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Prepared by: A. Ramírez (UU)

Reviewed by: A. Ramírez (UU)

Approved by: J.Brouwer (CATO-2 Director)

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	Title	**Doc nr**	**Version date**
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1 The flexibility requirements for power plants with CCS in a future energy system with a large share of intermittent renewable energy sources

GHGT-11

A.S.Brouwer[a,b]1, M. van den Broek[a], A.Seebregts[b], A.P.C.Faaij[a]

[a]*Utrecht University,Copernicus Institute, Heidelberglaan 2, 3584CS, Utrecht, The Netherlands.*
[b]*Energy Research Centre of the Netherlands (ECN), Amsterdam, The Netherlands.*

Abstract

This paper investigates flexibility issues of future low-carbon power systems. The short-term power system impacts of intermittent renewables are identified and roughly quantified based on a review of wind integration studies. Next, the flexibility parameters of three types of power plants with CO_2 capture are quantified, and used in a power system model of The Netherlands to determine the technical and economic feasibility. We find that coal-fired power plants with CO_2 capture achieve higher load factors and short-term profits than gas-fired plants in future power systems, and that those coal-fired plants are flexible enough to balance high levels of wind power.

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Keywords: Carbon Capture and Storage; Power plant; Flexibility; Renewables; Power system modeling

1.1 Introduction

The power sector in the European Union is facing a structural change towards low-emission power generation in order to reach the emission reduction goal of the European Commission (EC), as the sector may have to reduce its emission by 96-99% by 2050. The EC foresees that the electricity mix will be dominated by three generator types: 1) renewable sources with a share of 59-83% of generated electricity, of which 42%-65% by Intermittent Renewable Energy Sources (IRES), 2) Carbon Capture and Storage (CCS) with a share of 7-32% if commercialized, and 3) nuclear energy with a share of 3-19% [1]. The IEA predicts similar trends for other OECD countries in its 450-scenario [2].

As a result of these structural changes, the flexibility of the electricity system may become an important issue. The intermittent nature of IRES requires the power system not only to adjust to changes in electricity demand, but also to changes in IRES power production. Moreover, IRES cannot be 100% accurately predicted, which necessitates more (flexible) reserves. Low carbon thermal power generation is relatively inflexible, however. Carbon capture installations will probably reduce the flexibility characteristics of coal and natural gas power plants, and nuclear power is relatively inflexible by itself [3].

* Corresponding author. Tel.: +31-30-2537736; fax: +31-30-2537601.
E-mail address: a.s.brouwer@uu.nl

In this study, we address the research questions: what kind of flexibility is needed for large shares of IRES, and how can this be delivered by power plants with CCS in an economic and technically feasible way in a future low-carbon electricity system? The focus will be on The Netherlands, which may deploy large scale wind power in the future.

1.2 Methodology

Power system impacts of intermittent renewable energy sources

The main questions are answered in three steps. In the first step, the daily impacts of IRES on the power system are determined and quantified to assess which impacts should be accounted for in a power system model. We consider wind power as a typical type of IRES as it has comparable integration characteristics as solar PV and wave power, and as it is the only type of IRES for which large scale integration studies have been performed [3]. The impacts of large scale wind generation on the power system are quantified based on a literature review of 17 wind integration studies. These studies have investigated wind penetration levels of up to 47% of annual power production, with typically levels between 20-30%. Whenever wind penetration levels are mentioned, they refer to the wind power production as a percentage of the annual power production.

Flexibility of power plants with carbon capture

Secondly, an overview is made of the flexibility parameters (i.e. part-load efficiency, minimum load level, ramp rate, and startup time) of three types of power plants with carbon capture: ultra-supercritical pulverized coal (USC-PC) power plants, combined with post-combustion capture, integrated gasification combined cycle (IGCC) power plants with pre-combustion capture, and natural gas combined cycle (NGCC) power plants with post-combustion capture. The parameters are based on data available in the public domain, as well as expert consultation. Three sets of flexibility parameters are drafted per power plant: a most-likely reference set, a high flexibility set and a low flexibility set.

Modelling the performance of power plants with CCS in a future power system

Thirdly, the performance of the three types of power plants in a future power system is analysed using the REPOWERS model for a number of scenarios. The REPOWERS model is a unit-commitment simulation model for the Dutch power sector based on Lagrangian Relaxation. The model optimizes the dispatch of generation units based on their production costs whilst imposing flexibility constraints. It simulates power production at a 1 hour time step and accounts for exchange with Germany, Belgium and the United Kingdom. The model was developed by Energy Research Centre of The Netherlands [4].

The effects of IRES penetration on the role of power plants with CCS in a future power system are determined in 12 scenarios (see table 1). First, two CCS scenarios are evaluated. Both consist of the projected Dutch 2030 energy mix to which 1600 MW of UCS-PC-CCS capacity as well as 1000MW of NGCC-CCS capacity is added for one, and 1600MW of IGCC-CCS capacity and 1000MW NGCC-CCS capacity for the other. For both CCS scenarios, three levels of flexibility are evaluated. For the energy mix with USC-PC-CCS, three wind penetration levels of 20%, 40% and 60% of total electricity generated are considered, in conjunction with carbon prices of €20, €50 and €80 per tonne CO2 respectively.

Two weeks are simulated: one week with relatively high wind production (200% of average weekly production), and one with low wind production (60% of average weekly production). The technical and economic feasibility of power plants with CCS is assessed by determining the load factors during these weeks, as well as the margin between the generation costs (consisting of fuel, CO2, and variable O&M costs) and the electricity price ("short-run profit").

Table 1. Overview of scenario runs

		Reference flexibility	High flexibility	Low flexibility
USC-PC & NGCC	20% wind (9GWa), €20 tonne-1 CO2	X	X	X
	40% wind (16 GW), €50 tonne-1 CO2	X	X	X
	60% wind (24 GW), €80 tonne-1 CO2	X	X	X
IGCC & NGCC	40% wind (16 GW), €50 tonne-1 CO2	X	X	X

The installed wind capacity is relatively high due to a high share of onshore wind capacity.

Input data for the REPOWERS model are based on a number of sources. The Dutch electricity generation mix of 2030 is based on projections by the POWERS model [5]. To the generation mix, extra power plants with CCS and extra wind power capacity are added. Fuel prices are taken from [2], Flexible O&M costs from [6], and costs for transport and storage of CO2 from [7]. Electricity demand patterns and wind speed patterns are based on historic time series of 2009, where the demand is corrected for projected future growth. Power exchange with neighboring countries is modeled at an aggregated level, based on the projected business as usual generator capacity and electricity demand patterns from PRIMES [8]. In short, input parameters consist of a Dutch 2030 national demand of 126 TWh, 28.9 GW installed generation capacity, and 8.8GW interconnection capacity.

1.3 Impacts of large penetration of wind power

For large scale penetration of wind power we identified four key impacts on powers systems that will require more power system flexibility. First of all, the size of the primary and secondary reserves may need to increase, to balance the increase in variability and reduced predictability of power production by wind. Primary reserves are activated within seconds, and secondary reserves are activated within minutes. Secondly, thermal generation capacity may be displaced by wind generation, as the marginal generation cost of wind power is smaller than that that of thermal power generation capacity. As a result, the amount of CO2 emissions of the power system as a whole will be reduced. Thirdly, the efficiency of thermal power generators may be affected, because the variability and reduced predictability of wind power production necessitates more variable generation by these generators resulting in more startups, ramping and part-load operation. Lastly, large penetration of wind could result in curtailment of part of the wind generation capacity as a result of overproduction or insufficient transmission capacity [9].

Quantification of system impacts

Based on the analysis of 17 wind integration studies, it was concluded that the impact that needs most regulation is the increase of reserve sizes. The required size of the primary reserves increases is reported to increase by 0.3-0.5% of the installed wind capacity at 10% penetration, to 0.8-1.0% of installed capacity at 40% penetration. The size of reserves that are required at a timescale from a minute to an hour, among which the secondary reserve, increases more rapidly, from 5-10% of installed capacity at 10% wind penetration to 10-15% of installed capacity at 40% penetration. The increase is caused by the increasing correlation in wind power production between two wind production sites at longer timescales. As a result, fluctuations in power production and forecast errors are not evened out by opposing, uncorrelated fluctuations, but added together. Regarding displaced capacity, it is reported that mostly natural gas fired capacity is displaced, and to a lesser extent coal fired capacity. The exact displacement, and associated to this, emission reductions, also depend on regional characteristics, such as the energy mix. The reduction in generator efficiency has not been quantified by many studies. At wind penetration levels between 10-30%, the actual emission reductions resulting from wind displacing thermal capacity, are 90-95% of the emissions that would have other ways been emitted by the displaced capacity. Lastly, the curtailed wind capacity depends on the presence of sufficient interconnection and transmission capacity. When both are available, curtailment is <0.5% of the potential wind power production, but when either or both are insufficient, curtailment of up to 10% of potential production has been reported.

Flexibility requirement of system impacts

Of the four impacts, one requires extra flexibility from the power system: the increased reserve size. More reserves will have to be available, while a smaller share of power will be produced by thermal power capacity. The ramp rates of power plants may thus have to increase, and the minimum load (so that plants do not have to shut down), and startup time (to provide slower reserves) may have to decrease.

In addition, the extent of two impacts is determined by the flexibility of the power system: displacement and reduced efficiency. Whilst the makeup of the displaced capacity is largely determined by the merit order, flexibility constraints could also lead to inflexible power plants being displaced, especially at higher levels of IRES penetration. The extent of the efficiency reduction is considerably affected by the part load efficiency, as well as the extra fuel use during startup and ramping.

The REPOWERS model accounts for all four impacts. For each time step, a predefined spinning reserve size is required to be available within 15 minutes, and it is assumed that wind power can deliver downwards reserves through curtailment. Thermal power capacity is displaced by wind power, which has an earlier position in the merit order. Reduction of efficiency is accounted for through part load efficiency curves.. Lastly, the model can curtail wind power when the total production is larger than the demand.

1.4 Flexibility performance of power plants with CCS

The flexibility of post-combustion power plants is based on modelling and publicly available engineering studies. The full-load efficiency penalty of the capture unit is taken to be 8%point for both USC-PC plants and NGCC plants, based on the penalty reported by ZEP when advanced amines are used [10]. The efficiency penalty is expected to be larger at part-load. In a best case scenario with multiple parallel capture units it could remain stable, as then the operating load of the capture plants can always be kept close to 100% load [11]. In practice, the part load efficiency penalty for a USC-PC plant is expected to be higher, which is mainly caused by throttling losses to keep the steam pressure to the stripper sufficiently high at low loads, and also less efficient operation of compressors. Overall, an USC-PC efficiency penalty increase at 50% load of about 1%point [12] and 2%point [13] are reported. For NGCC plants, the penalty increase is somewhat similar: a couple of percentage points [12] to zero [14].

The minimum load level of a power plant does not seem to be affected by the capture unit. The FEED study of the USC-PC Kingsnorth CCS project states that the minimum load level of the capture unit is 25% of nominal power plant load [15]. A study by Foster-Wheeler reported the minimum load level of a packed absorber column is 30% of the gas design flow rate. The minimum load of a compressor train is 70%, but by using a number of parallel trains that bottleneck can be avoided [12].

The ramp rate does also not seem to be affected by the capture unit. Dynamic modelling shows that absorber can handle large changes in flue gas flow [16], [17]. In the FEED study for the Kingsnorth plant project, preliminary ramp rates of 2-3% of nominal capacity /min were specified between 30-50% and 90-100% load, and a ramp rate of 4-6%/min from 50-90% load [15]. Foster Wheeler Italiana concluded in their study that the ramp rates of a USC-PC plant with CCS are not affected by the capture unit, and that no modifications are needed to improve it. Ramp rates of 5%/min between 50-90% load and 4%/min between 90-100% load can be achieved [12].

Start-up times do not seem to be affected by the capture unit, according to dynamic simulations [17], [18]. However, Foster Wheeler Italiana reports that the stripper will have to heat up to its operating temperature during start-up, which might limit the flexibility of the power plant. This could require 2-4 hours (hot and warm start, respectively), from the moment the steam supply is established. This may especially be a problem for NGCC power plants, because the gas and steam cycles can start quickly, and because the steam is not immediately available to heat up the stripper. The operating flexibility of an USC- PC plant is less affected, as the start-up time of such a plant is also a couple of hours.

Table 2. Flexibility parameters of USC-PC and NGCC power plants with post combustion capture

	USC-PC CCS			NGCC CCS		
	Flexible	Typical	Inflexible	Flexible	Typical	Inflexible
η-penalty @ 100% load [%-points]	8	8	8	8	8	8
η-penalty @ 50% load [%-points]	8	10	12	8	9	11
Minimum load [% of max load]	25a	25a	35	40a	40a	40a
Ramp rate [% of max load /minute]	5	4a	3	7a	7a	5
Start-up time [hours]	2a	2a	4	1a	2	4

a) Not affected as compared to power plant without capture unit

IGCC power plants are relatively inflexible as a result of the inertia of the gasifier and the air separation unit, and little has been published on the operational flexibility of this type of power plants with pre-combustion capture. In a study commissioned by IEAGHG, a number of novel operational strategies were explored, which involve storage of O_2, H_2 or syngas - thereby evading the lengthy start-up time of the plant [12]. In our analysis, the flexibility performance of the reference IGCC case with capture is assumed to be the same as that of a IGCC plant without capture, as the capture unit is not expected to affect the flexibility [12]. In addition, a more flexible IGCC unit is considered which could be realized by means of H2 storage, and a less flexible unit, which could be the result of a retrofit.

Table A3: Flexibility parameters of an IGCC power plant with pre combustion capture

	Flexible	Typical	Inflexible	Sources
η-penalty @ 100% load [%-points]	8	8	8	[10], [19]
η-penalty @ 50% load [%-points]	8	8	8	[20]
Minimum load [% of max load]	30	50	50	[12], [21]
Ramp rate [% of max load /minute]	5	3	2	[12], [22], [23]
Start-up time [hours]	2	6	8	[12], [22]

1.5 Model outcomes

Preliminary model results of the load factors are shown in Figure 1. A number of trends can be distinguished. First of all, there is a large difference in load factors between the two weeks considered: during low wind conditions, the coal and natural gas fired power plants run ~95% and 70-80% of the time, respectively. During high wind conditions, load factors are progressively reduced at higher wind penetration levels. Natural gas fired capacity is most affected, and coal to a lesser extent, because the coal:natural gas price ratio is relatively low (1:3). In addition, the coal capacity is sufficiently flexible to deliver the required reserves at higher penetration levels of wind power, also when equipped with a capture unit.

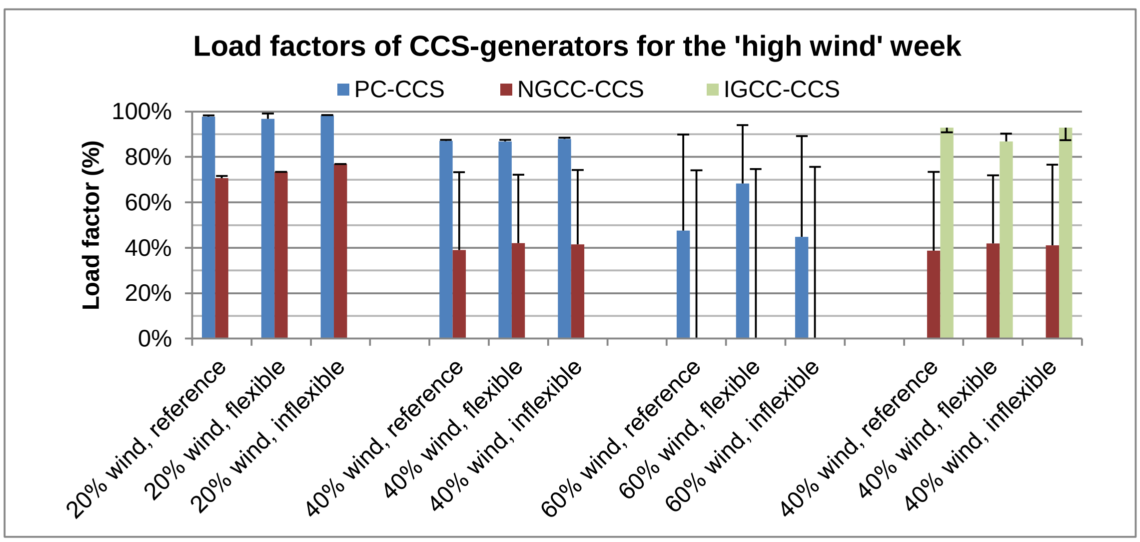

Figure 1: The load factors of power plants with CCS for different scenarios for the week with high wind production. The error bars show the load factors during the week with low wind production, indicating the annual range.

As share of wind power and carbon prices increase, the CO_2 emissions decrease. They are within the ranges of 1.17-0.85, 1.12-0.56, and 0.95-0.22 times the emissions of a typical week in the Netherlands in 1990, for the 20%, 40% and 60% wind penetration scenarios respectively. The larger reductions are achieved during high wind model runs.

The flexibility characteristics of the power plants do not significantly affect the load factors up to a wind penetration of 40%: the difference is typically around 1-4%points. The difference in load factor between the PC-CCS and the less flexible IGCC-CCS scenarios at 40% wind penetration are also small.

The weekly short-run profits of power plants with CCS shows that the these are also not much affected by the flexibility characteristics [Figure 2]. Again, a number of trends can be discerned. For all scenarios, the coal fired power plants achieve short-run profits. These increase for higher wind penetration rates in the low wind week, as the electricity price is increased by the higher CO2 price. The NGCC-CCS plant is less economic: in the high wind week they do not make any profit. In scenarios with 20% and 40% wind penetration, these units are (close to) the marginal generator, which leaves a very small short-run profit margin. During the low wind week, the NGCC-CCS units benefit from the high CO2 price.

1.6 Discussion

A sensitivity analysis was performed to assess the robustness of the preliminary model outcomes. It showed that the results are sensitive to changes in the coal:natural gas price ratio, and to the available export capacity. At a price ratio of 1:2, natural gas capacity will displace PC(-CCS) capacity, reducing its load factor and short-run profit. A decreased capacity to export power to neighbouring countries during hours of high wind power production leads to substantial wind curtailment (4% and 22% of total wind power production for 40% and 60% wind penetration respectively), and a further reduction of ~35%point of the load factor of PC-CCS and IGCC-CCS capacity. Instead, power and flexibility will be provided by natural gas fired CHP units.

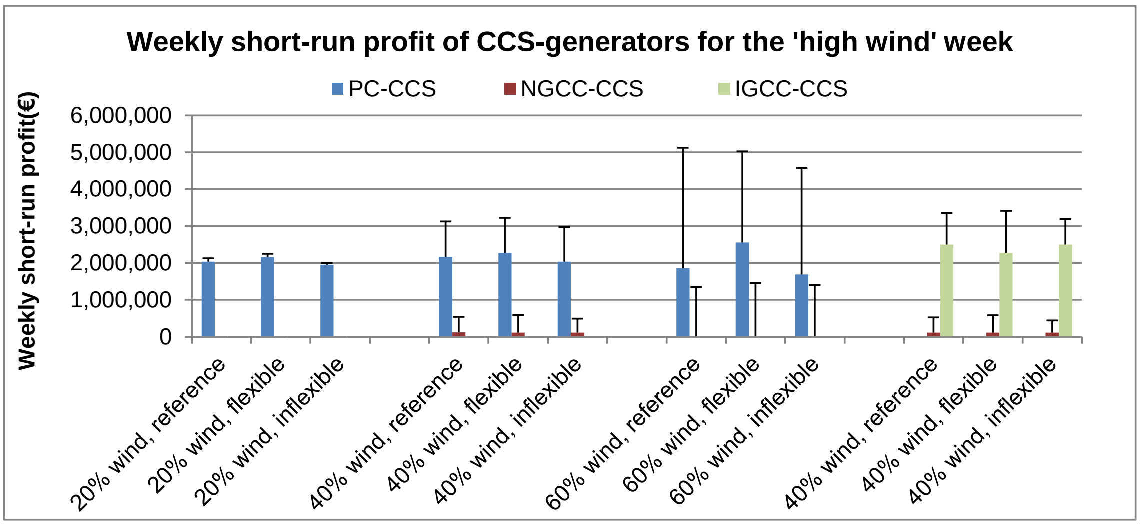

Figure 2: The weekly short-run profits of individual power plants with CCS (800MW coal fired plants and 500MW natural gas fired plants), for different scenarios for the week with high wind production. The error bars show the load factors during the week with low wind production, indicating the annual range.

Although the REPOWERS model already accounts for many power system dynamics, a number of enhancements could improve the results further. Stochastic modelling of IRES power production would allow the model to calculate the reliability and reserve deployment. In combination with a smaller time step, this would allow for in-depth analysis of reserve requirements. A more detailed simulation of neighbouring countries could improve the robustness of the results, as available interconnection capacity was shown to be an important factor when modelling future power systems.

A number of generating technologies were not included in this analysis. Oxyfuel capture was not included because its flexibility performance will probably not be substantially different from that of pre- and post-combustion capture, the results of which show large similarities. Electricity storage was not included because it falls outside the scope of the project, but it will be included in the future. Extra facilities to boost flexibility, such as CO2 venting or amine storage were investigated with the flexible scenarios as a proxy. An in-depth analysis of these facilities, including their ability to shift production/load is forthcoming.

1.7 Conclusion

Our preliminary review of wind integration studies shows that wind power, and relatedly other types of IRES, may have four impacts on the daily operation of power systems: increased demand for reserves, displacement of thermal power generation, efficiency reduction of thermal power generation and wind curtailment. These impacts require varying levels of extra flexibility from thermal power plants. The increased demand for reserves may require most flexibility from thermal power generators: faster ramp rates as well as lower minimum load levels and start-up times will enable power plants to provide more reserves. The effects of displacement and efficiency reduction impacts are partly determined by the flexibility characteristics of power plants. Finally, wind curtailment has not been reported to be affected by the flexibility of power plants.

The load factor and short-term profit of power plants with carbon capture in a 2030 power system with varying levels of wind power generation were investigated with the REPOWERS model. Our preliminary results show that coal fired generation with carbon capture has both higher load factors and short-term profits than gas powered generation with carbon capture, considering the currently projected coal:natural gas price ratio of 1:3 and moderate CO2 emission reduction targets. Coal fired generation with carbon capture also maintains high load factors at 60% penetration of wind power, and is able to provide sufficient reserves. Improved flexibility of power plants with carbon capture only affects the load factor and short-term profit at higher IRES penetration levels. These findings are dependent on fuel prices, and the availability of interconnection capacity. Further research will be performed to investigate the economic attractiveness of power plants with carbon capture for different energy mix scenarios.

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2 Preliminary results of a techno-economic assessment of CO_2 capture-network configurations in the industry

GHGT-11

N. Berghout[a],[2], T. Kuramochi[b], M. van den Broek[a], A. Ramírez[a], A. Faaij[a]

a Copernicus Institute, Faculty of Geosciences, Utrecht University, Budapestlaan 6, 3584 CD Utrecht, the Netherlands
b Climate Change Group, Institute for Global Environmental Strategies (IGES), Hayama, Kanagawa, Japan

Abstract
This paper evaluated the techno- economic performance of several CO_2 capture-network configurations for a cluster of sixteen industrial plants in the Netherlands using bottom- up analysis. Preliminary findings indicate that centralizing capture equipment – instead of capture equipment at plant sites – shows lower average CO_2 avoidance costs for both post-combustion (central: 70 €/t; decentral: 86 €/t) and oxyfuel combustion (central: 63 €/t; decentral: 80 €/t) technology, because of economic scale effects, use of large-scale CHP plants and revenues from electricity sale to the grid. Centralizing capture equipment is particularly interesting for small point sources, since these plants benefit most from economies of scale.

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Keywords: industry; techno-economic; regional case study; post-combustion; oxyfuel; system analysis; refinery; hydrogen; CHP

2.1 Introduction

Carbon capture and storage (CCS) can play a major role in mitigating CO_2 emissions in the industrial sector. According to the IEA [1,2], the deployment of CCS in the industrial sector can contribute to around 30-50% of the overall CO_2 emission reductions needed in the industrial sector to achieve a 450 ppm(v) stabilization target. However, carbon prices are currently well below CCS costs, and are not expected to increase sufficiently to make CCS a competitive CO_2 abatement option in the short term [3]. Reduction in CCS costs for the industry is, therefore, important. Previous research [4] has indicated that applying CCS to a cluster of industrial plants can be more cost-effective than a collection of individual CCS initiatives. Such configurations can be distinguished not only by the choice of the main CO_2 capture technology, but also by the way the capture technology is implemented. For example, by building the different units for the CO_2

* Corresponding author. Tel.: +31 30 253 7646
E-mail address: n.a.berghout@uu.nl

capture and compression processes either at each individual plant or at a central location. However, the techno-economic performance of industrial clusters has, so far, hardly been evaluated in detail. This paper reports the methodology and preliminary results of research currently being conducted to investigate the techno-economic performance of several post- and oxyfuel combustion CO_2 capture-network configurations for a cluster of industrial plants by using a bottom-up analysis. A complete assessment, including pre-combustion configurations as well as the location and spatial footprint of the configurations, will be presented in a research paper which is under preparation.

2.2 Method

System boundaries, timeframe and CO_2 capture technologies

The scope of this study covers CO_2 capture and compression, the local network needed for transport of CO_2, O_2, flue gases and/or post-combustion amine solutions, the location and spatial footprint of the configurations, and the additional electricity and heat infrastructure required for CO_2 capture and local transport. This study does not consider the optimal CO_2 capture and transport configuration on the plant site itself. CO_2 transport through a trunk CO_2 pipeline, and CO_2 storage are outside the system boundaries. The time frame of this study is the short term (2020-2025) and therefore, the CO_2 capture routes investigated are based on commercially available technologies: post-combustion using amine absorption (monoethanolamine, MEA) and oxyfuel combustion using cryogenic oxygen production.

Case study: Botlek area

The analysis focuses on the industrial Botlek area in the Netherlands, which has a high concentration of small and large point sources from various industrial sectors. This study investigated the sixteen largest CO2 emitters, together emitting around 7 Mt CO2 yearly (see Table 1). For the year 2020-2025, we assumed the planned trunk CO2 pipeline to operate at 110 bar.

Table 1. Main CO_2 point sources in the Botlek area and their respective annual CO_2 emissions in 2010 [5].

Plant type	CO_2 produced (kt/y)	Plant type	CO_2 produced (kt/y)	Plant type	CO_2 produced (kt/y)
Refinery	2,200	Chemical	228	Chemical	80
Waste processing	1,760	Utility	204	Chemical	61
Industrial gases	800	Chemical	181	Industrial gases	53
Utility	465	Chemical	133	Chemical	26
Chemical	411	Chemical	101	Biofuels	18
Industrial gases	403				
Total CO_2 emissions Botlek: 7,123 kt/y					

CO_2 capture-network configurations

Capture-network configurations were distinguished by varying the locations of the different units needed for CO2 capture and compression (such as the flue gas conditioning units, amine-absorbers, strippers, CO2 treatment units, compressors, energy plants, and air separation units). These units were either placed in a decentral location at a specific industrial site, or at a centralized location. As a consequence, the capture and utility units vary in scale: smaller scales at the industrial sites or larger at central locations where flows from different industrial sites are jointly treated. Also, the necessary infrastructure is completely different because different flows need to be transported, such as flue gas, low pressure CO2, high pressure CO2, O2, CO2-rich-amines, and/or CO2-lean-amines.

Three main post-combustion configurations were investigated: a decentralized case with all capture units at individual plant sites (Post-decentral), a centralized case with most units at one central location (Post-central), and a case in which the flue gas conditioning and absorption takes place at industrial plant level, but the regeneration and compression take place at a central location (Post-Recsor [3]) (see Figure 1). Sub-cases were designed based on the type of heat and electricity production unit used for the CO_2 capture process: a boiler without CO_2 capture (vent) and electricity import from the grid, an NGCC-CHP (CHP) without CO_2 capture, or by these technologies with CO_2 capture (CC).

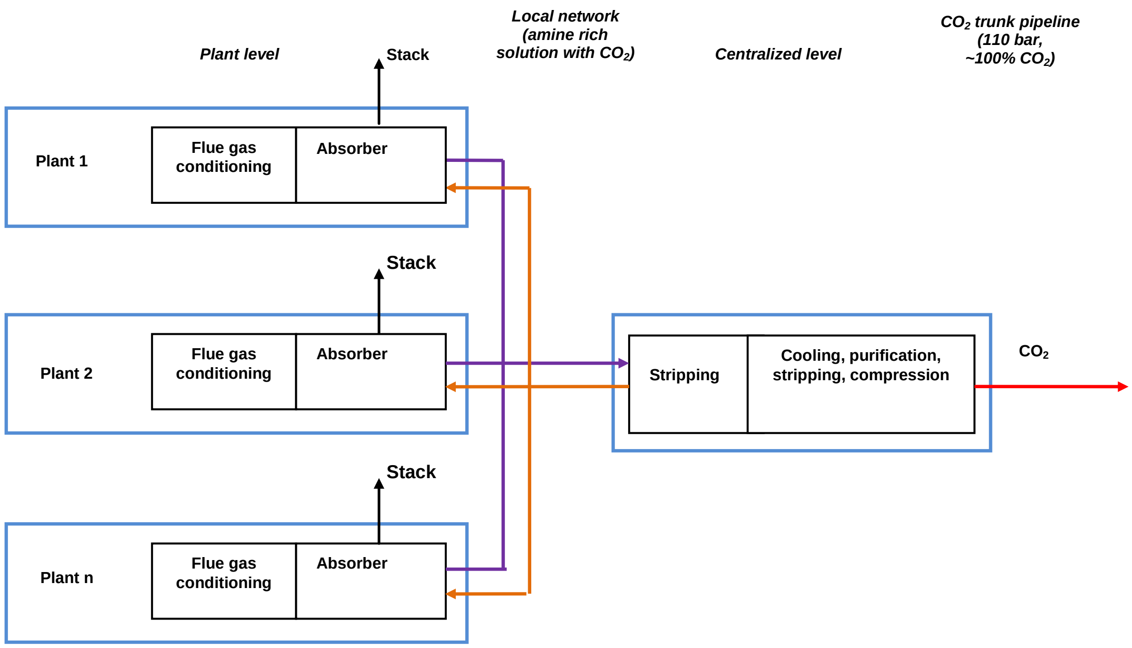

Figure 1 Schematic overview of CO_2 capture-network configuration with a separated absorption and stripping section. The purple, orange and red arrows denote the CO_2-rich amine flow, the CO_2-lean amine flow, and the CO_2 flows, respectively. The blue boxes represent the industrial plants' sites.

Two main oxyfuel combustion configurations were distinguished by having the ASU, CO_2 treatment units (drying, cooling, purification) and compressors: at plant level (Oxy-decentral), the ASU central and the CO_2 treatment and compression decentral (Comp-decentral), and all units at one or a few central locations (Oxy-central) (see Figure 2). Furthermore, the way of electricity production for the ASU and compressor was varied: either electricity import (EI), a gas turbine without CO_2 capture (GT/vent), or a gas turbine with CO_2 capture (GT/CC).

[3] Recsor stands for REmote Centralized SOlvent Regeneration

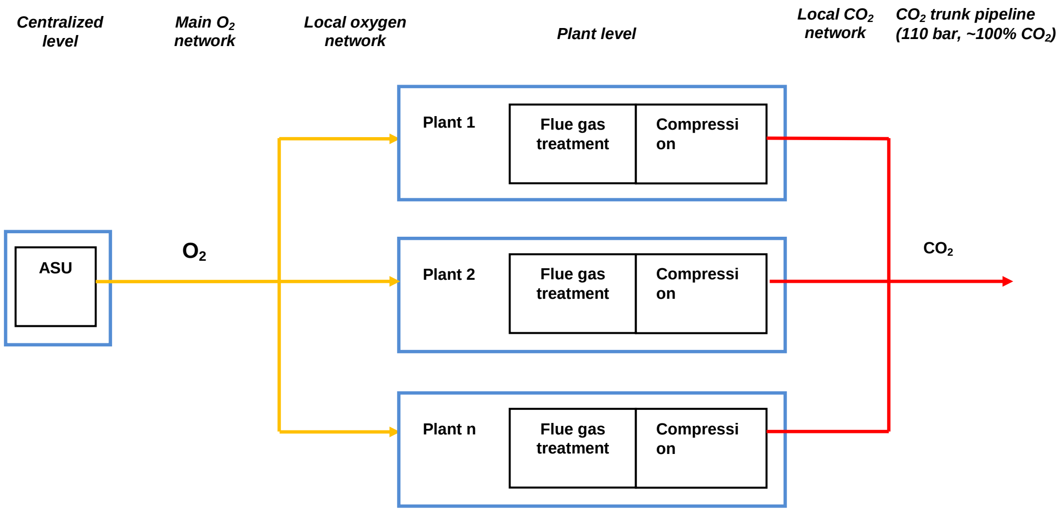

Figure 2 Schematic overview of oxyfuel combustion configuration with centralized oxygen production and flue gas purification and CO_2 compression at plant level. The yellow and red arrows denote the oxygen and the CO_2 flows, respectively. The blue boxes represent the industrial plants' sites.

Performance indicator and input data

A detailed description of the relevant equations used to calculate the technical and economic performance of the CO_2 capture-network configurations is given in [4] and [6]. Key performance indicators used in the analysis are shown in Table 2.

Table 2 Key performance indicators used in the analysis [4].

Performance indicator	Symbol	Unit
Electricity consumption	E_e	GJ_e/t CO_2 avoided
Heat consumption	E_{th}	GJ_{th}/t CO_2 avoided
Amount of CO_2 avoided	Y_a	t CO_2avoided/y
Specific capital costs	SC_{cap}	€/t CO_2 avoided
Specific O&M costs	$SC_{O\&M}$	€/t CO_2 avoided
CO_2 pipeline costs	C_p	€/t CO_2 avoided
CO_2 avoidance costs	C_{CO2}	€/t CO_2 avoided
Spatial footprint	A	m_2

Formula 1 presents the key economic performance indicator, CO_2 avoidance costs (€/t CO_2), which is particularly relevant for the results presented in this abstract.

$$C_{CO_2} = \frac{(El_{imp} - El_{exp}) \cdot P_{el} + E_{ng} \cdot P_{ng} + \alpha \cdot I + C_{O\&M}}{Y_a} \qquad (1)$$

with:

$$\alpha = \frac{r}{1-(1+r)^{-LT}} \qquad (2)$$

where El_{imp} is the annual electricity import from the grid (GJ_e/y), El_{ex} is the annual electricity export to the grid (GJ_e/y), P_{el} is the electricity price (€/GJ_e), E_{ng} is the annual natural gas consumption (GJ_p/y), P_{ng} is the natural gas price (€/GJ_p), α is the annuity factor, I is the total capital expenditure (€/y), $C_{O\&M}$ is the annual operation and maintenance costs (€/y), Y_a is the annual CO_2 emissions avoided (t CO_2/y), r is the interest rate and LT is the economic life time (y). Table 3 presents general input parameters used for this study.

Table 3 General input parameters used in this study.

Parameter	Unit	Value	Source
Interest rate (r)	%	10	[6]
Economic lifetime (LT)	Years	20	[6]
Industrial energy price in 2025			
Natural gas (P_{ng})	€/GJ_{LHV}	9.3	[7,8,9]
Electricity (P_e)	€/GJ_e	18.5	
CO_2 emission factor			
Dutch electricity production (EF_{en})	kg CO_2 /GJ_e	88.9	[10]
Natural gas (EF_{ng})	kg CO_2 / GJ_{LHV}	56.7	[11]

Total capital costs were calculated by summing up the component costs that were estimated using data from open literature. Techno-economic input data for the post-combustion configurations were mainly taken from [12,13,14]; for the oxyfuel combustion configurations, data were mainly taken from [15,16]. Costs data found in literature were converted to $€_{2010}$. Inflation and material price increases were accounted for by applying the Chemical Engineering Plant Cost Index (CEPCI) [17]. Economic scaling factors from literature were used to adjust for differences in scale in the modeled component and the literature data. Uncertainty ranges were ±30%. Data on techno-economic performance of CHP plants and gas turbines was mainly taken from [18,19]. A more detailed overview on input data can be found in [4].

2.3 Preliminary results

Post-combustion

Table 4 presents the performance results for decentralized and centralized post-combustion CO_2 capture from the 16 industrial plants presented in Table 1. Figure 3 shows the *average* CO_2 avoidance cost as a function of total annual CO_2 emissions avoided. For the Post-decentral cases, the annual CO_2 emissions of the industrial plants on the x-axis are ordered from the lowest *average* CO_2 avoidance costs to the plant with the highest *average* CO_2 avoidance costs. For the Post-central cases, the plants are ordered from the plant with the highest amount of annual CO_2 emissions avoided (first plant) to the plant with the lowest amount of annual CO_2 emissions avoided (sixteenth plant).

Table 4 Key performance results for decentralized and centralized post-combustion CO_2 capture in the Botlek.

POST-COMBUSTION		Boiler				CHP			
		Decentralized		Centralized		Decentralized	Centralized		Recsor
		Vent	CC	Vent	CC	Vent	Vent	CC	CC
Total CO_2 emissions avoided	Mt/y	4.3	5.3	4.1	5.1	4.7	5.2	7.6	7.6
CAPEX	M€/yr	761	879	541	636	761	310	709	758
OPEX	M€/yr	87	107	87	107	87	87	122	122
Average CO_2 avoidance cost	€/t	124	123	136	133	86	77	70	71

As figure 3 shows, the centralized post-combustion capture configurations show lower average CO_2 avoidance costs than the decentralized capture configurations. The economic scale effects of centralized post-combustion capture outweigh the higher transport costs for the centralized cases, with the exception of the Post-central (boiler/vent) case, which is more expensive than the Post-decentral (boiler/vent) case due to limited economic scale effects of boilers and high electricity consumption needed for flue gas transport. The *average* CO_2 avoidance costs range from 135 €/t CO_2 (Post-decentral (boiler/vent)) to 70 €/t CO_2 (Post-central (CHP CC)). The Post-Recsor (CHP/CC) case shows slightly higher average CO_2 avoidance costs (71 €/t CO_2) compared to the Post-central (CHP CC) case. In general, the lower operational flue gas blowing expenses for the Post-Recsor (CHP/CC) case appear to outweigh the higher scale effects of the Post-central (CHP CC) case. However, the marginal avoidance costs of the Post-Recsor (CHP/CC) case increase rapidly for the smaller industrial plants, which is mainly due to the relatively high CAPEX of the local absorbers.

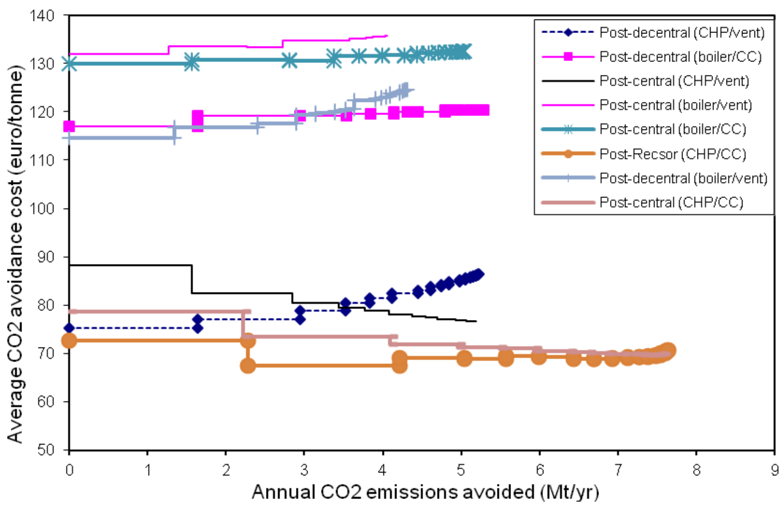

Figure 3 Average CO_2 avoidance costs as a function of annual total CO_2 emissions avoided for the post-combustion configurations.

Oxyfuel combustion

The average CO_2 avoidance costs using oxyfuel combustion for the four Oxy-central cases (~63-77 €/t CO_2 avoided) appear more economical than the Oxy-decentral case (~80 €/t CO_2 avoided). However, for oxyfuel combustion, decentralized capture is still economically preferable over centralized capture up to about a cumulative amount of 2.0 Mt CO_2/y avoided, because the oxygen compression power for transport between the centralized ASU and the industrial plant is large and therefore costly. The *average* CO_2 avoidance costs of the Oxy-central (GT/vent) case are ~66 €/t CO_2 avoided and for the Oxy-central (GT/CC) case ~63 €/t CO_2 avoided. Note that the peaks in the cost supply curves (also for the post-combustion cases) are due to two reasons: (1) the addition of an extra CO_2 capture component results in lower economic scale effects (the amount of captured CO_2 is divided over the total amount of capture units), and therefore increases the capital costs per tonne of CO_2 avoided; (2) some industrial plants require more ducting/pipelines in terms of distance, and thus costs, than other.

Table 5 presents the performance results for decentralized and centralized oxyfuel combustion CO_2 capture from point sources in the Botlek area. Figure 4 shows the *average* CO_2 avoidance cost as a function of total annual CO_2 emissions avoided.

The average CO_2 avoidance costs using oxyfuel combustion for the four Oxy-central cases

OXYFUEL COMBUSTION	Decentralized	Centralized			
			Centralized ASU		
	Local compression		Centralized compression		
			Electricity	GT	
	Electricity import				GT CC

(~63-77 €/t CO_2 avoided) appear more economical than the Oxy-decentral case (~80 €/t CO_2 avoided). However, for oxyfuel combustion, decentralized capture is still economically preferable over centralized capture up to about a cumulative amount of 2.0 Mt CO_2/y avoided, because the oxygen compression power for transport between the centralized ASU and the industrial plant is large and therefore costly. The *average* CO_2 avoidance costs of the Oxy-central (GT/vent) case are ~66 €/t CO_2 avoided and for the Oxy-central (GT/CC) case ~63 €/t CO_2 avoided. Note that the peaks in the cost supply curves (also for the post-combustion cases) are due to two reasons: (1) the addition of an extra CO_2 capture component results in lower economic scale effects (the amount of captured CO_2 is divided over the total amount of capture units), and therefore increases the capital costs per tonne of CO_2 avoided; (2) some industrial plants require more ducting/pipelines in terms of distance, and thus costs, than other.

Table 5 Key performance results for decentralized and centralized oxyfuel combustion CO_2 capture in the Botlek.

Total CO_2 emissions	Mt/y	5.8	5.7	5.7	5.8	6.5
CAPEX	M€	2089	1609	1211	1211	1266
OPEX	M€/yr	107	107	107	107	107
Average CO_2 avoidance	€/t	80	77	69	66	63

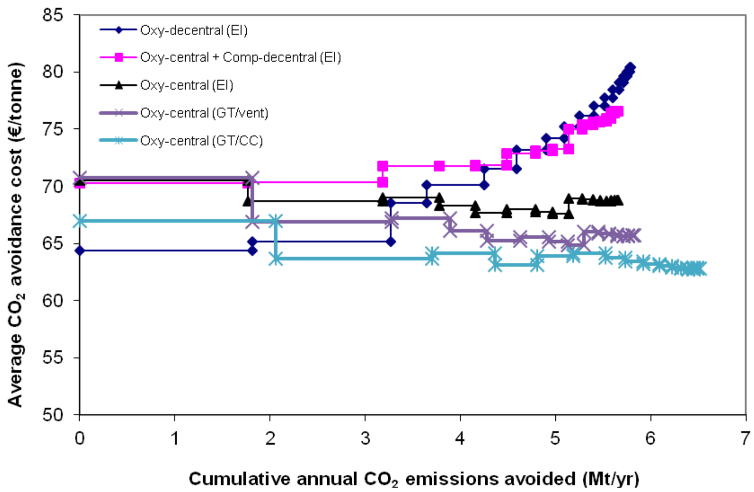

Figure 4 Average CO_2 avoidance costs as a function of annual total CO_2 emissions avoided for the post-combustion configurations.

2.4 Preliminary conclusions

This paper assessed the techno-economic performance of several CO_2 capture-network configurations for a cluster of 16 industrial plants, together emitting around 7 Mt CO_2 yearly, by using a bottom-up analysis. We presented the methodology and preliminary results of the post- and oxyfuel combustion configurations. A complete assessment, including pre-combustion configurations as well as the location and spatial footprint of the configurations, will be presented in a research paper that is under preparation.

Preliminary findings indicate that centralizing capture equipment (instead of placing capture equipment at industrial plant sites) results in lower average CO_2 avoidance costs for both post-combustion (Post-central (CHP/CC): 70 €/t; Post-decentral (CHP/vent): 86 €/t) and oxyfuel combustion (Oxy-central (GT/CC): 63 €/t; Oxy-decentral (El): 80 €/t) when capturing CO_2

emissions from all 16 industrial plants. Nevertheless, up to 2 Mt of avoided CO_2 emissions per year, decentralized oxyfuel combustion seems to be the most cost-efficient oxyfuel configuration. Overall, both for post- and oxyfuel combustion capture, the economic scale effects of centralized capture outweigh the higher transport costs for the centralized cases when capturing CO_2 from all 16 industrial plants. Centralizing CO_2 capture is particularly interesting for industrial plants with low CO_2 emissions, since these plants benefit most from economies of scale. Boilers are economically favorable for decentralized capture, while GT/CHP is economically favorable for centralized capture. The cases capturing CO_2 also from its own energy plants avoid significantly higher amounts of CO_2 compared to the other cases. This is not only because of the high capture rate, but also because of electricity export and thus the high amounts of CO_2 avoided in large-scale electricity plants. Currently, the research is being improved by using more specific data as well as by increasing the level of detail of particularly the local transport networks.

Further research is needed to investigate several aspects of the aforementioned capture network configurations in further detail, such as the impact of temporal fluctuations in flue gas and CO_2 streams on the techno-economic performance. Additionally, more attention needs to be given to the step-wise deployment of such configurations over time, the challenges it poses for the industrial plants and authorities, and the strategies needed to address these challenges in an adequate fashion.

Acknowledgements

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3 Economic optimization of CO_2 pipeline configurations.

GHGT-11

M.M.J. Knoope[a,4], A. Ramírez[a]. A.P.C. Faaij[a]

[a]*Energy & Resources, Copernicus Institute of Sustainable Development, Utrecht University, Budapestlaan 6, 3584 CD, Utrecht, The Netherlands*

Abstract

In this article, an economic optimization tool is developed taking into account different steel grades, inlet pressure, diameter and booster stations for point-to-point pipelines as well as for simple networks. Preliminary results show that gaseous CO_2 transport is cost effective for relatively small mass flows and short (trunk) pipelines. For networks, liquid CO_2 transport without the installation of a booster station before the trunkline is the most cost effective solution if the distance between the source and trunkline is short (<10 km). For longer distances (>50 km), installation of a booster station just before the trunkline is more cost-effective. In terms of materials, the results indicate that higher steel grades (X70) are the most cost effective for onshore pipelines transporting liquid CO_2 while for gaseous CO_2 lower steel grades (X42) are more cost effective.

Selection and/or peer-review under responsibility of GHGT

Keywords: Economic optimization; CO_2 pipeline transport; gaseous; booster stations; steel grades

3.1 Introduction

Carbon capture and storage (CCS) is a CO_2 abatement option that can contribute significantly to the reduction of CO_2 emissions to limit temperature increase [1, 2]. Projections show that CCS could avoid 1.4 and 8.2 Gt CO_2 in 2030 and 2050, respectively, which is about 10% and 19% of the necessary reduction worldwide in 2030 and 2050 [3]. To reach these targets, first estimations indicate that worldwide CO_2 pipeline networks would be required of approximately 100.000 km in 2030 and between 200.000 and 550.000 km in 2050, depending on the level of integration [3]. Building a CO_2 infrastructure of such a scale would require a significant effort and would represent a massive investment.

To estimate the costs of a CO_2 pipeline for a given diameter and length, several different types of models exist in literature, namely linear models [4-6]; models based on the weight of the pipeline [7, 8]; quadratic equations [9, 10] and the so-called CMU model [11]. In a previous study, these cost models are reviewed and compared [12]. This comparison shows that there is a large

[4]Corresponding author, Tel. +31 30 253 4995.
E-mail address: M.M.J.Knoope@uu.nl

cost variation for a given diameter on flat agricultural land. For instance, for a diameter of 0.4 m the costs varied 0.32-1.7 M€$_{2010}$/km, see

Fig. 5.

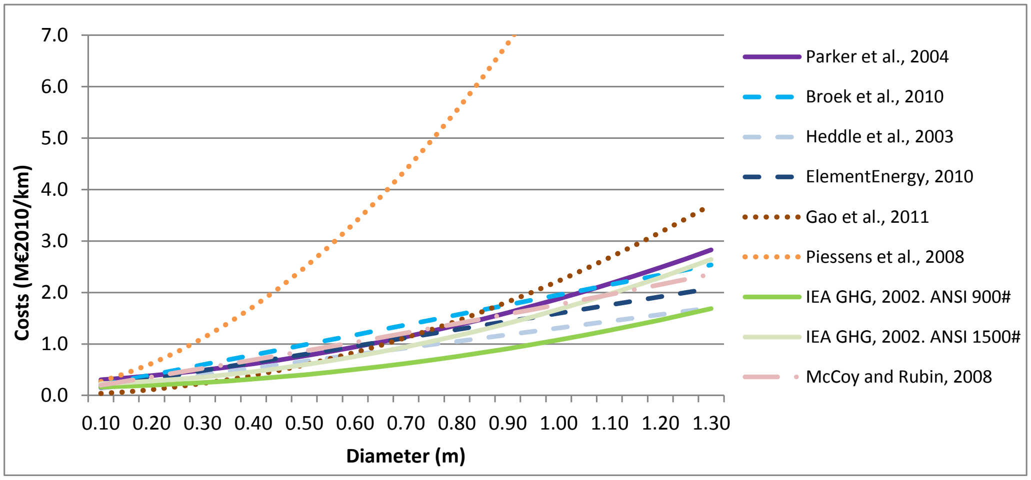

Fig. 5: Comparison of capital costs for nine different models for onshore CO_2 pipelines on flat agricultural terrain for 25 km (adapted from [12]).

Besides the large costs range, a number of major limitations were found [12]:

- Almost all models use existing natural gas pipelines as the basis for their cost estimation. Thereby the models, with exception of the weight base models, ignore the higher operation pressure required for CO_2 transport, which will require a larger wall thickness and pose higher costs.
- Most models are based on onshore natural gas pipelines constructed in the 1990s and early 2000s in the United States. Thereby, ignoring the large increase in material and construction prices of the last several years.
- Most cost models do not indicate the steel grade their cost equation is based on, while others base their cost equation on only one steel grade. However, steel grades determine for a large part the material costs and substantial cost reductions can be realized by using higher steel grades for pipelines operating on high pressures [13-16].
- All models are based on dense liquid CO_2 transport, while in certain conditions gaseous CO_2 transport may be more cost effective. Gaseous CO_2 transport requires a large pipeline diameter, which would increase the investment costs, but would require less compression capacity, which would decrease the capital and energy costs at the capture site. A similar economic decision has to be made between diameter, inlet pressure and the installation of booster stations for liquid CO_2 transport.

To overcome these limitations, an economic optimization tool for CO_2 pipeline transport has been developed. This tool include inlet pressure, diameter, different steel grades and the possibility of booster stations to evaluate under which conditions gaseous transport is more cost effective than liquid CO_2 pipeline transport and investigate when booster stations have to be installed. The economic tool is based on a new developed pipeline cost model, which is related to the weight of the pipeline and uses up-to-date steel prices and construction costs.

3.2 Methodology

Optimization tool of a point-to-point pipeline

In this study, both gaseous as well as dense liquid transport is included in the optimization process. For liquid cases, the inlet pressures range from 9 to 24 MPa, in steps of 1 MPa, and with 0 to 10 booster stations. For gaseous CO_2 transport, inlet pressure range from 1.6 to 3 MPa, in steps of 0.1 MPa, and the outlet pressure is fixed on 1.5 MPa. The possibility of recompressing is not included for gaseous transport, due to the high energy consumption and recompression costs. Overall, 191 cases are analyzed.

For each case, the specific pressure drop is calculated (see equation 1) which is used to calculate the diameter. However, not all diameters are commonly available in the market, and hence the diameter is increased to the next available nominal pipe size (NPS). If the calculated diameter is larger than the largest available NPS, the case is not taken into account further. At this moment, the possibility of placing multiple pipelines next to each other is not considered.

$$\Delta P_{design} = \frac{(P_{inlet} - P_{outlet}) * (n_{booster} + 1)}{L} + \frac{g * \rho * \Delta z}{L} \qquad (1)$$

where ΔP_{design} is the design pressure drop (Pa/m); P_{inlet} and P_{outlet} are the pressure inlet and outlet, respectively (Pa); $n_{booster}$ is the number of booster stations; L is the length of the pipeline (m); G is the gravity constant (9.81 m/s^2); ρ is the density (kg/m^3) and Δz is the height difference (m).

The thickness is calculated for each case based on the inlet pressure, a safety factor depending on the terrain, the NPS and the yield stress of the lowest steel grade. The material costs of the pipeline are calculated based on the thickness, steel costs for the specific steel grade and the NPS. The thickness and the costs of the pipeline are determined for each steel grade. The combination of steel grade, NPS and thickness resulting in the lowest capital costs is selected in the optimization.

To ensure that the combination between inlet pressure, diameter and number of booster stations is feasible, the velocity is calculated. A limit of 6 m/s for liquid CO_2 has been set to avoid erosion, vibrations and damaging of the pipeline [17] and above 0.5 m/s to ensure that the CO_2 flows. For gaseous CO_2 transport, a velocity range of 5-20 m/s is assumed. If a specific case results in a velocity outside the identified range, the case is ignored.

For each combination of booster stations, inlet pressure and pipeline diameter, the energy costs are calculated with an electricity price of 100 €/MWh and the operation and maintenance (O&M) costs are assumed to a fixed percentage of the investment costs. Subsequently, the levelized costs of CO_2 transport are calculated, see equation 2. The combination with the lowest levelized costs is considered the optimal combination of inlet pressure, diameter and number of booster stations. For an overview of the optimization process, see Fig. 2.

$$LC = \frac{CRF * (I_{boost} + I_{comp}) + CRF * I_{pipe} + OM_{boost} + OM_{pipe} + OM_{comp} + E_{boost} + E_{comp}}{m * OH * 3.6} \quad (2)$$

where LC are the levelized cost of CO_2 transport (€/t CO_2); CRF is the capital recovery factor, which is calculated with $\frac{r}{1-(1+r)^{-L}}$; r is the discount rate (%); L is the lifetime (years); I are the investment costs (€); OM are the O&M costs (€/y); E are the energy costs (€/y); m is the CO_2 mass flow (kg/s); OH are the number of operation hours (hr); and the subscripts boost, comp and pipe refer to booster stations, pipeline and compressors, respectively.

Optimization of simple networks

In the future, it is expected that not only point-to-point pipelines will be constructed but also trunklines will arise which transport CO_2 from multiple sources to one or more sinks [6, 18, 19]. Four different networks options are examined, namely:

I. Gaseous transport in the feeders as well as in the trunk line and spin-offs.
II. Gaseous transport in the feeders and liquid transport at the trunk line and spin-offs.
III. Liquid transport in the entire network, where the CO_2 is compressed at the capture sites.
IV. Liquid transport in the entire network, where a booster is installed before the trunk line.

The trunkline is optimized with respect to diameter, inlet pressure, number of booster stations and steel grade with the methodology described in 2.1. For the feeders transporting the CO_2 to the trunkline and for the spin-offs transporting the CO_2 from the trunkline to the sink, a more simple approach is taken to limit the calculation time. For these relatively short pipelines, a constant maximum design pressure drop is assumed and the possibility of installing booster stations is not considered. Furthermore, all feeders and spin-offs are assumed to be constructed from X70 for liquid CO_2 transport and of X42 for gaseous transport despite that the optimal steel grade for the trunkline may be different. These simplifications have a minor influence on the total levelized costs because compared to the trunk line, the feeders and spin-offs are limited in length.

The levelized costs of the four different network options are compared with each other, and the one resulting in the lowest levelized costs is selected.

3.3 Results

Preliminary results of the optimization process for point-to-point pipelines

Preliminary results of the optimization process for point-to-point pipelines over three kinds of terrains are given in Table 6. The results show that for onshore pipelines transporting liquid CO_2, the specific pressure drop is about 15-45 Pa/m, inlet pressures are 10-12 MPa and booster stations are placed roughly every 100 km.

For offshore pipelines, the installation of booster stations was excluded in the model because a platform should be installed which is very expensive. Consequently, for long offshore CO_2 pipelines the inlet pressure is increased at the capture plant to 13-19 MPa. For long offshore pipelines of 500 km or more, also the diameter is increased to lower the specific pressure drop.

Gaseous CO_2 transport is cost-effective compared to liquid CO_2 transport for mass flows up to 16.5 Mt/y and 100 km over agricultural terrain and for mass flows up to 15.5 Mt/y and 100 km for offshore pipelines. Savings in compression energy compensate the higher construction costs for a larger diameter pipeline. Nevertheless, if a pressure of 8 MPa or higher is required to inject the CO_2 in the storage field, then compression at the capture plant and transporting it as a liquid is more cost-effective than transporting it as a gas and compress it from 1.5 MPa to a liquid at the storage location.

Furthermore, the results show that for pipelines transporting liquid CO_2 steel grades X65 and X70 are used while for pipelines transporting gaseous CO_2 steel grades X42 and X52 are used. This is due to the minimal thickness requirement of 1% of the outer diameter.

Preliminary results of the optimization process for simple networks

Preliminary results of the optimization process for simple networks are given in Table 7. Compression and pumping at the capture side (network option III) is the best option if the network consists of short feeders and a long trunkline. If the distance of the feeders is increasing, network option IV, where a booster stations is installed just before the trunkline, becomes more cost effective.

For networks with short trunklines and small mass flows, gaseous CO_2 transport in whole the network (option I) can be the most cost-effective option. For instance, for two mass flows of 5 Mt/y, an onshore trunkline of 100 km, feeders and spin-offs of 10 km, gaseous transport is cheaper (10 €$_{2010}$/t) than liquid transport (12.0 €$_{2010}$/t and 12.1 €$_{2010}$/t for option III and IV, respectively). Gaseous transport in the feeders and compression before the trunkline (option II) become economically not the best alternative if the CO_2 is released at atmospheric pressure regardless the length, and mass flows through the feeders and trunkline.

3.4 Conclusions

In this study, an economic optimization model was developed including inlet pressure, diameter, booster stations and different steel grades to evaluate the most cost effective way to design CO_2 pipeline transport. Several conclusions can be drawn from the preliminary results:

- Higher steel grades, like X70, result on average in lower transportation costs for onshore pipelines transporting liquid CO_2 than lower steel grades, like X42.
- Inlet pressures for onshore pipelines transporting liquid CO_2 are about 10 MPa and booster stations are installed roughly every 100 km. For offshore pipelines, higher inlet pressures are selected because booster stations are not an option.
- Pipelines transporting CO_2 as a gas is in specific cases better than transporting CO_2 as a liquid for point-to-point as well as for simple networks.
- When the distance between the capture plant and the trunkline is small, the CO_2 is compressed to the required pressure at the capture plant. However, for longer distances, a

booster stations is installed just before the trunk line to increase the pressure to the required inlet pressure.

The economic optimization model is currently being extended to include time-aspects, the effect of impurities in the CO_2 flow and to make it more spatial explicit. The results will be reported in a forthcoming article.

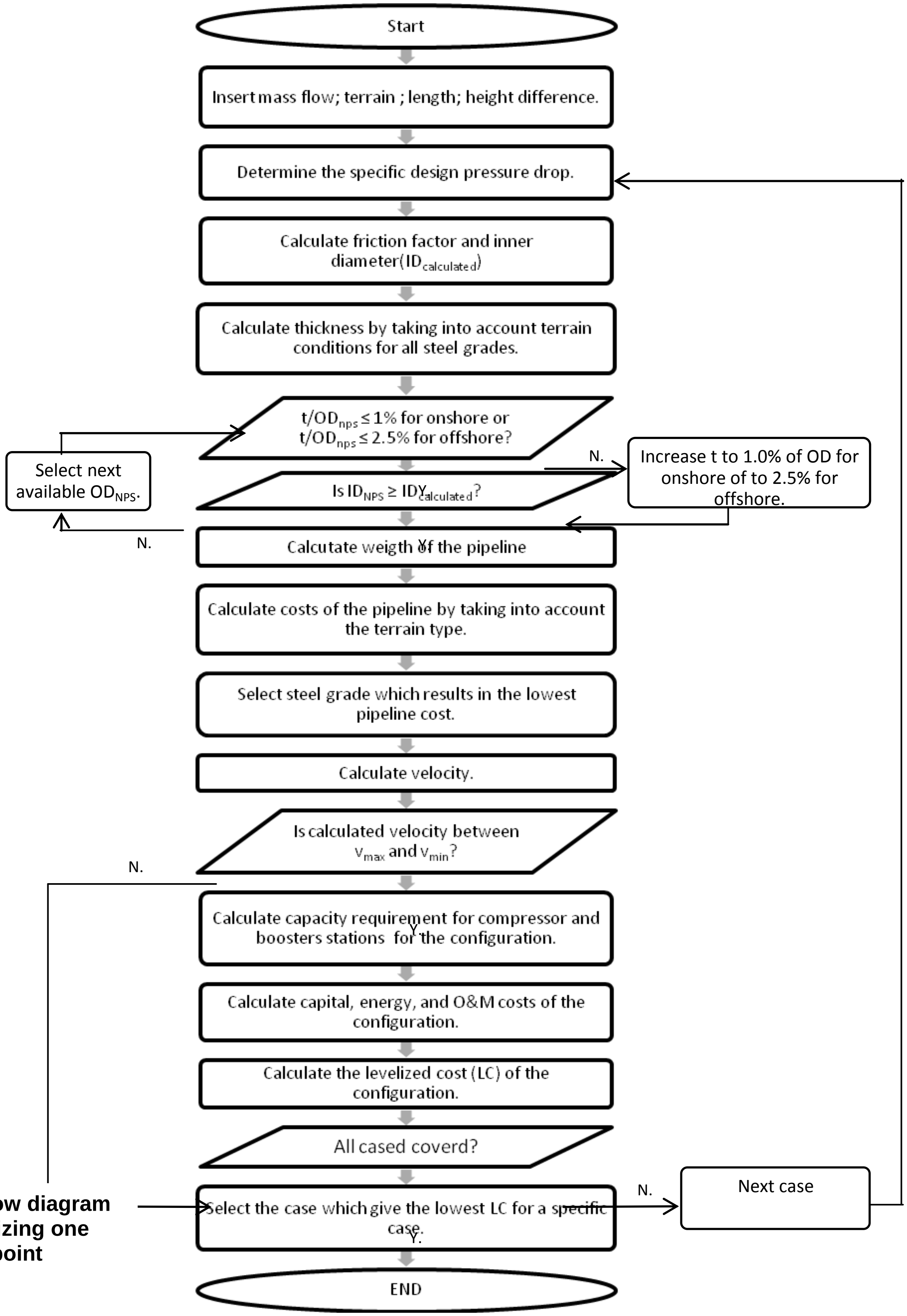

Fig. 6: Flow diagram for optimizing one point-to-point pipeline.

Table 6: Selection of preliminary results of the optimization process for point-to-point pipelines for several cases.

Terrain	Mass flow (Mt/y)	Length (km)	OD (m)	P_{inlet} (MPa)	$N_{booster}$	$L_{boosters}$ (km)	LC (€$_{2010}$/t)	ΔP_{act} (Pa/m)	Steel grade	Phase
Agricultural	10	100	0.61	10	0	127	12.3	16	X70	Liquid
Populated	10	100	0.51	10	2	46	12.3	43	X70	Liquid
Offshore	10	100	0.51	13	n.a.	n.a.	11.8	41	X65	Liquid
Offshore	10	300	0.61	13	n.a.	n.a.	14.0	16	X65	Liquid
Offshore	10	500	0.61	17	n.a.	n.a.	16.5	16	X65	Liquid
Offshore	5.0	100	0.41	12	n.a.	n.a.	12.4	33	X65	Liquid
Offshore	5.0	300	0.41	19	n.a.	n.a.	15.4	35	X65	Liquid
Offshore	5.0	500	0.51	14	n.a.	n.a.	19.3	10	X65	Liquid
Offshore	15.5	100	0.61	12	n.a.	n.a.	11.5	38	X65	Liquid
Agricultural	1.0	100	0.22	12	0	115	14.1	35	X70	Liquid
Agricultural	2.5	100	0.32	11	1	109	12.6	28	X65	Liquid
Agricultural	5.0	100	0.41	10	1	62	12.1	32	X65	Liquid
Agricultural	20	100	0.76	10	0	102	11.2	20	X65	Liquid
Agricultural	20	300	0.76	10	2	102	12.4	20	X65	Liquid
Agricultural	20	500	0.76	10	4	102	13.5	20	X65	Liquid
Agricultural	16.5	100	0.76	9.0	1	76	11.3	13	X65	Liquid
Agricultural	1.0	100	0.51	2.7	n.a.	n.a.	14.0	11	X42	Gaseou
Agricultural	2.5	100	0.76	2.4	n.a.	n.a.	11.4	8.6	X42	Gaseou
Agricultural	5.0	100	1.07	2.2	n.a.	n.a.	10.2	6.0	X42	Gaseou
Agricultural	10	100	1.42	2.1	n.a.	n.a.	9.4	5.4	X42	Gaseou
Agricultural	16.5	100	1.42	3.0	n.a.	n.a.	9.5	15	X52	Gaseou
Offshore	5.0	100	0.91	3.0	n.a.	n.a.	11.9	15	X42	Gaseou
Offshore	15.5	100	1.42	3.0	n.a.	n.a.	10.5	14	X42	Gaseou

Table 7: Selection of preliminary results of the optimization process for simple networks.

Location trunk line and spin-offs	Mass flow (Mt/y)	Length trunkline (km)	Location feeders	Length feeders (km)	Length spin-offs (km)	Network option	Levelized costs (€$_{2010}$/t)
Offshore	2 * 10	500	Populated	2*10	2*10	III	15.3
Offshore	2 * 10	500	Populated	2*50	2*10	III	16.1
Offshore	2 * 10	500	Populated	2*75	2*10	IV	16.6
Offshore	2 * 10	500	Agricultural	2*10	2*10	III	15.2
Offshore	2 * 10	500	Agricultural	2*50	2*10	III	15.7
Offshore	2 * 10	500	Agricultural	2*75	2*10	IV	16.0
Offshore	2 * 5.0	100	Agricultural	2 *25	2*10	I	10.9
Agricultural	2 * 5.0	100	Agricultural	2 *10	2*10	I	10.0

Agricultural	2 * 5.0	100	Agricultural	2 *50	2*10	I	11.0
Agricultural	2 * 10	250	Agricultural	2*10	2*10	III	12.4
Agricultural	2 * 10	250	Agricultural	2*25	2*10	IV	12.5

Acknowledgements

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4 A sensitivity analysis of the global deployment of CCS to the cost of storage and storage capacity estimates

GHGT-11

Barbara S. Koelbl[5]*, Machteld van den Broek[a], Bas van Ruijven[b], Detlef P. van Vuuren[c], André P.C. Faaij[a]

[a]Energy & Resources, Faculty of Geosciences, Copernicus Institute of Sustainable Development, UtrechtUniversity, Budapestlaan 6, 3584 CS Utrecht, The Netherlands
[b]National Center for Atmospheric Research (NCAR), Climate and Global Dynamics Division (CGD),Integrated Science Program (ISP), P.O. Box 3000, Boulder, CO 80307, USA
[c]PBL Netherlands Environmental Assessment Agency, PO Box 303, 3720 AH Bilthoven, The Netherlands

Abstract

The future deployment of carbon capture and storage (CCS) is uncertain. This may be caused by differences in assumptions about techno-economic parameters such as CO_2 storage cost and capacity**.** How much of the uncertainty in these variables translates into uncertainty in the deployment predictions of CCS is investigated using the TIMER model. Preliminary results show that storage cost variations result in a considerable range of global cumulative CO_2 captured until 2050 from electricity production of about 46-162 $GtCO_2$. Also, the regional impacts of storage costs differ strongly. Decreasing the storage capacity decreases global cumulative capture from power production by only -3 $GtCO_2$ until 2050.

Selection and/or peer-review under responsibility of GHGT

Keywords: Carbon Capture and Storage deployment, sensitivity analysis, storage cost, storage capacity

4.1 Introduction

The IPCC (2005) [1] notes that there are substantial uncertainties in the estimates of the amount of Carbon Capture and Storage (CCS) that will be deployed in the future. Various scenarios estimate wide ranges of cumulative CO_2 emission reductions from CCS until 2100 under different stabilization targets [1]. This large range results from uncertainty in variables that determine future emissions, such as economic development, or from uncertainty in future technological development [1]. This uncertainty may be reflected in the wide ranges of cost and performance data for various parameters along the CCS chain. In fact, large ranges are shown for cost and performance data for individual parts of the chain, as well as for storage capacity estimates reported. For this reason, Koelbl et al., [2] investigate the effect of the variation in

* Corresponding author. Tel.: +31 030 253 4994; fax: +31 030 253 7601
E-mail address: B.S.Koelbl@uu.nl.

performance and cost of fossil fueled power plants and capture systems, transport cost, storage cost and storage capacity on the uncertainty in the deployment prediction of CCS. The current paper focuses on preliminary results of this study with respect to the storage cost and storage capacity uncertainty. Variables like the capture and power plant cost and efficiency, as well as their development over time are not varied in this study. Likewise, transport cost are held constant in this study. How these variables affect the CCS deployment and which variable has the most severe impact, and the strongest regional differences, is investigated in Koelbl et al., [2].

Storage cost estimates vary mainly due to the heterogeneity of reservoir-specific properties [3][4]. Storage capacity estimates also vary strongly and contradict each other according to Bradshaw et al., [5]. They are contradictory, because many estimates use unreliable or rough generalized methodologies which ignore the highly individual nature of storage site specific properties that determine the practical capacity of a storage site [5]. Insofar as this uncertainty is covered by the available data in the literature, we will investigate how much this uncertainty influences the estimates in CCS deployment between 2010 and 2050. The results are analyzed on a global and regional level.

This paper will proceed as follows: First, a short overview of the methodology is provided in Section 2.. Subsequently, Section 3 presents the data for storage cost and storage capacity. Finally, Section 4 shows the preliminary results of varying either parameter on different indicators of CCS deployment, before Section 5 concludes.

4.2 Methodology

This analysis is undertaken using the global, regionally explicit, energy system simulation model TIMER [6];[7] which is part of the integrated assessment model IMAGE [8]. IMAGE was, for example, used for the generation of the RCP2.6 of the representative concentration pathways (RCP) [9,10]. CCS in TIMER can be applied in the electricity sector, production of hydrogen and some other industrial facilities [11]. There are 11 different reservoir types in TIMER [11]. The costs of storing CO_2 are determined by the region-specific transport cost to the respective reservoir type and the reservoir-type specific storage cost [11]. Together with the storage supply which is different per region, this results in regionally specific supply-cost-curves. Besides aquifers, depleted oil and gas reservoirs, and enhanced coal bed methane (ECBM) reservoirs, there are also undepleted oil and gas reservoirs. The availability of the latter two depends on the future production of these fuels which is endogenously determined in the model. All storage types besides ECBM are further distinguished by their on- or offshore location.

For the sensitivity analysis, first a Reference scenario was made. Subsequently, the low and high values for storage cost were used in this scenario to investigate the sensitivity of CCS deployment on a regional and global scale. Moreover, also the storage potential was reduced to look at the sensitivity to this parameter. As Reference scenario, we used the 450 ppm CO_2-eq emission pathways as derived from a slightly revised version of the Baseline of the OECD Environmental Outlook 2012 [12]. The revisions were made in order to update key parameters for CCS deployment to values that resemble average assumptions based on the literature research done for this paper. The values that were revised in this context are the development of the fossil fuel prices, timing of the availability of some technologies to produce electricity, performance and cost data for coal, natural gas and biomass fired power plants and capture units, the storage and transport cost of CO_2 and storage capacity assumptions. Finally, we also included the new transport sector as described in Girod et al., [13]. The Baseline scenario without any climate mitigation policy of this study is the Baseline of the OECD Environmental Outlook 2012 [12] modified by this transport module. In this Baseline, population grows to about 9 billion until 2050, while world GDP will be about four times as high in 2050 as in 2010 [12].

4.3 Data

The data used in these two experiments has been collected from the prevailing literature, in order to reflect the uncertainty in current data estimates. For sources and average values of the parameters that are not varied in this experiment, as well as a more detailed description of the assumptions, modifications and adjustments made concerning the data described below, and about the methodology, see Koelbl et al., [2].

The data set for preliminary storage cost input values which have been collected from [1][4][14][3][15] can be found in
Table 8. The original values as collected from literature were converted to USD_{2005}/tCO_2 using the conversion rates from fxtop.com [16] and the Upstream Capital Cost Index (UCCI) from IHS [17]. Monitoring cost are added to the values from the IPCC (2005) [1] and transport cost are subtracted from the upper value of EOR storage cost from the IPCC (2005) [1].

Table 8 Storage cost range collected from and based on the sources named above [1][4][14][3][15]

Storage cost USD_{2005}/tCO_2	EOR, onshore	EOR, offshore	Rem. gas, onshore	Rem. gas, offshore	Depl. oil, onshore	Depl. oil, offshore	Depl. gas, onshore	Depl. gas, offshore	ECBM	Aquifers onshore	Aquifers offshore
Observations	4		15		15				6	19	10
Low	-106.32	-106.32	0.81	1.63	0.81	1.63	0.81	1.63	-30.34	0.42	0.81
Reference	-26.76	-0.35	7.59	15.18	7.59	15.18	7.59	15.18	71.81	5.12	18.01
High	52.81	105.62	14.36	28.72	14.36	28.72	14.36	28.72	173.96	9.81	35.21

The range of the estimates is very large, and in some cases even reaches from deeply negative to high values. This is, for example, the case for Enhanced Oil Recovery (EOR), which is applied to all remaining oil fields in the model. The cost of EOR storage is, among other factors, influenced by the oil price [18], where generally, higher oil prices can lead to higher benefits [1].

As can be seen from the number of observations indicated in the first row of
Table 8, for some options little data could be found in the literature. Therefore, simplified assumptions had to be made in order to derive consistent ranges. For instance, except for the aquifers, the upper range of the offshore options is always assumed to be twice as expensive as the respective onshore option. Also, the storage cost of onshore as well as offshore options of remaining and depleted gas and oil reservoirs are assumed to be the same. The lower value of remaining oil reservoir (EOR) storage cost is assumed to be the same for on- and offshore options.

Two storage potential estimates are used which approximately correspond to the “low” and “best” estimates found in a study of IEA GHG (2011) [19]. EOR associated storage space was used from IEA GHG (2009a) [20] except for the potential for the regions in India and Rest S. Asia, which stem from Hendriks, et al., [18]. Depleted oil reservoir storage estimates also stem from Hendriks, et al., [18]. New aquifer and ECBM storage potentials are used from a study by IEA GHG (2011) [19]. The best estimate is used for the Reference scenario, and the low estimate is used for the low capacity scenario. However, the capacity of two regions of this source ("Non OECD Europe and Former Soviet Union" as well as "OECD Europe"), is assumed to be half the amount of the best estimate for the low capacity case in this study. Furthermore, the ECBM estimates are supplemented by the estimate for China given in Dahowski et al., [21] in the Reference scenario, which is lowered to 0.1% in the low capacity case. Finally, the storage capacity for all gas reservoirs was taken from IEA GHG (2009b) [22].

Country and reservoir distributions are mainly based on Hendriks, et al., [18]. The distribution of the Reference scenario estimates for EOR, all natural gas reservoir types, ECBM, and depleted oil reservoirs are based on the "best" and "high" estimate of Hendriks, et al., [18] for the low and Reference capacity of this study, respectively. The distribution between on- and offshore aquifer for different regions is based on Dooley et al., [23], while more detailed country distributions were from the "best" estimate of Hendriks, et al., [18]. Further detailed regional distributions are based on previous assumptions in TIMER.

The totals across regions per reservoir type can be seen in
Table 9. In the model we assume that EOR only applies to reservoirs that are not yet depleted. The estimates for depleted oil reservoirs in turn only apply to the reservoirs that were already depleted at the time where the estimate was made [18]. It is therefore implicitly assumed that the future use of undepleted oil fields for CO_2 storage is only up to the level to which EOR can be applied.

Table 9 Global storage capacity for the reference and low capacity estimate per reservoir type collected from sources named above [19,20,18,21,22]

$GtCO_2$	EOR, onshore	EOR, offshore	Rem. gas, onshore	Rem. gas, offshore	Depl. oil, onshore	Depl. oil, offshore	Depl. gas, onshore	Depl. gas, offshore	ECBM	Aquifers, onshore	Aquifers, offshore	Total
Low	110	30	168	126	33	60	95	11	171	2786	1054	4644
Reference	147	45	284	254	44	107	121	13	260	6912	2630	10818

The largest storage potential estimate is in both cases aquifers. The reason why, for example, the EOR capacity varies is because the low estimate takes only large oil fields into account, while the reference capacity is based on the estimate of large and small oilfields [20]. Similarly, the study on which we based the storage potential in gas fields [22] makes a distinction between theoretical, effective, and practical capacity, whereof we used the effective and the practical capacity. The theoretical capacity refers to "the physical limit that a geological system can accept" ([22]p.4). The effective estimates take into account technical constraints and are thus smaller than the latter. The third, practical capacity, excludes further fields that were considered to be too small, and is corrected by a fixed percentage to compensate for fields that could leak [22].

4.4 Results

Storage cost variations

The preliminary results of varying the storage cost on the electricity generation sector can be seen in Table 10. In 2050, the low and high storage cost case result in, respectively, a -2%-point and +6%-point change of the CCS share of total electricity generation capacity compared to the Reference scenario. The total spread is thus 8 percentage points, while the spread in GW of CCS plants installed in 2050 is about 1080 GW. There are several reasons why the large range of storage cost estimates results in a much smaller range of deployment numbers in 2050. First, the major cost element of the additional CCS cost is in most cases the capture cost (which are not varied in this paper) [1]. Second, the carbon tax between 2025 and 2050 is roughly 160 USD_{2005}/tCO_2. Given the high carbon tax levels there is a strong incentive in the scenario to replace fossil-fired power plants by those that emit low levels of CO_2. However, constraints on renewable deployment (increasing costs for high penetration levels) keep the CCS deployment relatively high in the high storage cost case.

Table 10 Impact of storage cost changes on the global CCS deployment

	High storage cost	Reference scenario	Low storage cost
Year	2050	2050	2050
% CCS Share in the electricity generation capacity installed	12%	14%	20%
Total CCS Capacity GW installed	1773	2052	2854
Period	2010-2050	2010-2050	2010-2050
Cumulative $GtCO_2$ captured 2010-2050 from power production	46	60	162
Cumulative $GtCO_2$ captured 2010-2050 from the industry	47	52	69

The cumulative CO_2 captured figures are presented in the bottom lines of Table 10. The cumulative CO_2 stored from 2010 to 2050 from electricity production decreases by 14 $GtCO_2$ and increases by 102 $GtCO_2$ compared to the Reference scenario, which makes a total global spread of 116 $GtCO_2$. This spread is considerable if we compare it to the emissions in the Baseline scenario. These are approximately 1780 $GtCO_2$ cumulatively between 2010 and 2050 globally. In the Reference scenario the global figures add up to about 1040 $GtCO_2$. As another comparison, the Energy Technology Perspective 2010 projects the CO_2 cumulatively captured globally from power generation for the same period to be 79 $GtCO_2$ in the *BLUE Map* [24], where the target is to reduce 2005 CO_2 emissions by 50% in 2050 [24]. Hence, a spread of more than 100 $GtCO_2$ caused by the uncertainty in the storage cost is quite considerable. The impact of the same storage cost uncertainty is milder for the industry CCS. The figure decreases by 5 $GtCO_2$ and increase by 17 $GtCO_2$.

The uncertainty range of storage cost is different per reservoir type. The supply of reservoir types per region varies as well as the transport cost differs by regions. Therefore, the effects on CCS deployment can be very different per region. To assess the degree of regional difference in the impacts we compute the standard deviation of the changes between the high and the low cost case, relative to the low cost case for cumulative CO_2 captured in the power sector.

The standard deviation is 24% and on average the change is 67%. The most severe impact occurs in Russia with a decrease of -100% while the region “Rest of Southern Africa” only experiences a decrease of -12%. However, both regions depart from relatively low levels of CCS deployment. Rest of Southern Africa captures 0.5 $GtCO_2$ cumulatively from electricity production in the low storage cost case. Emissions in the Baseline in this region are 11 $GtCO_2$ cumulatively for the study horizon. The same figures for Russia are under low storage cost 1.2 $GtCO_2$

captured and cumulative Baseline emissions of 65 $GtCO_2$. Both regions contribute by less than one percent to the cumulative global CO_2 captured from power production in the low storage cost case.

In contrast, China and the Middle East are two regions which have relatively high shares in the global CO_2 cumulatively captured from power production over the study period, but also react very differently to the change in storage cost. The Middle East contributes 4% (6.5 $GtCO_2$) to cumulative global CO_2 captured from power generation in the low cost case and 10% in the Reference scenario. China contributes 20% (32 $GtCO_2$) in the low storage cost case and 8% in the Reference scenario. The cumulative Baseline emissions of the two regions are 92 $GtCO_2$ and 469 $GtCO_2$, respectively.

The storage potential that is used in the two regions in each scenario is shown in

Fig. 7. Under high storage cost, the Middle East stores CO_2 exclusively in depleted oil reservoirs. Under low storage cost, EOR provides enough benefits to exclusively use undepleted oil reservoirs. In China, under low storage cost, different storage options are used up first. ECBM, and on- and offshore EOR, onshore depleted gas and oil get used up completely. In the high storage cost case, only the onshore reservoirs remaining gas, and depleted oil and gas are used up.

Fig. 8 shows the cost supply curves for the two regions with high and low storage cost including the medium transport cost. The cost supply curves for China are much steeper and cheap storage potential categories are scarcer than in the Middle East. Furthermore, comparing the emissions of the two countries in the Baseline scenario to their available storage capacity reflects the real scarcity of the storage supply. Chinas cumulative Baseline emissions between 2010 and 2050 amount to about 470 $GtCO_2$, whereas the cumulative Baseline emissions in the Middle East are only one fifth of this. At the same time, the storage capacity available in China is only about one third of the storage capacity in the Middle East. Hence, the demand for storage capacity is larger in China, which leads to that China stores CO_2 at much higher cost levels. At this cost level, it reacts more sensitive to an increase of storage cost than the Middle East which departs from a much lower cost level.

Table 11 Relative changes of cumulative CO_2 captured from power generation between 2010 and 2050 in different regions[6]

Region	%Change	Region	%Change	Region	%Change	Region	%Change	Region	%Change
Canada	-88%	M.East	-32%	Japan	-71%	Indonesia	-92%	W.Africa	-90%
USA	-73%	N.Africa	-18%	Oceania	-76%	Russia	-100%	W.Europe	-60%
Mexico	-64%	Rest C.Am.	-67%	C.Europe	-61%	SE.Asia	-88%		
Brazil	-91%	Rest S.Africa	-12%	China	-87%	South Africa	-90%		

6 For definitions of regions in IMAGE and TIMER see http://themasites.pbl.nl/tridion/en/themasites/fair/definitions/datasets/index-2.html

Turkey	-63%	Rest S.Am	-71%	E.Africa	-29%	Stan	-84%
Korea	-33%	Rest S.Asia	-70%	India	-75%	Ukraine	-50%

Fig. 7. Storage cost effects on reservoir use in China and the Middle East

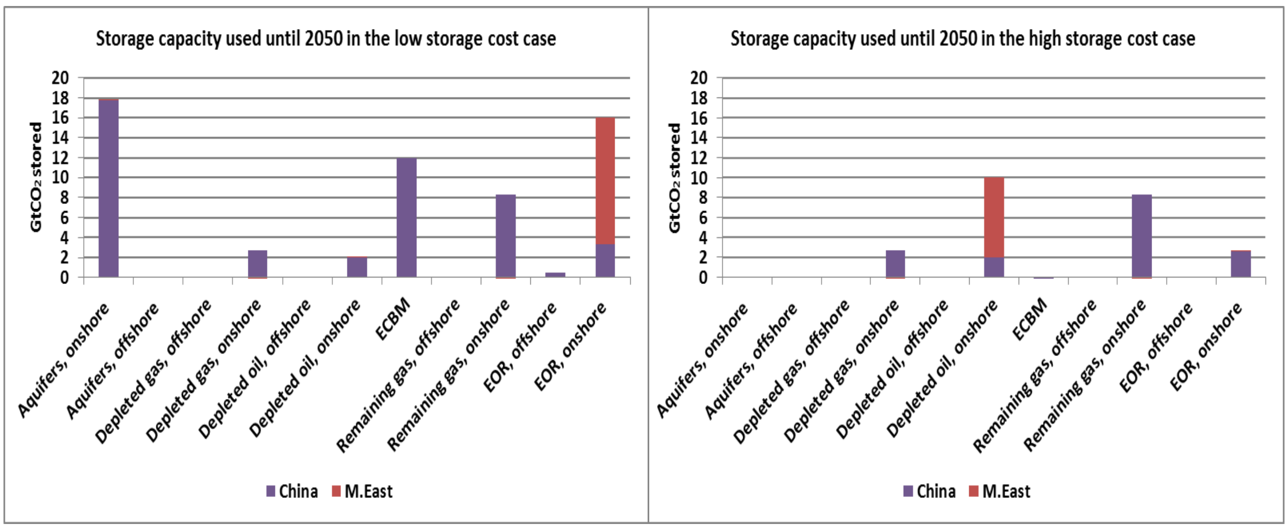
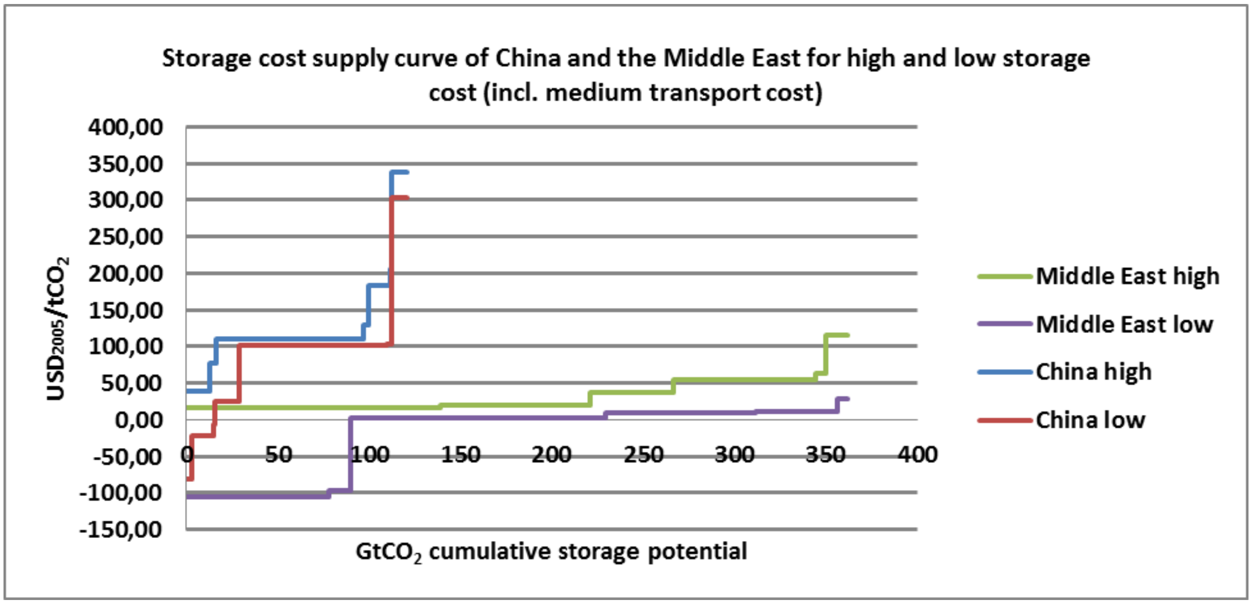


Fig. 8. Storage cost supply curve for the Middle East and China in the low and high storage cost case



Storage capacity variations

Table 12 shows the preliminary results of decreasing the storage capacity. In the low storage capacity case, the resulting decrease of the share of CCS capacity installed in the electricity production portfolio of 2050 compared to the Reference scenario is about 2%-point. The difference in cumulative $GtCO_2$ stored between 2010 and 2050 compared to the Reference scenario is only -3 $GtCO_2$ in the electricity sector and -3 $GtCO_2$ in the industry sector. Thus, assuming only half of the global storage capacity is available for storage does not have a substantial effect on the CCS activity until 2050.

Table 12 Effect of reducing the storage capacity on global CCS deployment

	Reference scenario	Low storage capacity case
Year	2050	2050
% CCS Share in the electricity generation capacity installed	14%	12%
Total CCS Capacity in GW installed	2052	1846
Period	2010-2050	2010-2050
Cumulative $GtCO_2$ captured 2010-2050 from power production	60	57
Cumulative $GtCO_2$ captured 2010-2050 from the industry	52	49

No region completely runs out of storage capacity in the Reference scenario. However, in the low storage capacity case, Korea and Japan run out of storage capacity. In this case, Korea has a storage capacity of 0.3 $GtCO_2$ and Japans storage capacity only amounts to about 2 $GtCO_2$, compared to 4 and 13 $GtCO_2$ in the Reference scenario.

Furthermore, the majority of the regions still have 80% and more of their storage capacity left. This indicates that there could also be enough storage capacity left for the period after 2050. However, this also depends on the development of CCS and other technologies.

Finally, critical could be the storage potential in China as only around 37% of the original potential may be left by 2050 in the low storage capacity case. As China's contribution to global CO_2 stored is the second largest in the world (i.e. 15% of CO_2 capture from all CCS applications the Reference scenario), limited storage capacity could have stronger effects on CCS deployment beyond 2050.

4.5 Conclusion

In this paper we have analyzed the impact of uncertainty in storage costs and storage potential for the application of CCS in future scenarios. Increasing the storage cost to high levels only has the effect of decreasing the share of CCS in the 2050 portfolio of electricity production capacity by -2%-points, while decreasing the cost from the Reference scenario has stronger impacts (+6%-points) on the shares. The effects are stronger when we look at the CCS activity over the total study period from 2010 to 2050 in terms of cumulative CO2 captured. The total range of GtCO2 captured from electricity production caused by storage cost uncertainty is 46 to 162 GtCO2.

Regional variations are significant also for countries that contribute strongly to total CO_2 captured from electricity production in the Reference scenario, such as China (8%) and the Middle East (10%). We can observe a high impact of storage cost on cumulative CO_2 captured from the electricity production in the Chinese case, while in the Middle East the impact is modest. The reason for this is the shape of the cost supply curve and the relative scarcity of storage capacity in relation to the emissions in a Baseline scenario without climate mitigation policy. China has a steeper cost supply curve for storage and therefore has very high storage cost for the last used option, even under low cost, the cost levels are substantially higher for all options. Since the capacity for storage is low compared to the Baseline emissions, China ends up on a very high level of the storage cost curve. At the higher cost levels, the reaction to a cost increase is very strong.

The effect of decreasing the storage capacity is similar when we compare it to the decrease of the CCS shares in 2050 electricity production capacity caused by higher storage cost. However, the difference in total CO_2 captured over the study period to the Reference scenario is smaller when storage capacity is decreased, than when storage cost is increased. In the electricity sector the effect of increasing storage cost from the Reference scenario is more than four times as high as decreasing the storage capacity. In the industry the storage cost increase is by 2 $GtCO_2$ higher than the effect of the storage potential decrease.

Furthermore, we can see that two regions run the risk of depleting storage capacity completely, Korea and Japan. More importantly, in China the storage capacity in 2050 is relatively scarce. In other regions, large amounts of the initially available storage capacity may remain available for future capture activity. This implies that the storage potential as used in this experiment has a comparatively mild effect on the CCS activity over the study period and on the electricity production capacity in 2050. However, the effects could intensify beyond 2050.

Finally, it is important to note, that the effect of these variables should be evaluated also in relation to the impact of the other variables along the CCS chain. For instance, the impact of the uncertainty in the cost of CCS equipped power plants can be expected to be even a lot stronger, since the capture cost is in most cases the major cost element of the CCS cost [1]. Which effect overweighs is, for example, interesting as a basis for decisions concerning the distribution of R&D resources.

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5 A model to forecast the long-term price of carbon allowances: does the EU-ETS support CCS deployment?

GHGT-11

Arnold Mulder[7]*, Catrinus Jepma[a]

[a] Department of global economics and management, University of Groningen , The Netherlands

Abstract

Several techno-economic studies have assessed the potential of CCS as a mitigation option in the power sector and/or energy system (Wise et al., 2007; Wise and Dooley, 2009; Luckow et al., 2007; Odenberger and Johnsson, 2010; Rafaj and Kypreos, 2007; Stangeland 2007; Broek et al., 2009; Broek et al., 2011). Although CCS is generally assigned an important role in the transition to a low-carbon economy, these studies potentially suffer from the 'flaw of averages' (Savage, 2002) as the tested deterministic scenarios assume, among others, constant emissions growth rates, linearly increasing carbon prices and linearly decreasing emission caps. Volatility and uncertainty of these parameters is thereby omitted from the analyses leading to potentially overly optimistic scenario outcomes. This is particularly true for the European Union where the level and timing of investments is dependent on a volatile market price under the European Union Emissions Trading Scheme (EU ETS) that covers multiple sectors. Under the EU ETS economic downturns can lead to large surpluses of carbon allowances, low carbon prices, delayed investments and little potential for CCS deployment. Alternatively, accelerated economic growth can deplete allowance reserves, push the market price up and spur the deployment of CCS. The implied uncertainty can be detrimental to the viability of individual projects and thereby directly influences the overall scope for CCS.

To complement the available literature, this study presents a stochastic simulation model of the EU ETS that simulates the volatile demand for allowances. A carbon price is endogenously calculated based on the scarcity of allowance and the marginal cost of the available abatement opportunities in the sectors under the EU ETS. Carbon allowance supply is modeled reflecting current EU ETS regulation whereas allowance demand volatility is simulated based on Monte Carlo experiments. The simulation results provide insight into the robustness of the EU ETS against economic volatility and the resulting uncertainty regarding the scope for CCS. Also, amendments to EU ETS allowance supply that are currently proposed by the European Parliament are tested. The model covers all major sectors that are covered by the ETS including the power, iron, steel, oil, gas, chemicals and cement sector. As a result, the scope for CCS can be examined both by type and by sectorial division.

The results indicate that CCS is a prerequisite to comply with EU ETS regulation until 2030 and that the carbon price is therefore likely to incentivize some level of investment in CCS by 2025, possibly already in 2020. Under current legislation the probability distribution of the cumulative deployment of CCS across sectors in 2030 has an average of 176 $MtCO_2e$ and a standard

* Corresponding author. Tel.: +31 030 253 4994; fax: +31 030 253 7601
E-mail address: B.S.Koelbl@uu.nl.

deviation of 89 $MtCO_2e$ per annum, resembling near normality. As a result, the exact amount and type of CCS application is highly uncertain, although large scale deployment in the cement, petroleum and gas sectors is unlikely before 2030. The European power sector bears the highest level of uncertainty in both absolute and relative terms. This is primarily so because the power sector already faces investment uncertainty at lower levels of the allowance price and is therefore impacted by allowance demand volatility in an earlier stage than the other sectors.

The uncertainty around the exact scope for CCS is also reflected by the 80% confidence interval around the average carbon price, ranging from approximately €48 to €125 in 2025 with an average of €80. The results imply that priority should be given to measures that could make the scheme more robust against economic volatility, thereby reducing carbon price volatility and improving the industry's ability to set long-term mitigation strategies. Current proposals to improve the scheme's ability to incentivise abatement are primarily focussed on limiting the supply of allowances to force the market price up, in response the financial and economic crisis that started in 2008. However, the results show that the subsequent oversupply is primarily a short-term phenomenon. Measures that one-sidedly limit the supply of allowances would not eliminate the factor that is most likely to undermine investments: demand volatility. A lack of measures that make the scheme more robust against demand volatility could make the currently proposed allowance supply amendments completely ineffective in case of a new demand shock.

6 The techno-economic potential of integrated gasification co-generation facilities with CCS Going from coal to biomass

J.C. Meerman8, M. Knoope, A. Ramírez, W.C. Turkenburg, A.P.C. Faaij

Energy & Resources, Copernicus Institute, Faculty of Geosciences, Utrecht University, Budapestlaan 6, 3584 CD Utrecht, The Netherlands

Abstract

This study analyses the impact of technological improvements and increased operating experience on the techno-economic performance of integrated gasification facilities producing electricity and/or transportation fuels. Also, the impact of using torrefied biomass instead of coal and/or applying CCS is examined. Results indicate that current production costs of electricity and/or transportation fuels are above market prices. Future improvements, however, could reduce production costs sufficiently to make gasification facilities economical. Furthermore, although CCS can be used to reduce CO_2 emissions at relative low CO_2 avoidance costs, only the use of biomass allows the production of carbon neutral electricity and/or transportation fuels and in combination with CCS can even result in negative CO_2 emissions.

Selection and/or peer-review under responsibility of GHGT

Future; Economic; Technical; Gasification; FT-liquids; Biomass; CCS

6.1 Introduction

To significantly reduce global CO_2 emissions requires the decarbonisation of both the transport and power sector [1]. Integrated gasification (IG) facilities producing electricity or Fischer-Tropsch liquids (FT-liquids) can potentially decarbonise both sectors by applying carbon capture and storage (CCS) and/or using biomass as feedstock. Being able to use biomass as well as coal means that these facilities can play a role in the transition towards a renewables based energy infrastructure.

In previous research we examined the technical and economic potential of state-of-the-art (SOTA) integrated gasification poly-generation (IG-PG) facilities [2,3]. Our results show that coal and biomass can be converted into electricity at 38-40% efficiency[9] and FT-liquids at 55-60% efficiency. Using torrefied wood pellets (TOPS) results in improved technical and economic performance compared to conventional wood pellets. Also, it was shown that with SOTA technology neither electricity nor FT-liquids can be produced competitively. Advanced

* Corresponding author. Tel.: +31-30 253 2590; fax: +31-30 253 7601. *E-mail address:* J.C.Meerman@uu.nl.
[9] All energy values and efficiencies given in this study are higher heating values, unless stated otherwise.

technologies and technological learning can, however, bring production costs down. This may make integrated gasification facilities profitable in the longer term. Therefore, in this study the impact of potential technological and operational improvements on the technical and economic performance of integrated gasification facilities is assessed.

Nomenclature

AGR	Acid gas removal
ASU	Air separation unit
CCS	Carbon dioxide capture and storage
EF	Entrained flow
FT	Fischer-Tropsch
IG	Integrated gasification
IGCC	Integrated gasification combined cycle
IG-FT	Integrated gasification Fischer-Tropsch
NPV	Net present value
SEWGS	Sorption enhanced water-gas shift
SOTA	State-of-the-art
TOPS	Torrefied wood pellets
WGS	Water-gas shift

6.2 Integrated gasification facilities

In an IG facility (Figure 1), a solid carbon-containing feedstock is fed into an entrained flow (EF) gasifier. The high operating temperatures (>1500ºC) result in a syngas consisting mainly of CO, CO_2, H_2 and H_2O. The required heat is supplied by combusting part of the feedstock by adding a sub- stoichiometric amount of oxygen, supplied by an air separation unit (ASU). Pure oxygen instead of air is used to obtain the required high temperatures, to increase overall efficiency and to reduce the size of downstream equipment [4,5]. The syngas is cooled and cleaned of contaminates. Depending on the desired product, the H_2:CO ratio of the syngas is adjusted in a water-gas shift (WGS) reactor. This can be done before or after the acid gas removal (AGR). When producing electricity, the syngas is fed into a gas turbine and combusted. When producing FT-liquids, the syngas is fed into a FT-reactor. The FT-liquids are purified and any off-gas is fed into a gas turbine and combusted. To increase the overall economics of an IG facility, steam is generated at various locations and used for electricity production in steam turbines. To lower the CO_2 emissions of the facility, CO_2 can be captured at the AGR, compressed and subsequently stored in underground geological reservoirs. Detailed information of the individual components, i.e., ASU, gas cleanup, gas and steam turbines, can be found in Meerman et al., [6].

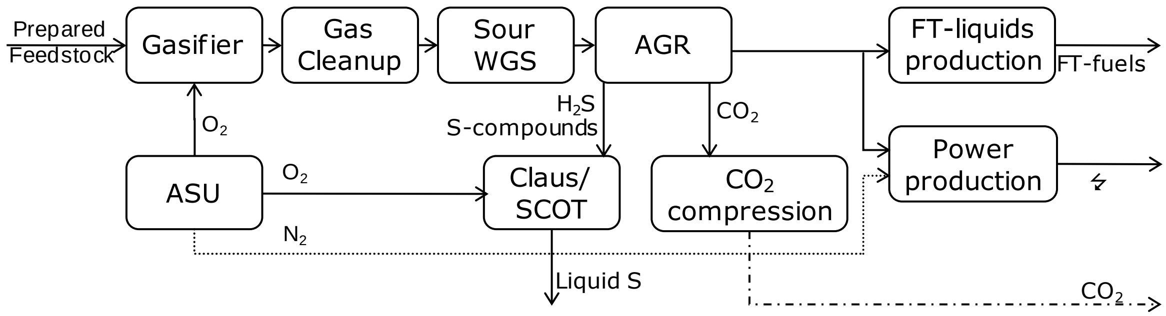


Figure 9 Simplified process layout of an integrated gasification facility using SOTA technology.
Waste, heat and recycle streams are not displayed [2].

6.3 Methodology

Based on commercially available technologies, plant configurations for SOTA IGCC and IG-FT facilities, both with CO_2 capture and storage (CCS) and without (Vent), were selected [6]. The time period in which new technologies are expected to become commercially available was selected based on the following criteria:

- Short term (2015-2020): technologies that are currently being tested in large-scale pilot projects;
- Mid term (2020-2035): technologies that have been successfully tested in laboratories and/or that are being tested in small scale pilot projects;
- Long term (2035-2050): technologies that are currently under development at lab scale or are at proof-of-concept stage.

When multiple technologies are available for the same process, the technology with the lowest production costs of the main product was selected. The resulting configurations were modelled in a component-based chemical AspenPlus simulation model [2]. This model calculates the relevant mass- and energy balances and, combined with an Excel-based economic model, allows the calculation of the production costs [2,3,6].

Production costs of the main product were calculated using the net present value (NPV) method, see equation (1) [7]. Note that temporary stored carbon in the chemical products still counts as emitted CO_2. To include transport and storage of CO_2, a fixed price per t CO_2 was taken. CO_2 avoidance costs were calculated according to equation (2). All cost data are given in €$_{2008}$. Common technical and economic parameters are presented in Table 13.

$$P_{MP}\ (€/GJ) = \frac{\alpha * I + O\&M + Feedstock - \sum \left(F_{SPx} * P_{SPx}\right)}{F_{MP}} \qquad (1)$$

$$CO_2\ \text{avoidance costs}\ (€/t\ CO_2) = \frac{P_{MP} - P_{MP\ ref}}{\left(E_{ref}/F_{MP\ ref}\right) - \left(E/F_{MP}\right)} \qquad (2)$$

Where α is capital recovery factor (yr^{-1}), calculated by $r/(1-(1+r)^{-L})$; r is discount rate; L is economic lifetime (yr); I is total capital investments of the facility (M€); O&M is operating and maintenance costs (M€/yr); Feedstock is coal or TOPS cost (M€/yr); F_{SPx} is annual flow side-product x (GJ/yr or kt/yr); P_{SPx} is market price of side-product x (€/GJ or €/kt); F_{MP} is annual flow of main product (GJ/yr); P_{MP} is production costs of main product (€/GJ); E is net CO_2 emission, including carbon in chemical products (t CO_2/yr); Ref is the reference system, namely a coal-fired integrated gasification facility without CCS.

Table 13 Technical and economic assumptions integrated gasification facilities.

Parameter	Unit	Value
Location	-	NW-Europe
Construction time [1)]	Year	3
Plant economic lifetime	Year	20
Discount rate	%	10
Plant size	MW_{HHV} coal eq.	1000
O&M costs [2)]	% of cap. cost	4
TOPS costs [3)]	€/GJ	3.0-6.3
Coal costs [3)]	€/GJ	2.25
CO_2 trans. & storage costs [4)]	€/t CO_2	10
Ref. electricity price [5)]	€/GJ	15.7
Sulphur price	€/t S	100
Slag price	€/t slag	0
CO_2 credits [6)]	€/t CO_2	0

1) Based on literature, a construction time of three years was assumed and capital costs were evenly divided over these years [5,8,9,10].
2) The O&M costs are assumed to be 4% for all components except if stated differently in literature.
3) Feedstock costs were 2.25 €/GJ for coal and 6.3 €/GJ for biomass pellets beginning 2010. Although TOPS are not produced commercially today, it was assumed that they have the same price as biomass pellets as the increase in production costs is compensated by reduction in transportation costs. Literature studies show that TOPS prices could drop to 3 €/GJ TOPS [11,12,13,14,15]. See Meerman et al., for more information [3].
4) According to the Zero Emission Platform, transport to and storage in depleted gas or oil fields of CO_2 will cost between 2-15.7 €/t CO_2. When storing offshore, the CO_2 transport and storage costs increase to 5.5-20 €/t CO_2 for depleted gas or oil fields [16]. Based on expert interview, the CO_2 transport and storage costs were set at
10 €/t CO_2 [17].
5) The reference electricity price is based on the average Dutch day-hourly market price between 2004-2008. The observed trends were considered representative for NW-Europe. During that period the electricity price varied between 0-1050 €/MWh (0-290 €/GJ), with an average price of 57 €/MWh (15.7 €/GJ) [18].
6) In this study CO_2 avoidance costs are calculated. Therefore, no CO_2 credit price was used.

6.4 Results

Configurations

Based on commercial technologies and expected technological development, the following configurations for the IGCC and IG-FT facilities were made (see Table 14).

Table 14 Processes used for the different time periods.

		Current	Short term	Mid term	Long term - GT	Long term - SOFC
Feeding		Lock hopper	Lock hopper	Solid feed pump	Solid feed pump	Solid feed pump
Oxygen production		Cryogenic ASU	Cryogenic ASU +	ITM	ITM	ITM
Quench	IGCC-Vent	Syngas	Syngas	Syngas	Syngas	Water
	IGCC-CCS IG-FT	Water	Water	Water	Water	Water
WGS AGR SRT	IGCC-Vent	Selexol Claus	Selexol + Claus	TDS & DSRP	TDS & DSRP	TDS & DSRP
	IGCC-CCS	WGS Selexol Claus	WGS Selexol + Claus	SEWGS TDS & DSRP	SEWGS TDS & DSRP	TDS & DSRP
	IG-FT	WGS Rectisol Claus	WGS Rectisol + Claus	Adv. WGS Rectisol ++ Claus	Adv. WGS Rectisol ++ Claus	N.A.
CO_2 compression		Conventional	Conventional	Shock wave	Shock wave	Shock wave
(Syn)gas combustion		GT	GT +	GT ++	GT +++	SOFC & GT +++
HRSG gasifier		IP steam	IP steam	IP steam	HP steam	HP steam
FT-liquids synthesis		Cobalt-based catalyst	Cobalt-based catalyst	Cobalt-based catalyst	Diesel selective catalyst	N.A.

ASU: air separating unit; ITM: ion transfer membrane; TDS: transport desulphurisation; DSRP: direct sulphur recovery plant; WGS: water-gas shift; SEWGS: sorption enhanced water-gas shift; GT: gas turbine; SOFC: solid oxide fuel cell; HRSG: heat recovery steam generation; IP: intermediate pressure; HP: high pressure; N.A: not applicable.

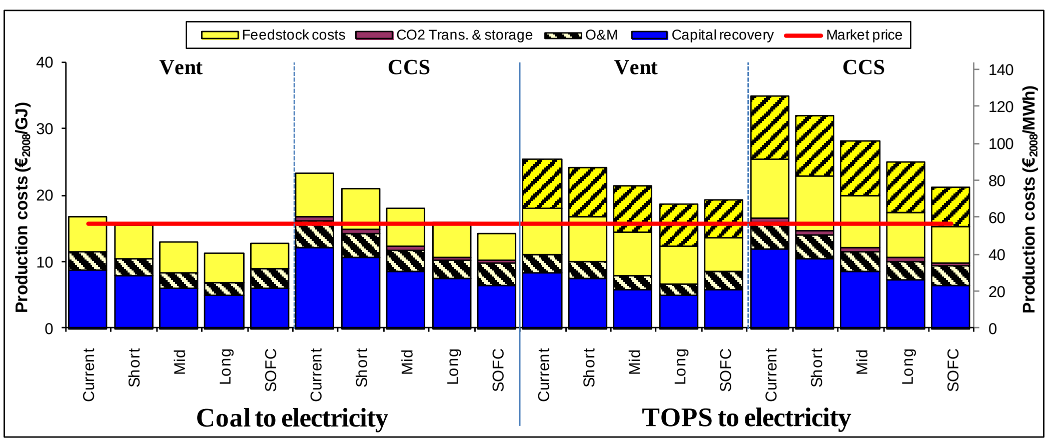
The current configurations consist of cryogenic ASU, lock-hopper feeding system, dry-fed Shell EF gasifier, candle filter, wet scrubber, WGS reactor (for CO_2 capture or FT-liquids production), solvent based AGR (Selexol for IGCC or Rectisol for IG-FT), Claus/SCOT, FT-reactor with conventional FT-catalysts (only for IG-FT) and SOTA gas and three pressure steam turbines. If CO_2 is captured, the integrated gasification facilities also contain a conventional CO_2 compressor.

In the short term, only gradual improvements to already existing technologies are expected. The improved technologies are cryogenic ASU, solvent-based AGR and the gas turbine.In the mid term several new technologies can be introduced which require alterations in the overall process configurations compared to SOTA. Common to both facilities is the replacement of the cryogenic ASU with an ion transfer membrane ASU. The lock-hopper is replaced by a solid feed pump and the gas turbine is upgraded to a high efficiency design. If CO_2 is compressed, the CO_2 compressor is replaced by a RamGen compressor. IGCC facilities can be equipped with hot gas cleaning and transport desulphurisation. The sulphur compounds are converted into elemental sulphur using the direct sulphur removal process, thereby eliminating the need for the Claus and SCOT installations. In the case of IGCC-CCS, the syngas is shifted using SEWGS after the sulphur compounds are removed. SEWGS also removes CO_2 from the syngas. A problem is that the H_2:CO ratio cannot be manipulated while still obtaining a low CO_2 concentration in the syngas. As the FT-reactor requires a certain H_2:CO ratio as well as a low CO_2 concentration, SEWGS cannot be used. Therefore, the IG-FT facilities will still rely on a separate WGS and CO_2 removal units. The WGS is upgraded to reduce the steam consumption and the Rectisol AGR is improved, resulting in reduced energy consumption.

In the long term, the operation conditions of the steam cycle could change from subcritical to supercritical. Also, the syngas cooler is expected to be upgraded to produce high pressure steam instead of intermediate pressure steam. The Rectisol based AGR in the IG-FT facilities is improved even further. The catalyst in the FT-reactors is replaced by a diesel selective catalyst with a different chain growth probability (α) depending on the length of the hydrocarbon. It is assumed that this has no effect on the reactor size and costs. The gas turbine is improved even further.

Integrated gasification facility performance

Currently, both the IGCC and IG-FT facilities have production costs above the market price of the main product (see Figure 10). Advancement in technologies, however, can make them profitable. In the long term, the efficiency of a coal-fired IGCC without CCS could increase from 44% to 52%, while production costs drop from 17 €/GJ (60 €/MWh) to 11 €/GJ (40 €/MWh). The increase in efficiency is mainly due to a higher output of the gas turbine. Production costs are affected by an increase in efficiency (-2.4 €/GJ) and availability (-1.7 €/GJ) and reduction in capital and O&M costs (-1.4 €/GJ). If SOFCs are used, the efficiency could increases to 59%, but the high capital and O&M costs of the SOFC increase production costs to 13 €/GJ (45 €/MWh). Applying CCS in the long term could result in an efficiency of 43% and production costs of 16 €/GJ. Compared to SOTA facilities, the energy consumption of the CO_2-capture equipment decreases, but energy demand of the CO_2 compressor increases as the CO_2 exiting the SEWGS is at a low pressure. Despite the higher energy penalty, this system was selected as the capital costs of a facility using SEWGS is much lower than if a solvent-based CO_2 capture system is used, resulting in lowest production costs for the SEWGS system. An IGCC equipped with CCS could have lower production costs if SOFCs become available. Although capital costs increase by 13%, overall energetic efficiency increase by 13%$_{pt}$, resulting in production costs of 14 €/GJ.



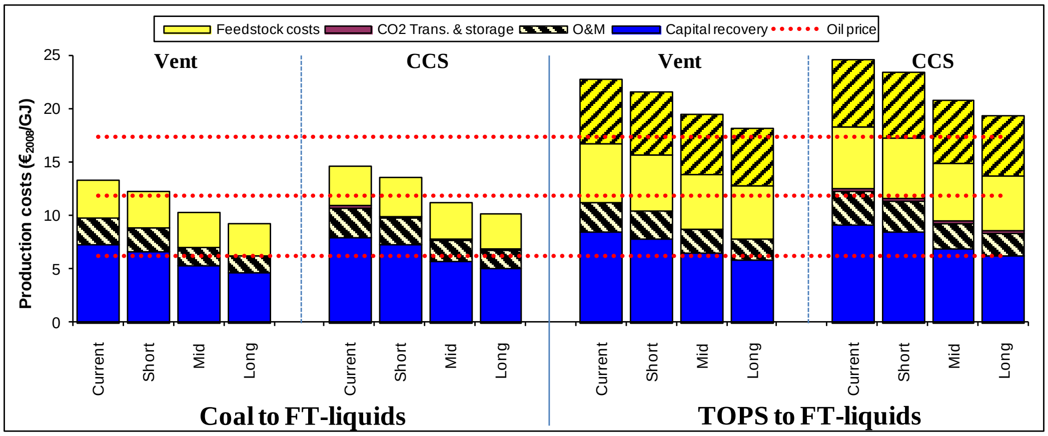


Figure 10 Production costs of electricity (above) and FT-liquids (below). The lighter upper part of the feedstock bar is the addition in production costs when using the high value for the TOPS price.

FT-liquids can currently be produced from coal for 13 €/GJ, which is competitive with crude oil derived fuels at an oil price of 113 $/bbl. In the long term, overall energetic efficiency could increase from 61% to 65%. The higher efficiency, lower capital costs and increased availability could reduce produce costs to 9 €/GJ. Applying CCS at a SOTA coal-fired IG-FT would results in an efficiency of 58% and production costs of 15 €/GJ. In the long term, the efficiency could increase to 63% and production costs could drop to 10 €/GJ.

CO_2 emissions

The CO_2 emissions of the SOTA coal-fired IG facilities are around 2,000 kt CO_2/yr, which could increase to 2,400 kt CO_2/yr due to a higher availability. For electricity this means specific emissions of 0.7 kg CO_2/kWh. As overall energetic efficiency is expected to increases over time, this value could drop to 0.5 kg CO_2/kWh in the long term. For FT-liquids, the specific emissions are around 0.2 t $CO_2/GJ_{FT\text{-}liquids}$, both now and in the long term. If CCS is applied, specific emission of the IGCC facility are currently 0.03 kg CO_2/kWh and could drop to 0.01 kg CO_2/kWh in the long term. The production of FT-liquids while applying CCS shows a different picture. As a significant fraction of the carbon is embedded in the end product, specific emissions are 0.1 t CO_2/GJ, both now and in the long term.

In order to produce carbon-neutral electricity or transportation fuels, the use of biomass is mandatory. If only TOPS is used and CCS is not applied, specific CO_2 emissions are zero, regardless of production. If, however, TOPS and CCS are combined, specific emissions of electricity production are -0.9 kg CO_2/kWh for SOTA installations and could change to -0.6 kg CO_2/kWh in the long term. The increase in specific emissions is due to the higher efficiency, meaning that for the same amount of electricity, less biomass is needed and less CO_2 can be stored. The specific emissions of TOPS-based FT-liquids while applying CCS are around -0.1 t CO_2/GJ.

Effect of a CO_2 price

The effect of a CO_2 price on the production costs of SOTA IGCC and IG-FT facilities is given in Figure 11. The impact of the biomass price on the production costs is clearly visible. The main difference between the IGCC and IG-FT facilities is the penalty of applying CCS. For the IGCC facilities, CCS becomes attractive only at higher biomass (>6 €/GJ) and/or CO_2 prices (>25 €/t

CO_2). For IG-FT facilities CCS is already attractive at low CO_2 prices (>10 €/t CO_2), even if biomass prices are low (>3 €/GJ). The results also indicate that at moderate CO_2 prices (>30-40 €/t CO_2, depending on the biomass price) the combination biomass and TOPS results in the lowest production costs.

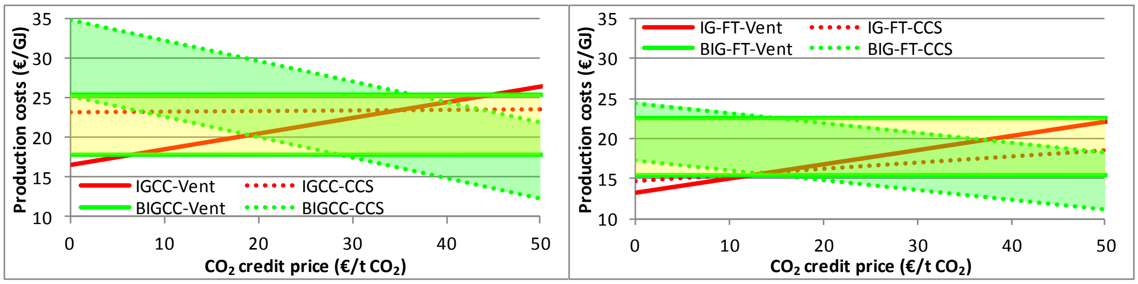


Figure 11 Effect CO_2 credit price on production costs of SOTA integrated gasification facilities. The shaded area is the range due to low and high TOPS prices.

6.5 Conclusion

Advanced technologies may reduce production costs of a coal-fired IGCC without CO_2 capture from 17 €/GJ to 11 €/GJ. When CO_2 is captured, it is found that production costs are lowered from 23 €/GJ to 14 €/GJ using SOFC. This would result in IGCC becoming profitable in the short term if CCS is not applied and in the long term if CCS is applied. When TOPS are used as feedstock, production costs are currently calculated at 25 €/GJ without CCS and 35 €/GJ with CCS, dropping to respectively 19 €/GJ and 21 €/GJ in the long term. New technologies alone do not lower production costs of TOPS-fired IGCC under the current average electricity market value of 16 €/GJ. If, as several studies indicate, TOPS prices drop to 3 €/GJ, production costs would decrease to 12 €/GJ without CCS and 15 €/GJ with CCS in the long term. In this case, production costs would drop under the current market price.

New technologies in IG-FT facilities are found to have a slightly smaller impact on the production costs. When using coal, production costs decrease from 13 €/GJ to 9.1 €/GJ if CO_2 is vented and from 15 €/GJ to 10 €/GJ if CO_2 is captured and stored. The use of TOPS would result in 23 €/GJ and 18 €/GJ without CCS and 24 €/GJ and 19 €/GJ with CCS for respectively now and in the long term. Here, lower biomass feedstock costs of 3 €/GJ results in production costs of 11 €/GJ without CCS and 12 €/GJ with CCS.

Specific CO_2 emissions can be reduced by capturing CO_2 or by substituting coal by TOPS. If both options are applied, net negative emissions can be obtained. This option becomes attractive both for IGCC and IG-FT facilities at moderate CO_2 prices (>30-40 €/t CO_2).

It is concluded that gasification can be an attractive technology to produce carbon neutral electricity and/or transportation fuels. Although production costs are currently above market prices, future improvements can lower the production costs and make gasification facilities profitable. Furthermore, both biomass and CCS can be used to reduce CO_2 emissions at relative low CO_2 avoidance costs.

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