Cost and performance of some carbon capture technology options for producing different quality CO_2 product streams

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ABSTRACT

A techno-economic assessment of power plants with CO_2 capture technologies with a focus on process scenarios that deliver different grades of CO_2 product purity is presented. The three leading CO_2 capture technologies are considered, namely; oxyfuel combustion, pre-combustion and post-combustion capture. The study uses a combination of process simulation of flue gas cleaning processes, modelling with a power plant cost and performance calculator and literature values of key performance criteria in order to evaluate the performance, cost and CO_2 product purity of the considered CO_2 capture options. For oxyfuel combustion capture plants, three raw CO_2 flue gas processing strategies of compression and dehydration only, double flash system purification and distillation purification are considered. Analysis of pre-combustion capture options is based on integrated gasification combined cycle plants using physical solvent systems for capturing CO_2 and sulfur species via three routes; co-capture of sulfur impurities with the CO_2 stream using Selexol^{TM} solvent, separate capture of CO_2 and sulfur impurities using Selexol^{TM}, and Rectisol$^{®}$ solvent systems for separate capture of sulfur impurities and CO_2. Analysis of post-combustion capture plants was made with and without some conventional pollution control devices. The results highlight the wide variation in CO_2 product purity for different oxyfuel combustion capture scenarios and the wide cost variation for the pre-combustion capture scenarios. The post-combustion capture plant with conventional pollution control devices offers high CO_2 purity (99.99 mol%) for average cost of considered technologies. The calculations performed will be of use in further analyses of whole chain CCS for the safe and economic capture, transport and storage of CO_2.

Dedication: This paper is dedicated to the memory of our friend and colleague, Dr. Robert M. Woolley, who made a significant input to the CO_2QUEST project and whose expertise, commitment and great humour will never be forgotten.

KEYWORDS

Carbon Capture and Storage, CCS, Cost Estimates, CO_2 Impurities, CO_2 Quality

1. INTRODUCTION

CO_2 Capture and Storage (CCS) technologies will produce CO_2 product streams that are expected to contain a range of impurities at certain levels depending on the technology type and several other factors. The impact of these impurities on the safe and economic transportation and storage of CO_2 is a fundamentally important issue that must be addressed prior to wide scale deployment of CCS (CO_2QUEST, 2015). The ultimate composition of the CO_2 streams captured from fossil fuel power plants or other CO_2 intensive industries and transported to storage sites using high pressure pipelines will be governed by safety, environmental and economic considerations. Even though from a technological perspective, very high purity CO_2 from fossil fuel-fired power plant flue gas is achievable, it may not be required for some transport and storage applications, and so the associated increase in cost in achieving high purity levels may be avoided. Conversely, the extent to which impurities can be co-disposed along with CO_2 in capture streams is currently uncertain in terms of its technical feasibility and acceptability. Impurities in CO_2 mixtures can potentially cause problems with compression, as well as corrosion issues for pipeline transport. Economic viability and acceptability in terms of the risks to health and the environment are also crucial factors. Pipeline operators and CO_2 end users may impose regulations that limit impurities concentrations that are accepted, therefore further purification will become necessary. Some previous studies have assumed that impurities can be co-captured for co-disposal while others assume flue gas purification is necessary. Therefore, it is important to determine the optimal balance between purification costs and the transport and storage requirements. This study presents a cost benefit analysis in relation product purity in CO_2 capture systems to enable the evaluation of the economic viability of co-capture scenarios in full chain CCS systems.

Impurities in CO_2 captured from combustion-based power generation with CCS can arise in a number of ways and include major and minor fuel oxidation products (e.g., H_2O, SOx, NOx, Hg), air related impurities (N_2, O_2 and Ar) and process fluids, such as solvents (e.g. monoethanolamine (MEA) and Selexol^{TM}) used for capture (Porter et al., 2015). CO_2 impurities are known to have a number of mainly detrimental impacts on the downstream transport and storage CCS chain elements. CO_2 impurity impacts can be classified into chemical (e.g. those caused by SO_2), physical impacts (e.g. those caused by N_2) and toxic/ecotoxic effects (e.g those caused by mercury) (Farret, 2015). The numerous types of impacts of impurities on transport and storage in CCS have been outlined in two reports by the IEAGHG (2004; 2011) and further studies by the National Energy Technology Laboratory (NETL) (Matuszewski and Woods, 2012) and the Dynamis project (de Visser et al., 2008) which have provided recommended impurity limits for CO_2 stream components in studies of CO_2 capture utilisation and storage systems. Limits are suggested based upon a number of different factors and these quality guidelines may serve as a basis for conceptual studies.

Of the different capture technologies, oxyfuel combustion is known to have the widest possible range of CO_2 purity, being dependent mostly on the selection of the CO_2 purification strategy (e.g. compression and dehydration only, “double flash” phase separation, or cryogenic distillation). Detailed modelling of these processes has been reported in work performed by Mitsui Babcock, Alstom and Air Products for the IEAGHG (Dillon et al., 2005) with costs and CO_2 product quality reported. Further process simulation studies have aimed to optimise these processes (Posch and Haider, 2012) and have analysed the impact of impurities on the purification requirements (Li et al., 2009). The highest concentration impurities from oxyfuel combustion capture are O_2, N_2 and Ar, but SOx and Hg may also be present at certain levels posing corrosion concerns.

The level of CO_2 purity derived from pre-combustion capture in Integrated Gasification Combined Cycle (IGCC) plants has a narrower range as compared to oxyfuel combustion capture. Potentially problematic impurities from pre-combustion capture are H_2S, due to corrosion issues when mixed with water, and H_2 which can lead to increased pumping costs and reduced storage capacity. Process factors that have a large influence on the CO_2 purity in pre-combustion capture include the choice of solvent and the CO_2 capture process configuration and, in particular, the decision whether to remove sulfur species simultaneously with CO_2 (co-capture scenario) or to remove them in a separate stream for possible further processing (separate capture scenario). The potential benefits of co-capturing impurities in pre-combustion gasification systems have been investigated in a report published by the IEAGHG (2004), resulting in cost savings relative to CO_2-only capture for Selexol^{TM} solvent systems. Ordorica-Garcia et al. (2006) have performed detailed process system simulation studies of IGCC systems with glycol solvents with plants that co-capture impurities showing substantial techno-economic advantages over separate capture plants due to their decreased energy penalty and lower capital costs. Further work by Padurean et al. (2012) has compared the techno-economics of the use of different solvents in IGCC at different levels of CO_2

capture, concluding that Selexol^{TM} is the more energy efficient solvent when compared to the others investigated such as Rectisol$^{®}$.

Post-combustion capture generally has low levels of impurities, with dried CO_2 purity usually reported in excess of 99% (E.C., 2011; CO_2PIPETRANS, 2008) and impurities are less of an issue, N_2, water and O_2 are the main impurities of highest concentration. Estimates for the efficiency penalty typically range between 8-16 percentage points for pulverised coal plants with post-combustion capture units (Goto et al., 2013). Techno-economic studies often aim to find the optimal configuration for the process (Rao and Rubin, 2006; Schach et al., 2011;). Lee et al. (2009) estimated the impurities included in the CO_2 stream from a post-combustion capture control unit with different combinations of air pollution control devices and different flue gas compositions, concluding that plants employing Flue Gas Desulfurisation (FGD) systems followed by absorption using monoethanolamine are the most favourable in terms of minimising the impacts from CO_2 impurities in geological storage.

Comparative techno-economic assessments of CO_2 capture technologies as applied to fossil fuel power plants have been performed by a number of authors (Rubin et al., 2005, 2007; Ekström et al., 2009; Parsons Brinckerhoff, 2012), including those that incorporate a significant portion of biomass in the fuel input (Al-Qayim et al., 2015; Catalanotti et al., 2014). However, to our knowledge, there has been no published study of a cross-comparative cost-benefit analysis for producing CO_2 product streams of different quality from the three leading capture technologies of oxyfuel combustion capture, pre-combustion capture and post-combustion.

The purpose of this paper is to develop an understanding of the dependence of capture cost on the required purity level. A scenario-based cost analysis is presented for the three capture technologies of oxyfuel combustion capture, pre-combustion capture and post-combustion capture with respect to impurities removal and variation. The scenarios include different power plant configurations and options for CO_2 purification. The performance of the different scenarios with respect to mass and energy balances, energy production and CO_2 purity is assessed. To account for the many factors that affect the power output, cost of electricity, emissions and cost of CCS at combustion based power plants, we have used the Integrated Environmental Control Model (IECM) to perform techno-economic calculations. The IECM was selected because it provides ready built in process performance models for a range of combustion based power generation and CO_2 capture technologies and therefore extends the scope of this study to a large range of scenarios. The IECM model cases have been supplemented in some areas where necessary using calculations performed using a process systems simulator and with information gathered from a detailed literature survey. The engineering cost models are applied to calculate capital costs in addition to operational and maintenance costs; these costs are then used to calculate the cost of electricity and other techno-economic indicators for each of the technologies and scenarios considered. Finally, the costs of each scenario and different CO_2 purity levels are compared and discussed.

2. ANALYSIS OF OXYFUEL COMBUSTION CARBON CAPTURE WITH RESPECT TO COST AND CO_2 IMPURITIES

2.1 Modelling methods and assumptions

Currently, one of the leading technologies for CO_2 capture from coal fired power plants is oxy-combustion capture. This capture method comprises of an ASU to produce a high purity oxygen stream which is mixed with recycled flue gas, providing an oxidation environment in which to burn the fuel that is low in nitrogen but has similar characteristics to those encountered in air combustion. The flue gas produced by oxyfuel combustion will vary in purity, and still requires dehydration, further purification and compression in order to be suitable for transport and storage. The latter is performed by means of a CO_2 compression and purification unit (CO_2CPU). A great deal of work to date has focused on optimising the combustion process (Edge et al., 2011; Seepana and Jayanti, 2012; Tan et al., 2006) and minimising the energy penalty caused by the ASU which is usually around 5 percentage points (Boot-Handford et al., 2014). In contrast, little work has been undertaken on reducing the energy penalty caused by the CO_2CPU which, through this study, is also found to fluctuate by around 5 percentage points.

Highlighting the importance of the CO_2CPU within the oxyfuel combustion capture process, three variations of the unit were modelled in Aspen HYSYS V8.4 with the objective of using the results to supplement whole plant techno-economic calculations that will be presented in section 2.4. The first CO_2CPU model is the most simplistic, consisting of a six-stage compression and dehydration system. The two remaining models are more complex systems, built on the compression and dehydration model, with different product stream purities. One consists of a double flash system with heat integration and the other of a six-stage distillation column also with heat integration. As these models increase in complexity, they also increase product purity with, as will be discussed later, variations in capture efficiency, energy penalty, and capital and operational costs.

These models were based on similar approaches to those presented by Posch and Haider (2012) using a Peng-Robinson property method with mixing parameters taken from Eggers and Köpke (2008). These were found to be most suitable for the components considered in the flue gas (CO_2, H_2O, N_2, Ar, O_2, SO_2) and the range of temperatures (-60°C to 250°C) and pressures (1 bar to 120 bar) considered. Each plant was assumed to have 8460 working hours per year and a plant lifetime of 35 years. The flue gas inlet composition and flow rate considered were taken from a pulverised coal firing power plant at nominal load (~350 MWe) retrofitted from an existing plant (Posch and Haider, 2012). These values are summarised in Table 1.

Table 1. Example of raw flue gas produced from an oxy-combustion pulverised fuel power plant (taken from Posch and Haider (2012)).

Flue Gas Properties (CPU inlet)	**Value**
Temperature	13.2 °C
Pressure	1 bar
Flow Rate	342.7 tonne/hr
Composition (mole %):	
CO_2	76.38
O_2	7.83
N_2	11.34
Ar	3.11
H_2O	1.34
SO_2	(100 ppm)

2.2 CO_2 compression and purification system process scenarios

In this section, three CO_2 compression and purification unit models developed in Aspen HYSYS V8.4 are briefly described. More detailed descriptions can be found elsewhere (Kolster et al., In prep.) and for similar processes in (Posch and Haider, 2012). Detailed simulations of the CO_2 Compression and Purification Unit (CPU) section of the plant which can deal with the removal of non-condensable components of N_2, O_2 and Ar, and compression of the product stream to high pressures (> 100 bar) were carried out. Based on the same composition and flow rate of raw oxyfuel CO_2 flue gas shown in table 1, three different compression and purification process strategies were considered:

1) CO_2 compression and dehydration only

2) 'Double flash' purification system

3) Distillation purification system

In all cases, the CO_2 product pressure is 120 bar. The first case of CO_2 compression and dehydration only, consists of a 3-stage compression train with interstage cooling and flash separation, followed by a dehydration step and a final 3-stage compression train with interstage cooling to the final delivery pressure. In the second double flash case, a 3-stage compression train with interstage cooling and flash separation followed by a dehydration step is again used. Following this, the flue gas is cooled to low temperatures in 2 multi-stream heat exchangers which are each followed by flash separation vessels. A CO_2 rich liquid stream exits the bottom of the flash separation vessels and stream rich in non-condensable gases exits the top. Cooling for the multi-stream heat exchangers is provided by auto-refrigeration expansion of the CO_2 product stream. The product stream is compressed further in a 3-stage compression train with interstage cooling. The third distillation case is similar to the double flash case but with phase separation handled by a 6-stage distillation column instead of the double flash vessel system.

2.3 CO_2 compression and purification system performance and cost

CO_2CPU performance and costs were evaluated using AspenTech Activated Economics Analysis (Hegy et al., 2013) using a UK metric based cost system. Costs were then converted to euros. The internal cost of electricity (defined as the price the base plant sells electricity to other plant areas and used to calculate their O&M costs) was equal to 0.0733 €/kWh.

The capture efficiency of each system was calculated using:

$$\eta_{cap} = \frac{\dot{m}_{CO2\,product}}{\dot{m}_{CO2\,inlet}} \tag{1}$$

where η_{cap} is the capture efficiency of CO_2 from the initial flue gas into the system, $\dot{m}_{CO2\,product}$ is the mass flow rate of CO_2 out of the system (after product compression for storage), and $\dot{m}_{CO2\,inlet}$ is the mass flow rate of CO_2 into the system (before the pre-compression stage).

As shown in Table 2, as the models increase in complexity (Distillation > Double Flash > Compression and Dehydration) and in product purity, the capital and operational costs incurred increase as well. This implies an increase in energy requirement per tonne of CO_2 captured as well as an increase in the power plant net efficiency loss with complexity and product purity. In addition, while the systems decrease in product purity and complexity, they increase in capture efficiency (see Equation (1)). The compression and dehydration system captures 100% of the CO_2 in the system, whereas the double flash and distillation plants capture 92% and 90%, respectively, of the CO_2 entering the system as a raw flue gas. The latter indicates that, with decreased system complexity, less CO_2 would be vented to the atmosphere and indeed more of the CO_2 coming into the system would be captured.

Table 2. System performance and economic evaluation of the three CO_2CPUs modelled.

Property of CPU	**Compression and dehydration only**	**Double flash**	**Distillation**
CO_2 Product Stream Mt/year	2.88	2.25	2.16
Capital Cost	€42 M	€43 M	€65 M
Operating Cost per Annum	€35 M	€41 M	€43 M
Product CO_2 Purity (mole %):	77.40	96.61	99.99
CO_2 Capture Efficiency η_{cap}	100%	92%	90%
Unit Energy (kWh/tonne of CO_2 captured)	103	150	172

2.4 Impact of CO_2 compression and purification system selection on overall plant costs and CO_2 purity

In this section, the modelling input parameters and results from the oxyfuel compression and purification systems considered in Sections 2.1 to 2.3 are used to develop an understanding of the overall oxyfuel combustion plant capital costs, operating and maintenance (O&M) costs and Levelised Cost of Electricity (LCOE). To account for the many factors that affect the power output and the cost of CCS in oxyfuel combustion power plants, we have used the Integrated Environmental Control Model (IECM) to perform whole plant techno-economic calculations. In this study, version 9.0.1 Beta of IECM was employed which allows for the techno-economic modelling of oxyfuel combustion capture with an integrated ASU. Environmental control techniques were also considered in the modelling, and these include in-furnace NO_x control, and the use of an electrostatic precipitator (ESP) and wet flue gas desulfurisation (FGD). Prior to entry of the CO_2 CPU unit the raw CO_2 flue gas is also considered to be cooled and dehumidified in a direct contact cooler (DCC). The process performance model calculations are based on fundamental mass and energy balances, which together with user-specified plant size, empirical relationships and sub-models are used to define component and system mass flows, energy flows and the efficiencies of unit operations. The final CO_2 product purity may be specified by the user along with the CPU unit energy requirement and other performance parameters for this unit. The process performance calculations are linked to engineering economic and financial models for each major process area in order to calculate the capital costs and O&M costs (consisting of fixed and variable costs) of various plant components. The cost models for each of the many process areas come from a variety of sources and therefore have a variety of origin dates. Costs are reported for years ranging from three decades ago, but are scaled to other years using the chemical engineering plant cost index. Cost data are used to form scaling relationships based on material flows through each unit operation. The data and scaling relationships for the process cost models form part of the IECM and further details of these can be found in the technical documentation of the software (IECM, 2015). The capital and O&M costs are used to calculate the LCOE for the overall plants. The LCOE represents the per-kilowatt hour cost of building and operating a generating plant over its lifetime. The LCOE is implemented in IECM as:

$$\mathrm{LCOE}\ (\$/MWh) = \frac{(\mathrm{TCC})(\mathrm{FCF})+\mathrm{FOM}}{(\mathrm{CF})(8760)(\mathrm{MW})} + \mathrm{VOM} + (\mathrm{HR})(\mathrm{FC}) \qquad (2),$$

where TCC is the Total Capital Cost ($), FCF is the Fixed Charge Factor (fraction), FOM is the Fixed Operating & Maintenance costs ($/yr), VOM is the Variable Operating & Maintenance Costs, excluding fuel costs ($/MWh), HR is the power plant Heat Rate (MJ/MWh), FC is the unit Fuel Cost ($/MJ), CF is the annual average Capacity Factor (Fraction) and MW is the net power plant capacity.

Comparison of plants with the three CPU technologies described in Sections 2.1 to 2.3 is made based on a set of technical and financial assumptions. In each case, the reference plant is a 400 MW gross power output facility with oxyfuel carbon capture. The plants use a low sulfur bituminous coal and are supercritical units. Financial data used in all cases are the same. Costs generated in the IECM were based on 2012 USD; a conversion factor of 0.96 was applied in the conversion from 2012 USD into 2014 €. Costs are expressed in the constant form. The costs and financial assumptions were partially based on those suggested by the NETL in previously published DOE reports (Grol et al., 2011; Rubin et al., 2007) relating to US plants, and those provided in Sections 2.1 to 2.3. A review of CCS techno-economic evaluations from numerous studies by Rubin et al. (2015) that are based on either European or US assumptions show considerable overlap for plant performance and costs; however, fuel prices and price trends between US and European studies are very different. Further details of the technical and financial assumptions for the cases of the present study are summarised in Table 3. The costs given refer to retrofitted plants in order to maintain compatibility to the calculations presented in Sections 2.1 to 2.3 that are based on the detailed retro-fit study for an existing coal power plant by Posch and Haider (2012). Older coal fired plants operate at higher excess oxygen than modern state of the art technology. In addition, air ingress in retrofit situations will be higher than in new build oxyfuel systems. As a consequence, the oxygen concentration in the raw CO_2 flue gas is higher and the requirements for the CO_2CPU are similarly higher in retrofit as compared to new build oxyfuel CCS. The total capital required for non-CCS plant components was amortised by 25% to account for the financial implications of retrofit.

Table 3. Key assumptions for the oxyfuel combustion plants.

Parameter	**Compression and dehydration only***	**Double flash***	**Distillation***
Fuel	Low sulfur bituminous coal†	Low sulfur bituminous coal†	Low sulfur bituminous coal†
Gross Power Output (MW)	400	400	400
Net Power Output (MW)	310	270.6	265.8
Net Plant Efficiency, HHV (%)	33.81	29.51	28.99
Capacity Factor (%)	96.5	96.5	96.5
Fixed Charge Factor (%)	17.21	17.21	17.21
Fuel Price (€/GJ, HHV)	1.75	1.75	1.75
CO_2 Capture Efficiency (%)	100	92	90

* Supercritical boiler; electrostatic precipitator particulate control system and wet FGD system SO_x removal units (85% removal efficiency) are included.

† As-fired properties are: 71.74 wt% C, 4.62 wt% H, 6.09 wt% O, 0.07 wt% Cl, 0.64 wt% S, 9.79 wt% ash, 5.63 and 30.42 MJ kg^{-1} HHV.

Table 4 summarises the major results of the oxyfuel combustion plant analysis. The oxyfuel plant with distillation type CO_2 purification has the highest CO_2 emission rate, followed by the double flash case. The plant with compression and dehydration only has zero CO_2 emissions due to its 100% capture efficiency. The compression and dehydration only plant also has the lowest LCOE due in large part to it having the lowest energy penalty for final CO_2 processing. Table 4 also shows that the cost of CO_2 avoided (€/tonne CO_2), defined as the difference in LCOE compared to an unabated reference plant without equipment for CO_2 capture but with all other equipment and assumptions remaining the same, divided by the difference in CO_2 emission rate per MWh of the capture and reference plant, is highest for the distillation system and lowest for the compression and dehydration system. The capital cost of a 400 MWg plant with a double flash CO_2 purification in M€ is roughly the same as the plant with compression and dehydration, at 1183 and 1180 M€, respectively. However, the compression and dehydration only case has the lowest capital cost expressed in €/kW-net due to its lower CO_2 capture energy penalty. As one might expect, the cost of electricity increases with increasing CO_2 purity, due largely to the increasing energy penalty for CO_2 purification and the increasing capital cost for the distillation case. As the value of 8460 plant working hours per year may represent an upper limit for most operations, figure 1, shows the variation of LCOE with plant working hours (using equation 2) to increased values of 174.2, 200.0 and 210.0 €/MWh for dehydration only, double-flash and distillation only oxyfuel combustion capture scenarios, respectively when the plant annual working hours are decreased to 5256 hrs (60 % capacity).

Table 4. Results of techno-economic calculation for the oxyfuel combustion plant cases.

Parameter	**Compression and dehydration only**	**Double flash**	**Distillation**
CO_2 Emission Rate (kg/MWh)	0	84.5	107.5
CO_2 Captured (kg/MWh)	1108	997.4	974.8
Total Capital Required (€/kW-net)	3806	4371	4608
Total O&M Costs (M €/yr)	101.9	102.0	103.6
Cost of Electricity[*] (€/MWh)	116.3	133.5	139.8
Cost of CO_2 Avoided[*, **] (€/tonne CO_2)	70.97	103.52	116.1
Product Stream Composition:			
CO_2	77.69 mol%[†]	96.61 mol%[††]	99.99 mol%[††]
O_2	7.61 mol%[†]	1.40 mol%[††]	0.55 ppmv[††]
N_2	11.63 mol%[†]	1.46 mol%[††]	0.34 ppmv[††]
Ar	2.98 mol%[†]	0.51 mol%[††]	0.22 ppmv[††]
H_2O	126 ppmv[†]	0[††]	0[††]
SO_2	126 ppmv[†]	136 ppmv[††]	137 ppmv[††]
SO_3	1.31 ppmv[†]	1.63 ppmv[‡]	1.69 ppmv[‡]
HCl	8.27 ppmv[†]	-	-
NO_x (NO / NO_2)	424 / 22.3 ppmv[†]	81 ppmv[‡]	20 ppmv[‡]
NH_3	5.2 ppmv[†]	-	-

All costs in constant 2014 Euros.

[*] Levelised cost excluding tax on emissions and cost of CO_2 transport and storage.

[**] All avoided cost values are relative to a reference plant without CO_2 capture for the same system.

[†] Calculated by IECM.

[††] Calculated by Aspen HYSYS.

[‡] Assumed on the basis of literature studies (Kather and Kownatzki, 2011; Pipitione and Bolland, 2009; Porter et al., 2015)

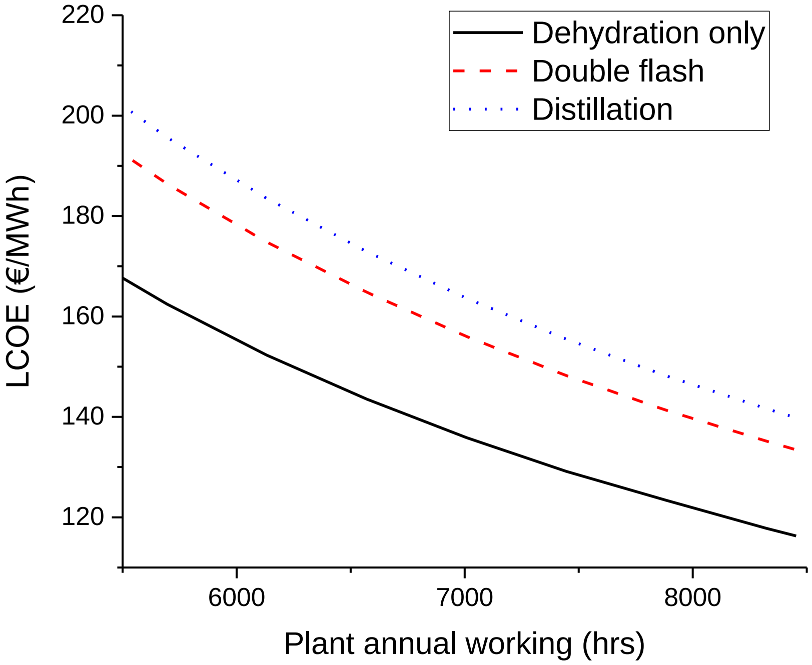

Figure 1. Variation of LCOE (€/MWh) with annual plant working hours for the different oxyfuel combustion capture technologies.

3. ANALYSIS OF PRE-COMBUSTION CARBON CAPTURE WITH RESPECT TO COST AND CO_2 IMPURITIES

In this section an understanding is developed of the influence of process configuration, fuel characteristics and CO_2 capture technology on the purity of CO_2 product deriving from pre-combustion carbon capture in an integrated gasification combined cycle (IGCC) power plant. Impurities in the product CO_2 stream from IGCC-CCS applications arise mainly from components contained in the syngas produced from the gasification of coal or other fuels (e.g. biomass). Other sources of impurities in IGCC-CCS include the physical solvents such as those based on methanol (e.g. Rectisol®). Syngas sulfur species predominantly consist of hydrogen sulphide (H_2S) with roughly 5% of the sulfur species being carbonyl sulfide (COS). COS can be converted to H_2S in a water gas shift reactor and the same physical solvents used for CO_2 capture in IGCC are also used to capture H_2S. There are two possible separation processes for dealing with the captured H_2S; namely, separate capture and co-capture. In the separate capture configuration, H_2S is isolated in a separate stream and further processed to elemental sulfur in a Claus process. In the co-capture configuration, H_2S is separated into the CO_2 product stream and the requirement for the H_2S processing plant is eliminated. The co-capture configuration offers significant capital and O&M cost savings over the separate capture approach as a smaller capture plant with a lower energy requirement can be used. A cost disadvantage of the co-capture configuration is the loss of revenue from the sale of elemental sulfur. Despite the economic advantages of co-capture IGCC, there are concerns surrounding the impact of H_2S on downstream capture and storage. In enhanced oil recovery (EOR) applications, however, H_2S is known to reduce the minimum miscibility pressure of oil and CO_2 mixtures and can therefore have a beneficial effect by reducing EOR energy requirements. Co-injection of H_2S for EOR has been employed extensively in Canada, such as in the Weyburn CO_2 injection project.

A physical solvent favoured for pre-combustion capture, Selexol™, consists of dimethyl ethers of polythene glycol. Selexol™ has the advantages of high solvent stability, low volatility and low vapour pressure, so that losses during regeneration are minimised (Mohammed et al.; 2014). The Selexol™ process is also relatively less complex than the process needed for another methanol based solvent considered for IGCC-CCS, i.e. Rectisol®. Operating costs for Rectisol® can also be higher due to the refrigeration requirement for low operating temperatures. However, Rectisol® can be used in a flexible process that can lead to higher purity syngas and CO_2 product streams. The different process options for pre-combustion CO_2 capture are further discussed in Section 3.2.

3.1 Modelling methods and assumptions

The IECM model described in Section 2.4 is again used to calculate the cost of pre-combustion carbon capture technologies using the same financial assumptions. Three main scenarios are explored; Selexol^{TM} with separate capture of impurities, Rectisol$^{®}$ with separate capture of impurities, and Selexol^{TM} with co-capture of impurities. The potential for analysing the use of Rectisol$^{®}$ with co-capture of impurities was reviewed; however, due to the lack of available data on capital and operating costs of this process it was not possible to calculate its overall costs. As the IECM model only includes cases for Selexol^{TM} with separate capture of impurities, supplementary calculations were carried for the remaining cases by performing mass and energy balances, and economic calculations were performed for the remaining cases, overwriting the IECM Selexol^{TM} base case. The impact of different fuels on costs and CO_2 purity has also been explored. In all of the cases the IGCC plant uses aGE entrained-flow slurry fed gasifier. This gasifier was chosen since a number of studies have indicated that for bituminous coals, they offer the lowest capital costs (Holt, 2003; IEAGHG, 2003; IEAGHG, 2004a).

3.2 Pre-combustion capture process scenarios

3.2.1 Selexol^{TM} with separate capture of sulfur species and CO_2

This case is based on an IGCC plant that has one full size GE quench gasifier with one spare, one gas turbine with a respective heat recovery steam generator (HRSG), and a steam turbine. The syngas produced by the gasifier comprises mainly CO (38%) and H_2 (34%), with the remainder being made up of CO_2 (15%), H_2O (10%), with smaller amounts of N_2 (0.90%), Ar (0.87%), CH_4 (0.56%), H_2S (0.56%), COS (0.03%), NH_3 (0.01%) and HCl (0.01%). The syngas is steam shifted in high temperature and then low temperature reactors which convert most of the CO to CO_2 and H_2. The shifted syngas is scrubbed in a Selexol^{TM} plant to yield a H_2 rich syngas and an acid gas stream that is processed in a Claus/Beavon-Stretford plant for sulfur recovery. In the Selexol^{TM} plant, 95% of the CO_2 contained in the syngas is captured and compressed to 120 bar. Capture rate in pre-combustion plants may vary between 50 - 98 %. The hydrogen rich fuel gas is moisturised with water before entering the gas turbine. The plant has a net power output of 265 MW.

3.2.2 Rectisol® with separate capture of sulfur species and CO_2

The Rectisol® process employs chilled methanol as a solvent to purify syngas and operates at very low temperatures between -40 ºC and -60 ºC. The process is also more complex compared to others involving solvents like Selexol™, but ensures very deep H_2S removal rates down to single figure ppm_v levels. There are many possible process configurations for this technology depending on the gas cleaning requirements. In a process configuration described by Padurean et al. (2012), a high level of both CO_2 and H_2S removal is required. The syngas is cooled to -30 to -40 ºC before it enters the first absorption column where Rectisol®, that is pre-loaded with CO_2, selectively removes H_2S. The H_2S rich solution leaves the bottom of the absorber and is regenerated by first flashing at medium pressure to recover useful syngas, which is then recycled back to the H_2S absorber, and then by heating to boiling temperature and stripping with methanol vapour. The stripper acid gas stream, consisting of over 95% H_2S, is sent to the Claus plant for elemental sulfur recovery. The desulfurised gas enters the CO_2 absorber for CO_2 removal. The rich CO_2 solution leaving the absorber is regenerated in a flash regenerator (Kohl and Nielsen, 2005). Limited information relating to the technical and economic details of the process are available in the literature, although two notable modelling studies have been published by Sun and Smith (2013) and by Padurean et al. (2012). Technical parameters for energy requirements used to model the process are those provided by Padurean et al. (2012) for a specific power consumption (0.144 MJ/kgCO_2), specific cooling consumption (0.081 MJ/kgCO_2) and specific heating consumption (0.35 MJ/kgCO_2). Sources of costs include a presentation dated October 2003 by Eastman Gasification Services entitled “Coal Gasification – Today’s Technology of Choice and Tomorrow’s Bright Promise” which reported estimated capital costs of $20 million for Selexol™ and $40 million for Rectisol®. Plant size was not given, but the cost factor of two in estimating the difference between Selexol™ and Rectisol® is helpful (EPA, 2006). Similar cost factor differences between Selexol™ and Rectisol® plants for Ammonia production have been reported by Fluor and UOP (Mak et al., 2004). In the present calculations, it has been assumed that Rectisol® plant equipment costs are a factor two higher than the ones reported by IECM for Selexol™ plants. The presented CO_2 composition is based on a recent report by North West Redwater Partnership (Heal and Kemp, 2013).

3.2.3 Selexol^{TM} with separate co-capture of sulfur species and CO_2

The overall power plant for this case is similar to the Selexol^{TM} plant with separate capture, with the main difference being that the CO_2 and H_2S are removed from the fuel gas simultaneously in a single stage, thereby eliminating the need for the sulfur removal and processing equipment. The absorption plant configuration is less complex than the separate capture case, consisting of a single CO_2-H_2S absorber, a two stage glycol flash and an acid gas stripper for simultaneous CO_2 and H_2S recovery. The CO_2 capture level remains at 95%, while the H_2S removal is 94%. The CO_2 product stream is compressed to an export pressure of 120 bar as with the other cases. Energy requirements for the co-capture Selexol^{TM} plant are assumed to be a factor 3.8 lower than the separate capture Selexol^{TM} plant on the basis of calculations by Ordorica-Garcia et al. (2006). Although this is an approximation since the calculations by Ordorica-Garcia et al. were performed for plants with 2 gas turbines, total separation energy is likely to scale with amount of processed material. The concentrations of sulfur species are calculated based on the mass balance and process assumptions, whereas concentrations of other impurities are based on literature sources since the IECM does not describe their behaviour; IEAGHG (2004b) for CO, H_2, H_2O, N_2, and E.C. (2011) for CH_4, NH_3, HCl and Ar.

3.3 Impact of pre-combustion scenario selection on overall plant costs and CO_2 purity

In this section, the technical and economic results of the modelling of IGCC plants with the different pre-combustion capture options noted in Sections 3.2.1 to 3.2.3 are presented. Each case is based on the use of a single GE 7FB gas turbine and one GE slurry fed entrained gasifier with one spare. The calculations refer to new build plants since although pre-combustion capture retrofits to IGCC plants are technically feasible, their number is expected to be limited since only a handful of prototype IGCC plants are currently operating. Financial data used in all cases are the same as those used for the oxyfuel combustion capture analysis. Details of the technical and financial assumptions are summarised in Table 5.

Table 5. Key assumptions for the pre-combustion capture plants.

Parameter	**Selexol$^{\text{TM}}$ separate capture***	**Selexol$^{\text{TM}}$ co-capture*,****	**Rectisol$^{®}$ separate capture*,****
Fuel	Low sulfur bituminous coal†	Low sulfur bituminous coal†	Low sulfur bituminous coal†
Gross Power Output (MW)	343.3	343.3	343.3
Net Power Output (MW)	268.7	295.2	259.6
Net Plant Efficiency, HHV (%)	30.78	33.83	29.73
Capacity Factor (%)	96.5	96.5	96.5
Fixed Charge Factor (%)	17.21	17.21	17.21
Fuel Price (€/GJ, HHV)	1.75	1.75	1.75
CO_2 Capture Efficiency (%)	95.0	95.0	95.0

* Based on GE quench gasifier (1+1 spare), 1 GE 7FB gas turbine.

** 98% sulfur removal efficiency via hydrolyser and physical solvent system; sulfur recovery via Claus and Beavon-Stretford plants.

† As-fired properties are: 71.74 wt% C, 4.62 wt% H, 6.09 wt% O, 0.07 wt% Cl, 0.64 wt% S, 9.79 wt% ash, 5.63 and 30.42 MJ kg^{-1} HHV.

Table 6 summarises the major results of the analysis of pre-combustion capture plants. The Rectisol$^{®}$ plant has the highest CO_2 emission rate, followed by the separate capture Selexol$^{\text{TM}}$ plant. The Selexol$^{\text{TM}}$ co-capture plant has the lowest LCOE. With CO_2 capture, all three plants remove 95% of the CO_2, being subject to an energy penalty in each case. In IGGC technologies, Table 6 also shows that the cost of CO_2 avoided is highest for the Rectisol$^{®}$ plant. The capital cost of the IGCC plant with a separate capture Rectisol$^{®}$ system is estimated to be 10% higher than the equivalent Selexol$^{\text{TM}}$ system. Due to the lower capital cost as well as higher plant efficiency, the LCOE for the co-capture Selexol$^{\text{TM}}$ system is projected to be 15% less than the Selexol$^{\text{TM}}$ separate capture case. There are some uncertainties in the capture plant estimates for Rectisol$^{®}$ systems which could be quantified and analysed in future work. Nevertheless, the initial analysis given here shows that IGCC plants with CO_2 capture can be cost competitive when compared to oxyfuel power plants to provide relatively high purity CO_2.

Table 6. Results of techno-economic calculation for the pre-combustion plant cases.

Parameter	**Selexol^{TM} separate capture**	**Selexol^{TM} co-capture**	**Rectisol$^{®}$ separate capture**
CO_2 Emission Rate (kg/MWh)	95.18	86.63	98.55
CO_2 Captured (kg/MWh)	885.3	806.7	916.3
Total Capital Required (€/kW-net)	4125	3490	4764
Total O&M Costs (M €/yr)	93.90	90.08	99.10
Cost of Electricity* (€/MWh)	125.2	107.1	142.03
Cost of CO_2 Avoided *,** (€/tonne CO_2)	46.49	21.73	67.22
Product Stream Composition:			
CO_2	97.91 mol%†	97.64 mol%†	99.51 mol%††
CO	0.2 mol%††	0.2 mol%††	0.073 mol%††
H_2	1.8 mol%††	1.7 mol%††	0.295 mol%††
CH_4	112 ppm$_v^{\dagger\dagger}$	112 ppm$_v^{\dagger\dagger}$	980 ppm$_v^{\dagger\dagger}$
H_2S	72 ppm$_v^{\ddagger}$	3794 ppm$_v^{\ddagger}$	1.5 ppm$_v^{\dagger\dagger}$
COS	trace‡	1 ppm$_v^{\ddagger}$	0††
NH_3	38 ppm$_v^{\dagger\dagger}$	38 ppm$_v^{\dagger\dagger}$	-
HCl	17.5 ppm$_v^{\dagger\dagger}$	17.5 ppm$_v^{\dagger\dagger}$	-
H_2O	300 ppm$_v^{\dagger\dagger}$	300 ppm$_v^{\dagger\dagger}$	0††
N_2	200 ppm$_v^{\dagger\dagger}$	200 ppm$_v^{\dagger\dagger}$	50 ppm$_v^{\dagger\dagger}$
Ar	200 ppm$_v^{\dagger\dagger}$	200 ppm$_v^{\dagger\dagger}$	40 ppm$_v^{\dagger\dagger}$
Methanol	-	-	160 ppm$_v^{\dagger\dagger}$

All costs in constant 2014 Euros.

* Levelised cost excluding tax on emissions and cost of CO_2 transport and storage.

** All avoided cost values are relative to a reference plant without CO_2 capture for the same system.

[†] Balance.

[††] Assumed on the basis of literature studies (E.C., 2011; Heal and Kemp, 2013; IEAGHG, 2004b).

[‡] Calculated via IECM.

4. ANALYSIS OF POST-COMBUSTION CARBON CAPTURE WITH RESPECT TO COST AND CO_2 IMPURITIES

In this section the costs and CO_2 purity levels associated with post-combustion carbon capture are analysed. Post-combustion capture (PCC) can be applied to plants that run on various fuels, but the application to coal utilisation using standard monoethanolamine solutions for CO_2 absorption is presented here. Commercial amine based solvents such as Econamine FG Plus can offer improved process efficiencies, impacting on overall costs and so cross comparative studies of solvent performance are warranted. Additional environmental control techniques were also considered in the modelling, including in-furnace NO_x control, electrostatic precipitator particulate separation units, hot-side selective catalytic reduction (SCR) for further NO_x control and flue gas desulfurisation units for SO_x removal.

4.1 Modelling methods and assumptions

To account for the many factors that affect the power output, cost of electricity, emissions and cost of PCC-CCS plants, the IECM model is again used to perform the techno-economic calculations. These cases are in parity with the oxyfuel combustion plants presented in Section 2, with all of the same technical and financial assumptions, but with the fundamental difference being the choice of capture technology. In each case, the plant is a 400 MW gross power output facility with carbon capture; however in the PCC case, the base plant size is larger compared to the oxyfuel case because of the increased energy requirement for amine steam use. The associated energy penalty of carbon capture results in a plant with reduced net plant electrical power output.

4.2 Post-combustion capture process scenarios

Details of the assumptions used for the post-combustion capture scenarios are summarised in Table 7. Two scenarios are considered: a process plant that has all the aforementioned environmental control techniques (in-furnace NO_x controls, ESP, SCR and FGD) and a similar case but with the SCR and FGD process areas removed. In both cases an SO_2 polisher is used to further limit the sulfur levels of the flue gas to low levels (<10 ppmv) on entry to the post-combustion capture plant. This is to prevent excessive amine loss due to the formation of heat stable salts from the combination of SO_2 with the amine, and also has the added benefit of reducing other impurities. To maintain parity with the oxyfuel cases, the costs given in this section refer to retrofitted plants, with the total capital required for non-CCS plant areas amortised by 25%.

Table 7. Key assumptions for the post-combustion capture plants.

Parameter	**ESP particulate control only***	**With NO_x control by LNB/SCR and SO_2 control by Wet-FGD ****
Fuel	Low sulfur bituminous coal†	Low sulfur bituminous coal†
Goss Power Output (MW)	400	400
Net Power Output (MW)	321.6	313.8
Net Plant Efficiency, HHV (%)	25.95	25.66
Capacity Factor (%)	96.5	96.5
Fixed Charge Factor (%)	17.21	17.21
Fuel Price (€/GJ, HHV)	1.75	1.75
CO_2 Capture Efficiency (%)	90	90

* Supercritical boiler; electrostatic precipitator particulate control system included.

**Supercritical boiler; electrostatic precipitator particulate control system, in-furnace NO_x controls, hot-side SCR and wet FGD SO_2 control included.

† As-fired properties are: 71.74 wt% C, 4.62 wt% H, 6.09 wt% O, 0.07 wt% Cl, 0.64 wt% S, 9.79 wt% ash, 5.63 and 30.42 MJ kg^{-1} HHV.

4.3 Post-combustion plant costs and CO_2 purity

Table 8 summarises the major results of the analysis of the post-combustion CO_2 capture plants. Performance data for the plants with and without the additional environmental controls are somewhat similar, with CO_2 emission rates around 120 kg/MWh. The plant with additional environmental controls has a slightly higher capture rate than the one without due to its lower net plant efficiency. As expected, the capital costs for the plant with additional environmental controls are higher due to the extra equipment required; however, the total O&M costs are higher for the plant without environmental controls due to the impact of higher concentrations of flue gas impurities on the CO_2 capture plant. The cost of electricity for the plant with the additional environmental controls is higher than for that without due to the capital costs of the additional equipment whose operation results in a modest increase in calculated CO_2 purity due to the reduction of HCl and NO_2 in the CO_2 product stream. Some literature studies also report low levels of air contaminants, moisture and carbon monoxide in post-combustion capture derived streams (E.C., 2011).

Table 8. Results of techno-economic calculation for the post-combustion capture plant cases.

Parameter	**ESP particulate control only**	**With NO_x control by LNB/SCR and SO_2 control by Wet-FGD**
CO_2 emission rate (kg/MWh)	119.8	121.6
CO_2 captured (kg/MWh)	1078	1094
Total capital required (€/kW-net)	3204	3572
Total O&M costs (M €/yr)	147.1	142.8
Cost of electricity* (€/MWh)	119.3	126.5
Cost of CO_2 avoided *,** (€/tonne CO_2)	102.1	100.2
Product stream Composition†		
CO_2	99.95 mol%	99.99 mol%
HCl	349 ppm_v	35 ppm_v
SO_2	83 ppm_v	91 ppm_v
SO_3	11 ppm_v	11 ppm_v
NO_2	38 ppm_v	10 ppmv

All costs in constant 2014 Euros.

* Levelised cost excluding tax on emissions and cost of CO_2 transport and storage.

** All avoided cost values are relative to a reference plant without CO_2 capture for the same system.

† Calculated via IECM.

5. DISCUSSION

This paper has presented a techno-economic analysis of different carbon capture technologies with varying levels of refinement of the CO_2 product stream, considering the three leading technologies proposed for capture from the power generation sector, namely; oxyfuel combustion, pre-combustion and post-combustion CO_2 capture. The analysis was performed using a combination of modelling with Aspen HYSYS and the Integrated Environmental Control Model, and information available from literature sources. This enabled the calculation of key performance parameters for several power plant process configurations that impact the CO_2 product purity level, in addition to capital and O&M costs and ultimately the levelised cost of electricity of individual scenarios.

The specific capital costs for the range of CO_2 capture technologies and scenarios considered can be broken down by overall process area, as illustrated Figure 2. The oxyfuel compression and dehydration scenario has a similar capital cost to the slightly more complex double flash case, due partly to the need for larger compressors in the compression and dehydration case caused by the higher flow rate of CO_2 product. The CO_2 control area for the oxyfuel distillation has a higher capital cost due to the higher cost of the distillation column. In the pre-combustion cases, capital expenditure progressively increases when sulfur control is added and when the more expensive Rectisol® system is used, leading to this latter technology being the most expensive of all the scenarios considered at 4764 €/kW-net. In the post-combustion power plant scenarios, capital expenditure is added with the additional conventional pollution control devices. The post-combustion capture scenario without the assortment of conventional pollution control devices was found to have the lowest capital cost at 3204 €/kW-net.

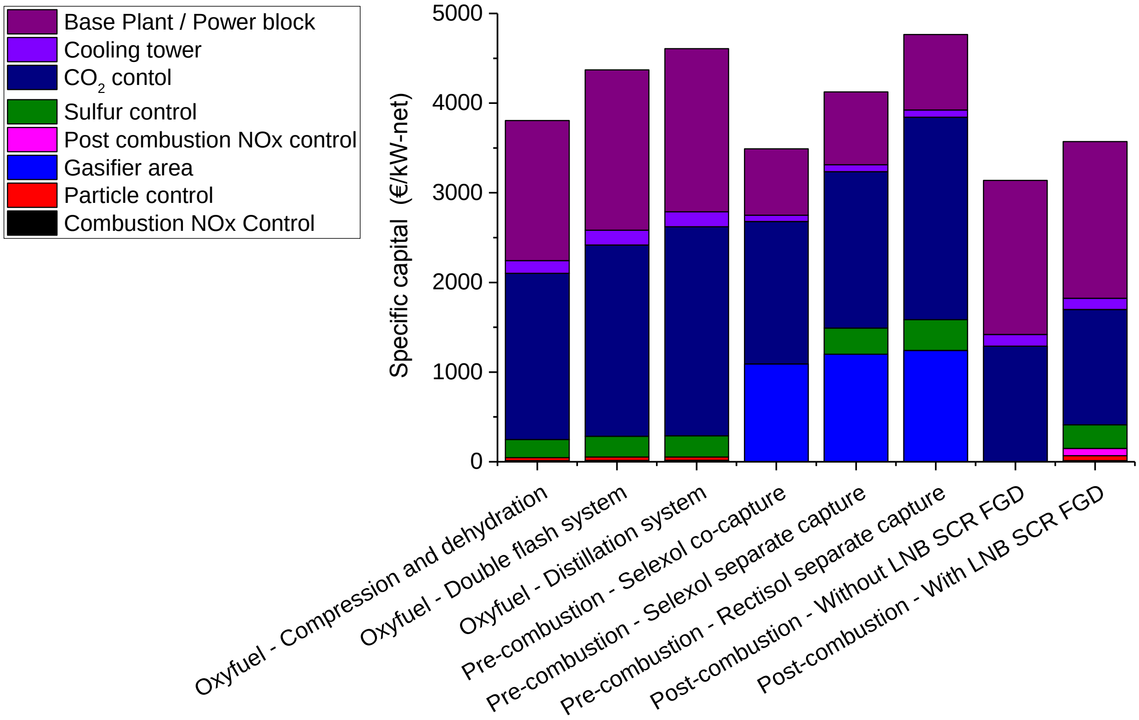

Figure 2. Specific capital required (constant 2014 €/kW-net) for the different CO_2 capture technologies and purification scenarios.

Total O&M costs for the different CO_2 capture technologies and scenarios considered in this study are shown in Figure 3. The pre-combustion capture scenarios have the lowest O&M costs that scale with CO_2 impurity, due to the costs of operating sulfur capture plants and the higher operational costs of the cold methanol Rectisol® process. The oxyfuel combustion capture scenario O&M costs are slightly higher than those of the pre-combustion capture cases, with the distillation case being the highest amongst them due to it being the most energy intensive cryogenic separation. Out of the post-combustion cases, the scenario without most of the conventional pollution control devices has slightly higher O&M costs due to the increased solvent degradation caused by impurities, resulting in this technology having the highest total O&M cost out of all the cases in this study.

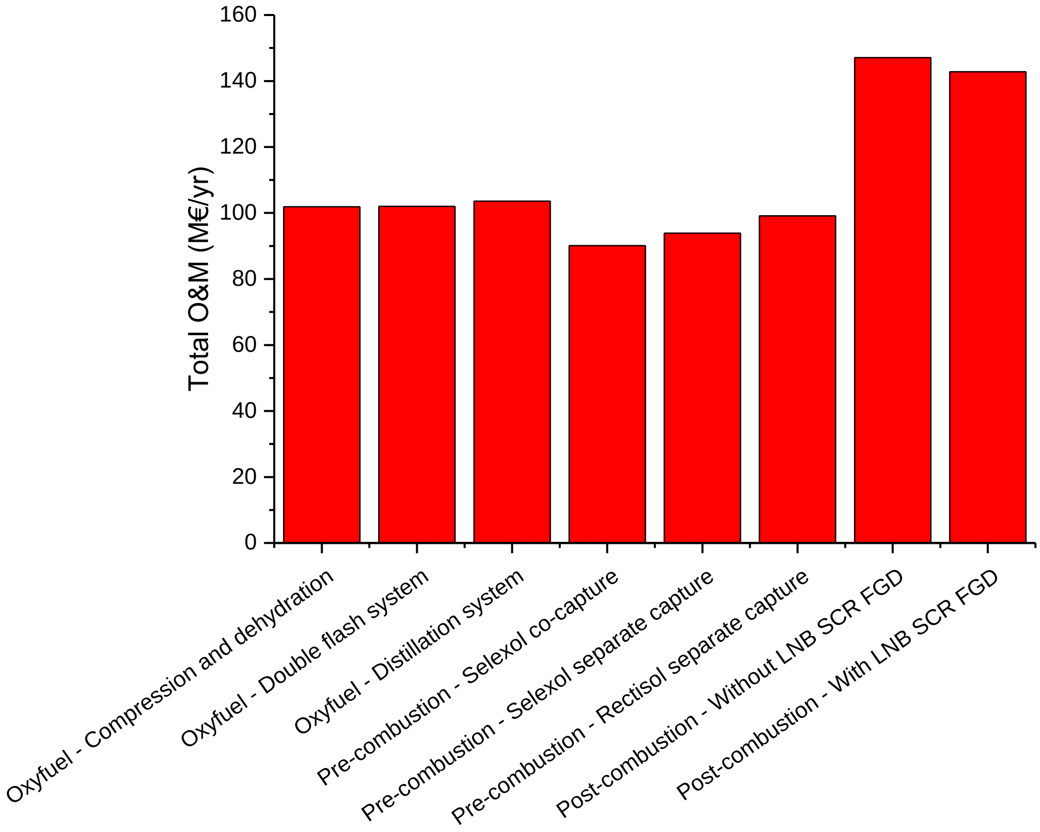

Figure 3. Total O&M costs (millions of constant 2014 € per year) for the different CO_2 capture technologies and purification scenarios.

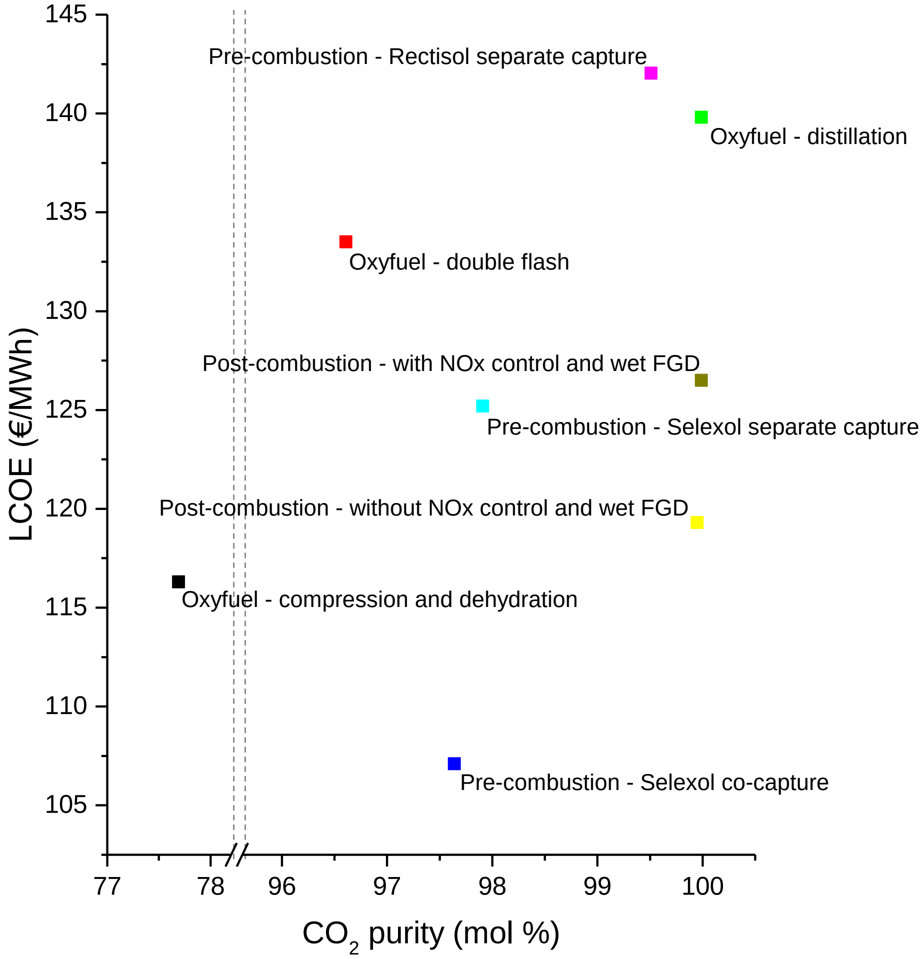

Figure 4. Cost of electricity (constant 2014 €/MWh) versus CO_2 purity for different CO_2 capture technologies using a low-sulfur bituminous coal.

Figure 4 illustrates the trade-off between cost and purity of the captured CO_2 stream in the analysed cases. The technology with the lowest LCOE is pre-combustion capture using the Selexol^{TM} physical solvent with co-capture of impurities. This technology produces CO_2 with an estimated purity of 97.64 mol%, but high estimated levels of H_2S (at 3974 ppmv). Conversely, the highest cost technology in this analysis is found to be pre-combustion capture using Rectisol$^{®}$ as the solvent and with separate capture of sulfur impurities. The CO_2 stream produced by this technology is dry, with low levels of other contaminants such as CO and H_2. The technologies that produce the highest grade of CO_2 are post-combustion capture with NO_x and wet FGD environmental control, and oxyfuel combustion plant with CO_2 purification by distillation, with both producing 99.99 mol% CO_2 product, but with post-combustion capture having the lowest cost. The three analysed oxyfuel combustion capture technologies produce the widest range of CO_2 purity, with the compression and dehydration only system, that does not include any additional purification of the raw CO_2 flue gas stream, producing the lowest grade CO_2 stream that contains 77.69 mol% CO_2 and high levels of non-condensable species (O_2, N_2 and Ar), plus acid gas species. Bassi et al. (2015) have recently outlined a range of cost estimates for CCS from selected literature sources. LCOEs of coal-fired plants in the literature review averaged from about 80-210 €/MWh with an average of 115 €/MWh which is somewhat lower than the average LCOE of the scenarios presented in this study of 126 €/MWh that exclude transport and storage costs. This may be a reflection of the fuel price use in our study.

While the costs given in this analysis are current at the date of publication, it should be borne in mind that as each of the presented technologies mature their costs are likely to decrease at potentially different rates. The current analysis has focussed on the main process performance factors that are likely to affect CO_2 purity; final CO_2 processing in the cases of oxyfuel combustion and pre-combustion capture, and upstream process configuration for the case of post-combustion capture. However, there are other factors that can affect cost and also CO_2 product purity, including plant size, fuel selection, retrofit versus new build, and mode of operation of the power plant. While the analysis has focussed on retrofitted plants for oxyfuel combustion and post-combustion capture, and new-build plants for pre-combustion capture, future comparisons of retrofitted and new-build plants for similar technologies are recommended. Although gas-fired power plants were not considered in the analysis, the application of post-combustion capture to this type of power generation is likely to produce electricity at even lower cost and with high CO_2 product purity. The selection of appropriate carbon capture technology will be influenced by whole chain CCS techno-economics, legal, environmental, and health and safety considerations. For example, in some countries where acid gas injection is commonly practiced, pre-combustion capture with co-capture of impurities may be acceptable, and the most cost-effective solution when coupled to enhanced oil recovery CO_2 storage applications. Scope for CCS cost reduction through relaxing CO_2 purity limits from capture source may also exist when a collection of CCS plants connect to a shared CO_2 transport network infrastructure (Kolster et al., in prep.). For example, if lower purity sources are mixed with higher purity sources this may provide a final CO_2 stream of quality that is suitable for the geological storage site. Furthermore, where distance from the capture source is short, higher levels of impurities may be permissible if internal pipeline surfaces are protected from corrosion, for example, by using stainless steel (Sim et al., 2014).

The present study should facilitate further analysis of whole CCS chain techno-economics and process configuration.

6. Concluding Remarks

A techno-economic modelling study of power plants with CO_2 capture technologies which focusses on process scenarios that deliver different degrees of CO_2 stream purity has been carried out. The three leading CO_2 capture technologies for the power sector were considered, namely; oxyfuel combustion, pre-combustion and post-combustion capture. The study uses a combination of process simulation of flue gas cleaning processes, modelling with a power plant cost and performance calculator and literature values of key performance criteria in order to calculate capital costs, operational and maintenance costs, the levelised cost of electricity and CO_2 product purity of the considered CO_2 capture options .

For oxyfuel combustion capture, the calculations are based on a 400 MWg retrofitted power station that uses a low sulfur coal and considers three raw CO_2 flue gas processing strategies of compression and dehydration only, double flash system purification and distillation purification. Analysis of pre-combustion capture options is based on new build integrated gasification combined cycle plants with one gas-turbine and a GE entrained-flow gasifier. Integrated physical solvent systems for capturing CO_2 and sulfur species were considered in three ways; co-capture of sulfur impurities with the CO_2 stream using Selexol^{TM} solvent or separate capture of CO_2 and sulfur impurities using either Selexol^{TM} or Rectisol$^{®}$ solvent systems. Analysis of post-combustion capture plants was made with and without some conventional pollution control devices.

Of the different cases considered, pre-combustion capture with co-capture of impurities and CO_2 using Selexol^{TM} offered the lowest cost with a reasonably high purity of CO_2 at 97.64 mol%, but high estimated levels of H_2S (at 3974 ppmv) in the captured stream. The most expensive system was pre-combustion capture using Rectisol$^{®}$ with separate capture of CO_2 and sulfur impurities, producing a dry 99.51 mol% pure CO_2 stream. The system with the lowest grade of CO_2 was oxyfuel combustion capture with compression and dehydration of the raw CO_2 stream only, which resulted in 77.69 mol% pure CO_2 and with the second lowest cost. The oxyfuel plant with a distillation purification system and a post-combustion capture plant with conventional pollution control devices had the joint highest CO_2 purity (99.99 mol%), with the post-combustion capture system estimated to be the cheaper of the two. The calculations performed are of use in further analyses of whole chain CCS for the safe and economic capture, transport and storage of CO_2.

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