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Understanding the pitfalls of CCS cost estimates

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ABSTRACT

This paper reviews and compares the prevailing methods, metrics and assumptions underlying cost estimates for CO_2 capture and storage (CCS) technologies applied to fossil fuel power plants. This assessment reveals a number of significant differences and inconsistencies across different studies, not only in key technical, economic and financial assumptions related to the cost of a CCS project (such as differences in plant size, fuel type, capacity factor, and cost of capital) but also in the underlying methods and cost elements that are included (or excluded) in a particular study (such as the omission of certain "owner's" costs or the cost of transport and storage). Such differences often are not apparent in the cost results that are reported publicly or in the technical literature. In other cases, measures that have very different meanings (such as the costs of CO_2 avoided, CO_2 captured and CO_2 abated) are all reported in similar units of "dollars per ton CO_2". As a consequence, there is likely to be some degree confusion, misunderstanding and possible mis-representation of CCS costs. Given the widespread interest in the cost of CCS and the potential for lower-cost CO_2 capture technology, methods to improve the consistency and transparency of CCS cost estimates are needed.

1. Introduction and objectives

Carbon dioxide capture and storage (CCS) is a potentially critical technology for mitigating global climate change, but its current cost is a major barrier to applications at power plants and other large industrial sources of CO_2 (NRC, 2010; IEA, 2011; GCCSI, 2011). Efforts are thus underway worldwide to develop new lower-cost technologies, especially for CO_2 capture—the costliest component of a CCS system (IPCC, 2005; Figueroa et al., 2008; Rubin et al., 2012). Given its potential importance in reducing greenhouse gas emissions, information on CCS costs is sought by a broad range of actors in government, industry and other organizations for purposes of policy analysis, investment decisions, technology assessments, R&D activities, and energy-environmental policy-making, including development of legislation and regulations involving CCS.

Yet, as this paper will show, there are significant differences and inconsistencies in the way CCS costs are currently calculated and reported by various authors and organizations. The major objective of this paper, therefore, is to highlight key methodological issues related to CCS cost estimates, including the specification of project scope, terminology, calculation procedures, and the items included (or excluded) in reported CCS costs. The paper also discusses the various measures of CCS cost that are commonly sought and reported, and identifies some of the critical (and sometimes controversial) assumptions underlying such estimates. Also discussed are how or whether CCS costing methods treat such issues as the level of technological maturity, technological change over time, and the vintage of facility analyzed (e.g., new vs. retrofitted plants). Issues related to uncertainty, variability and bias in assumptions and data also are discussed.

2. Cost measures and metrics

A variety of measures are used in the literature to report the cost of CO_2 capture and storage systems, as well as other CO_2 reduction measures. The most common metrics include the cost of CO_2 avoided; cost of CO_2 captured; cost of CO_2 abated (or reduced); and the increased cost of electricity (for studies related to power plants) (IPCC, 2005). As discussed below, the first three of these measures have very different meanings, but because all three are reported in similar units of "dollars (or other currency) per ton CO_2" there is significant potential for misunderstanding. Similarly, the metric of increased cost of electricity also is used in different contexts. Users of these CCS cost measures must therefore be careful to clearly understanding their meaning.

2.1. Cost of CO_2 avoided

The cost of CO_2 avoided is one of the most commonly reported measures of CCS cost (e.g., IPCC, 2005; EPRI, 2009; NETL, 2010; Finkenrath, 2011; GCCSI, 2011). It compares a plant with CCS to a "reference plant" without CCS, and quantifies the average cost of

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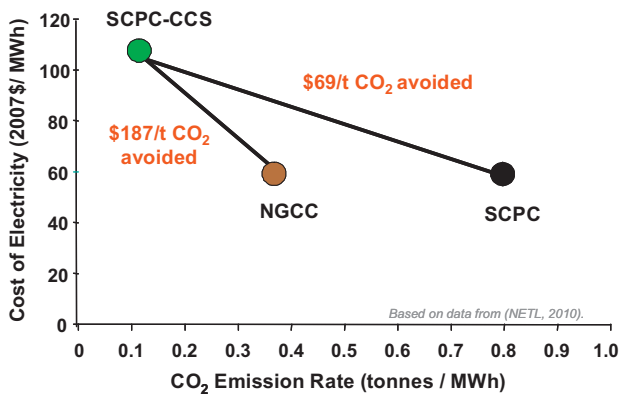

Fig. 1. Influence of reference plant choice on the cost of CO_2 avoided for a supercritical pulverized coal plant with CCS (SCPC-CCS). When compared to the same SCPC plant without CCS the avoidance cost in this example is \$69/ton CO_2 (constant 2007 dollars). When compared to a natural gas combined cycle (NGCC) plant the cost is \$187/ton CO_2. In this example both reference plants happen to have the same COE, so the incremental cost of CCS is \$48/MWh in both cases. Because the CO_2 reduction is smaller for the NGCC case the avoidance cost per tonne is higher (see Eq. (1)).

avoiding a ton of atmospheric CO_2 emissions while still providing a unit of useful product (e.g., 1 MWh, in the case of a power plant). For a power plant it is defined mathematically as (IPCC, 2005):

$$\text{Cost of } CO_2 \text{ Avoided } (\$/tCO_2) = \frac{(COE)_{ccs} - (COE)_{ref}}{(tCO_2/MWh)_{ref} - (tCO_2/MWh)_{ccs}} \quad (1)$$

where COE = cost of electricity generation (\$/MWh), $tCO_2/MWh = CO_2$ mass emission rate to the atmosphere in tons per MWh (based on the net capacity of each power plant), and the subscripts "ccs" and "ref" refer to plants with and without CCS, respectively. The cost of CO_2 avoided also equals the carbon tax (\$/tCO_2 applied to atmospheric emissions) at which the COE of the reference plant equals that of the plant with CCS (Rao and Rubin, 2002).

Because emissions to the atmosphere are not avoided unless and until the captured CO_2 is sequestered, the cost of CO_2 avoided must include the full cost of CCS. Some cost studies, however, include only the capture technology cost and omit the costs of transport and storage (IPCC, 2005). This is a common misuse of the term avoidance cost, and a source of misunderstanding (and misrepresentation) of reported cost estimates.

The choice of reference plant without CO_2 capture plays a central role in determining the CO_2 avoidance cost. Most commonly, the reference plant is assumed to be one that is identical or similar to the plant with CCS (for examples, see IPCC, 2005, Chapter 3, which presents assumption details for approximately 30 studies). This choice is appropriate to quantify the cost of CCS for a particular plant or plant type. Alternatively, a different choice of reference plant is needed to address other questions, such as the cost of carbon reductions if a plant with CCS is built in lieu of a different type of plant without CCS (for example, a coal-fired plant with CCS instead of an NGCC plant; or an IGCC plant with CCS instead of a conventional coal combustion plant). In these situations the reference plant is typically the one most likely to be built in a particular location in the absence of a carbon constraint. Numerically, the avoidance cost in such cases can differ dramatically from comparisons based on the same type of power plant. This is illustrated in Fig. 1, which shows that the avoidance cost increases by nearly a factor of 3 when a pulverized coal (PC) combustion plant with CCS is compared to an NGCC reference plant rather than a similar PC plant without capture. Thus, a clearly framed question or problem statement is needed to properly represent and interpret the cost of CO_2 avoided.

2.2. Cost of CO_2 captured

Another cost measure reported in the literature is the cost of CO_2 captured for a particular capture technology and plant type (IPCC, 2005). This measure is used to assess the economic viability of a CO_2 capture system relative to a market price for CO_2 as an industrial commodity. For an electric power plant it can be defined as:

$$\text{Cost of } CO_2 \text{ Captured } (\$/tCO_2) = \frac{(COE)_{cc} - (COE)_{ref}}{(tCO_2/MWh)_{captured}} \quad (2)$$

where $(tCO_2/MWh)_{captured}$ = total mass of CO_2 captured per net MWh for the plant with capture (equal to CO_2 produced minus emitted), and COE is again the cost of electricity. Here, the reference plant is the same type as the capture plant, and the COE with capture, $(COE)_{cc}$, excludes the costs of CO_2 transport and storage since the purpose of this measure is to quantify only the cost of capturing (producing) CO_2 (a commodity sought by commercial markets such as the food industry for use in beverages and the petroleum industry for enhanced oil recovery). In this regard, the concept of CO_2 capture cost is distinct from the CO_2 avoidance cost in that there is no assumption (or requirement) that the captured CO_2 be sequestered. Numerically, the cost of CO_2 captured is always lower than the cost of CO_2 avoided, mainly because the added energy requirements for capture means that more CO_2 is captured than avoided per net kWh generated (IPCC, 2005); thus, the cost per ton is lower. Since some technology developers report only the cost of CO_2 captured, casual readers could easily mistake it for the cost of CO_2 avoided.

2.3. Cost of CO_2 abated

A "cost per ton of CO_2" also is commonly reported in the context of greenhouse gas reduction strategies involving multiple CO_2 emission sources rather than a single power plant. Such results are produced by various types of energy-economic or integrated assessment models (e.g., Riahi et al., 2004; IPCC, 2005; Clarke et al., 2008, 2009; IEA, 2011). In this context, it represents the cost of moving from one situation (such as the current mix of electricity generators, fuels and emissions in a country, region or utility system) to a different situation with lower CO_2 emissions. Scenarios with reduced emissions usually include changes in the power generation mix as well as demand reduction measures—not just CCS. This is a very different concept than the cost of CO_2 avoided discussed above for a single plant. We refer to it as "the cost of CO_2 abated (or reduced)" since there is no stipulation that the same amount of useful product (i.e., electricity) is provided before and after emissions are reduced; nor is CCS necessarily the only means of reducing CO_2 emissions. This cost measure can be calculated as:

$$\text{Cost of } CO_2 \text{ Abated (or Reduced) } (\$/tCO_2) = \frac{(NPV)_{low\text{-}C} - (NPV)_{ref}}{(tCO_2)_{ref} - (tCO_2)_{low\text{-}C}} \quad (3)$$

where NPV = net present value cost of the specified scenarios, $tCO_2 = CO_2$ mass emission rate in tons per year, and the subscripts "ref" and "low-C" refer to values before and after a specified carbon reduction scenario, respectively. In large-scale energy-economic models, this value of "dollar per ton CO_2" also may refer to the carbon price or tax needed to achieve a specified level of CO_2 reduction for the system being analyzed. The cost-per-ton figures for such scenarios therefore should not be compared to (or mistaken for) the cost of CO_2 avoided as defined earlier for a single plant.

2.4. Increased cost of electricity

This cost measure also can apply to individual plants or a collection of plants, so a clear understanding of the context is extremely important. In engineering-economic studies of CCS cost at the plant level, the overall cost of CCS is the difference in COE between a power plant with CCS and a reference plant without CCS. The COE in each case can be expressed as:

$$\mathrm{COE} = \frac{(\mathrm{TCC})(\mathrm{FCF}) + (\mathrm{FOM})}{(\mathrm{CF})(8766)(\mathrm{MW})} + \mathrm{VOM} + (\mathrm{HR})(\mathrm{FC}) \quad (4)$$

where COE = cost of electricity generation ($/MWh), TCC = total capital cost ($), FCF = fixed charge factor (fraction/year), FOM = fixed operating and maintenance (O&M) costs ($/year), VOM = variable non-fuel O&M costs ($/MWh), HR = net power plant heat rate (MJ/MWh), FC = unit fuel cost ($/MJ), CF = plant capacity factor (fraction), 8766 = total hours in an average year, and MW = net plant capacity (MW).

Eq. (4) shows that many factors affect the COE of a power plant, and thus the cost of CCS. Because many parameter values (such as the capacity factor, fuel cost, and other operating costs) change over the operating life of a plant, the COE also may vary from year to year. To account for such variations, some cost methods (e.g., Bohm et al., 2007; NETL, 2010) use a discounted cash flow analysis to calculate the net present value (NPV) of expected costs and revenues based on assumptions for each year of plant construction and operation.

Most engineering-economic studies of CCS, however, use Eq. (4) to calculate and report a single value of COE based on a fixed set of cost parameter values (e.g., see IPCC, 2005; Rubin et al., 2007; IEAGHG, 2009; EPRI, 2009). Unless otherwise indicated, this COE represents the "levelized" cost of electricity, defined as the uniform annual cost that produces the same NPV as a stream of variable year-to-year costs over a specified plant life. Some cost studies explicitly label this as "LCOE" (e.g., NETL, 2010; ZEP, 2011; Rubin and Zhai, 2012). By definition, it equals the uniform revenue stream (from the sale of electricity) that a power plant must realize to fully recover all capital and operating costs, while earning a specified rate of return over the plant life. That rate is embedded in the fixed charge factor, FCF.

If not clearly labeled, however, reported values of COE can be ambiguous and easily misunderstood. For example, the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL) recently started using COE to mean the "first year COE" for power plant and CCS costs (NETL, 2010). In this case, all parameter values in Eq. (4) are for the first year of plant operation. To then calculate the LCOE, the annual O&M costs in Eq. (4) are each multiplied by a "levelization factor" (LF), whose value can be calculated from specified rates of inflation and real cost escalation (for each item) over the life of a plant (EPRI, 1993). Until recently, most CCS cost studies implicitly assumed LF = 1.0, reflecting a "constant dollar" analysis with no inflation or real cost escalations. But if either factor is assumed to be greater than zero (as in a "nominal" or "current dollar" analysis), the value of LF can be much greater than 1.0. This results in much higher values of reported LCOE. We return to this issue later in the paper.

Either implicitly or explicitly, LCOE is the most common metric used to quantify the increased cost of electricity for a power plant that installs CCS. LCOE values also are used in Eq. (1) to calculate the cost of CO_2 avoided. Thus, unless otherwise stated, all parameters in Eq. (4) (including FCF and CF) implicitly reflect their levelized values over the life of the plant.

Finally, readers should not confuse this plant-level COE with the increased cost of electricity to consumers for CO_2 reductions scenarios involving CCS and other measures. The latter depends on the overall cost of generation, transmission, distribution and other costs in the context of a utility system serving a particular region. Such system-wide cost projections are obtained using capacity planning models for the electricity supply sector, examples of which are found in large-scale energy-economic models (e.g., EIA, 1994, 2011; Clarke et al., 2009).

3. A hierarchy of CCS costing methods

Across the landscape of reported costs for CCS one can find a variety of methods that underlie such figures. They include:

- Expert elicitations
- Using published values
- Modifying published values
- Deriving new results from a model
- Commissioning a detailed engineering study

In this paper the focus is on methods and assumptions used on the lowest rungs of this ladder to derive plant-level cost estimates for specific technologies. Directly or indirectly, such estimates provide the basis for the less-detailed figures used or cited by others at the higher rungs of this ladder (for example, the costs used by developers of large-scale energy systems models, or reported in the press based on conversations with CCS experts). Several organizations, including the Electric Power Research Institute (EPRI) and the Association for the Advancement of Cost Engineering International (AACE), have defined different classes of plant-level cost estimates ranging from "simplified" to "finalized" (EPRI, 1993; AACE, 2005). As illustrated in Table 1, these classes reflect increasing levels of effort and information as a project moves from conceptual and preliminary design to the final stages of construction. In all cases, however, a clear definition of the project scope and boundaries is needed for any CCS costing method.

Fig. 2 illustrates elements of the project scope that must be specified by authors—and understood by users—of CCS cost estimates. For the most part, CCS costs reported in the technical literature and the media are based on "simplified" to "detailed" estimates, corresponding to Classes I–III in Table 1. Details of "finalized" (Class IV) cost estimates—such as those from so-called FEED (Front-End Engineering Design) studies—usually are not available publicly. The focus in this paper, therefore, is on the prevailing methods used for preliminary cost estimates found in the public domain.

4. Status of current costing methods

To bring a degree of consistency and uniformity to their own power plant and CCS cost estimates, a number of national and international organizations representing electric utility companies and government agencies (such as EPRI, DOE/NETL, and the International Energy Agency Greenhouse Gas Programme, IEAGHG), each have developed detailed procedures and guidelines for calculating plant-level capital costs, O&M costs, and COE (EPRI, 1993; IEAGHG, 2009; NETL, 2011). Studies conducted by and for these organizations by independent contractors also are directed or encouraged to employ the specified methods and assumptions. At the same time, other private companies, governmental organizations and study groups also have developed procedures and terminology for estimating and reporting plant-level CCS and power plant costs (e.g., Melien, 2005; Simbeck and Roekpooritat, 2009; DECC, 2010; Rezvani, 2011; ZEP, 2011).

While standardization of costing methods is laudable and necessary for certain purposes (e.g., comparing technologies on a consistent basis), a comparative assessment reveals significant differences in the costing methods currently used by a number of prominent organizations. The result, in many cases is to confuse,

Table 1
Categories and attributes of different levels of cost estimates (EPRI, 1993).

Item	Design estimate effort	Project contingency range (%)[a]	Design information required	Cost estimate basis		
				Major equipment[b]	Other materials[b]	Labor
Class I (similar to AACE Class 5/4)	Simplified	30–50	General site conditions, geographic location and plant layout; process flow/operation diagram; product output capacities	By overall project or section-by-section based on capacity/cost graphs, ration methods, and comparison with similar work completed by the contractor, with material adjusted to current cost indices and labor adjusted to site conditions.		
Class II (similar to AACE Class 3)	Preliminary	15–30	As for type Class I plus engineering specifics, e.g., major equipment specifications; Preliminary P&I (piping and instrumentation) flow diagrams	Recent purchase costs (including freight) adjusted to current cost index	By ratio to major equipment cost on plant parameters	Labor/material ratios for similar work, adjusted for site conditions and using expected labor rates
Class III (similar to AACE Class 3/2)	Detailed	10–20	A complete process design; engineering design usually 20–40% complete; project construction schedule; contractual conditions and local labor conditions			
Class IV (similar to AACE Class 1)	Finalized	5–10	As for Class III, with engineering essentially complete	As for Class III, with most items committed	As for Class III, with material on approx. 100% firm basis	As for Class III, some actual field labor productivity may be available

[a] Percentage of the total of process capital, engineering and home office fees, and process contingency.
[b] Pertinent taxes and freight included.

rather than clarify, the cost of a particular CCS technology or process.

To illustrate some of the differences in methodology, Fig. 3 shows the schemes used by EPRI and DOE/NETL to calculate the capital cost of a power plant. The DOE/NETL method was recently revised and differs from the method it used in previous studies (NETL, 2007). While the EPRI and DOE/NETL methods employ many similar terms, other terms differ, as do the cost calculation procedures. Without significant effort one cannot easily tell whether capital cost estimates from these two sources are directly comparable.

Table 2 presents a broader comparison of the cost elements included in five recent CCS cost studies in the U.S. and Europe (NETL, 2010; IEAGHG, 2009; NETL, 2007; EPRI, 2009; DECC, 2010). Not only do some capital cost elements differ across studies, so too do elements of fixed and variable O&M cost. If one looks more deeply at particular cost items, still other differences emerge. For example, Table 3 shows the components of "owner's costs" in the five studies. Two studies (NETL, 2007; DECC, 2010) exclude owner's costs altogether, while three others have some items in common, but not all. The new DOE/NETL methodology (NETL, 2011) includes an owner's cost called "other" which is a lumped cost for seven items described in the NETL documentation. Based on a "rule-of-thumb," this adds 15 percent to the capital cost of a power plant—more than many of the other items listed in Table 2. The IEAGHG also has an ambiguous owner's cost category called "other miscellaneous costs."

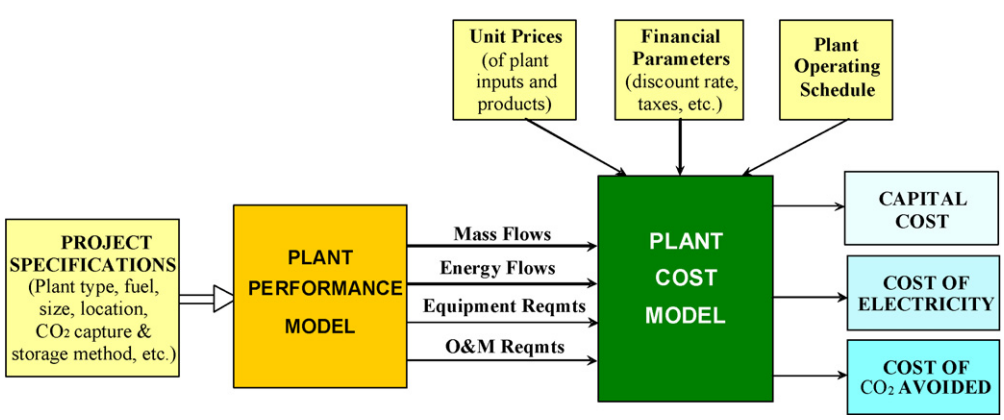

Fig. 2. Analytical framework for estimating the cost of a CCS project for a specified project scope. The plant performance and cost "models" represent the methods used in a particular study to quantify the items shown in the diagram. Those methods and the level of detail specified vary significantly across the four classes of cost estimate described in Table 1.

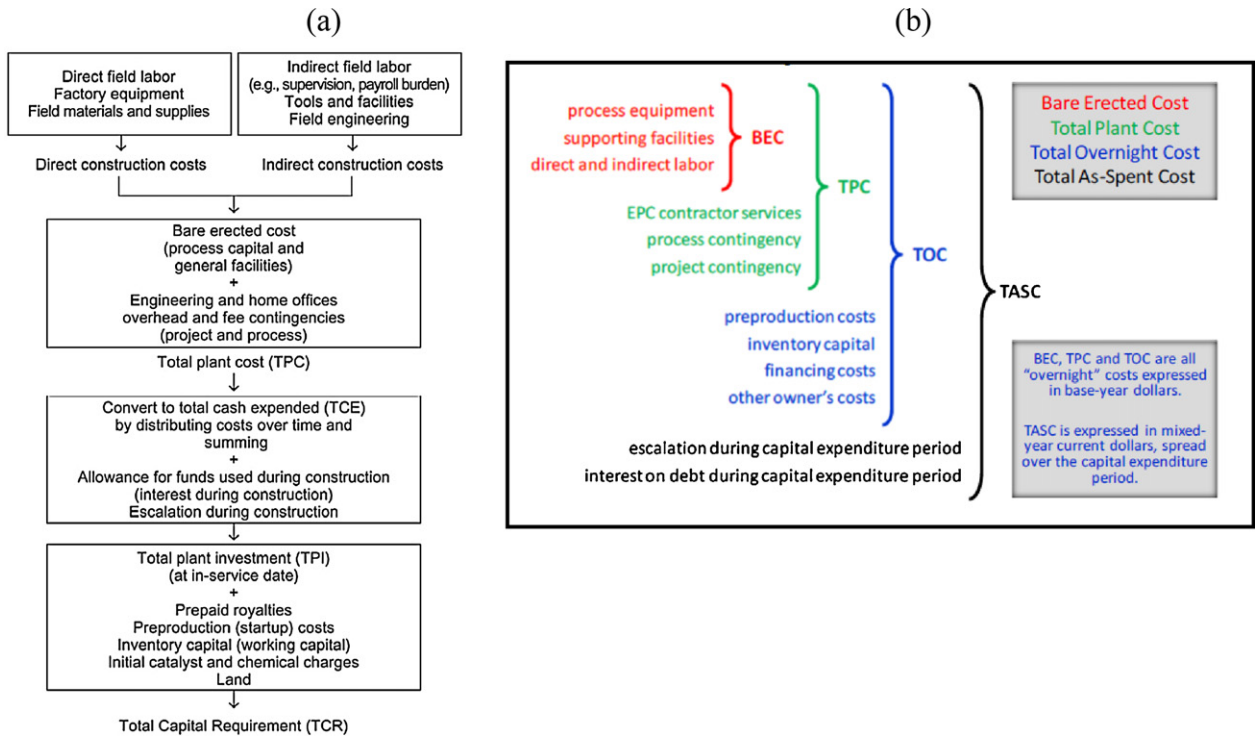

Fig. 3. Capital costing method used by, (a) EPRI (1993) and (b) NETL (2011).

The plant-level costing methods discussed above typically treat CO_2 transport and storage costs as variable operating costs based on a specified \$/ton CO_2 transported and stored (e.g., EPRI, 2009; NETL, 2010; Gibbins et al., 2011). This approach implicitly assumes that other parties will build and operate the transport and storage facilities and charge the power plant a fee for those services (similar to the way other power plant waste streams and byproducts are commonly handled in engineering-economic studies). A number of more detailed performance and cost models also have been developed to calculate the capital and operating costs of transport systems and geological storage facilities (e.g., IPCC, 2005; Wise et al., 2007; Damen et al., 2007; McCoy and Rubin, 2008a,b; ZEP, 2011). While such methods are more complex and data-intensive than simple cost-per-ton estimates, they are better able to incorporate site-specific factors and cost items that may otherwise be overlooked.

The inclusion (or omission) of certain items in the costing methodology can have a significant influence on cost results. For example, the 2010 revision of the DOE/NETL (2007) cost study showed increases of 37% in total capital cost and 17% in LCOE for the same post-combustion capture system used in both studies. However, a close examination of the two studies reveals that the basic cost of the CCS system (reported as the "bare erected cost") had not increased at all, and in fact had declined slightly. Rather, the reported increases were due mainly to the addition of new owner's costs in the 2010 study.

5. CCS cost assumption—the devil is in the details

For any given costing method, the specific assumptions brought to a CCS cost analysis also can have a major impact on numerical results. Table 4 illustrates some of the important assumptions used in five recent studies of similar coal-fired power plants with amine-based post-combustion CCS systems. Different assumptions reflect different circumstances or perspectives, which result in different estimates of cost.

One example of differences in perspective concerns the assumed maturity or commercial readiness of a technology, which is an indicator of technological and related risks (GAO, 2007). Here, CCS cost studies often fail to state explicitly whether, for example, the cost analysis pertains to an assumed "*N*th-of-a-kind" installation of a mature technology built many times before, or a "first-of-a-kind" installation of a technology that has not yet been built or widely replicated at the scale or conditions of the analysis. Nonetheless, the analysis perspective is implicitly reflected in the values chosen for key parameters. One of these is the capital charge factor assumed for different types of power plants (e.g., PC vs. IGCC), or for plants with and without CCS. For the cases in Table 4, the EPRI study assumes the same cost of capital for plants with and without CCS, implying no difference in financial risk, while the DOE/NETL studies assume a higher cost of capital for the plant with CCS, implying a "riskier" project than the plant without CCS. In a more transparent way, the DECC (2010) study employs different financial assumptions for first-of-a-kind and *N*th-of-a-kind plants (see Table 4).

Another important parameter that can vary with the assumed maturity (or riskiness) of a technology is the annual average capacity factor of the plant. DOE/NETL, for example, assumes a capacity factor of 85% for PC plants (Table 4) but only 80% for IGCC plants, implying lower availability (NETL, 2010). In turn, a lower capacity factor increases the COE (see Eq. (4)), hence, the cost of CCS. Other parameters related to technological maturity include the "process contingency" factors used in capital cost estimates (Table 2). For studies of CCS retrofits to existing plants, critical assumptions include the type and design of existing plant equipment; the need for equipment upgrades; the degree to which equipment has been amortized; and capital cost "retrofit factors" reflecting the difficulty of access to various plant areas. Such assumptions can have a large impact on the cost of a CCS project—for example, if a flue gas desulfurization (FGD) system also must be retrofitted to an existing plant in order to meet the SO_2 inlet specification for a post-combustion CO_2 capture unit (Rao and Rubin, 2002).

Table 2
Summary of CCS cost elements in several recent studies.

Cost category	NETL (2007)	NETL (2010)	EPRI (2009)	IEAGHG (2009)	DECC (2010)
Capital cost elements	Bare erected cost	Bare erected cost	Process facilities capital	Direct materials	Pre-licencing costs, technical and design
	Engineering and home office fees	Engineering and home office fees	General facilities capital	Labor and other site costs	Regulatory + licensing + public enquiry
	Project contingency cost	Project contingency cost	Engineering, home office, overhead and fees	Engineering fees	Engineering, procurement and construction (EPC)
	Process contingency cost	Process contingency cost	Contingencies-project and process	Contingencies	Infrastructure/connection costs
	Total plant cost	**Total plant cost**	**Total plant cost**	**Total plant cost**	**Total capital cost (excluding indirect)**
		Pre-production costs	AFUDC (interest & escalation)	Construction interest	
		Inventory capital	**Total plant investment**	Owner's costs	
		Financing costs	Owner's costs: royalties, preproduction costs, Inventory capital, Initial catalyst and chemicals, Land	Working capital	
		Other owner's costs		Start-up costs	
		Total overnight cost	**Total capital requirement**	**Total capital requirement**	
Fixed O&M costs	Operating labor	Operating labor	Operating labor	Operating labor	Operating labor
	Maintenance labor	Maintenance labor	Maintenance labor	Indicative cost	Planned and unplanned maintenance (additional labor, spares and consumables)
	Admin. and support labor	Admin. and support labor	Overhead charges (admin & support labor)	Administrative and support labor	
		Property taxes and insurance		Insurance and local property taxes	Through life capital maintenance
Variable O&M costs (excluding fuel cost)	Maintenance materials	Maintenance materials	Maintenance costs	Maintenance costs	Repair and maintenance costs
	Consumables (water, chemicals, etc.)	Consumables (water, chemicals, etc.)	Consumables (water, chemicals, etc.)	Consumables (water, chemicals, etc.)	
	Waste disposal	Waste disposal	Waste disposal	By-products and wastes disposal	Residue disposal and treatment
	Co-product or by-product credit	Co-product or by-product credit	Co-product or by-product credit		Connection transmission charges
					Insurance
	CO_2 transport and storage	CO_2 transport and storage	CO_2 transport and storage	CO_2 transport and storage	CO_2 transport and storage
					Carbon price

Capital cost items in bold represent the sum of all preceding items.

Table 3
Elements of "owner's costs" included in several recent studies.

NETL (2007)	NETL (2010)	EPRI (2009)	IEAGHG (2009)	DECC (2010)
(None)	Preproduction (start-up) costs	Preproduction (start-up) costs	Feasibility studies	(None)
	Working capital	Prepaid royalties	Obtaining permits	
	Inventory capital	Inventory capital	Arranging financing	
	Financing cost	Initial catalyst and chemicals	Other miscellaneous costs	
	Land	Land	Land purchase	
	Other			

Table 4
Selected assumptions used in recent CCS cost studies.

Parameter	NETL (2007)	NETL (2010)	EPRI (2009)	IEAGHG (2009)	DECC (2010)
Plant size (PC case)	550 MW (net)	550 MW (net)	750 MW (net)	800 MW (net)	1600 MW (gross)
Capacity factor	85%	85%	85%	85% (year 1: 60%)	Varies yearly
Constant/current $	Current	Current	Constant	Constant	Constant
Discount rate	10%	10%	7.09%	8%	10%
Plant book life (years)	20	30	30	25	32–40 (FOAK) 35–45 (NOAK)
Capital charge factor					
no CCS	0.164	0.116	0.121	n/a	n/a
w/CCS	0.175	0.124	0.121	n/a	n/a
Variable cost levelization factor					
no CCS	1.2089 (coal) 1.1618 (other)	1.2676	1.00	1.00	n/a
w/CCS	1.2022 (coal) 1.1568 (other)	1.2676	1.00	1.00	n/a

n/a = not available.

Differences in perspective also are inherent in DOE/NETL's use of "current" dollars to report LCOE, based on an assumed inflation rate over the project life (3% per year in the 2010 study). In contrast, recent studies by EPRI and others report LCOE in "constant dollars" excluding general inflation. While either method will yield the same relative rankings of different options, a current-dollar analysis yields higher absolute costs. For example, the LCOE for a power plant or CCS system is approximately 30% higher based on current rather than constant dollars using DOE's assumed inflation rate (NETL, 2010). In turn, the reported cost of CO_2 avoided also increases. For the examples, a change from constant to current dollars adds approximately \$20–\$50/ton to the reported avoidance costs in Fig. 1.

Often, however, important differences in assumptions are not obvious or transparent in reported CCS cost results. Seldom, for example, is the assumption of current or constant dollars clearly stated on the summary tables and graphs of most CCS cost studies. Similarly, the cost year for an estimate is often unstated on tables and/or graphs.

Recognizing such issues, some meta-studies that compare CCS cost results from different sources adjust reported values to put them on a more common footing (where possible) (Rubin et al., 2007; MIT, 2007; Kheshgi et al., 2010; Finkenrath, 2011; GCCSI, 2011). Computer-based tools also are publicly available for estimating CCS costs under a range of assumptions (IECM, 2012). In all cases, however, users of CCS cost information must be sufficiently knowledgeable to avoid drawing false conclusions about real differences in the technology costs reported by different authors or organizations.

6. Uncertainty, variability, and bias

The methods employed in nearly all CCS cost studies yield deterministic values of cost that are often reported to four or more significant figures—implying a high degree of confidence and accuracy in those results. Some plant-level studies include sensitivity analyses to show the effects of alternative assumptions for one or more selected variables, such as the capacity factor, boiler type or fuel type (e.g., Damen et al., 2007; Rubin et al., 2007; EPRI, 2009). A smaller number of studies include probabilistic results varying multiple plant or process parameters simultaneously (e.g., Rao et al., 2006; Gibson, 2011; Rubin and Zhai, 2012). In all cases, however, it is helpful to consider uncertainty, variability and bias as factors that can influence the integrity and interpretation of CCS cost estimates.

"Uncertainty" reflects a lack of knowledge about the precise value of one or more parameters affecting CCS costs. This is especially relevant to cost estimates for new CCS technologies that are still under development and not yet commercial. For example, there may be substantial uncertainty about the cost of a new absorber design that has never been fabricated, or about the commercial cost of a new solvent or sorbent that has never been manufactured in large quantities. Cost methods may, in principle, account for such uncertainties by assigning ranges or probability distributions to uncertain parameters (which may include a variety of technical, financial and cost factors). Here, the techniques of expert elicitation, prior experience with related systems, and insights from relevant "learning curves" can help inform the judgments required for a cost estimate. Some rules of thumb also have been developed and incorporated into the concept of contingency cost factors, which are commonly used in capital cost calculations. For example, Table 5 show the "process contingency" cost adders recommended by EPRI for technologies at different levels of maturity or technology readiness (EPRI, 1993). Based on these guidelines, technologies in the early stages of development should employ much higher values of contingency cost than processes already in commercial use. Often, however, it is difficult to determine what assumptions (if any) have been made about process contingency costs in a particular study.

Table 5
Guidelines for process contingency costs for different stages of technology development (EPRI, 1993).

Technology status	Process contingency (% of associated process capital)
New concept with limited data	40+
Concept with bench-scale data	30–70
Small pilot plant data	20–35
Full-sized modules have been operated	5–20
Process is used commercially	0–10

As distinct from uncertainty, "variability" refers to the different value a given parameter may take on (for example, across a collection of facilities, or at different points in time at a given facility). In this case the values of the parameter are assumed to be known (or knowable), and thus subject to quantitative data analysis. The result can therefore be expressed as a distribution function or (more simply) as a range of values. For example, the variability of power plant size across the U.S. coal plant fleet might be of interest for a CCS cost analysis, as might be the variability of annual average capacity factor for baseload power plants. CCS cost methods can account for parameter variability just as with uncertainty, via parametric (sensitivity) analysis or a probabilistic analysis, as illustrated in Fig. 4.

The term variability also is sometimes used colloquially to describe changes in technology over time due to innovation, technological "learning" and other factors. Large-scale energy models, for instance, commonly incorporate exogenous or endogenous specifications to quantify changes in the future cost of technology as a function of time or other variables (Weyant and Olavson, 1999; Clarke et al., 2009; EIA, 2009; NRC, 2011). Some plant-level cost estimates also use the concept of a learning curve (or experience curve) to project the future cost of a CCS technology (e.g., Rubin et al., 2007), while some organizations also rely on their own judgment about future costs (e.g., Klara and Plunkett, 2010; Léandri, 2011). Users of cost estimates must therefore clearly understand the time frame to which a cost estimate applies as well as the method used to derive the estimate.

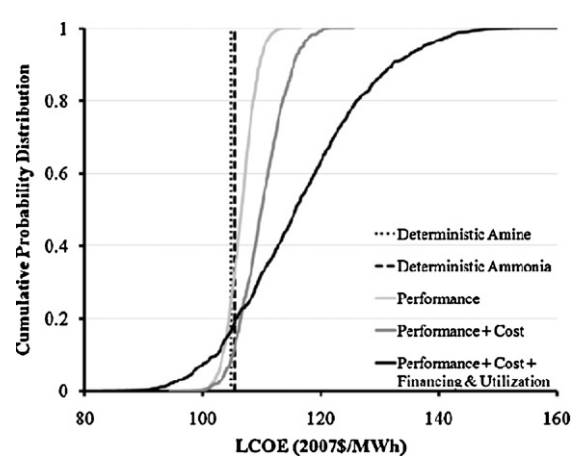

Fig. 4. Example of a probabilistic cost estimate (in constant dollars) reflecting uncertainties and/or variability in selected parameters for an ammonia-based capture system. For comparison, deterministic results for ammonia and amine-based system are shown by vertical dashed lines (Versteeg and Rubin, 2011).

Finally, the term "bias" as used here refers to assumptions that skew an analysis in a particular direction while ignoring other valid alternatives, factors or data. This is not meant to imply something nefarious done to deceive or misrepresent. Rather, it is simply a recognition that the choices of project design specifications and/or parameter values can sometimes bias a particular cost estimate toward higher or lower values. The presence of bias in a CCS cost estimate can be difficult to detect or "prove" since it depends heavily on technical and professional judgments. However, in cases where an assumed parameter value can be shown to differ significantly from actual or historical values, the resulting cost estimate may be more clearly seen as biased in a particular direction—unless a new "storyline" or paradigm can explain and justify the assumption in question.

An example of the latter in recent U.S. cost studies is the common assumption of an 85% *levelized* capacity factor over the life of a coal-fired plant (see Table 4). Historically, the annual average capacity factor of U.S. coal plants has varied between roughly 65% and 75%, with the latter value representative of larger, newer plants (see Fig. 5). Some baseload plants do operate for many years at higher capacity factors of 85% or more. However, the value required for an LCOE calculation is the *levelized* CF over the life of a plant —not the highest value or even the average. Because of the required discounting, the levelized CF is strongly influenced by the first few years of operation, when the CF is typically low. The IEAGHG, for example, assumes a CF of 60% during this initial "breaking in" period (IEAGHG, 2009).

To illustrate the difference between levelized and annual average capacity factors, Fig. 6 shows the annual capacity factor for a large coal-fired plant in Pennsylvania over a 25-year period from 1981 to 2005. While the CF in recent years was indeed around 85% for a period of time, the *average* CF over the full 25-year period was 77% while the *levelized* CF was only 71% (based on a 10% discount rate). Thus, the common assumption of a levelized CF of 85% in lieu of actual historical values would bias LCOE results toward lower costs (about 20% lower in this example). Only if future new coal plants somehow achieve and sustain much higher rates of utilization over their entire lifetime—including the critical first years of operation—would such an assumption be justified. Absent a historical precedent, a persuasive technical argument (not merely an assertion or assumption) is needed to dispell any perception of bias. Such arguments are lacking in the recent cost studies cited above. (Indeed, in this particular case one could argue that future coal plant capacity factors may well *decrease* due to the higher dispatch costs of plants with CCS and the increased cycling of coal plants in response to growing deployment of renewable technologies with low or near-zero dispatch costs; e.g., EIA, 2011.)

Methodologically, issues or questions of bias in cost estimates can be addressed only with careful scrutiny of key assumptions and the data or arguments that support them. Where appropriate, the use independent (third party) evaluations can help identify issues of concern.

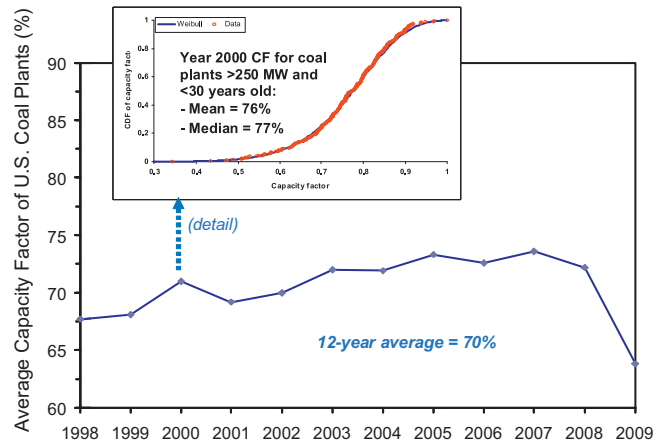

Fig. 5. Actual annual average capacity factor for all U.S. coal-fired power plants from 1998 to 2009 (EIA, 2010). Insert shows the distribution of CFs in 2000 for large, newer plants (Chen and Rubin, 2009), whose mean CF was 5%-points higher than the mean for all plants that year.

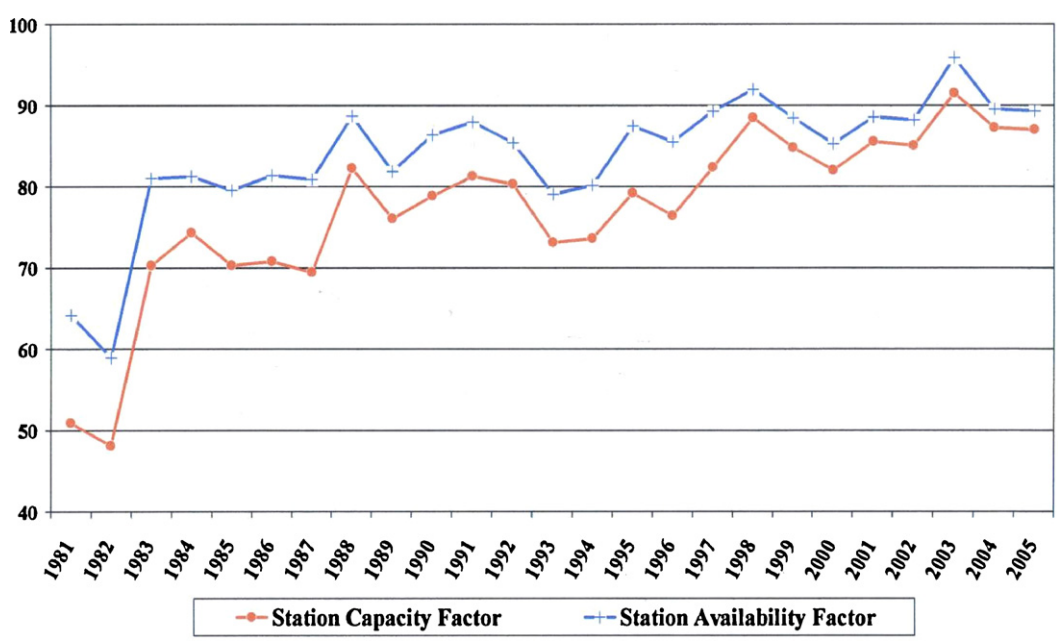

Fig. 6. Actual capacity factor (and availability) for a large coal-fired plant in Pennsylvania over a 25-year period (Mooney, 2007). On a levelized basis the values in early years weigh more heavily than values in later years.

7. Conclusion

This paper has reviewed and discussed the prevailing metrics and methods that underlie plant-level engineering cost estimates for CO_2 capture and storage technologies applied to fossil fuel power plants. This assessment revealed a number of significant differences in the costing methods employed by leading governmental and industry organizations—not only in key technical, economic and financial assumptions related to the cost of a CCS project but also in the elements of cost that are included (or omitted) in a CCS cost estimate. Such differences often are not readily apparent in publicly reported cost results. As a consequence, there is likely to be some degree of confusion, misunderstanding, and misrepresentation of CCS cost information, especially among audiences not closely involved in, or familiar with, the details of CCS costing.

Nothwithstanding the plethora of published cost estimates that are available, we also must remember that no one has yet built and operated a full-scale (e.g., 500 MW) power plant with CCS. Thus, there is still no empirical data on the actual costs of such plants. In this regard, more careful attention to the analysis and reporting of uncertainties in current cost estimates is especially important.

Given the international importance of CCS as a potential option for climate change mitigation, concerted efforts to improve the understanding and communication of CCS cost estimates within the technical and policy communities is especially urgent and timely (if not overdue). A suggested path forward is the creation of an independent group of CCS cost experts drawn from industry, government and academia to review current practice and recommend ways to harmonize the major costing methods currently in use. An analogous undertaking to systematize estimation methods for CO_2 storage capacity in geologic reservoirs (Bachu et al., 2007; Bradshaw et al., 2007) illustrates the potential benefits of such an effort to the CCS community. A subsequent paper is thus envisioned to propose solutions to problems identified in this paper.

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