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Edward S. Rubin
Carnegie Mellon University, rubin@cmu.edu

A B. Rao
Carnegie Mellon University

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J. Gale
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Y. Kaya
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UNCERTAINTIES IN CO_2 CAPTURE AND SEQUESTRATION COSTS

E.S. Rubin and A.B. Rao

Department of Engineering and Public Policy
Carnegie Mellon University
Pittsburgh, PA 15213

ABSTRACT

The cost of CO_2 avoidance depends on a wide variety of factors and assumptions whose impacts have not been fully considered in past assessments of carbon capture and sequestration technologies. As part of the USDOE's Carbon Sequestration Program, we have developed an integrated modeling framework to evaluate the performance and costs of alternative CO_2 capture and sequestration technologies for fossil-fueled power plants, in the context of multi-pollutant control requirements. This model (called the IECM-CS) allows for explicit characterization of the uncertainty or variability in any or all model input parameters. This paper reviews the major sources of uncertainty or variability in CO_2 cost estimates, then uses the IECM-CS to analyze uncertainties in CO_2 mitigation costs for currently available (amine-based) CO_2 capture technologies applicable to coal-fired power plants.

INTRODUCTION

Development of improved technology to capture and sequester the CO_2 emitted by power plants using fossil fuels — especially coal — is the subject of major research efforts worldwide. The attraction of this option is that it would allow abundant world resources of fossil fuels to be used for power generation and other applications without contributing significantly to atmospheric emissions of greenhouse gases. The two key barriers to carbon capture and sequestration (CCS), however, are the high cost of current CO_2 capture technologies, and uncertainties regarding the technical, economic and political feasibility of CO_2 storage options.

Assuming geological storage of CO_2 indeed proves to be viable, how much would it likely cost to capture and store the CO_2 from a new coal-fired power plant? Various studies have addressed this question [1-7], but each study typically employs different assumptions that produce different results. Herzog (1999) and others have summarized recent cost studies and sought to adjust their results to a more consistent basis [8, 9]. Nonetheless there still remains substantial confusion and lack of understanding in both the technical and policy communities about the magnitude of CCS costs and the factors that affect it.

FACTORS AFFECTING CCS COST

In this paper we attempt to peel back some of the cobwebs that continue to obfuscate answers to what many believe is the simple question of how much it costs to capture and sequester CO_2 emissions from power plants. We use the term "uncertainties" very loosely in this paper to describe the many different factors that contribute to differences in reported cost results for CCS systems. We begin with a brief review of the key determinants of CO_2 control cost.

Defining the System Boundary: The first requirement is to clearly define the "system" whose CO_2 emissions and cost are being characterized. The most common assumption in economic studies is a single power plant that captures CO_2 and transports it to an off-site storage area such as a geologic formation. The CO_2 emissions not captured are released at the power plant stack along with other pollutants. Other system boundaries that are sometimes used (or implied) in reporting CO_2 abatement costs may include CO_2 emissions over the complete fuel cycle that includes the extraction, refining and transportation of coal or other fuels used for power generation, as well as any emissions from byproduct use or disposal. Emissions of other greenhouse gases (expressed as equivalent CO_2) also are included in some analyses. Still larger systems might include all power plants in a utility company's system; all plants in a regional or national grid; or a national economy where power plant emissions are but one element of the overall energy system being modeled. In each of these cases it is possible to derive a mitigation cost for CO_2 but the results are not directly comparable because they reflect different system boundaries and considerations.

Defining the Technology and Time Frame: Costs will vary with the choice of CCS technology and the power system that generates CO_2 in the first place. What is often less clear in economic evaluations is the nature and basis of assumptions about the future cost of a technology, particularly "advanced" technologies that are still under development or not yet commercial. Such cost estimates frequently reflect assumptions about the "n^{th} plant" to be built sometime in the future when the technology is mature. Other estimates may reflect the expected benefits of technological learning. The choice of time frame and assumed rate of cost improvements can make a big difference in CCS cost estimates.

Different Measures of Cost: Several different measures of cost are used to characterize CCS systems, but because many of these have the same units (e.g., dollars per tonne of CO_2) there is great potential for misuse or misunderstanding. Perhaps the most widely used measure is the "cost of CO_2 avoided," defined as:

$$\text{Cost of } CO_2 \text{ Avoided} = [(COE)_{capture} - (COE)_{ref}] \,/\, [(CO_2/kWh)_{ref} - (CO_2/kWh)_{capture}]$$

This value reflects the average cost (\$/ton) of reducing atmospheric CO_2 emissions by one unit of mass (nominally one ton), while still providing one unit of electricity to consumers (nominally one kWh). The choice of both the capture plant and the reference plant without CO_2 capture and storage thus plays a key role in determining the CO_2 avoidance cost. Usually (but not always) the reference plant is assumed to be a single unit the same type and size as the plant with CO_2 capture. If there are significant economies of scale in power plant construction costs, differences in power plant size also can affect the cost of CO_2 avoided.

A measure having the same units as avoided cost can be defined as the difference in net present value of projects with and without CCS, divided by the difference in their CO_2 mass emissions. However, unless the two projects produce the same net electrical output, the resulting cost per tonne is not the cost of CO_2 avoided; rather, we call it the "cost of CO_2 abated." Numerically, this value can be quite different from the cost of CO_2 avoided for the same two facilities. Arguably, it is the cost of electricity (COE) for plants with CO_2 capture that is most relevant for economic, technical and policy analyses. It can be calculated as:

$$COE = [(TCR)(FCF) + (FOM)]/[(CF)(8760)(kW)] + VOM + (HR)(FC)$$

where, COE = cost of electricity (\$/kWh), TCR = total capital requirement (\$), FCF = fixed charge factor (fraction/yr), FOM = fixed operating costs (\$/yr), VOM = variable operating costs (\$/kWh), HR = net plant heat rate (kJ/kWh), FC = fuel cost (\$/kJ), CF = capacity factor (fraction), 8760 = hrs/yr, and kW = net plant power (kW). Thus, many factors affect the COE, and hence the cost of CO_2 avoided.

Unreported Assumptions: For a variety of reasons, cost studies do not always report all of the key assumptions that affect the cost of CO_2 control. For example, the total capital requirement (TCR) includes the cost of purchasing and installing all plant equipment, plus a number of "indirect" costs that typically are estimated as percentages of total plant cost (TPC) [10]. Assumptions about such factors (such as contingency costs) can have a pronounced effect on cost results. Further, some CO_2 cost studies exclude certain items (like interest during construction and other "owner's costs") when reporting total capital cost and COE. The term "total plant cost" doesn't always mean what it seems!

The addition of a carbon capture and storage (CCS) system increases a plant's capital and operating costs, while lowering the net power output because of auxiliary energy requirements. The result is a higher COE relative to the identical plant without CO_2 capture. The capacity factor of the capture plant is typically assumed to be the same as the reference plant, although some studies suggest that CCS plants may be utilized more extensively than an equivalent plant without CO_2 capture [11]. Thus, the COE and the cost of CO_2 avoided are both influenced by many factors that are not directly related to the design or cost of a CO_2 capture and storage system (see Table 1). Unless such assumptions are transparent, results can be easily misunderstood.

TABLE 1
TEN WAYS TO REDUCE CO_2 CONTROL COSTS
WITHOUT EVEN CONSIDERING THE COST OF CO_2 CAPTURE

10.	Assume high power plant efficiency
9.	Assume high-quality coal properties
8.	Assume low fuel costs
7.	Assume EOR credits for CO_2 disposal
6.	Omit certain capital costs
5.	State results in short tons
4.	Assume a long plant lifetime
3.	Assume a low interest rate (discount rate)
2.	Assume high plant utilization (capacity factor)
1.	Assume **all of the above!**

QUANTIFYING COST UNCERTAINTIES

As noted earlier, we use the term "uncertainty" loosely to reflect the combination of imprecise knowledge of a parameter value, as well as the *variability* in parameter assumptions used for cost estimates. To quantify the impact of these factors, we use a computer model (called IECM-CS) developed for the U.S. Department of Energy [12, 13]. The IECM-CS estimates the performance and cost of a user-specified power plant configuration that may include a variety of emission control technologies for regulated air pollutants (SO_2, NO_x, particulates and mercury) in addition to CO_2 capture. The model also includes an amine scrubber system for CO_2 capture at a pulverized coal plant. Models of a natural gas combined cycle (NGCC) system and an integrated coal gasification combined cycle (IGCC) system with and without CO_2 capture will soon be added. In each case the CCS system includes the costs of CO_2 pipeline transport plus storage in a geologic reservoir (including options for enhanced oil recovery or enhanced coalbed methane recovery), or ocean disposal. A unique feature of the IECM-CS is its ability to represent any or all input parameters as probability distribution functions rather than discrete (deterministic) values. The probabilistic results then reflect the interactions among all uncertain input variables.

TABLE 2
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			SO_2 control	FGD[h]
Coal	Low-S	High-S	CO_2 control	MEA[i]
HHV (kJ/kg)	19,346	25,300	CO_2 capture efficiency (%)	90
% S	0.48	3.25	CO_2 product pressure (kPa)	13,790[j]
% C	47.85	61.2	Distance to storage (km)	165
Mine-mouth cost ($/tonne)	13.73	32.24	Cost year basis (constant $)	2000
Delivered cost ($/tonne)	23.19[c]	41.37[l]	Fixed charge factor	0.15[k]

[a]Nominal case is a sub-critical unit. Uncertainty case includes supercritical unit. The uncertainty distributions used are: Unc = Chance distribution (8968(p=0.5), 9600(p-0.5)); [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, SO_2 = 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 3 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) [l]Unc = Triangular (35.31, 41.97, 51.96)

Case Study of a New PC Plant: To illustrate the effect of uncertainties on CO_2 control cost for one technology we present a case study of a new pulverized coal (PC) power plant with an amine (MEA-based) CO_2 capture system representing current commercial technology.

TABLE 3
AMINE SYSTEM PERFORMANCE MODEL PARAMETERS

Performance Parameter	Units	Data (Range)	Nominal Value	Unc. Representation (Distribution Function)
CO_2 removal efficiency	%	Mostly 90	90	Uniform (85, 95)
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	Uniform (20,30)
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 make-up	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	molNH_3/molMEA ox	1	1	-
Caustic for MEA reclaimer	kg NaOH/tonneCO_2	0.13	0.13	-
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	%	70-80	75	Uniform (70,80)
Gas-phase pressure drop	kPa	14-30	26	Triangular (14,26,30)
Fan efficiency	%	70-80	75	Uniform (70,80)
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	6.9-15.16	13.79	Triangular (6.9,13.79,15.16)
Compressor efficiency	%	75-85	80	Uniform (75,85)

TABLE 4
MEA COST MODEL PARAMETERS

Capital Cost Elements	Nom. Value*	O&M Cost Elements	Nom. Value*
Process area costs (9 areas)[a]		**Fixed O&M Costs (FOM)**	
Total process facilities cost	PFC[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]		
Project contingency	15 % PFC[e]	Admin. & support labor	30 % of total labor
Process contingency	5 % PFC[f]	Operating labor	2 jobs/shift[k]
Total plant cost (TPC) = sum of above		**Variable O&M Costs (VOM)**	
Interest during construction	calculated	Reagent (MEA) cost	$1250/tonne MEA[l]
Royalty fees	0.5 % PFC[g]	Water cost	$0.2/m^3$
Pre-production costs	1 month[h] VOM & FOM	CO_2 transport cost	$0.02/tonne CO_2/km[m]
Inventory (startup) cost	0.5 % TPC[i]	CO_2 storage/disposal cost	$5/tonne CO_2[n]
Total capital reqmt (TCR) = sum of above		Solid waste disposal cost	$175/tonne waste[b]

*Uncertainty distributions are given below. [a]The individual process areas modeled are: flue gas blower, absorber, regenerator, solvent processing area, MEA reclaimer, steam extractor, heat exchanger, pumps, CO_2 compressor. The sum of these is the total process facilities cost (PFC). The uncertainty distributions used are: [b]Normal (1.0,0.1), [c]Triangular (5,7,15), [d]Triangular (5,10,15), [e]Triangular (10,15,20), [f]Triangular (2,5,10), [g]Triangular (0,0.5,0.5), [h]Triangular (0.5,1,1), [i]Triangular (0.4,0.5,0.6), [j]Triangular (1,2.5,5), [k]Triangular (1,2,3), [l]Uniform (1100,1300), [m]Triangular (0.004,0.02,0.06), [n]Chance distribution (-10(p-0.25), -5(p=0.25), 3(p=0.05), 5(p=0.35), 8(p=0.1))

Table 2 lists the key power plant parameters and assumed uncertainty distributions, while Tables 3 and 4 show the performance and cost parameters, respectively, for the CO_2 capture and storage system. The nominal case assumes geologic storage of CO_2 at a net cost to the plant owner, while the uncertainty (variability) case includes the sale of CO_2 for enhanced oil recovery (EOR).

TABLE 5
PROBABILISTIC COST RESULTS FOR CO_2 CAPTURE PLANTS

Case	COE ($/MWh)			Avoidance Cost ($/tonne CO_2 av.)		
	Mean	Median	Range	Mean	Median	Range
Low-S coal						
Reference plant	48.0	48.0	36-63			
CO_2 capture plant:						
unc. in both ref & capture plant	89.5	98.1	54-132	53.0	53.3	21-91
unc. in capture plant only	89.5	98.1	54-132	49.5	48.8	6-102
High-S coal						
Reference plant	55.3	55.0	43-69			
CO_2 capture plant:						
unc. in both ref & capture plant	96.3	95.9	63-138	55.8	56.3	23-90
unc. in capture plant only	96.3	95.9	63-138	52.2	51.7	9-106

Figure 1 shows the cumulative distribution function (cdf) for the cost of CO_2 avoided. One curve reflects only the uncertainty and variability in the parameters of the CO_2 capture and storage system. A second curve adds uncertainty and variability in four key power plant parameters that also influence the COE and avoided cost. We consider cases where these parameter values are identical for the reference and capture plants, and another case where they differ. Table 5 summarizes the mean, median, and range of the overall distributions for COE and cost of CO_2 avoided for several cases. The mean and median values of the cost of CO_2 avoided lie in the range of roughly $49 to $56/ tonne CO_2. When uncertainty and variability assumptions are taken into account the range widens considerably. With uncertainties only in the CCS system, the 95% probability interval varies by approximately a factor of three, from $32 to $75/ tonne CO_2. The most significant variables here were the CO_2 capture efficiency, lean solvent CO_2 loading of the amine system (which determines the regeneration heat requirements), the efficiency of heat integration (in terms of net power loss), and the CO_2 storage/disposal cost. Adding variability in plant parameters has a measurable effect on COE, but a small impact on avoidance cost if the reference plant and capture plant employ the same assumptions. Otherwise the impact on avoidance cost can be large, as illustrated in Table 5. Results for the two different coal types show that fuel choice assumptions also can have a large effect on COE but a much smaller effect on avoided cost relative to the same plant without CCS.

CONCLUSIONS

The analysis method used in this paper can be readily applied to other types of power generation and CCS systems, which will be part of our on-going work. While this study did not attempt to quantify the effects of technology innovation and learning on future cost reductions, this is nonetheless an important factor that is being considered in other research [14]. In the context of long-term scenarios or projections, assumptions about rates of technical are critical to cost estimates for CO_2 capture and storage.

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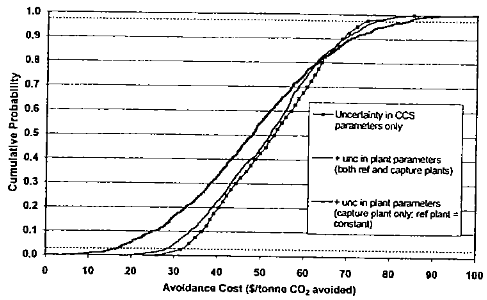

Figure 1: Effects of parameter uncertainty and variability on the cost of CO_2 avoided. The dotted lines at the top and bottom of the graph encompass the 95% probability interval.

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