Best practices and recent advances in CCS cost engineering and economic analysis

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Abstract:
Cost engineering and economic analysis are key elements of the performance assessment of carbon capture and storage (CCS) technology. The CCS field has seen noticeable advances in the transparency and rigor of costing studies, but there is still significant room for improvement in three major areas: the more rigorous application of good cost engineering practices; the inclusion (and progression) of recent methodological advances; and adaptation to changing policy focus. Here, we discuss each of these three areas, bringing diverse information sources together into one paper, and summarising important advances made in recent years, with the goal of strengthening CCS cost engineering and economic analysis in general. The first part of the paper discusses equipment design and sizing; cost indices and location factors; process and project contingency costs; CO_2 transport and storage costs; and uncertainty analysis and validation. The second part discusses new insights and advances in capture plant integration costs; the costs of steam supply; flexible dispatch of power plants with CCS; a hybrid method for the costing of advanced CCS technologies; qualitative uncertainty analysis methods; and calculation methods for CO_2 avoidance costs in non-power industries. The third part highlights several recent changes in the policy environments and how they affect the requirements of CCS costing studies. We close the paper by echoing earlier calls for the transparent reporting of assumptions and input variables underlying costing studies and by prioritising three CCS costing issues for further methods and guideline development.

Introduction

Cost engineering and economic analysis are key elements of the performance assessment of carbon capture and storage (CCS) technology. CCS cost estimates are used extensively for policy making, R&D strategies, funding decisions, and investment decisions [1], [2], in conjunction with technical, environmental, and societal feasibility assessments [3]–[5]. Sound cost engineering and analysis of future CCS technologies is difficult, however, not only because of a lack of good basic equipment cost data in the public domain, but also because it requires a high level of experience with, and understanding of process and equipment design issues and knowledge of CCS technology specifics, in addition to principles of economics and cost engineering.

Several CCS-specific publications in the professional and scientific literature have contributed to improving CCS cost estimates, especially focusing on harmonization of CCS costing frameworks and guidelines, and on providing baselines for the costing and comparison of new CCS technologies. The 2013 joint white paper by Rubin et al., focused on the former [1], [6], providing a harmonized framework for estimating and reporting CCS capital and operating costs, clearly outlining all costs elements that need to be included in CCS cost estimates, and explaining financial and economic analysis and cost metrics of CCS projects from power plants. It also stressed the importance of transparency, because the outcomes of any cost estimate will strongly depend on how the estimate is produced, and which assumptions were used. Transparency is therefore key to an informed interpretation of any costing study. Providing sound baselines is one of the merits of the increasing body of knowledge by DOE/NETL (e.g., [7]–[9]), IEAGHG (e.g., [10]–[14]) , EBTF (e.g., [15]–[17]), ZEP (e.g., [18]–[20]), GCCSI [21] and others. Their publications sought to provide location and technology-specific baselines for CCS costs, often including transport and storage of the captured CO_2. These reports have proven very useful for understanding the costs of current CCS technologies, assessing specific technology arrangements under specific assumptions and conditions. As such, they have also been used widely as a basis for comparisons with new technologies.

While this previous work lays a strong foundation for sound cost estimates of CCS technologies, our observation is that there is still significant room for improvements in three major areas. First, there are good practices that need to be applied more rigorously, especially in the research and development field, to avoid incorrect representations of overall capital or operating costs. Second, there is a need to incorporate and extend recent methodological advances that have the potential to further improve CCS costing. And third, there is a need to reflect the changing policy and industrial environments in which CCS costing studies are undertaken. In Europe for instance, the idea of baseload coal-fired power plants with CCS is being abandoned ([22]–[24]), with the focus instead shifting towards flexible gas-fired power plants with CCS, and to industrial CCS and CO_2 utilisation [25].

Here, we discuss each of these three areas, bringing scattered information together into one paper, which is structured as follows. The first part identifies several existing pitfalls in cost engineering basics that we have observed in the current CCS costing literature, and provides suggestions to tackle those issues. Part II describes recent advances in CCS cost engineering and how they impact cost engineering practice and CCS cost estimates. Part III highlights the implications for CCS costing of several recent changes in the international policy environments regarding CCS. The paper finishes with an outlook for future CCS costing work. The contents of this paper are based on the open literature, including our own work of the last half decade. Our aim is to provide a reference that draws attention to existing pitfalls of CCS cost estimates, while summarizing important methodological advances made in recent years. Our goal is to strengthen CCS cost engineering and economic analysis in general, while acknowledging that this work is not intended to provide an exhaustive review of CCS costing studies.

Part I. Revisiting the basics

In this section we review and discuss five topics that underlie all CCS cost estimates, but which continue to be treated inconsistently across published cost studies. Often, these are the sources of misunderstandings or misrepresentations of CCS cost estimates. The five topics include equipment design and sizing; cost indices and location factors; process and project contingency costs; CO_2 transport and storage costs; and uncertainty analysis and validation. For each topic, we briefly review common pitfalls and methods of improvement.

1.1. Equipment design and sizing: the basis of every good cost estimate

Previous studies have shown that large differences exist between capital cost estimates[16], [26], even for the exact same installations, differences in equipment costs of 60 percent have been observed [2]. One major source of these differences lies in the design and sizing of CCS processes and equipment. There are four main reasons why bare equipment cost estimates in CCS studies can deviate, and are frequently underestimated in practice: i) the scope is too narrow, i.e., necessary equipment is left out; ii) mistakes are made in the sizing of individual equipment; iii) equipment is sized for standard operating conditions, neglecting operating and safety margins; and iv) a sparing

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philosophy[1] is neglected. Since the sizing and costing of individual equipment is the basis of every bottom up (factorial) capital cost estimate [1], [27], an under- or overrepresentation of bare equipment costs inevitably propagates to the final CAPEX estimate. We illustrate here some examples of common pitfalls in typical CCS equipment design and design practices that are often forgotten or overlooked. With respect to equipment design aspects, we discuss just three typical carbon capture plant equipment: packed columns, heat exchangers and CO_2 compressors (the most costly items in solvent-based capture plants).

Equipment-specific design considerations

CO_2 capture processes often employ a packed column, whose initial design usually starts from a process simulator, where the packing width is calculated based on the allowed level of flooding and the packing height is optimized based on desired process performance (such as a separation factor). Packing vendors recommend to design CCS columns at lower hydraulic loads than the hydraulic limit (i.e. 80% flooding), which improves performance of processes where mass transfer and chemical reaction happen in the liquid film that allows lower column designs, thereby reducing the pressure drop and thus blower costs [28]. The widest columns with which packing suppliers have experience are around 15 meters in diameter, larger diameters are possible but require additional measures to safeguard good vapour distribution [28]. Packing sections have a maximum height of around 10 meters, 12 at best, after which gas and liquid need to be collected and redistributed to avoid poor distribution. That means that when a total packing height of 20 m is calculated using a process simulator or otherwise, the packing will be divided in two sections. A typical value for the space left between sections is two to two and half meters for narrower columns (< 8 m diameter), and three to five metres for wider columns, depending on which internals are used. In the top of each column, space is required for a demister and a liquid distributor, in the bottom for a gas distributor and the column sump. All these considerations influence the so-called tangent to tangent height of a column and thus its costs. Transparency of the design is key to understand a column's cost estimate and how realistic it is. The same applies to the choice between a steel or concrete column. Although larger columns (e.g., diameter > 10 m) tend to favour concrete, both would be a valid assumption at the level of design and costing effort underlying most CCS studies, as long as it is made explicit which of the two is selected.

Heat exchanger design for initial costing may be a little more straightforward than column design, but also varies based on the underlying assumptions. When initially costing a heat exchanger, this is usually done based on the required exchanger surface area, which is in turn calculated from the required heat duty, heat transfer coefficient, and log mean temperature difference (LMTD). Where the heat duty should result from process simulations, the overall heat transfer coefficient can be found for specific cold and hot fluid combinations in design engineering books (e.g., [29]) and on engineering websites (e.g., [30]). Bear in mind when sizing exchangers that standard Shell and tube HX's have a maximum size of around 1000 m^2 surface area. Larger versions can be custom made, but at a cost. For plate and frame exchangers, Towler and Sinnot report a maximum size of 1500 m^2 [29]. The ReCap project [11] considered a maximum size of 2500 m^2 based on vendor information. The Aspen capital cost estimator [31] allows maximum sizes of 1250 and 1670 m^2 for shell & tube, and plate and frame heat exchangers, respectively.

CO_2 compressors also represent a large cost element in CCS costing studies, where the design, especially the number of compression stages and amount of intercooling, presents a trade-off between capital and operational costs. In earlier studies, centrifugal integrally geared compressors with three or four intercooled stages are frequently encountered [12], [15]. Currently the trend goes towards a higher number of intercooled stages leading to higher compression efficiencies, but coming at the expense of higher capital costs [8], [32]. Intercooling has the benefit of improving the

[1] The sparing philosophy determines which critical equipment should have a spare installed or should have a spare in the workshop.

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exergy efficiency of compression, and is usually preferred, unless there is a useful outlet for the higher temperature heat generated without the intercooling [32]. In the recently constructed demonstration and commercial scale CCS plants, eight intercooled stages is the norm (e.g., Shell Quest [33], Boundary Dam 3 [34] and Petra Nova [35]). These kinds of compressors are so large and application specific that generic cost relations, e.g., from the Aspen capital cost estimator or textbooks, are seldom useful. More reliable cost estimates can generally be obtained from studies executed by engineering firms, which are often based on vendor quotes (e.g., the IEAGHG and DOE/NETL studies, as well as the EBTF compressor cost study[2] [15], [16]) and published FEED studies ([36], [37]). One can then scale these CO_2 compressor costs to the required volumetric flow rate (and/or power duty), for instance using the scaling parameters provided in the DOE/NETL quality guidelines [38].

Another consideration in compression design is the pressure at which the critical point is reached. For pure CO_2 this is at 73.9 bar at 31.1°C [39], while Nazeri et al. showed that the critical point is above 80 bar for mixtures containing 5% of combined N_2 and O_2, and around 100 bar when these impurities occupy around 20% of the gas mix [40], with other studies confirming the large impact of impurities on CO_2 vapour liquid equilibria [41], [42]. The decision to remove such impurities is again a trade-off between compressibility and compressor energy use at the one hand and the removal costs at the other. Reporting which design assumption is made, is again key for understanding and comparing different compression costs.

Safety margins and sparing

Safety and operational margins are added to the standard operating design, to account for unexpected situations such as temperature or pressure excursions. They allow for some operational leeway before safety measures like relief valves are activated. Rules and guidelines for this differ per industry, and therefore so may the incremental costs that these margins incur. As an example, the design pressure guideline by the API RP 520 is 10% above the operating pressure [29]. The ReCap project is another example of a guideline to calculate design pressures and temperatures, which includes guidelines for the overdesign of equipment to account for pumping and/or heating duties greater than the normal operating point [11]. A variety of basic textbooks and references provide additional guidance on equipment design [29], [43].

Sparing philosophies usually focus on equipment that has an important role in operating the process safely, and which at the same time may be prone to failure and/or fouling. Usual suspects include pumps, and sometimes blowers or filter packages. The sparing philosophy is always a trade-off between the cost of having a spare and the cost of operational hick ups and safety, where safety understandably imposes a hard constraint. When a spare is installed, this is usually a single piece, irrespective of the amount of operating pieces. For example, if a liquid stream contains one pump, then there will be one spare. But if it contains three parallel pumps to pump the same liquid, then it will still contain one spare, since unlikely that three pumps will fail simultaneously. The DOE/NETL reports on CCS detail exactly which items are spared [8]. IEAGHG studies on the other hand consider sparing cost as a percentage of the total plant cost (typically 0.5% of TPC [11]).

1.2. Costing indices and location factors

Capital and operational costs are time and location dependent. The costs of building a new power plant or process plant varies over time, and can differ significantly with location or region. For a cost estimate to have any value, it needs to state what the economic basis is (currency, year, and when possible quarter), and which construction location is assumed [1]. This is straightforward

[2] The costs of the post-combustion capture plant that were reported in the EBTF guidelines have been proven too low (see e.g., [2], [16]), but the compressor cost was based on vendor quotes obtained in CATO-2, and is considered more reliable (e.g., [61]).

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when cost estimating software is used such as the Aspen capital cost estimator [31] or the IECM [44], because it lets the estimator select a location (although limited location choices are available, or the user must supply needed adjustment factors). However, when costs from earlier studies are used and are transferred to different base years and/or locations, this may lead to errors. A commonly observed practice is that an inappropriate cost index is used (e.g., [15], [17], [45]–[48]). For example, many costing studies use the Chemical Engineering Plant Cost Index, published by Chemical Engineering magazine [49]. However, this index is a generic index for the United States, and may therefore be unrepresentative for other regions in the world. Figure 1 shows this by comparing three different chemical engineering cost indices, the US CEPCI, the Dutch Webci, and the German Chemie Technik index and the North American and European power capital cost indices for the period between 2000 and 2016. The Dutch and German chemical indices are generally aligned, but the CEPCI showed clearly different behaviour over the investigated period, especially at the beginning of the time series. The indices align more during the last ten years displayed, with greater differences at the beginning of the century between the European chemical plant indices (Webci and Chemie Technik) and the European power capital cost index. Furthermore, the UCCI is aligned with the other indices only around the year 2010, but shows appreciable differences up to 2007 and from 2012 onwards. The reason for this can be partly sought in the different contractors and service operators that are active in the upstream business (notably in offshore oil and gas production) versus the downstream business. Other reasons may be sought in the data underlying this index, but exact information on this is not publicly available. In general, differences between cost indices are partly explained by which elements are included in the index and with which weight. What Figure 1 therefore makes very clear is that selection of a cost index matters, and that it is good practice to use one that aligns with the purpose and location of the costing study.

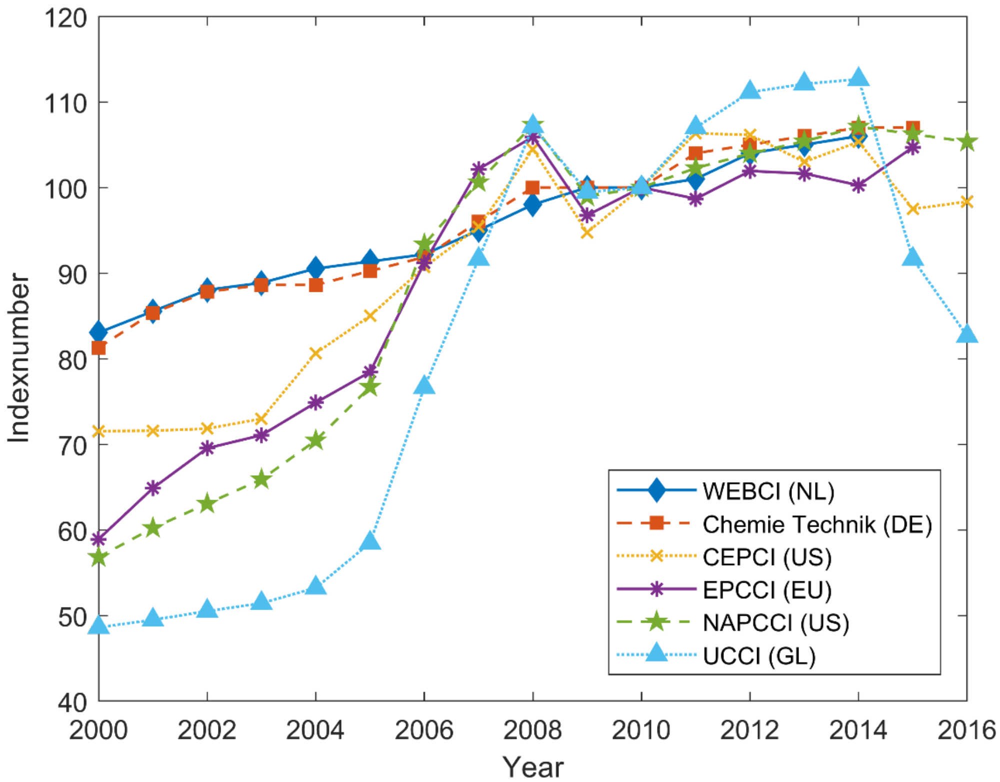

Figure 1. Comparison of cost indices from the US and EU with the base year converted to 2010. US: Chemical Engineering plant cost index (CEPCI [49]*) and North American Power Capital Cost Index (NAPCCI without nuclear, but including wind projects* [50]*); EU: Dutch association of cost engineers special working group cost engineering process industry (Webci* [51]*), German Chemie Technik index* [52]*, and European Power Capital Cost Index (EPCCI* [53]*); Global: Upstream Capital Cost Index (UCCI* [54]*). Values of the data points are provided in Appendix A.*

A similar issue is observed with respect to location. Often, costs from a plant in one continent, country, or region are used to represent the costs for a plant in another. Simply correcting for the

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currency would lead to bias, but is something that we often observe. More correct would be to also apply a location factor, because items like equipment, materials, and labour incur different costs at different locations. It is not uncommon to find differences of several tens of percentages. For example, in 2007, the construction costs in London, UK, were 38% higher than the average US costs, whereas those in Taiwan were 13% lower [55]. Also within a country the cost may vary. Compare for instance the 2007 cost of building in Alaska (> 30 % above US average) with those of building in the Carolinas (~15% below US average). The 2018 IEAGHG study shows equipment and material costs in China of some 13% lower than in the US (Gulf coast) and 10% higher in Canada. A useful source to retrieve location factors is *Richardson international construction factors* [55], although recent data are located behind a paywall. To provide at least some insight into costs differences between locations, we included some location factors in Table 1. The IEAGHG also showed in their 2018 report that the cost of building a CCS plant in different locations is not only a function of materials and labour costs and productivity, but also of local ambient conditions, feedstock and consumables prices, contingency costs and economic parameters (e.g., the cost of capital). This means that plant designs vary between locations as do operational expenses, both of which influence economic performance [56]. This adds another level of complexity that must be accounted for when applying CCS cost data from one region to another.

Table 1. Locational capital and O&M cost adjustment factors. Location adjustment factors present a deviation to a normalised value of a reference location (represented by a 1). In many sources the US gulf coast is selected as the reference location. Richardson uses a US average (Richardson, US) as the reference value.

Country/Region	GCCSI[1] [21] Ref year = 2010			IEAGHG[2] [56] Ref year = 2018			Richardson[3] [55] Ref year = 2007
	Equipment	Materials	Labour	Equipment and materials	Labour (productivity)	Labour (costs)	Composite location factor
US gulf coast	1	1	1	1	1	1	0.90
US Mid-West	-	-	-	0.95	1.19	1.04	1.18
Australia	1.21	1.21	1.58	1.01	1.54	1.87	1.18
Canada	1.08	1.01	2.16	1.10	1.40	1.30	1.09
China	0.81	0.81	0.05	0.87	2.86	0.21	0.95
Eastern Europe[4]	1.01	0.81	0.79	0.93	1.60	0.55	0.96
Euro region[5]	1.19	1.16	1.33	1.01	1.25	1.36	1.20
India	1.27	1.11	0.26	0.94	3.03	0.35	1.02
Japan	1.21	1.41	1.84	0.90	1.22	0.92	1.26
Middle East[6]	1.27	1.21	0.35	0.94	2.30	0.32	1.08
South Africa	1.27	1.11	1.04	1.05	2.80	0.95	1.09
South America[7]	1.16	1.16	0.97	1.01	2.00	0.38	1.08
South East Asia	-	-	-	0.93	2.22	0.32	1.08

[1]Location factors from the GCCSI study stem from Richardson Products' International Cost Factor Location Manual 2009-2010 Edition. Calculation basis is US gulf coast.
[2]Location factors from the IEAGHG study stem from the AMEC Foster Wheeler proprietary database, Compass Global Construction Cost Yearbook, and the Aspen capital cost estimator. Calculation basis is US gulf coast. The labour productivity factor adjusts costs to regional differences in productivity. A factor larger than 1 means lower productivity of a worker than in the reference location. The overall labour cost adjustment factors is therefore retrieved by multiplying the labour productivity with the labour cost factor.
[3]Richardson 2007 location factors use a US average (Richardson, USA) as the calculation basis. The composite location factor includes i) country specific fees for imported equipment, ii) cost differences in locally sourced materials and equipment between the location of study and the reference location and iii) cost differences in labour between the location of study and the reference location. These three cost drivers are aggregated into the composite location factor using the weighted construction cost of a typical process (refinery/chemical) plant.
[4]GCCSI: Poland. IEAGHG: average. Richardson: Poland.
[5]GCCSI: Germany. IEAGHG: The Netherlands. Richardson: The Netherlands.
[6]GCCSI: Saudi Arabia. IEAGHG: Egypt. Richardson: Egypt.
[7]GCCSI: Brazil. IEAGHG: average. Richardson: Brazil.

1.3. Process and project contingencies

Capital cost estimates for CCS (or other) technologies typically include "contingency costs" to account for the additional costs that are difficult to estimate in detail, or typically overlooked, when preparing preliminary cost estimates, especially for early-stage technologies. Thus, they are

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estimates of the cost of additional equipment or other cost items that would be found in the more detailed final design of an actual project for a particular site. These contingency costs are based on the maturity of the technology (process contingencies) and the level of site-specific detail of the cost estimate (project contingencies). Guidelines for estimating process and project contingencies for power plant projects were originally published by EPRI in the mid-1980s (based on guidelines developed by the Association for the Advancement of Cost Engineering, now AACE International, which were derived largely from experience in various process industries). Later, these guidelines were also adopted by NETL and international organizations like IEA, GCCSI and IEAGHG [6].

However, as pointed out in previous studies [1], [6], these guidelines are rarely followed in the literature, leading to a structural underrepresentation of costs, especially for new or advanced technologies. For example, assessments of new solvent technologies often assume the (low) process contingency of a commercial solvent process, independent of the level of maturity of the solvent considered. Furthermore, technologies or materials that are mature in one application are often assumed to be mature in new applications without considering additional challenges (and higher contingency costs) that might arise in the new application (due to issues of scale, integration, impurities, variability, or other factors). Similarly, assumed values of project contingencies in published studies, especially for new or advanced technologies, tend to be systematically lower than guideline values. Studies of new or advanced technologies seldom have the required high level of site-specific detail that would warrant low (e.g., 20%) project contingencies, as is often assumed in published studies. The overall impact of incorrect process and project contingency cost assumptions combined can be to underestimate total capital cost by as much as 50 percent or more [6].

Process developers are therefore often reluctant to use guideline values of contingency costs since they would systematically increase the overall cost of the technology, which could adversely affect conclusions about technology feasibility. Thus, researchers and process developers often publish estimates of the so-called N^{th}-of-a-kind (NOAK) plant cost in which the technology is assumed to be mature after successful development and commercial adoption.[3] Often, NOAK studies of early stage technologies also assume the process contingencies for a mature process. This understates the projected cost since process contingency cost adders are supposed to be based on the current status of technology development. So even if one asserts/assumes that the future cost of purchasing and installing a new technology is X $/kW (called the Bare Erected Cost), the appropriate process contingency cost adder should be based on the current level of technology development. If that level corresponds to a pilot plant scale of testing (i.e., TRL 6 or 7), the adder, according to guidelines, would be 20% to 35%—not 0% to 10% as for a full-scale commercial level of maturity (TRL 9). Based on these guidelines, the additional project contingency cost also tends to be underestimated in generic NOAK cost studies.

To improve published cost estimates, authors of cost studies must first be made aware of current guidelines and should be encouraged (or required) to employ them, or to justify alternative assumptions. While such a requirement may be difficult (or impossible) to enforce in the "gray" literature not subject to rigorous peer review, the editors and reviewers of peer-reviewed journal publications have an important role and responsibility in ensuring the transparency and rigor of published information.

Over time, improved estimates of appropriate contingency cost factors are also needed. The current guidelines published by EPRI and NETL, for example, have not changed in decades, which may raise the question if they are still applicable given improved costing experience and methods. Also, their empirical basis is not well documented, which could make CCS costing practitioners reluctant to apply them, afraid to include unsubstantiated factors. Thus, a concerted effort to update current

[3] Later in this paper (Section 2.4) we argue that the current method of estimating NOAK plant cost is fundamentally flawed and suggest an alternative method of estimating the future cost of a successful new technology.

guidelines, drawing on more recent experience in power plant and emission control technology construction projects, as well as relevant projects in industrial applications, would be extremely valuable. This could e.g. be done by surveys among technology developers, contractors and operators, or through the bottom up rationalisation and subsequent quantification of process contingencies for typical CCS technologies.

1.4. CO_2 transport and storage costs

Using valid costs for CO_2 transport and storage requires selecting a specific CO_2 capture point and storage site, and including a transport modality that fits the transport volume and distance (onshore vs. offshore, trunk line vs. point-to-point, ship vs. pipe, location). Some examples of transport cost models depending on distance and capacity can be found in McCoy [57] and NETL [58] for US-based estimates, Roussanaly et al. [59] and Knoope et al. [60], [61] for Europe-based estimates, and Wei et al. [62] for China-based estimates.

Another option is to use generic transport and storage costs reported in the open CCS literature, such as IEAGHG, DOE/NETL, ZEP, and other studies. Table 2 summarizes the results of such studies, building on and updating a 2015 comparison of published estimates [25]. Note that for regions like NW-Europe, where offshore CO_2 storage is the most realistic option, the IEAGHG transport and storage cost assumption of 10 €/tonne may be optimistic. In comparison, ZEP and Pale blue dot/DECC estimated offshore T&S costs that are on average more than twice as high. The high ends of these studies represent mostly point-to-point transport and storage of smaller volumes of CO_2. Also, the 2008 McKinsey costs [61] can be considered optimistic, but do provide a range that extends into higher values. More recent offshore storage cost estimates in the North Sea [63] have seen an increase compared to previous studies, especially due to higher well cost [64].

Table 2. Comparison of transport and storage cost elements reported by different costing studies.

Study	McKinsey [65]	ZEP onshore [18], [20]	ZEP offshore [18], [20]	DOE/NETL [8]	Pale blue dot/ DECC [63]	IEAGHG [14]
Year of publication	2008	2011	2011	2015	2016	2017
Storage location	Offshore	Onshore	Offshore	Onshore	Offshore	-
Storage reservoir	SA/DOGF[2]	SA/DOGF	SA/DOGF	SA[1]	SA/DOGF	-
Transport costs (per tonne)	4-6 $€_{2007}$	1.5-5.4 $€_{2Q2009}$	3.4-28.7 $€_{2Q2009}$	2.24 USD_{2011}	1.2-6.73 GBP_{2015}	-
Total storage costs (per tonne)	4-12 $€_{2007}$	1-12 $€_{2Q2009}$	2-20 $€_{2Q2009}$	8.69-21.81 USD_{2011}	7.82-27.15 GBP_{2015}	-
Sum (original currency/tonne)	8-18 $€_{2007}$	2.5-17.4 $€_{2Q2009}$	5.4-48.7 $€_{2Q2009}$	11-24 USD_{2011}	9.09-32.32 GBP_{2015}	10 €
Sum ($€_{2015}$/tonne) [3]	8.3-18.7	2.2-15.6	4.8-43.7	7.1-15.5	12.2-43.5	10

[1] SA: Saline Aquifer
[2] DOGF: Depleted Oil and Gas Field
[3] Updated based on the IHS Upstream Capital [54] and Operating [66] Costs Indexes assuming a cost split of 70% capital cost and 30% operating cost.

1.5. Uncertainty and comparative analysis as essential elements of costing studies

Preparing a cost estimate is the first step in understanding the costs of a process. Subsequent essential elements of costing studies include an uncertainty analysis and (where possible) a comparative analysis with other studies and/or industry results of the same or similar technologies to understand the causes of any significant differences. Such comparisons can include different parts of the estimate, for instance the costs of a single piece of equipment, the costs of a certain unit(s) within a plant, or of the plant as a whole [2]. Ideally, this should involve independent sources that were not used to prepare the current cost estimate (see e.g., Van der Spek et al. [2] or Van der Sluijs et al. [67]). Where such sources are unavailable, one can resort to cost studies (for components) of similar processes, though the level of "ground-truthing" is obviously lower.

Quantitative uncertainty analysis comes in many forms, but the most common are sensitivity analysis—varying one input variable, or multiple variables simultaneously—or probabilistic uncertainty analysis (e.g., Monte Carlo simulation) [67], [68]. Monte Carlo simulation, illustrated in Figure 2, is typically the more sophisticated method, though the effect of changes in a single input variable (or a cluster of variables) cannot be seen unless the simulation is decomposed and presented as a "spider diagram" or "tornado diagram" with an increasing number of uncertain variables. Conversely, single variable sensitivity analysis is transparent, but neglects interactions between inputs. Selecting the right method very much depends on the purpose, model structure, and the audience of the study [69].

A major pitfall in any quantitative uncertainty analysis is the selection of ranges (or distributions) for input values, and the interpretation of the resulting output ranges. If, for instance, the input ranges are based on educated guesses, then the output range also should not be seen as more than that. Alternatively, if the input ranges are based on measured data, taken over a representative time period from multiple reliable sources, then the output range can be expected to represent the same. Transparency on this is, again, key for the informed interpretation of costing results. Examples of uncertainty analysis include CCS costing studies by IEAGHG (e.g., [14]), earlier work by Zhai and Rubin (e.g., [70]), or the work by the Carbon Capture Simulation Initiative (e.g., [71]).

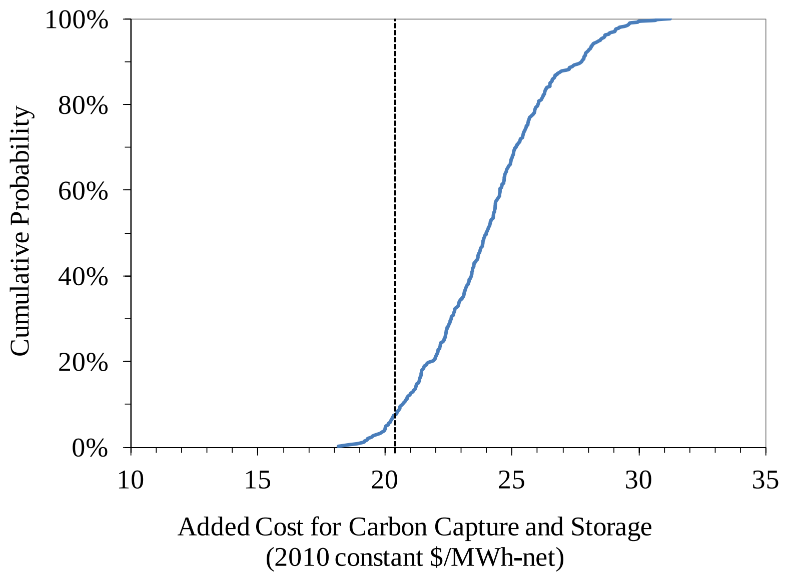

Figure 2. Output of a Monte Carlo uncertainty analysis from [70]. The figure shows both the deterministic (vertical dashed line, no uncertainty) and the probabilistic (solid line) values of the added cost of CO_2 capture for a supercritical coal power plant under the constraint of a 1000 lb of CO_2/MWh gross emission (US) performance standard. For the assumptions of this study there is less than a 10% likelihood of realizing the nominal (deterministic) value of added cost. The most likely cost (50% probability) is $24.5/MWh (about 4 $/MWh more than the deterministic value).

Part II: Recent advances and new insights in CCS cost engineering

This section of the paper describes recent advances in six areas of CCS cost engineering: capture plant integration costs; costs and impacts of steam production; flexible dispatch of power plants with CCS; a hybrid method for costing advanced CCS technologies; qualitative uncertainty analysis methods; and calculation of CO_2 avoidance costs for industrial CCS. Brief descriptions of each topic follow.

2.1. Capture plant integration costs

The cost of integrating a CO_2 capture plant with a host plant has been neglected in many past studies. Although integration costs may be limited in the case of greenfield plants with CCS, these costs were shown to be significant when retrofitting existing power and/or industrial plants, which

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is the most likely situation in regions with large existing fleets (e.g., Europe, US, Australia, China). The number of studies investigating capture plant integration is still limited, but it is worth noting that the following elements could have a non-negligible impact on the cost of CO_2 capture implementation and are therefore important to include when evaluating CO_2 capture costs:

- Flue gas interconnection cost: due to limitations in space availability for CO_2 capture units near flue gas exhaust points, flue gas transport over long distances may be required in certain cases. This can especially be the case for retrofitting CCS from industrial emitters [11], [72], as well as for many power plants [73]. Existing pilot and demonstration CCS projects, such as the Boundary Dam Demo facility, often exhibit long and large ducting to transport flue gas from the emission point to the CO_2 capture area. Although the flue gas interconnection cost depends on distances between units, capacity of the interconnection, and so forth, it can be a significant contributor to the CO_2 capture cost. For example, in the case of CO_2 capture retrofit to a refinery, this cost was evaluated to range 16-35 €/$t_{CO2,avoided}$ for different unit retrofit scenarios [11]. Similarly, Exhaust Gas Recirculation (EGR) is sometimes considered for power plants to achieve a higher CO_2 content in the exhaust flue gas with the aim of reducing the CO_2 capture cost [74], [75]. However, although rarely included in cost estimates, such configurations would also result in large ducting to accomodate the exhaust recirculation, especially again for retrofit applications where the exhaust points and the air inlet may be several hundreds of meters apart. This may be expected to result in significant investment costs, which may impair, at least partly, the cost advantage of the exhaust gas recycling.
- Steam supply integration for the CO_2 capture plant: steam extraction and connection for use in the CO_2 capture plant may result in significant modifications of the host plant (or the need for a secondary steam production plant) and can require transport over a significant distance, again, especially, in retrofit cases [11]. Therefore, this may also impact or bias technology comparisons when different technologies require different utilities (e.g., steam versus electricity). The same applies to the supply of other utilities (chilled water, nitrogen, and so on).
- Flue gas treatment: depending on impurities present in the flue gas and the capture technology considered, additional gas cleaning may be required before or after CO_2 capture, for instance desulphurisation, NO_x removal, oxygen removal, or drying. The cost associated with this potential treatment may also have significant impact on technology comparison [76] or alternatively can result in significant increase in the costs of transport and storage if impurity removal is not considered [77], [78]. Cost studies that ignore these additional costs or fail to attribute them to the cost of CCS thus understate the real costs of CCS.
- Impact of CCS on the products of the plant: certain CO_2 capture technologies can have an impact on the main product of the plant resulting in additional cost (or value decrease). For example, CO_2 capture based on oxy-combustion in a cement plant can impact the quality of the produced clinker, incurring additional post-treatment of the clinker to improve its quality and thus cost [79]. The same may hold for other processes that involve changing the conditions of core processes when separating CO_2.

2.2. Cost and GHG emissions impact of steam production

Another new cost-related development is the mode of steam production for CCS. In non-power industries, the cost and climate-related impacts due to GHG emissions from steam production for CO_2 capture can vary significantly from case to case, depending on the availability of waste heat, and the availability of combined heat and power (CHP) generation with spare capacity on the site [80]. As discussed by Mantripragada et al. [81], the steam production strategy is also important for power plant applications as steam extraction from the turbine may not always be the most cost-efficient strategy.

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The cost and GHG emissions of four steam production options for CO_2 capture were previously investigated [80]: waste heat recovery, natural gas boiler, extraction prior to an LP steam turbine and natural gas-based CHP. As illustrated in Table 3, large variations in costs (7-28 €/$MW_{th}h$) and GHG emissions (0-205 $kg_{CO2}/MW_{th}h$) of steam were obtained for the different steam production options. Furthermore, case evaluations showed that the considered market electricity prices can have a significant impact on the cost of steam from different sources. If steam for the CO_2 capture plant is obtained through extraction prior to the LP steam turbine of a nearby power plant, high electricity market prices result in a high steam cost for the CO_2 capture plant as the extracted steam could have been used to produce high value electricity. Meanwhile, when steam is produced by a natural gas CHP dedicated to the CO_2 capture facilities, high electricity prices actually "subsidises" the steam production as excess electricity can be sold externally at a high value or used internally by the plant to reduce the purchase of expensive electricity.

These large variations in both cost and emissions impact can result in large variation in CO_2 avoidance costs, even for a single capture technology. For CO_2 capture from a cement plant [80], the range in steam generation costs resulted in a cost of CO_2 between 54 and 86 €/$t_{CO2,avoided}$. Beyond uncertainty in the cost performance of a given CO_2 capture technology, steam supply strategy can thus also have a significant impact on which overall configuration is cost optimal [82].

Table 3. Steam cost and climate impact depending on the steam source [80].

Steam source	Steam cost (€/$MW_{th}h$)	Steam emissions impact ($kg_{CO2}/MW_{th}h$)
Waste heat available on the plant	7	0
Natural gas boiler	25	205
External coal power plant, electricity cost 58 €/MWh	13.5	178
External coal power plant, electricity cost 80 €/MWh	18.5	178
Natural gas CHP, electricity cost 58 €/MWh	27.5	205
Natural gas CHP, electricity cost 80 €/MWh	3.5	205

2.3. Flexible dispatch of power plants with CCS

A new research line in CCS economics concerns flexible dispatch and part-load operation of power plants with CCS. This research stems from the growing penetration of low-cost renewable energy sources such as wind, which forces higher-cost fossil fuel power plants to ramp their production up and down to match power demand with supply. This flexible type of operation is already commonplace in many fossil power plants today, and will likely increase in the coming decades due to the further penetration of intermittent renewables into the power grid [22], [23], [83], [84]. This may similarly become true for the industrial sector, where e.g. hydrogen production for energy needs may vary according to fluctuations in demand. Flexible dispatch and part load operation have large implications both on the technical performance (lower efficiency) of the power and capture plant, as well as on their economics (higher costs of a produced unit). In the last half decade, at least three approaches have been proposed to incorporate flexible dispatch into the techno-economic performance evaluation of fossil power plants with CCS:

- In their 2012 study on gas power plants with CCS, IEAGHG [13] opted to undertake a complete techno-economic analysis for full-load operation, complemented with a complete techno-economic analysis for part load operation, where the power plant was operated at 40% of the maximum gas turbine loading. This allowed to understand the technical performance and levelised costs of operating the power with CCS plant at two discrete operating points.
- Imperial College London uses an approach where they model the power plant with CCS dynamically as part of the total power system, over a given time period (e.g., [22], [83]). Their approach includes simulated future plant scheduling and dispatch profiles using reduced order models to represent the technical performance of the plant. Rather than looking at the levelised costs of the power generator alone, they calculate the total power system costs. The argument for this is that total system costs allow fairer comparison of

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fossil-based power generators (with and/or without CCS) and intermittent renewable power generators, because accounting for the intermittency smoothening that the latter generators inherently need (be it either by electricity storage, interconnectors, or by back-up thermal power).

- Utrecht University and Politecnico di Milano [23], [24] introduced a techno-economic method that calculates the steady-state techno-economic performance of a power plant with CCS at 5-7 discrete operating points (e.g., from maximum GT loading to minimum stable load), and aggregated the results into weighted average techno-economic indicators using pre-specified dispatch profiles. This allows one to understand the technical performance and cost at different plant operating points, as well as overall levelised costs given realistic dispatch assumptions.

The selection of an approach for techno-economic assessment of flexible power with CCS strongly depends on the purpose of the assessment. The dynamic simulation approach of Imperial College may be computationally and time-intensive, but provides a high level of detail. It also allows one to estimate the economic value of flexible dispatch, rather than only its costs, by comparing the total system costs of scenarios with different technology mixes and associated dispatch constraints. This may be especially useful if one seeks a detailed representation of power system costs over time, and if one wants to study the dispatch of individual power generators (including the ones with CCS) given power system dynamics. The approaches by Van der Spek et al. [23], [24] and IEAGHG [13] are particularly suited for the purpose of comparing different types of CCS technology because they balance modelling time with resulting insights into part-load technology characteristics and performance.

2.4. Hybrid method for the costing of advanced CCS technologies

As noted earlier, cost studies for new or advanced CCS and power plant technologies typically are for Nth-of-a-kind process designs that are assumed to be mature and widely deployed. Such cost estimates commonly employ the same "bottom up" costing method used for projects that would be built now or in the near future [1].

However, in recent presentations, Rubin [85], [86] argues that such NOAK cost estimates are methodologically inappropriate, since one cannot know today what the future design of a successful new technology will look like, much less what its various components will cost in the future. This is because technology and process designs typically evolve over time once they are successfully adopted and commercially deployed in increasing numbers. At the same time, costs tend to decline from their initial values as experience accumulates. Thus, the only way to reliably estimate the NOAK plant cost is by first building ($N-1$) plants.

In general, detailed bottom-up cost estimates instead should be reserved for proposed near-term projects, which is the application and purpose for which that method was intended. For a new technology not yet built and operated at a commercial scale, the costs of a near-term project would be the cost of the first-of-a-kind (FOAK) installation. If successful, its future cost is likely to follow a "learning curve" trajectory in which costs decline with increasing experience and cumulative deployment of the technology. A large literature body describes and documents such trends for power generation and other technologies, and discusses the applicability of, and uncertainties in, learning rates [87], [88].

The proposed hybrid method estimates the cost of an advanced technology by first estimating its FOAK cost by applying the traditional bottom-up costing method to a FOAK process design. Then, a learning curve (also called experience curve) is developed based on literature values for the same or similar process components. This offers a cost trajectory as a function of cumulative installed

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capacity (or utilization) of the new technology. Projections for different plant components also can be aggregated to the overall plant level.

Figure 3 illustrates the hybrid approach. As the current (FOAK) cost of a technology (at cumulative capacity, C_1) declines with further deployments, one can estimate the cumulative capacity needed to reach the cost of a current baseline technology (denoted by C_2) or a future cost goal (denoted by C_3). One can also estimate the cost of the N^{th} plant, given a definition of N (in total capacity units).

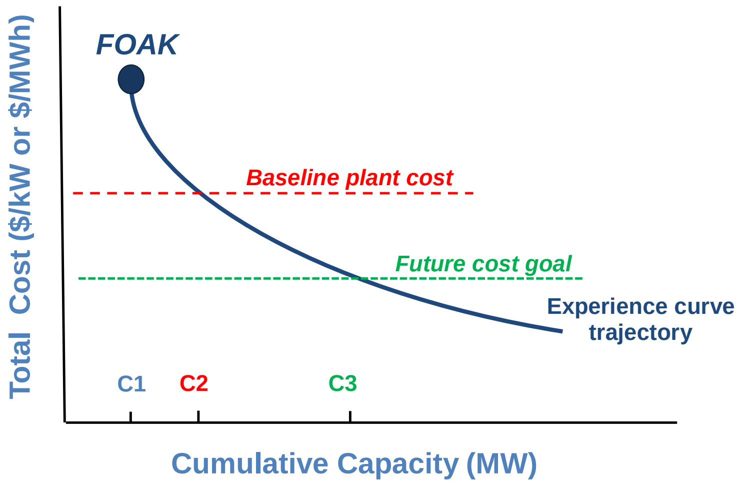

Figure 3. Illustrative cost trajectory of an advanced technology from FOAK plant to mature plant, showing the deployment of the technology needed to meet a given cost goal [86].

Recently, van der Spek, et al [89] applied this hybrid method to estimate the future cost of an advanced NGCC power plant design with exhaust gas recycle and an electric swing adsorption process for CO_2 capture. They first estimated the FOAK cost of the project, then assumed that the NOAK level is reached after 20 built plants. At that point, based on learning rates obtained from the literature, the estimated capital cost of the advanced capture plant was roughly 20 percent higher than their "direct" estimate of NOAK cost, with both estimates having significant uncertainties.

The primary value of this approach, in contrast to current NOAK assumptions, is that it provides an empirically-grounded basis for estimating future costs, along with an estimate of the commercial experience (hence, time) needed to achieve future cost reductions. It can also facilitate more rigorous analysis of uncertainties at different stages of process development [89]. Thus, its use for advanced technology cost studies offers a potentially more realistic method of evaluating and comparing proposed new technologies.

2.5. Qualitative uncertainty analysis methods

It has recently been argued that when CCS costing studies are used for policy and decision making, there may be a need for more comprehensive analysis of the techno-economic uncertainties than can be provided by quantitative uncertainty analysis methods alone [2], [68], [90]. The reason for this is that quantitative uncertainty analysis methods are only capable of capturing uncertainties that can be given a value, thereby leaving out a share of model uncertainty that is unquantifiable. This unquantifiable uncertainty is found, for example, in epistemic uncertainty (how much do we really know?), contextual uncertainty (which choices were made with respect to system boundaries and definitions used in an assessment?) and methodological uncertainty (how strong are the methods we used to model a specific phenomenon, or to measure a specific quantity?) [67], [68], [91]. Therefore, qualitative uncertainty analysis methods can be an important complement to quantitative uncertainty analysis methods, especially for new or emerging technologies.

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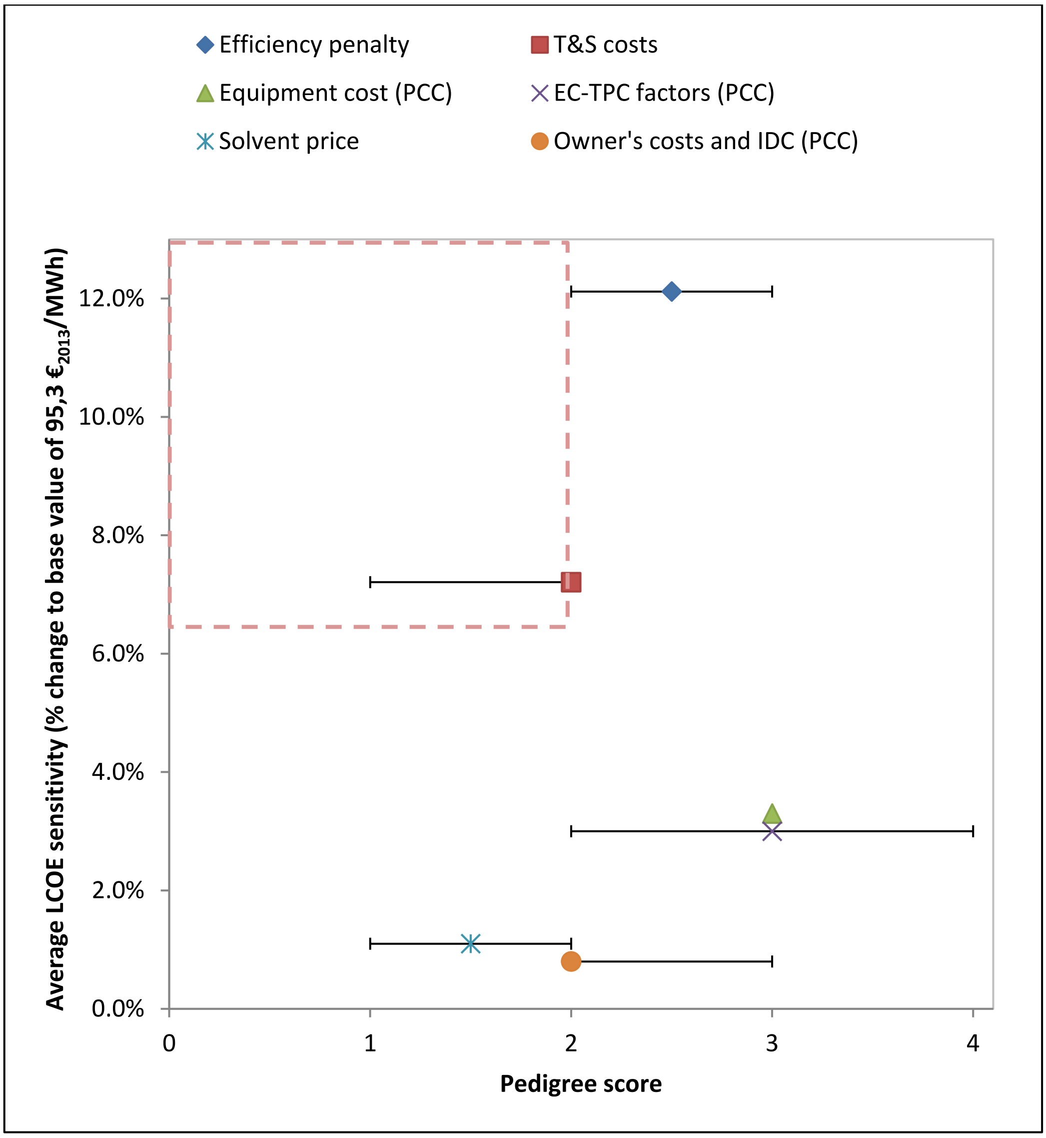

Figure 4. Diagnostic diagram of a techno-economic study on postcombustion capture from coal power flue gas using AMP/PZ solvent [2]. *The investigated numeral is the levelised cost of electricity (LCOE). On the y-axis, the average (of the positive and negative) sensitivity of the LCOE to the input parameters is plotted. For example, the LCOE has an average (of the positive and negative ends of the range) sensitivity of 12 percent to the "Efficiency penalty" (blue diamond). The x-axis represent the pedigree score (or strength) of an input parameter. For example, "Efficiency penalty" has a median pedigree score of two and a half, while the minimum and maximum scores assigned were respectively two and three. The red dashed quadrant includes parameters to which LCOE is most sensitive and that are highly uncertain, indicating the weak spots of the modelling study. The diagnostic diagram shows that the LCOE is most sensitive to efficiency penalty and least sensitive to Owners Costs and IDC. "Equipment cost (PCC)" and "EC-TPC factors (PCC)" have the highest pedigree score, thus strength, "Solvent price" has the lowest pedigree score.*

Although this is a relatively new research line within CCS techno-economics, to our knowledge, at least one method has been applied to both process modelling and cost estimation (e.g., [2], [68], [90], [92], [93]). *Pedigree analysis* is a method that qualitatively assesses the strength of models, their inputs, and their knowledge base. It is based on expert judgments of the strength of models, their submodels and input data, elicited using pedigree matrices, a "tool that systematically scores (sub)model and/or parameter strength with respect to a number of pre-defined quality indicators, called pedigree criteria" [68]. Examples of pedigree matrices for process modelling and economic analysis are provided in Appendix B. Pedigree analysis is part of a wider approach to understand and foster the quality of policy relevant modelling work, called NUSAP (numeral, unit, spread, assessment, pedigree) [67], [94], intended to facilitate the integration of modelling studies with quantitative and qualitative uncertainty analysis. One output is the combination of quantitative uncertainty and pedigree analysis is a so-called diagnostic diagram, of which an example is displayed in Figure 4. This diagram combines the uncertainty analysis data into one figure that allows one to identify the strengths and weaknesses of a modelling study. Combined with proper

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validation of both the technical and economic models, this can provide a robust means to evaluate the reliability of a CCS costing study.

2.6. Calculating CO_2 avoidance cost for CCS from non-power industrial plants

Unlike the power generation sector, three different calculation methods are often used to evaluate the CO_2 avoidance cost (CAC) in the case of CCS from industrial sources [95]. However, potential users of these equations are not always aware of the conditions for their validity, or of their advantages and drawbacks.

The "exhaustive" calculation method is similar to the CO_2 avoidance calculation method used in the power generation industry. In this method, the CO_2 avoidance cost is calculated based on the cost and CO_2 emission intensity of the "primary products" of the industrial plant with and without CCS as shown in Equation 1 [82], [96], [97].

$$CAC = \frac{(LCOP)_{\mathrm{CCS}} - (LCOP)_{\mathrm{ref}}}{(t_{CO2}/U_P)_{ref} - (t_{CO2}/U_P)_{CCS}} \qquad (1)$$

Where CAC is the cost per ton of CO_2 avoided, $(LCOP)_{ref}$ is the levelised cost per unit of product(s) of the industrial plant without CCS, $(LCOP)_{CCS}$ is the levelised cost per unit of product(s) of the industrial plant with CCS, $(t_{CO2}/U_P)_{ref}$ is the CO_2 emissions per unit of product(s) of the industrial plant without CCS, and $(t_{CO2}/U_P)_{CCS}$ is the CO_2 emission per unit of product(s) of the industrial plant with CCS.

The second and third methods, referred to here as the "net present value" and "annualisation" methods, are similar to the approaches normally used to evaluate a production cost, such as the cost of electricity, as shown in Equations 2 [98] and 3 [99]. These methods are derived from the unit cost calculation based on the discounted cash flow of implementing CCS.[4]

$$CAC = \frac{NPV_{\mathrm{CCS}}}{\sum_i \frac{\dot{M}_{\mathrm{CO2,avoided,i}}}{(1+r)^i}} \qquad (2)$$

$$CAC = \frac{I_{\mathrm{CCS,a}} + O_{\mathrm{CCS}}}{\dot{M}_{\mathrm{CO2,avoided}}} \qquad (3)$$

In Equation 2, NPV_{CCS} is the net present value of total annual CCS costs (which may vary from year to year), $\dot{M}_{CO2,\ avoided,\ i}$ is the mass of CO_2 avoided by CCS implementation in year i, r is the discount rate, and the summation applies to all years of operation. In Equation 3, all terms are assumed to be constant for all years of operation. $I_{CCS,a}$ is the annualised investment cost of CCS, O_{CCS} is the annual operating cost of CCS, and $\dot{M}_{CO2,\ avoided}$ is the annual reduction in CO_2 emissions due to CCS for a plant producing the same amount of product(s) with and without CCS.

Although all of these methods result in the same CO_2 avoidance cost when the necessary requirements are met [95], each method has its advantages and drawbacks. The exhaustive method is always valid but requires a complete assessment and evaluation of the industrial plant, both with and without CCS. This detailed assessment and evaluation is not required in the other two methods, hence, they require significantly less effort than the exhaustive method and can therefore be more efficient. However, these two approaches also come with limitations that are not always understood by users and therefore must be used carefully. For example, the implementation of CCS must not

[4] Note that the apparent discounting of the annual mass of CO_2 avoided by CCS in Equation 2 is an artefact resulting from manipulation of that equation to display the value of CAC. The actual value being discounted is the total annual cost of CO_2 avoidance, a monetary value represented by the product of CAC and $\dot{M}_{CO2,\ avoided,\ i}$. Since CAC is constant, it can be moved outside the summation sign to display its value in terms of the other parameters.

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impact the output flow (volume, mass) of primary product(s) of the industrial plant, which may not be possible for certain combinations of CCS technologies and industrial plants.

In view of these factors, Roussanaly [95] recommends using Table 4 to ensure the selection of a CO_2 avoidance cost calculation method which is both valid and efficient for a particular case.

Table 4: Summary of assumptions required to ensure the validity of each CO_2 avoidance cost calculation methods. For the "exhaustive" method none of these assumptions are required. [95].

Assumption	"Exhaustive" method	"Net present value" method	"Annualisation" method
Production of industrial plant not affected by CCS implementation	-	Yes	Yes
Additional costs and CO_2 emissions avoided due to CCS implementation can be assessed separately	-	Yes	Yes
Annual operating costs and CO_2 emissions avoided are constant over project duration	-	-	Yes
CO_2 emissions linked to construction of the CCS facility can be neglected or excluded	-	-	Yes

Part III: Evolving policy environments and implications for CCS costing

Recent shifts in the policy environment related to CCS also have implications for CCS costing. In this section we briefly highlight several recent developments, recognizing that a detailed discussion of this topic is beyond the scope of this paper. In Europe, for example, changes in policy landscape are reflected in the H2020 and ERA-NET ACT call texts of the European Union [25], and in the EU's strategic energy technology (SET) plan [100]–[103]. Whereas the focus in the previous EU framework programs was much more on CO_2 capture technology discovery and research, the current focus is on the upscaling, integration, and implementation of CCS technology. This means higher TRL-level technologies are targeted, including proving them in pilots and demonstrations to pave the way for commercial roll out starting in the early 2020's. This implies a need for greater efforts on the realistic integration of the CO_2 capture plant with the host facility, such as described in sections 2.1 and 2.2, as well as the combination of CO_2 source hubs and sinks into potential but realistic early CCS networks.

Furthermore, the EU policy environment is moving away from CCS in the power sector (with the exception of flexible CCS at gas-fired power stations), and more towards CCS in heavy industry. An important observation here is that the European Commission expects more innovation projects to be industry-led, which is clearly visible in the SET plans and the ACT call text [104]. Another trend that is continuing in European policy is the focus on reuse of CO_2 in the frame of the circular economy, intermittent renewable electricity storage, and CO_2 emission mitigation [25].

In the US, recent policy developments also have shifted the focus of CCS applications away from power sector applications and more toward industrial applications as the use of coal has diminished in response to the growing use of natural gas and renewables for power generation. Thus, the recent regulatory requirements enacted by the Obama Administration—including a requirement for partial CO_2 capture on new coal-fired power plants and limit on emissions from existing plants—are being reviewed and rolled back by the current Trump Administration. Despite the successful start-up and operation of the post-combustion capture unit at the coal-fired Petra Nova plant in Texas, there are no new utility-scale CCS projects anticipated in the US at the present time.

At the same time, however, new incentives for smaller-scale capture and storage project were recently enacted by the US Congress in the form of an expanded program of tax credits, known as the Section 45Q tax credits for sequestration of carbon oxides [105]. This program provides credits of up to \$35/tCO_2 (plus inflation) for permanent storage in EOR applications and up to \$50/tCO_2

(plus inflation) for other geological sequestration for capture projects that begin construction by January 1, 2024. These credits are expected to be most attractive to a variety of industrial facilities, though utility projects as well as air capture projects are also eligible.

Elsewhere in the world, interest in the utilization of captured CO_2 for enhanced oil recovery also is growing. This is seen, for example, in recent projects at industrial facilities in the Middle East [106] and at industrial and utility sites in China [107].

In contrast to the current European focus, the *carbon capture innovation challenge* of the *Mission Innovation Challenge* initiative (stemming from the 2015 Paris Accord on climate change) [108], [109] concentrates more on early-stage disruptive capture technologies. It seeks "to identify and prioritize breakthrough technologies, and recommend R&D pathways and collaboration mechanisms" [108]. Given that Mission Innovation is a global initiative, the challenges defined by that body may find their way into the national or regional RD&D policies of participating countries [100]. In the US, for example, the main focus of capture technology R&D is also on "next generation" processes that can substantially reduce the cost of CO_2 capture.

There are several implications of the above developments for CCS costing methods. First, the increased attention to industrial process applications means that CCS cost methods must be able to adapt to the wide variety of situations and process conditions that are likely to be encountered. The discussion of Section 2.5 is thus especially relevant in this regard.

Next, the application of CCS costing to electric utility plants must be increasingly sensitive to issues such as integration costs and partial CO_2 capture (at coal-fired plants), as well as design and operating differences for natural gas combined cycle plants. Better and more transparent methods for translating CCS cost studies across national borders also are needed in the international community.

Finally, the continued and increased focus on advanced capture technologies evidenced in the new Mission Innovation program, and in other R&D activities worldwide, demands improved methods of characterizing the cost of new or emerging technologies. Various sections of this paper have discussed recent developments in this regard.

Closing remarks and outlook for CCS costing

In this paper, we have discussed a number of pitfalls, best practices and recent advances in cost engineering and economic analysis of CCS technology. Where possible, we attempted to provide guidance on how to deal with identified shortcomings, beginning with the importance of reporting all underlying assumptions and resulting outputs transparently. Because different technical and economic assumptions may lead to very different results and outcomes of CCS costing studies, we also remind readers of earlier work that defined the difference between variability, uncertainty, and bias in CCS costing studies [6]. Here, variability referred to differences in input and/or output values due to variations in known and measured (or measurable) factors; uncertainty referred to differences due to lack of knowledge of the precise parameter value, and bias referred to differences due to assumptions that systematically skew results in a particular direction, often favouring one option over another. Because all three elements may be present in CCS cost studies, diligence in the reporting and justification of assumptions remains critical to the understanding of CCS cost results from different sources.

We also argued that more rigorous design and costing principles and methods are needed in future CCS studies. The development and application of such approaches and methods represents work in progress. Towards this end, a collaborative effort among several industrial research institutes (EPRI, SINTEF Energy Research), universities (CMU, Delft, ETH, NTNU, Sydney U.),

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governmental laboratories (NETL) and non-governmental organisations (IEA IEAGHG) has recently begun to draw up a complementary set of CCS costing guidelines, building on an earlier collaborative effort to establish a common nomenclature and framework for cost analyses [1]. This group has identified three areas where further guidelines and better practices are needed, and where efforts are underway to address these topics. The first is a better understanding of cost evolutions from lab scale to the first large-scale plant, then onwards to the N^{th}-of-a-kind plant. Here, guidelines on how to deal with the costing of early-stage technologies would be especially helpful, and the hybrid method described in Section 2.4 could be one example. The second area is uncertainty analysis methods to provide better and more meaningful insights from, and interpretation of future costing studies. A final area of work is on guidelines for the costing of CCS technologies in non-power industries, especially on the integration of host plant, CCS plant and utilities systems, and on the connection of CO_2 sources to CO_2 sinks (including further investigations into the costs of early as well as more mature transport and storage networks). Progress in these three areas will be the subject of future reports to enhance the quality and value of CCS cost estimates.

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Appendices

Appendix A: Cost indices

Table A1. Plant cost index number from selected sources, converted to the base year 2010: WEBCI [51], *Chemie Technik* [52], *CEPCI* [49], *EPCCI* [53], *NAPCCI* [50], *UCCI* [54].

Year	WEBCI (NL)	Chemie Technik (DE)	CEPCI (US)	EPCCI (Eur)	NAPCCI (US)	UCCI (Glob)
2000	83	81	72	59	57	49
2001	86	85	72	65	60	49
2002	88	88	72	70	63	51
2003	89	89	73	71	66	51
2004	91	89	81	75	70	53
2005	91	90	85	78	77	58
2006	92	92	91	91	93	77
2007	95	96	95	102	101	92
2008	98	100	104	106	107	107
2009	100	100	95	97	99	99
2010	100	100	100	100	100	100
2011	101	104	106	99	102	107
2012	104	105	106	102	104	111
2013	105	106	103	102	105	112
2014	106	107	105	100	107	113
2015		107	97	105	106	92
2016			98		105	83

Appendix B. Pedigree matrices for techno-economic models

Table B1. Pedigree matrix for the assessment of uncertainty in process models and their submodels [92].

	Strength				
Criterion	**4**	**3**	**2**	**1**	**0**
Theoretical Understanding	Well established theory	Accepted theory with partial nature (in view of the phenomenon it describes)	Accepted theory with partial nature and limited consensus on reliability	Preliminary theory	Crude speculation
Methodological Rigour	Best available practice in well-established discipline	Reliable method common within established discipline; Best available practice in immature discipline	Acceptable method but limited consensus on reliability	Preliminary methods; unknown reliability	No discernible rigour
Level of Validation	The (sub)model as a whole has been compared with independent measurements	Parts of the (sub)model have been compared with independent measurements	Measures are not independent, include proxy variables or have limited domain	Weak and very indirect validation	No validation performed
Modelling resources	High expertise from multiple practitioners in subject matter and limited time constraints	Good expertise from single practitioner and limited time constraints	Limited expertise but enough time to build skill for the specific purpose; medium to high expertise but constrained in time	Limited expertise and limited time available	No expertise in the subject matter and big time constraints

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Table B2. Pedigree matrix for the assessment of uncertainty in technical data, coefficients and parameters [92].

	Strength				
Criterion	**4**	**3**	**2**	**1**	**0**
Proxy	An exact measure of the desired quantity	Good fit to measure	Well correlated but not measuring the same thing	Weak correlation but commonalities in measure	Not correlated and not clearly related
Empirical Basis	Controlled experiments and large sample, direct measurements	Historical/field data, uncontrolled experiments, small sample, direct measurements	Modelled/derived data, indirect measurements	Educated guesses, indirect approximation, rule of thumb estimate	Crude speculation
Theoretical understanding	Well established theory	Accepted theory with partial nature (in view of the phenomenon it describes)	Accepted theory with partial nature and limited consensus on reliability	Preliminary theory	Crude speculation
Methodological Rigour	Best available practice in well-established discipline	Reliable method common within established discipline; best available practice in immature discipline	Acceptable method but limited consensus on reliability	Preliminary methods, unknown reliability	No discernible rigour
Level of Validation	Compared with independent measurements of same variable over long domain	Compared with independent measurements of closely related variable over shorter period	Measures are not independent, include proxy variables or have limited domain	Weak and very indirect validation	No validation performed

Table B3. Pedigree matrix for the assessment of uncertainty in economic data, parameters, and coefficients [2].

	Strength				
Criterion	**4**	**3**	**2**	**1**	**0**
Proxy	A direct measure of the desired quantity	Good fit to measure	Correlated but does not measure the same thing	Weak correlation but commonalities in measure	Not correlated and not clearly related
Reliability of source	Measured/official industrial, vendor, and/or supplier data	Qualified estimate by industrial expert supported by industry data	Reviewed data derived from independent open literature	Non-reviewed data derived from open literature	non-qualified estimate or unknown origin
Completeness	Complete data from a large number of samples over a representative period	Complete data from a large number of samples but for unrepresentative periods or from representative periods but for a small number of samples	Almost complete data but from a small number of samples or for unrepresentative periods or incomplete data from adequate number of samples and periods	Almost complete data but from a small number of samples and unrepresentative periods	Incomplete data from a small number of samples for an unrepresentative period
Validation process	Compared with independent data from similar systems that have been built	Compared with independent data of similar systems that have not been built	Validation measurements are not independent, include proxy variables or have limited domain	Weak and very indirect validation	No validation performed

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