbon mitigation cost decreases

slightly, by about \$1–1.5/tonne CO₂ avoided. Even with SO₂ credits, however, the CO₂ mitigation cost for the retrofit plant is likely to be higher than for a new plant. This is mainly because of the much higher energy penalty resulting from limitations in efficient heat integration. Retrofit costs also are likely to be higher because of site-specific difficulties of installing new equipment at an existing plant location. Assuming a 25% capital cost premium for retrofit applications (cases B and C with rf = 1.25 in Figure 7) adds about \$3–5 per tonne of CO₂ avoided. Still, the overall COE for the retrofitted plant (cases B and C) is less than the new plant COE because of the amortized capital. Other schemes that can reduce the energy penalty costs (e.g., an auxiliary boiler system fired by low-cost natural gas) could potentially improve the economics of retrofit applications.

Results for High-Sulfur Coal Plants. CO₂ mitigation costs for case D (3.25% S coal) were again minimized by adding new FGD capacity to achieve 99% SO₂ removal. The COE for the fully amortized plant was \$27/MWh without CO₂ control and \$75/MWh with controls, yielding a nominal CO₂ mitigation cost of \$64/tonne avoided. The effects of SO₂ credits and retrofit cost premiums were similar to those for the low sulfur coal cases in Table 6.

Benefits of R&D

R&D programs that improve the performance of current amine-based system can reduce the future cost of CO₂ capture. The Supporting Information includes a hypothetical example in which improvements in MEA system performance, and reductions in uncertainties, produce a substantial reduction in the cost of CO₂ avoided. New or improved sorbents, lower regeneration heat requirements, and overall process optimization are some of the potential sources of cost reduction. Government-sponsored R&D efforts, together with industrial initiatives such as the CO₂ Capture Project (45), are actively pursuing such goals. Our future modeling research will seek to realistically estimate potential process improvements and apply those results to quantify potential R&D benefits and priorities.

Discussion

The present study has established a framework for quantifying the impacts of carbon capture and sequestration technology on power plant performance, emissions, and economics. For amine (MEA)-based absorption systems applied to coal-fired power plants, the cost of carbon avoidance was shown to depend strongly on assumptions about the reference plant design, details of the CO₂ capture and storage system designs, and interactions with other pollution control systems. Climate mitigation policy models that overlook or oversimplify these factors may produce misleading results regarding the feasibility and cost of CO₂ capture and sequestration options.

The presence of acid gas impurities such as SO₂ and NO₂ in power plant flue gas was seen to adversely affect the

performance and cost of the CO₂ removal system. Adding or upgrading an FGD unit to remove SO₂ was essential to minimize the cost of carbon mitigation. The presence of NO_x had a much smaller effect on CO₂ capture costs since most NO_x is NO, not NO₂. Because of such interactions, more stringent future regulation on SO_x, NO_x, and other emissions (e.g., for control of PM_{2.5}, ozone, air toxics, or acid rain) could make subsequent carbon capture less expensive (at the margin), thus integrating local and regional air pollution policies with the global issue of climate change.

An analysis of retrofit options found that the large energy requirements of CO₂ capture lead to a more substantial loss of plant capacity compared to a new plant affording better heat integration. Site-specific difficulties may further increase the capital cost of a retrofit installation. Thus, the overall cost of CO₂ capture is likely to be greater than that of a new plant, despite the lower cost of electricity for plants that are fully or partially amortized, or the potential credits for new SO₂ reductions accompanying CO₂ controls.

The large plant derating resulting from amine-based CO₂ controls also will significantly affect the capacity planning decisions of electric utilities if this technology is widely implemented. Analysis of these system-wide effects on future capacity requirements, technology choices, demand projections, costs, and CO₂ emissions require a more comprehensive modeling framework (46) but must be part of any large-scale policy analysis of CO₂ capture and sequestration technologies.

Finally, an important feature of the study is that it takes into account the uncertainties and variability in key performance and cost parameters that influence the cost of carbon mitigation. Understanding the nature of these uncertainties, and the potential for reducing them, is crucial to projecting future costs and capabilities of new technologies for carbon capture and sequestration. A characterization of potential R&D benefits is the subject of ongoing analysis.

Acknowledgments

This research was supported by the U.S. Department of Energy's National Energy Technology Laboratory (Contract No. DE-FC26-00NT40935), and by the Center for Integrated Study of the Human Dimensions of Global Change through a cooperative agreement between the National Science Foundation (SBR-9521914) and Carnegie Mellon University. The authors are grateful to C. Mariz, H. Herzog, D. Simbeck, M. Guha, J. Dingman, and other individuals who provided helpful input and review of this work. The authors alone, however, are responsible for the content of this paper.

Supporting Information Available

MEA process description and potential benefits of R&D. This material is available free of charge via the Internet at <http://pubs.acs.org>.

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Received for review December 31, 2001. Revised manuscript received June 26, 2002. Accepted July 1, 2002.

ES0158861