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The Cost of Carbon Capture and Storage for Natural Gas Combined Cycle Power Plants

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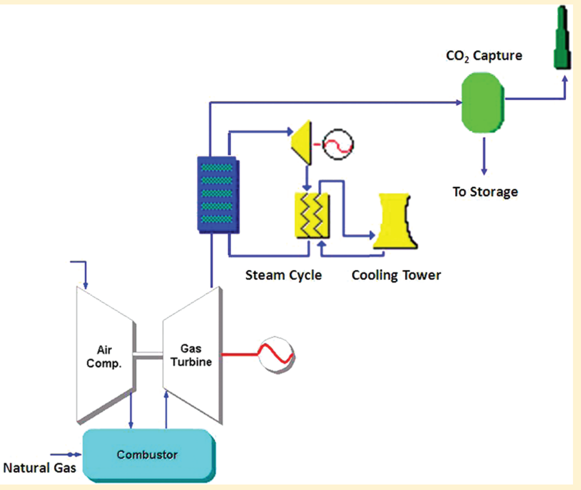
Supporting Information

ABSTRACT: This paper examines the cost of CO_2 capture and storage (CCS) for natural gas combined cycle (NGCC) power plants. Existing studies employ a broad range of assumptions and lack a consistent costing method. This study takes a more systematic approach to analyze plants with an amine-based postcombustion CCS system with 90% CO_2 capture. We employ sensitivity analyses together with a probabilistic analysis to quantify costs for plants with and without CCS under uncertainty or variability in key parameters. Results for new baseload plants indicate a likely increase in levelized cost of electricity (LCOE) of \$20–32/MWh (constant 2007\$) or \$22–40/MWh in current dollars. A risk premium for plants with CCS increases these ranges to \$23–39/MWh and \$25–46/MWh, respectively. Based on current cost estimates, our analysis further shows that a policy to encourage CCS at new NGCC plants via an emission tax or carbon price requires (at 95% confidence) a price of at least \$125/t CO_2 to ensure NGCC-CCS is cheaper than a plant without CCS. Higher costs are found for nonbaseload plants and CCS retrofits.



INTRODUCTION AND OBJECTIVES

Over the past two decades natural gas has become an increasingly important source of U.S. electricity generation. Historically, natural gas has been used to provide peak-load power at a relatively high cost per kilowatt-hour during the daytime intervals when electricity demands peak and cannot be supplied wholly by baseload generators. The introduction of high-efficiency natural gas combined cycle (NGCC) power plants, coupled with declining natural gas prices in the 1990s, spurred greater interest in natural gas for baseload and intermediate loads, as well as peak power production. By 2009, gas-fired power plants contributed more than 20% of all electricity supplied to the grid, up from 10% in 1990.[1] This share is projected to grow to 47% by 2035, with natural gas accounting for 60% of new generating capacity additions between 2010 and 2035 in the Department of Energy's reference case scenario.[1,2]

Electric utilities are thus looking to natural gas as a preferred energy source in response to the bullish outlook for domestic gas supplies from new shale gas production,[3] as well as from new air quality regulations that are expected to force the retirement of many older existing coal plants. Besides reducing emissions of criteria air pollutants, switching from coal to natural gas is also a strategy for reducing greenhouse gas emissions linked to global climate change since new NGCC plants emit roughly half the CO_2 per kilowatt-hour as conventional coal-fired plants.[4] Recent studies indicate that even accounting for the higher life cycle emissions associated with natural gas produced from shale formations, NGCC power plants still have much lower GHG emissions than conventional coal-fired power plants.[5]

Despite their lower GHG emissions, recent studies also indicate that increased natural gas use in lieu of coal for electricity generation will be insufficient to achieve the large (50 to 80%) reductions in U.S. greenhouse gas emissions needed to stabilize climate change unless a portion of gas-fired plants are equipped with CO_2 capture and storage (CCS).[6,7] To date, however, most studies of CCS have focused on its potential application to coal-based power plants.[8] In this paper, therefore, we focus on CCS applied to NGCC plants. More specifically, we undertake a systematic examination of how the addition of CCS as a CO_2 reduction strategy would affect the cost of generating electricity from natural gas. We begin with a review of other recent studies of CCS costs for NGCC power plants and attempt to understand the reasons for significant differences in published cost estimates. We then undertake a more systematic analysis that includes a characterization of uncertainties and variability in NGCC plant costs with and without CCS. This analysis seeks to identify the parameters and

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Table 1. Summary of Assumptions and Results for Several Recent Cost Studies for U.S. Natural Gas-Fired Power Plants[a]

case	parameter	DOE/NETL (2007)	DOE/NETL (2010)	EPRI (2009)		Interagency Task Force (2010)	DOE/EIA (2011)
reference plant without CCS	turbine class/type	7FB	7FB	7FB	7FB		H
	net power output (MW)	560.4	555.1	550	550		400
	net plant efficiency, HHV (%)	50.8	50.2	46.7	42.3		53.1
	capacity factor (%)	85	85	80	40		87
	cost year	2007	2007	2007	2007	2009	2009
	inflation rate (%)	1.87	3	0	0	3	
	fixed charge factor	0.164	0.105	0.12	0.12	0.150	
	levelization period (yrs)	20	30	30	30	30	30
	natural gas price ($/MBtu)	6.75	6.55	7.00	7.00		
	total plant cost ($/kW)	554	584	800	800		
	total overnight cost ($/kW)		718				1003[b]
	first-year COE ($/MWh)		58.9				
	levelized COE ($/MWh)	68.4	74.7	66.4	85.3	77	63.1
same plant with CCS	CO_2 capture system	Econamine FG+	Econamine FG+	Econamine FG+	Econamine FG+		
	CO_2 capture efficiency (%)	90	90	90	90	90	
	net power output (MW)	481.9	473.6	467.5	467.5		340
	net plant efficiency, HHV (%)	43.7	42.8	39.7	35.9		45.4
	fixed charge factor	0.175	0.111	0.12	0.12	0.157	
	CCS T&S cost ($/MWh)	2.9	3.2	4.1	4.5		
	CCS T&S cost ($/t CO_2)			10	10		
	total plant cost ($/kW)	1172	1226	1370	1370		
	total overnight cost ($/kW)		1497				2060[b]
	first-year COE ($/MWh)		85.9				
	levelized COE ($/MWh)	97.4	108.9	91.2	121.1	121	89.3
cost of CCS	**levelized COE ($/MWh)**	**29.0**	**34.5 (27.0)**[c]	**24.8**	**35.8**	**44**	**26.2**
	cost of CO_2 avoided ($/t CO_2)	**92**	**106 (83)**[c]	**74**	**95**	**114**	

[a]Missing values are not reported in the indicated study. [b]Cost year is 2010. [c]Value based on constant dollars.

assumptions that most influence overall cost results. It also analyzes the requirements of a market-based policy option to incentivize CCS at new NGCC plants.

REVIEW OF RECENT STUDIES

A number of recent studies have reported cost estimates for NGCC power plants with and without CCS.[2,4,9−16] Table 1 summarizes the key assumptions and cost results from five recent studies of NGCC plants in the United States by agencies of the U.S. government and by the industry-sponsored Electric Power Research Institute (EPRI). As seen in the table, there are similarities as well as pronounced differences in the underlying assumptions of these analyses. All but one study assumes a "reference case" NGCC plant (without CCS) using General Electric 7FB gas turbines with a net power output of approximately 550 MW for the combined cycle plant. The DOE Energy Information Administration (DOE/EIA), however, assumes an advanced H-class turbine yielding a net plant output of 400 MW. For the cases with CCS (shown in the lower part of the table), all studies assume an amine-based postcombustion system capturing 90% of the flue gas CO_2, with pipeline transport and storage of CO_2 in a deep geological formation.

In all cases the addition of CCS reduces the net plant efficiency and net power output while increasing the cost of electricity (COE) generation. Even without CCS, the reported costs summarized in Table 1 vary significantly across the five studies, with the COE ranging from $63/MWh to $85/MWh on a levelized basis over the life of the plant. With CCS the levelized cost of electricity (LCOE) varies from $89/MWh to

\$121/MWh—increases of approximately 35% to 60% over the reference case without CCS. In turn, the cost of CO_2 avoided varies widely from \$74 to \$114 per metric tonne of CO_2 avoided. The latter measure is widely used to compare the cost of alternative CO_2 reduction options[17] and corresponds to the "carbon price" or tax on CO_2 emissions at which a plant with CCS equals the cost of the reference plant without capture. Because NGCC reference plants have a lower carbon intensity than coal-based plants, the avoidance cost for NGCC-CCS plants is typically higher than for PC or IGCC plants.[11,18,19]

The cost differences seen in Table 1 for similar or identical facilities arise from two types of sources: differences in the underlying cost estimation method and differences in the assumptions about technical, economic, and financial factors. In terms of methodological differences, most significant is the exclusion of so-called "owner's costs" in the total plant capital cost of the 2007 DOE/NETL study. Owner's costs include such items as expenses for financing, royalty payments, initial inventories, working capital, land purchases, and other items deemed necessary for a project.[11,20] Such costs can add 20% or more to the estimated capital cost of a power plant. NETL's most recent (2010) cost study employed a revised costing method that now includes owner's costs; this accounts for most of the increase in the reported plant capital costs relative to the 2007 DOE/NETL study. Thus, while prominent organizations such as DOE, EPRI, and IEAGHG have each developed methods to estimate the cost of power plants with and without CCS, there is not yet a common method and nomenclature used by all parties at interest.[21] This can make it difficult to determine the extent to which dissimilar cost estimates reflect differences in underlying parameter assumptions or broader differences in project scope and items included in the cost estimate.

Where costing methods and project scope are similar, cost differences across studies typically reflect different assumptions about key parameters. As illustrated in Table 1, the NETL and EPRI studies both assume the same type and size of NGCC power plant but report different values of net plant efficiency. Across these studies there are also differences in the assumed plant capacity factor, natural gas price, total plant cost, fixed charge factor, and assumed rate of inflation. The latter factor alone can make a significant difference in reported levelized costs since the inclusion of inflation in a "current dollar" cost estimate results in a higher reported cost for a given system than the "constant dollar" costs reported in most technology cost studies.

Another source of differences seen in Table 1 is the assumed fixed charge factor (FCF) for plants with and without CCS. The FCF reflects the assumed cost of capital for a project over a specified amortization period. In the NETL and U.S. Task Force studies the NGCC plant with CCS has a higher FCF than the plant without CCS. This reflects a higher cost of capital—thus, a higher financial risk—assumed for the plant with CCS. The EPRI studies, on the other hand, assume the same FCF for both plants, indicating no "risk premium" for the CCS plant. Other recent studies (such as UKDECC, 2010[13]) also employ different financing assumptions for "first-of-a-kind" (FOAK) plants with CCS, which are viewed as riskier than mature "Nth-of-a-kind" (NOAK) plants and technologies. Such differences in financial assumptions are another factor contributing to differences in CCS cost estimates across different studies.

Because of the different ways in which multiple technical and economic parameters affect the "bottom line" cost of a power plant, it is not possible to assess the influence of various factors on CCS costs simply by examining published studies. In this paper, therefore, we undertake a more systematic examination of CCS costs for NGCC plants using an engineering-economic model, as elaborated below.

■ ANALYTICAL APPROACH TO COST ANALYSIS

In this study, the recently enhanced Integrated Environmental Control Model (IECM v. 6.2.4) is used to systematically analyze the cost of new NGCC power plants with and without CCS. The IECM is a widely used and publicly available computer modeling tool developed by Carnegie Mellon University.[22] The model employs fundamental mass and energy balances, together with empirical data, to calculate plant-level performance and material flows, including environmental emissions, for current and advanced power plant designs whose configuration and parameters are specified by the user. Available plant configurations include pulverized coal (PC), integrated gasification combined cycle (IGCC), and NGCC systems with a variety of emission control options, including CO_2 capture and storage. The IECM also provides the capability to quantify uncertainties in model input parameters and express results as probability distribution functions as well as deterministic values. Comparative analyses of different system designs also can be performed easily.

Plant-level capital and operating costs (fixed and variable) are calculated using selected flowsheet variables, together with cost data for major pieces of equipment or plant subsystems. Current IECM default data for NGCC plants and post-combustion CCS systems were derived primarily from detailed cost studies by DOE/NETL.[10,11] The general IECM costing method and nomenclature are based on the EPRI Technical Assessment Guide,[20] which has been an industry standard for many years. The "bottom line" output of the economic analysis is the levelized cost of electricity (LCOE) for the overall plant. The LCOE represents the uniform annual revenue requirement needed to recoup all costs of building and operating a plant over a specified lifetime. It is calculated as[9]

$$\mathrm{LCOE} = \frac{\mathrm{FCF}\cdot\mathrm{TCR} + (\mathrm{FOM} + \mathrm{VOM})\cdot\mathrm{LCF}}{(\mathrm{CF}\cdot 8766)\cdot\mathrm{MW_{net}}} \quad (1)$$

where LCOE is the total levelized cost of electricity (\$/MWh); TCR is the total capital requirement (\$); FCF is the fixed charge factor (fraction/yr); FOM is the fixed O&M cost (\$/yr); VOM is the variable O&M cost (\$/yr); LCF is the levelization cost factor (a multiplier that accounts for inflation and real cost escalations; default value = 1.0); CF is the levelized annual capacity factor (fraction of equivalent full-load operation during a year); 8766 is the total hours in a year (averaged over leap years); and MW_{net} is the net plant power output (MW). Further details on the structure and components of TCR, FOM, and VOM are presented in the Supporting Information. Other technical details regarding the IECM power system and CCS parameters are available elsewhere.[22−25]

In this study we first establish a "base case" NGCC plant and use the IECM to estimate its cost with and without CCS. Then we conduct a series of sensitivity analyses to identify the parameters that most strongly influence overall plant costs and the incremental cost of CCS. Next, we conduct a probabilistic analysis to quantify the combined effect of uncertainties and variability in multiple cost-related parameters. Finally, we use results of the probabilistic analysis to evaluate the policy option of a CO_2 emissions tax as a way to promote the deployment of CCS at NGCC plants. We conclude with a summary of findings from the current study.

BASE CASE ASSUMPTIONS AND RESULTS

Table 2 summarizes the major assumptions defining the base case NGCC plants with and without carbon capture and storage. Both configurations are assumed to be new baseload plants with two GE 7FB gas turbines and a 3-stage heat recovery steam generator yielding a net power output of roughly 500 MW with a net plant efficiency of 50.0% (HHV basis) without CCS and 42.6% with CCS. The case with CCS uses an amine-based system to capture 90% of the flue gas CO_2, which is compressed and sent via pipeline for sequestration in a deep geological formation. All costs are reported in constant 2007 U.S. dollars assuming no real escalation of O&M costs. Nominal parameter values for the amine-based capture system are presented in Table 3.

Table 2. Base Case Assumptions and Results for NGCC Plants with and without CCS

variable	case 1: no CCS	case 2: with CCS
gas turbine model	GE 7FB	GE 7FB
natural gas composition[a]	NETL	NETL
carbon capture and storage system	none	Econamine FG+
CO_2 capture efficiency (%)	0	90
net power output (MWe)	526.6	448.9
net plant efficiency, HHV (%)	50.0	42.6
capacity factor (%)	75	75
cost basis[b]	Constant 2007$	Constant 2007$
fixed charge factor (fraction)	0.113	0.113
natural gas cost ($/MBtu)	6.55	6.55
operating labor rate ($/h)	34.65	34.65
CCS T&S cost ($/t CO_2)	0	7
CO_2 emission rate (lbs/MWh)	803	94
total capital requirement ($/kW)	759.6	1336
total levelized cost of electricity ($/MWh)	60.8	84.2

[a]NETL nature gas composition is assumed in this study (NETL, 2010).[11] [b]The levelization cost factor shown in eq 1 is one since the cost is evaluated on a constant dollar basis.

The results in Table 2 show that with CCS the CO_2 emission rate per kWh falls by about 88% (slightly less than the 90% capture efficiency because of the CCS energy requirement), while the plant capital cost increases by about 76% and the LCOE by about 39%, or $23.4 per MWh. The resulting cost of CO_2 avoided for the NGCC plants with and without capture is $73 per metric tonne of CO_2. This cost agrees well with the EPRI estimate of $74/t CO_2 in Table 1 for the baseload plant but is somewhat lower than the NETL estimate of $83/t CO_2 for first-year COE (equivalent to a constant dollar LCOE). Because multiple factors affect reported costs, we next undertake a sensitivity analysis to more systematically examine the influence of various parameters on NGCC cost estimates.

SENSITIVITY ANALYSIS

A sensitivity analysis was first carried out for the base case NGCC plant (without capture) to identify and rank the plant parameters that most influenced the LCOE. The nominal values of ten technical, economic, and financial parameters in the IECM were each increased by 10%, with all other parameters held constant at their nominal values. Five parameters had the largest impact on LCOE, producing changes (some positive, some negative) of approximately 8% to 2%: the gas turbine efficiency (reflecting different turbine classes or operating conditions), natural gas price, plant

Table 3. Assumed Distribution Functions for Probabilistic Analyses

uncertainty source	parameter	unit	nominal value	distribution function[a]
power block capital cost	total plant cost	% of base	100	uniform (90, 140)
	other owner's cost	%	2	uniform (2,10)
financing	fixed charge factor:			
	N[th]-of-a-kind	fraction	0.113	uniform (0.100, 0.150)
	first-of-a-kind	fraction	*b*	uniform (0.106, 0.180)
utilization	capacity factor	%	75	uniform (65, 85)
O&M cost	natural gas price	$/MBtu	6.55	uniform (5.00, 7.50)
	labor rate	$/h	34.65	uniform (30.00, 40.00)
CO_2 capture system[c]	ID fan efficiency	%	75.0	uniform (70.0, 75.0)
	pump efficiency	%	75	uniform (70.0,75.0)
	Regen. heat requirement	Btu/lb CO_2	1712	uniform (1290, 2150)[d]
	system cooling duty	t H_2O/t CO_2	123	triangular (67, 123, 162)[e]
	nominal sorbent loss	lb/ton CO_2	0.6	triangular (0.5, 0.6, 3.1)
	solvent pumping head	psia	30	triangular (5, 30, 36)
	captured CO_2 purity	vol. %	99.5	uniform (99.0, 99.8)
	CO_2 product pressure	psig	2000	uniform (1800, 2200)
	CO_2 compressor efficiency	%	80	uniform (75, 85)
	total indirect capital cost	%	37.0	uniform (20.0, 60.0)
	other owner's cost	%	2	uniform (2, 10)[f]
CO_2 T&S	transport and storage cost	$/t CO_2	7	uniform (4, 10)

[a]Except where noted, the assumed distributions reflect the range of assumptions for the studies noted in Table 1 (with some ranges slightly expanded based on the authors' judgment and data from other references[1,9,24]). A uniform distribution is assumed where there is no strong basis for selecting a most probable value within a specified range. In two cases a triangular distribution is assumed based on the references cited. For several parameters the nominal value lies toward one end of the range. In these cases the opposite end of the range reflects a higher value used a particular study. [b]The FOAK value is represented as an increase in the fixed charge factor of the NOAK case. A uniform distribution (0.006, 0.03) is added to the FCF distribution of the NOAK case to obtain the FCF distribution for the FOAK case. [c]All parameter ranges based on Rao and Rubin[25] and other references where noted. [d]Reference: Bolland and Undrum, 2003.[27] [e]Reference: Zhai et al., 2011.[28] [f]Assumed to be the same as for the plant power block.

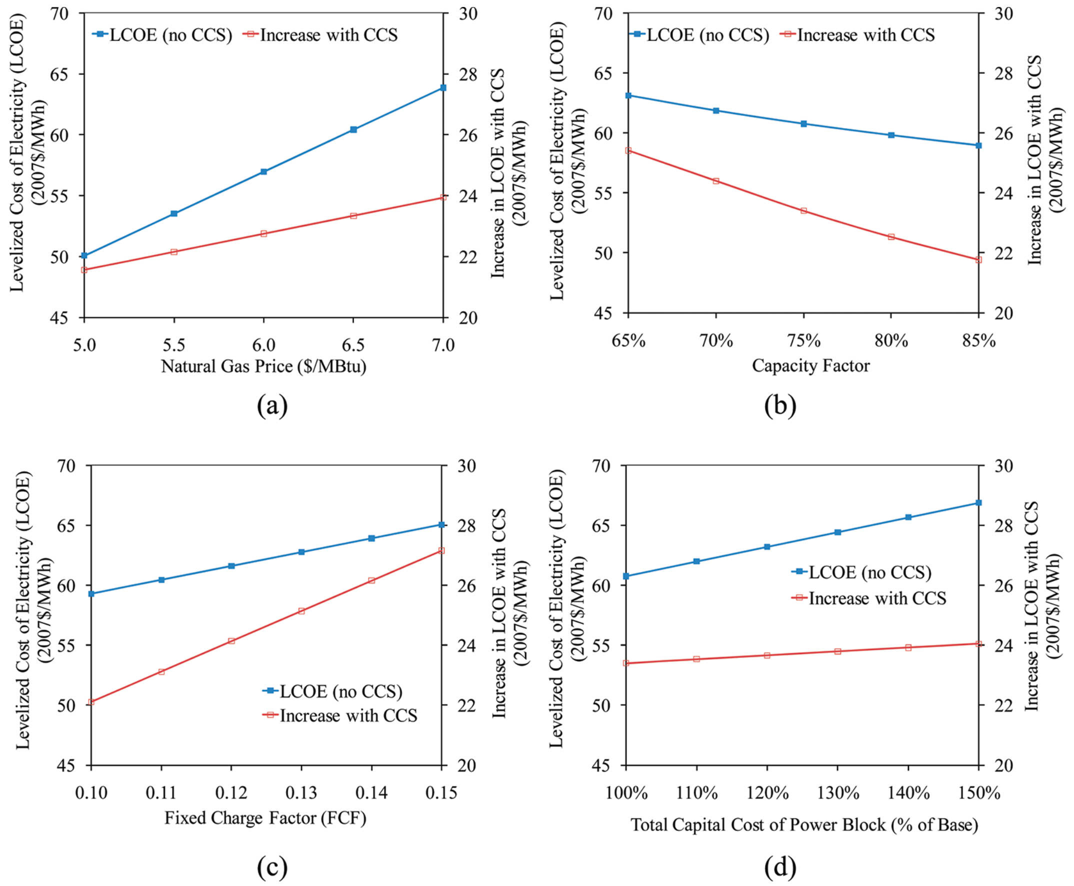


Figure 1. Effect of key parameter values on base plant cost of electricity (LCOE) and the added cost of carbon capture and storage (CCS).

capacity factor, fixed charge factor, and power block capital requirement. Four other parameters (power block indirect capital costs, plant book life, steam cycle heat rate, and plant labor rate) induced LCOE changes of only 0.1% to 0.8%, while the remaining parameter (miscellaneous owner's costs) induced a much smaller change (less than 0.1%) (see Figure S-1 of the Supporting Information for details).

Additional sensitivity studies were next conducted for several key parameters. Here, the range of parameter values encompassed those found in other recent studies of baseload NGCC plants (Table 1). Figure 1 shows the resulting effects on the base plant LCOE and the added cost of CCS. Over the parameter ranges shown, the plant LCOE increased by 28%, 10%, 10%, and −7% in response to the changes in natural gas price, fixed charge factor, power block capital cost, and plant capacity factor, respectively. (The negative value indicates that an increase in capacity factor decreases the LCOE.)

Figure 1 further shows that changes in these NGCC plant parameters also affect the added cost for CCS. Here, the cost of CCS increases by 23%, −14%, 11%, and 3% over the indicated ranges of fixed charge factor, plant capacity factor, gas price, and power block capital cost, respectively. Thus, the cost of CCS depends not only on the cost of the technology for capture, transport, and storage but also on the design, cost, and operation of the base power plant.

Several additional sensitivity analyses are shown in Figure S-2 of the Supporting Information. One case shows the effect on LCOE of lower plant capacity factors (30% to 50%), representing plants that operate as intermediate rather than baseload plants. This more closely reflects the actual utilization of most NGCC plants in the U.S. over the past two decades.[26] At a capacity factor of 40%, for example, the added cost for CCS rises to $35.4/MWh, 51% more than at the nominal baseload capacity factor (excluding any additional costs due to part-load operation or more frequent startups and shutdowns). Figure S-2 also shows the effect of varying three other cost parameters: inflation rate, miscellaneous owner's costs, and the reference year for cost reporting. Changes in the owner's costs and the cost year had only a small or negligible effect on the cost of CCS.

■ PROBABILISTIC ANALYSIS

A limitation of sensitivity analysis is that uncertain variables typically are examined one at a time with all other parameters held constant. Thus, interactions among several uncertain parameters may be overlooked. In some cases, several parameter values may be changed simultaneously, for example, as a bounding analysis with parameters set to their maximum or minimum values. However, this provides no information on the likelihood of such extreme outcomes. A more rigorous approach is a probabilistic analysis in which distribution functions are assigned to multiple independent variables. The distributions are sampled repeatedly using Monte Carlo (or related) methods to yield a distribution function showing the probability of a specified outcome or result.[20,22] In this paper we used the probabilistic capability of the IECM to characterize the effect on LCOE of uncertainty or variability in several of the dominant parameters identified in our sensitivity analysis. Those parameters are discussed below.

LCOE for Plants with and without CCS. We first conducted an analysis for the base case NGCC plant without CCS in which probability distribution functions (PDFs) were assigned to capital cost, O&M cost, financing cost, and plant operating variables, as summarized in Table 3. A second analysis for the plant with CCS included additional PDFs for the CO_2 capture and storage system (also shown in Table 3). The choice of distribution functions in Table 3 is based on previous assessments in the literature.[2,4,9−11,14,24,27,28] Parameter values are based on the range of assumptions in recent CCS cost studies for new baseload NGCC plants (Table 1) and data from other references.[1,9,24]

The LCOE results are characterized as a cumulative distribution function that yields confidence intervals and the probability of different outcomes for a given simulation scenario. Figure 2 shows the distribution for the no-capture case. It has a mean LCOE of $63/MWh and a 95-percent confidence interval of approximately $52 to $75/MWh. For the CCS case the mean increases to $93/MWh and the 95% confidence interval ranges from $76 to $113/MWh. The probability that the LCOE is higher than the deterministic estimate is more than 60% for the no-capture case and about 80% for the plant with CCS. These results reflect the assumed distributions for parameters like the fixed charge factor (FCF) and power block capital cost, which are nonsymmetric relative to the nominal deterministic value. That asymmetry results from the range of parameter values found in the studies in Table 1. Figure S-3 of the Supporting Information decomposes the overall distribution function for LCOE and shows that variations in the natural gas price (the dominant O&M cost), fixed charge factor, and total capital cost of the power block are the major sources contributing to the overall uncertainty. Figure S-4 of the Supporting Information shows the effect on LCOE of uncertainties in the CCS system parameters alone. Here too, other plant parameter uncertainties (or variability) dominate the overall distribution.

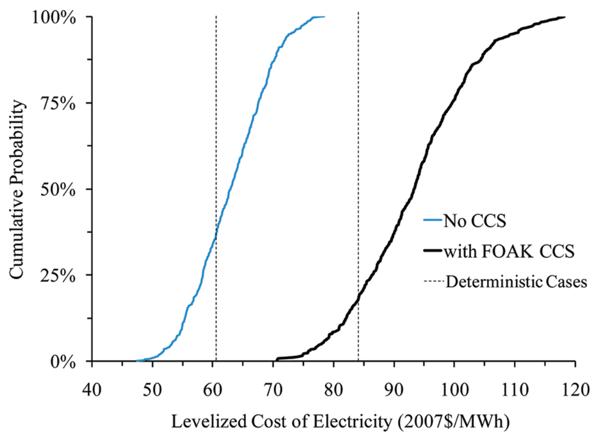


Figure 2. Probability distributions for the levelized cost of electricity (LCOE) of NGCC plants with and without CCS. The CCS case assumes a higher fixed charge factor (FOAK) than the plant without CCS.

Increase in LCOE Due to CCS. The results above show that cost of NGCC plants with and without CCS are both subject to uncertainty and variability. In this case the incremental cost of CCS cannot be found simply as the cost difference between the two plant configurations. What then is the cost of CCS and what is the associated uncertainty? To answer this question we use the LCOE results above to generate a probabilistic *difference* in cost, recognizing that some parameters should have the same value for plants with and without CCS, such as the power block capital cost, natural gas price, and the plant labor rate. The fixed charge factor also is the same unless the CCS plant is considered a "first-of-a-kind" (FOAK) technology subject to a higher FCF. Consistent with the studies cited, we do not explicitly include other types of risks in the FOAK case, such as higher capital and operating costs or shortfalls in performance. For this analysis we further assume the baseload plant capacity factor is the same with or without CCS, although its value varies over the range shown in Table 3. Other uncertain parameters unique to the plant with CCS were assumed to be uncorrelated and independent.

To account for the correlated variables in comparing cases with and without CCS, we employed the procedure for probabilistic cost differences used by Frey and Rubin.[29,30] The identical set and sequence of 500 random samples was assigned to the variables common to both plants, while independent variables for the CCS plant were sampled randomly. Results for each iteration were then paired, sample-by-sample, to obtain a cost difference for each pair. The resulting set of sample differences was then used to construct a cumulative probability distribution for the added cost of CCS.

Figure 3 shows the results for two scenarios with different financing assumptions for the plant with CCS. The NOAK scenario assumes the same fixed charge rate with or without CCS. In contrast, the FOAK scenario assumes higher financing costs for the plant with CCS. This "risk premium" adds between 0.006 and 0.03 (assumed to be a uniform distribution) to the FCF value. The resulting distributions for the incremental cost of CCS have mean values of $26/MWh and $30/MWh for the NOAK and FOAK cases, respectively. The 95-percent confidence intervals (CIs) range from $21−32/MWh for the NOAK case and $22−39/MWh for the FOAK case. The mean values in both cases are higher than the corresponding deterministic estimates of CCS cost in Table 2. Given the range of parameter values that might apply, the probability that the CCS cost will exceed the deterministic estimate is about 80% for the NOAK case and about 95% for the FOAK case.

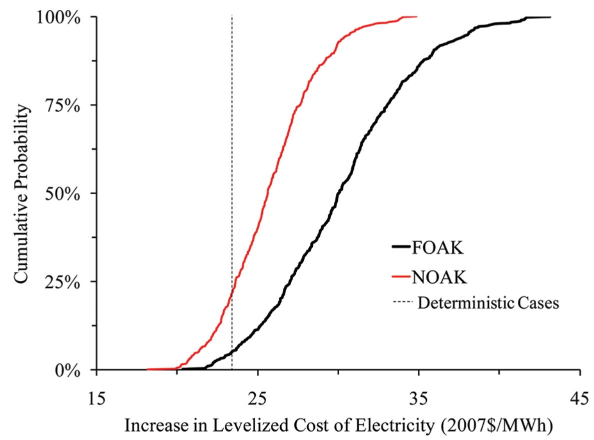


Figure 3. Probability distributions for added cost (LCOE) of CCS for fixed charge rates reflecting first-of-a-kind (FOAK) and Nth-of-a-kind (NOAK) plants.

Finally, if costs are expressed in current rather than constant dollars, with additional uncertainty in the inflation rate, the estimated CCS costs will have broader ranges than shown above. Figure S-5 and Table S-2 of the Supporting Information show results for the NOAK and FOAK cases assuming a uniform distribution of 0% to 3%/yr annual inflation. In current dollars the mean cost of CCS for the FOAK case increases to \$35/MWh, while the 95-percent confidence interval extends from \$25/MWh to \$46/MWh.

■ PRICING CO_2 EMISSIONS TO PROMOTE CCS DEPLOYMENT

Placing a price or tax on greenhouse gas emissions is widely viewed as a preferred strategy to establish markets for low-carbon technologies such as CCS.[6] Figure 4 shows the effect on LCOE as a function of the added cost of a CO_2 emissions tax (or carbon price) for the NGCC plants with and without CCS based on the nominal assumptions in Table 3. The breakeven CO_2 tax at which the LCOE of both plants is the same is \$73/t CO_2. This is also equal to the avoided cost of CO_2 mentioned earlier. For a CO_2 price or tax above this value, the natural gas plant with 90% CO_2 capture has a lower LCOE than the uncontrolled plant, thus making CCS economically attractive. At lower carbon prices the NGCC plant without CCS is more economical.

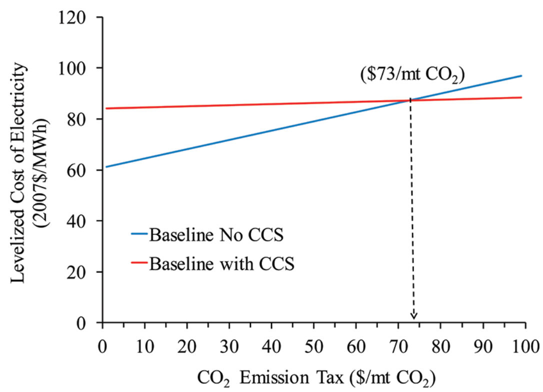
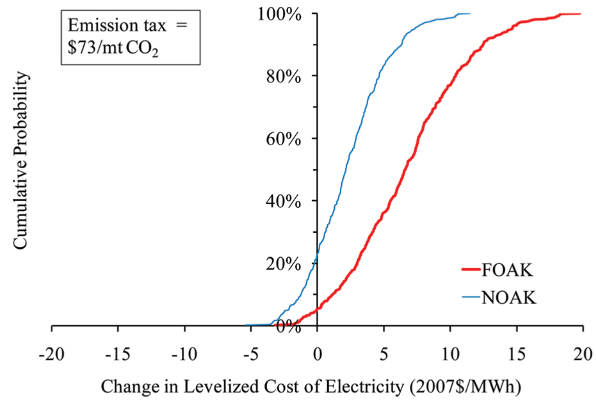


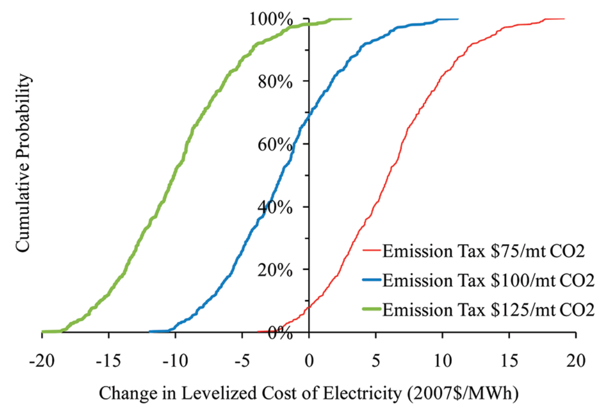
Figure 4. Breakeven CO_2 emission price or tax based on nominal deterministic parameter values.

Considering the effect of uncertainties in the natural gas price, financing rate, plant capacity factor, and other parameters discussed earlier, the two cost lines shown in Figure 4 would shift upward or downward, and the resulting intersection or breakeven price would thus also vary. Viewed another way, this means that a specified (deterministic) carbon price or tax that is intended to stimulate the use of CCS may or may not be adequate in light of the uncertainties and variability that apply to new NGCC plants.

To demonstrate this effect, we again calculate a cumulative probability distribution for the *difference* in LCOE between new NGCC plants with and without CCS, but this time with the additional cost of a CO_2 emissions charge or tax. Figure 5(a) shows results for the two financing assumptions, NOAK and FOAK, shown earlier in Figure 3. On this graph, a negative cost difference means that the CCS plant has a lower LCOE than the uncontrolled plant; a positive difference means the CCS plant is more costly. The probability corresponding to a zero cost difference represents the likelihood that CCS is the lower-cost option (and thus likely to be adopted) at the specified carbon price (in this case, \$73/t CO_2). Figure 5(a) shows that taking into account the uncertainty and variability in the parameters summarized in Table 3, the likelihood of adopting CCS is only about 20% in the NOAK case and 5% in the FOAK case. Thus, a carbon tax based on the nominal estimate of the breakeven CO_2 price would have a low probability of success in incentivizing the use of CCS.



(a)



(b)

Figure 5. Likelihood of a difference in LCOE between NGCC plants with and without CCS subject to a specified CO_2 emissions charge. A negative value means the plant with CCS has a lower LCOE under the specified carbon tax. Case (a) shows results for two financing cases (FOAK and NOAK) with the deterministic breakeven CO_2 emission price of \$73/t; Case (b) shows results for the FOAK case for three different CO_2 emission charges.

To see what level of carbon price would be needed to encourage widespread adoption of CCS over a broad range of assumptions, Figure 5(b) shows probabilistic difference curves for the higher-cost FOAK case with three CO_2 prices: \$75/t, \$100/t, and \$125/t CO_2. Only at the highest price is there a high likelihood (above 95%) that CCS will be the lower-cost option. Thus, to ensure an economic incentive for CCS in the face of estimated uncertainties, the CO_2 emission charge must be more than 70% above the nominal deterministic estimate.

■ DISCUSSION

Several important caveats accompany this analysis. First, the probabilistic results do not reflect the full range of conditions that might apply at NGCC power plants. In particular, they do not encompass plants that operate at the lower capacity factors seen at U.S. NGCC plants over the past decade. A sensitivity analysis showed that LCOE values would increase by 50% or more if plants served only intermediate or peak loads rather than baseload electricity demands.

Second, our analysis applies only to new plants and does not reflect the cost of retrofitting CCS to existing NGCC units. Retrofit costs would be higher for several reasons. For one, the capital cost of the capture unit increases due to site-specific difficulties (such as limited space or access) typically encountered with retrofit installations. CO_2 transport and storage costs could increase, depending on plant location, and financing costs would rise if the remaining plant life is short. Existing plants with older less efficient gas turbines also incur higher CCS energy penalties and associated costs. As noted earlier, most existing units currently operate at load factors well below baseload, which would further increase the LCOE. An additional sensitivity study in the Supporting Information (Table S-3) illustrates the LCOE impact of CCS retrofits. For a fully amortized plant with an older (model 7FA) gas turbine and a 40% load factor the cost for CCS in that example is approximately $40/MWh, equivalent to $123/t CO_2 avoided. These costs are roughly 70% higher than the corresponding costs in Table 2 for a new baseload plant.

Finally, we note that this paper does not reflect potential cost reductions achievable from technological advances in CO_2 capture system designs (including innovations such as flue gas recycle) nor advances that reduce the cost of gas turbines or other power plant components. Other studies indicate that improved technologies, widely deployed, could reduce the future cost of CO_2 capture at new NGCC plants by roughly 40%.[31] The plant-level analytical model used in this study also offers electric utilities, technology developers, researchers, policy analysts, and other stakeholders a tool to further explore the impact of alternative assumptions on the cost of CCS for NGCC power plants.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Additional tables and figures regarding parametric analyses and cost estimates. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare no competing financial interest.

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