POTENTIAL FOR BIOMASS AND CARBON DIOXIDE CAPTURE AND STORAGE

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POTENTIAL FOR BIOMASS AND CARBON DIOXIDE CAPTURE AND STORAGE

Background

Biomass use for energy production in processes such as combustion and gasification, and its use to produce biofuels such as bioethanol, results in emissions of CO_2. This CO_2 produced during combustion is approximately the same quantity consumed during biomass growth; therefore emissions from biomass combustion are considered to be CO_2 neutral (Demirbas, 2009)*. Capture and long-term storage of these CO_2 emissions would effectively result in net removal of atmospheric CO_2; and Biomass with CCS is potentially one of the few options for 'negative emissions' (Figure 1). Several mitigation scenarios show biomass in combination with CCS is likely to be required to meet low stabilisation concentrations (e.g. as discussed in Lindgren et al., 2006; IEA/OECD, 2008), and as biomass use is expected to increase, the potential application of CCS will also increase.

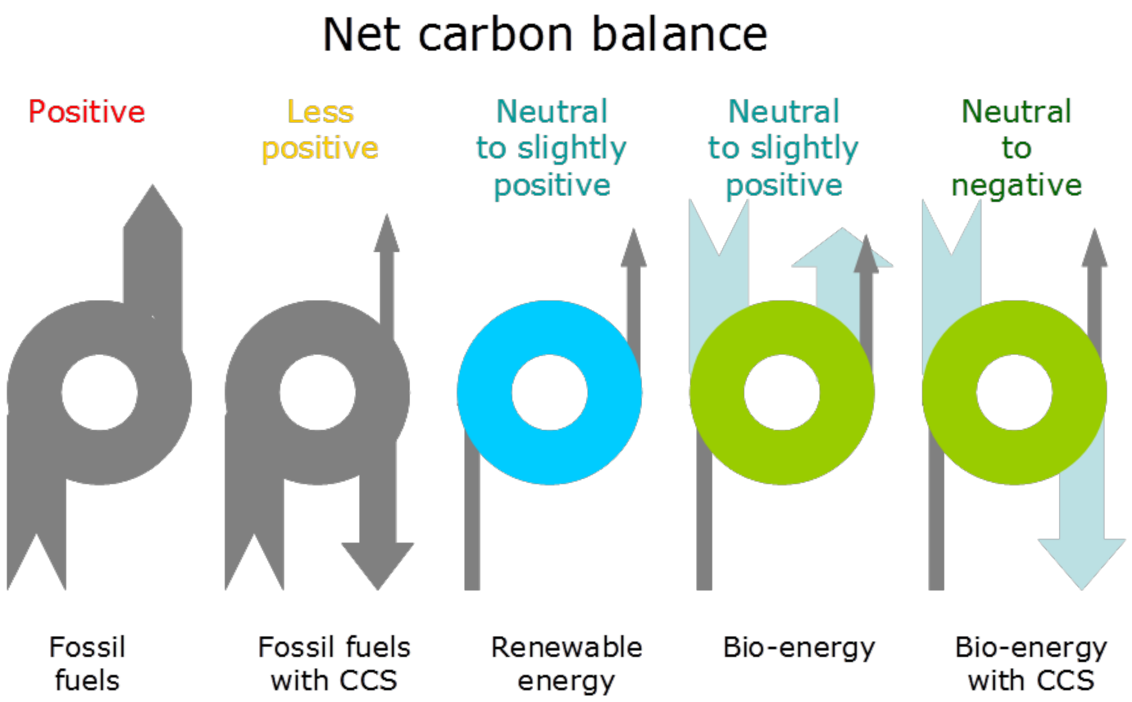

Figure 1. Carbon balance for different energy systems (adapted from www.ecofriendlymag.com 2010 by Koornneef for IEAGHG, 2011).

The combination of biomass and CCS in energy conversion technologies has many technological similarities with CCS applied to fossil fuel conversion; however there are also several differences such as biomass fuel typically has other combustion/gasification properties, lower energy density and greater variation between biomass types. Biomass with CCS (BE-CCS) is not restricted to production of electricity or heat, and other production processes such as bio-ethanol production produce pure CO_2 streams as a by-product which can easily be captured and separated. BE-CCS has many advantages, and consequently there is a need to understand deployment potential. An overview of global and regional biomass

*Note all references are provided in the Ecofys report.

potential mapped with CCS potential has not yet been published, and understanding of global potential, drivers and obstacles which may accelerate or limit BE-CCS implementation is imperative for assessment of this negative emissions mitigation option.

Scope and Methodology

A contract for this study was awarded to Ecofys B. V. of the Netherlands. The aim of the study was to provide a global and regional assessment of potential for BE-CCS, identifying the main potential types of biomass, technologies applicable for energy conversion/process and whether CCS application is possible; considering deployment to target future scenarios; complimenting the IEAGHG study on 'Techno-economic evaluation of biomass fired or co-fired power plant with post-combustion CO_2 capture'. The contractor was asked to assess the net carbon balance for likely biomass CCS technology options, taking into account biomass supply chains and processing; to provide quantitative indications of the emissions performance potential; consider other potential greenhouse gas impacts such as land-use change, identifying any potential negative environmental consequences, such as non-sustainable biomass production; and consider deployment issues, in terms of policy and regulatory barriers and incentives.

Classification of Potentials

As there is no common terminology for energy potentials, it is important to consider the specific potential approach and assumptions used in evaluating techno-economic potential, which fundamentally depends upon availability of resources and cost of these resources. If there were no constraints on using all available resources, this potential would be the maximum potential or in this study, the ***theoretical potential***. ***Technical potential*** is the potential applying current or future technical constraints, which for BE-CCS is constrained only by resource availability, CO_2 storage capacity, and future technical performance of the technology. ***Realisable potential*** is technically feasible, determined by possible deployment rate and expected demand, hence increases in time with deployment rate (where deployment rate is dependent on the possibility of applying BE-CCS to existing energy conversion technologies and retirement rate of technologies it replaces). The Realisable Potential is hence a limitation applied to the Technical Potential by including capital stock turnover, final energy demand and deployment rate. ***Economic potential*** is the potential at economic cost, considering cost of use of resources and of competing resources, determined by combining the price of biomass resources with the cost for biomass conversion and CCS; assessing the cost of producing electricity and biofuels with and without CCS, taking the CO_2 price into account. Therefore, the Economic BE-CCS Potential is the total final energy that can be converted at lower cost than the (fossil) reference technologies. ***Market potential***, a variant of the economic potential, indicates the proportion of technical potential attractive to investors, including obstacles and drivers (e.g. regulation, subsidies and taxes). See Figure 2. This study focuses on technical, realisable and economic potential.

Determining Potentials

Regional and global *Technical potential* (see Chapter 4); in terms of primary energy converted, final energy and net greenhouse gas emissions; was determined by the net energy conversion efficiency (including the energy penalty) and the carbon removal efficiency of the BE-CCS route, combining existing studies on biomass potentials, and CO_2 storage potentials. For regional assessment the world has been divided into seven regions: Africa and Middle East (AFME), Asia (ASIA), Oceania (OCEA), Latin America (LAAM), Non-OECD Europe and the Former Soviet Union (NOEU), North America (NOAM) and, OECD Europe (OEU). It is noted this is division is for a first level assessment and further work should conduct assessments at a more detailed regional level.

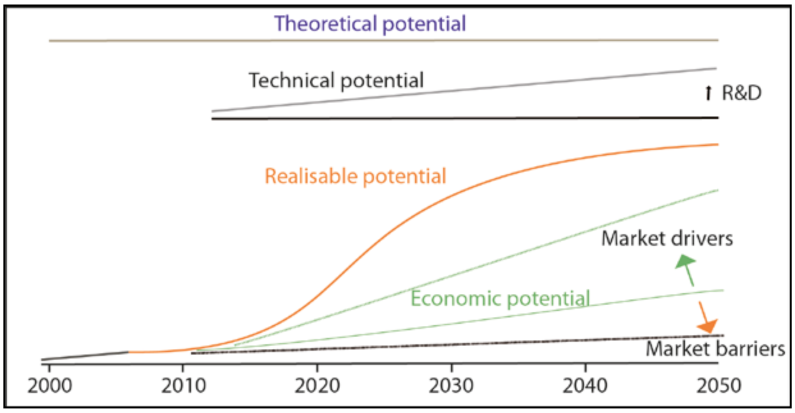

Figure 2. Graphical representation of the definitions for potentials used in this study (adapted from Resch, Held et al., 2008 for this study).

Three categories of biomass, representing more than 50% of the land-based resources area are analysed further: energy crops, forestry residues and agricultural residues; and sustainable biomass potential is estimated based on data from previous studies (van Vuuren et al., 2009; Hoogwijk, 2004; Hoogwijk, 2010; Vliet et al., 2009), using the lowest estimates to provide a conservative approach. Numbers for biomass potential for energy crops were derived from van Vuuren et al. (2009) and Vliet et al. (2009) with applied *strict* criteria based on water scarcity, biodiversity conservation and land degradation. Biomass types exclude categories such as organic waste, and potential aquatic biomass production as these are less extensively studied at present, needing further research before further consideration.

The *Realisable Potential* (see Chapter 5) adds limitations to the technical potential by including energy demand, capital stock turnover and possible deployment rate. General assumptions used to calculate the realisable potential can be seen in Table 1. Realisable potential estimates for electricity supply and transport fuels BE-CCS routes are based on the reference scenario in the IEA World Energy Outlook (IEA, 2009) which has been adapted to include the view year of 2050 (with electricity demand increasing at the same rate per year from 2030 to 2050 as the 2007 to 2030 scenario predictions).

Economic Potential combines the price of biomass resources with costs for biomass conversion and CCS for selected BE-CCS routes. The cost of producing electricity and biofuels (with and without CCS) are assessed, considering the CO_2 price, yielding supply curves for the BE-CCS routes and reference technologies; providing an economic potential which is the biomass potential presented in final or primary energy that can be converted at lower cost than the fossil reference technologies. It is important to reference assumptions used (see Table 6-1 p93) when reviewing these results.

Assumption	Default value
Annual electricity demand growth - global	2.4%
Share of existing stock (built before 2007) replaced every 5 years	20%
New (BE-)CCS will be implemented on power generation installed from year	2020
Retrofitted CCS will be implemented on power generation installed from year	2007
Power plants will be retrofitted before year	2025
Fraction of retrofitted power generation equipped with CCS	100%
Biomass input in final energy in BE-CCS routes replacing 'Coal'	30% from 2020 onwards 50% in 2050
Biomass input in final energy in BE-CCS routes replacing 'Biomass and Waste'	100%
Coal input in final energy in BE-CCS routes replacing 'Coal'	70% from 2020 onwards 50% in 2050

Table 1. General assumptions used in the realisable potential model for electricity conversion technologies.

For energy crops, cost supply curves are combined from Hoogwijk (2004) and van Vuuren et al. (2009), specified on a regional level. For agricultural and forestry residues, the assumption from Hoogwijk et al. (2010) is used that 10% of the potential fulfilling certain sustainability criteria is available at costs below 1 \$/GJ and 100% below 50 \$/GJ. A ratio was assumed to convert biomass production cost into the price of biomass on the market, based on figures reported by the IEA (Bauen, Berndes et al., 2009), yielding the price and associated potential before pre-treatment and transport. Biomass pre-treatment and transport is a significant part of the biomass supply chain cost, and is assumed to be an average cost adding approximately 1.3 €/$GJ_{primary}$. Fuel conversion and capture costs vary significantly, with energy conversion costs including installation capital costs, operation and maintenance, fuel costs and CO_2 costs. This is explained in detail in the report in chapter 6.3.3 and section 6.4. CO_2 transport costs are assumed to be between 1 and 30 €/tonne, with a default of 5 €/tonne and an uncertainty range of 1 to 30 €/tonne (taken from IEAGHG, 2009), and storage costs average 1 to 13 €/tonne, with a default of 5 €/tonne and an uncertainty range of 1 to 13 €/tonne. General assumptions can be found in Table 6-1 on p93.

Selecting BE-CCS routes

Potential assessment focuses on BE-CCS technologies noted in available literature to have the greatest anticipated potential (e.g. see IEAGHG, 2009; Luckow, Dooley et al., 2010; Rhodes and Keith, 2005; Ecofys, 2007), therefore not all possible BE-CCS technologies are incorporated, for example application of BE-CCS in the pulp and paper sector. Six routes have been selected for detailed analysis from two major sectors: large-scale electricity generation and biofuel production (see Table 2).

Further details on these routes are also available in the Factsheets provided in the Appendix of the report.

Route name	Technology description	Feedstock and CO_2 capture principle
Electricity production		
PC-CCS co-firing	Pulverized Coal fired power plant with direct biomass co-firing	Co-firing share[1] is 30% in 2030 and 50% in 2050. *Post-combustion*
CFB-CCS dedicated	Circulating Fluidised Bed combustion power plant	100% biomass share. *Post-combustion*
IGCC-CCS co-firing	Integrated Gasification Combined Cycle with co-gasification of biomass	Co-firing share[1] is 30% in 2030 and 50% in 2050. *Pre-combustion*
BIGCC-CCS dedicated	Biomass Integrated Gasification Combined Cycle	100% biomass share. *Pre-combustion*
Biofuel production		
Bio-ethanol-advanced generation	Advanced production of Bio-ethanol through hydrolysis + fermentation	100% biomass share *Nearly pure CO_2; only drying and compression.*
FT biodiesel	Biodiesel based on gasification and Fischer Tropsch-synthesis	100% biomass share *Nearly pure CO_2 from Pre-combustion; only compression*

Table 2. The six BE-CCS technologies selected to be assessed within this study.

Results and Discussion

Energy and Negative Greenhouse Gas Emissions Potential

The global *Technical Potential* for BE-CCS technologies is found to be large and, if deployed, can result in negative emissions up to 10 Gt of CO_2 equivalent annually per technology route (Figure 3a); which compared to the IEA ETP (2010) estimate of 43 Gt of global CO_2 emissions reductions required from the energy sector by 2050, shows significant potential. Negative emissions are largest for the dedicated CCS routes with CCS: Biomass Integrated Gasification Combined Cycle (BIGCC): final energy of 57 EJ/yr, CO_2 stored of 10.7 Gt/yr and net GHG balance of -10.4 Gt/yr in 2050; and Circulating Fluidised Bed (CFB): final energy of 47 EJ/yr, CO_2 stored 10.7 Gt/yr and net GHG balance of -10.4 Gt/yr in 2050 (see Figure 3a and 3b). The potential for negative emissions for biofuels with CCS are the lowest, ranging between 0.5 and 6 Gt, because a smaller fraction of the CO_2 is captured and stored i.e. a significant proportion of the carbon remains in the product, in residues or is emitted further along the chain with a maximum CO_2 capture efficiency of 54% in Fischer Tropsch (FT) biodiesel. The amount of CO_2 stored ranges between 1 and 21 Gt/yr, largely dependent on the primary energy input, the primary energy potential and the CO_2 capture efficiency.

Deploying the full *Technical Potential* equates to up to 16 PWh (59 EJ) of bio-electricity or 1.1 Gtoe (47 EJ) of biofuels. This assumes a sustainable supply of biomass feedstock of 73 and 126 EJ/yr, in 2030 and 2050 respectively, and the amount of sustainable biomass greatly influences the technical potential for BE-CCS technologies with the availability of sustainable biomass being the limiting factor.

The *Technical Potential* is found to be the greatest in Asia and Latin America, and lowest in Oceania, Non-OECD Europe, the Former Soviet Union and, OECD Europe. There appears to be vast storage potential in North America, Non-OECD Europe, the Former Soviet Union, Africa and the Middle East; however these regions are limited by the supply of sustainable biomass. Storage capacity does not seem to be a limiting factor, except where depleted hydrocarbon fields are used solely, though there is a need for consistent and detailed storage capacity estimates.

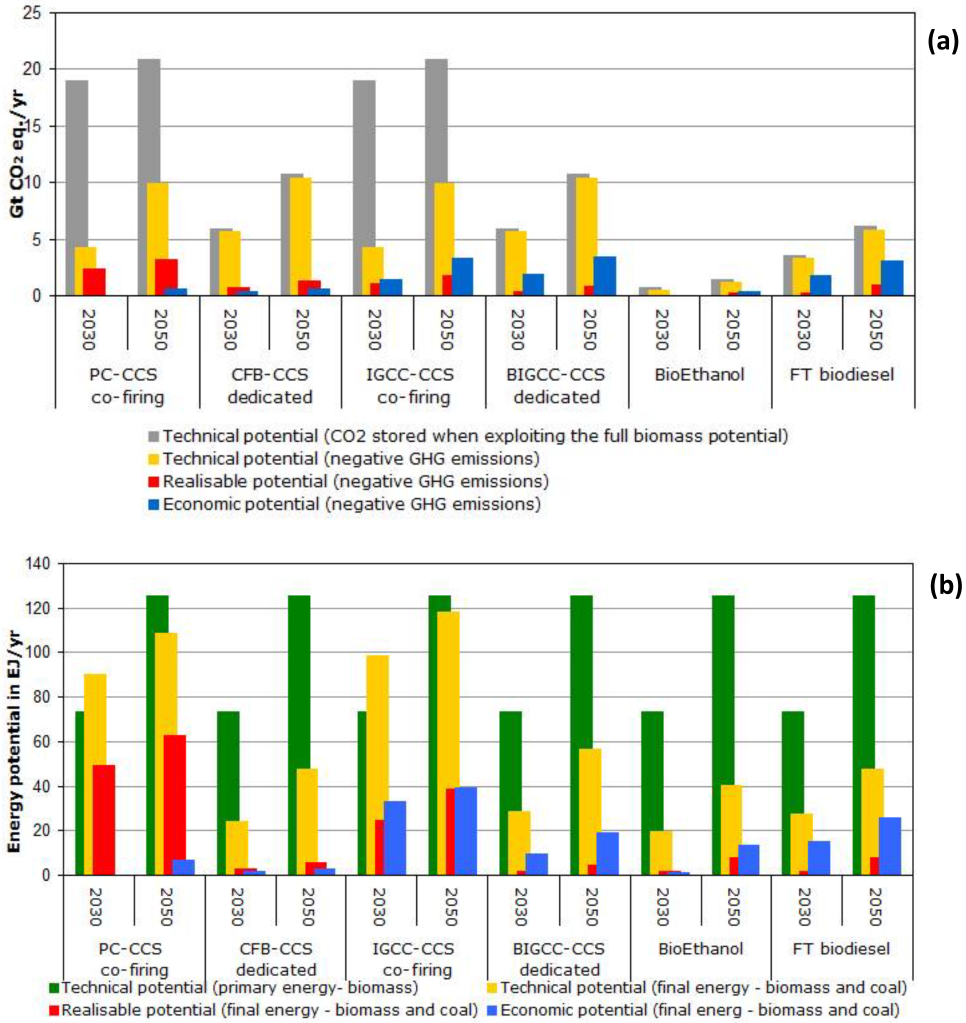

Figure 3. (a) Greenhouse gas emissions balance (Gt CO_2 eq./yr) and CO_2 stored for global Technical, Realisable and Economic potential per BE-CCS route for 2030 and 2050. **(b)** Global Technical, Realisable and Economic energy potential (EJ/yr) per BE-CCS route for 2030 and 2050. See Executive Summary Table 2 p3 of the report for overview results. Note potentials are assessed on a

route to route basis and cannot simply be added, as they may compete and substitute each other. ‘Coal’ is only applicable for the co-firing routes.

Bioethanol production produces a high purity CO_2 stream, with approximately 765g of CO_2 generated per litre of ethanol produced, and this can be captured with relative low cost. In 2008, worldwide CO_2 emissions resulting from this fermentation produced 50 Mt of CO_2. The largest producers of bioethanol are Brazil and the United States, both of which have large storage potential; hence these countries may represent early opportunities for BE-CCS, providing storage reservoirs are in the vicinity of bioethanol plants.

The *Realisable Potential* in the short term for the selected BE-CCS technologies (for the biomass share of final energy production in co-firing routes; note Figure 3a displays results of biomass and coal final energy production for co-firing routes) is estimated to be limited by early deployment opportunities, but increasing to between 2 and 15 EJ/yr in 2030 (1-4 PWh) and between 4 and 20 EJ/yr (1-6 Pwh) in 2050 for producing electricity routes, and for both biofuel routes: 2 EJ/yr in 2030 and 8 EJ/yr (191 Mtoe) in 2050 with a cumulative potential of 123 EJ up to 2050, which is a small fraction of the technical potential and is likely to be a conservative estimate (see Figure 3a). Associated negative greenhouse gas emissions range from 0.3 to 2.3 Gt CO_2 eq./yr in 2030 and 0.8 to 3.2 Gt CO_2 eq./yr in 2050 for producing electricity routes; from 0.0 to 0.2 Gt CO_2 eq./yr in 2030 and 0.2 to 1.0 Gt CO_2 eq./yr in 2050 for biofuel routes (see Figure 3b).

In both the medium and long-term, the largest *Realisable Potential* is found to be for the PC-CCS co-firing route, in which all new power plants are assumed to be equipped with CCS after 2020, and existing and newly added power plants without CCS may be equipped with CCS at a later date; hence allowing for retrofitting with biomass co-firing and CCS. This advantage over dedicated and gasification routes explains why the realisable potential is considerably higher for this co-firing route; however the potential of dedicated routes in terms of GHG performance is relatively better, showing dedicated routes result in higher negative emissions per EJ than co-firing routes. Both extending the lifetime of an existing installed capacity and extending the implementation date have a negative influence on the potential for BE-CCS technologies.

The *Economic Potential* for BE-CCS technologies, assuming a CO_2 price of 50 €/tonne, has been found to be up to 20 EJ (5 PWh) for bio-electricity routes, or up to 610 Mtoe (26 EJ) for the biofuel routes. About one third of the technical potential can be considered economically attractive under the assumptions used (see Table 6-1 on p93 for general assumptions), yielding a technology economic potential of up to 3.5 Gt of negative greenhouse gas emissions per year.

Greatest potential is in gasification based routes, with *Economic Potential* of 39 EJ/yr and GHG emissions balance of -3.3 Gt per year in 2050 for IGCC and, 19 EJ/yr and GHG emissions balance of -3.5 Gt per year for BIGCC in 2050 (see Figure 3a and 3b). The route using BIGCC with CCS has the lowest cost of energy production when using low cost biomass, despite higher specific investment and lower conversion efficiency when compared to other BE-CCS technologies. The smallest potential appears to be in PC and CFB routes of approximately 0.0 and 1 EJ/yr in 2030 (0.0 and 0.3 Gt CO_2 eq./yr in 2030 respectively), where the costs of PC-CCS co-firing and CFB-CCS co-firing is higher than reference technologies (in this case PC-CCS coal and IGCC-CCS coal), though potential would exist at somewhat higher cost than reference technologies (see section 6.4.1). For biofuels, highest potential lies in FT-biodiesel, at 26 EJ/yr in 2050, equating to approximately 3 Gt of negative greenhouse gas emissions per year (see Figure 3a). Cost curves can be found in Chapter 6.

The dedicated route using CFB is the only route in 2030 where conversion cost for power production is lower overall when the plant is not equipped with CCS, with the largest cost difference in the medium-term. Dedicated firing requires higher specific investment cost compared to co-firing, which is mainly due to more extensive fuel treatment methods required for 100% biomass combustion and lower conversion efficiency. The capital requirements for adding CO_2 capture to CFB power plants is assumed to be significantly higher, though reducing to 2050. A CO_2 price higher than 50 €/tonne would be needed in 2030 to make CFB-CCS economically attractive over dedicated firing without CCS. In all other production routes the costs are considerably lower when CCS is implemented. Estimates for the economic potential are of course highly sensitive to assumptions made for the CO_2 price and biomass price, particularly those of IGCC and PC co-firing, and the coal price affects all routes generating electricity, but significantly for co-firing routes. The Economic Potential is also of course dependant on policy drivers, and implementation of such would influence these conclusions.

For the sensitivity analysis of these results see Chapter 8.

Market Drivers and Obstacles

Several technical, financial, public and policy drivers and obstacles have been charted for the deployment of BE-CCS technologies. One important issue which can be both a driver and an obstacle is the CO_2 price, which is influenced by climate policy and, the development and availability of other mitigation options. Under the EU ETS, storing CO_2 from biomass will not ‘create’ sellable allowances, so there is no economic value to ‘negative emissions’; and current CO_2 prices are highly unlikely to result in an economic potential for BE-CCS. Stricter climate policy would be needed to increase the CO_2 price, and inclusion of BE-CCS in the Clean Development Mechanism (CDM) would be key drivers for all BE-CCS routes as it would facilitate financing of BE-CCS projects in developing countries. These drivers are also relevant to CCS in general.

The relatively immature state of the technology is considered a potential obstacle, as advanced biomass conversion technologies, such as BIGCC, are not considered mature; therefore the financial risk is higher, potentially leading to a higher financing cost.

The secure supply of low cost sustainable biomass will be an issue which limits the deployment of BE-CCS technologies, and factors such as land use scenarios and biomass price fluctuations will influence availability and cost.

Positive public perception is identified as another possible driver of BE-CCS, and there are suggestions BE-CCS may face less resistance than fossil fired CCS because of its association with renewable energy supply. This hypothesis needs to be tested with dedicated surveys.

Sustainability criterion for sustainable biomass potential

Though the sustainability criterion 'strict' used in this study is deemed appropriate, more detailed assessment of this criterion and factors which may limit sustainable supply will be important for future research. Large scale biomass for bioenergy has met concerns on sustainability, and is considered a major challenge. The debate on what factors classify sustainable supply include: labour conditions, protection of areas with high ecological value and high historical or cultural value, respect of indigenous populations and land rights of local communities, food prices and security, avoidance of (indirect) land use change (ILUC – when existing plantations are used to cover feedstock demand of biofuel production displacing the previous production function, and LUC – when new areas, such as forests, are used to produce feedstock for bioenergy which can cause negative effects such as loss of biodiversity) e.g. deforestation. Competition for land (and food prices) as well as ILUC and LUC are key areas of debate. There are various international efforts to establish sustainability criterion, such as that for the EU Renewable Energy Directive and proposed by the Roundtable on Sustainable Biofuels (RSB), and future research would benefit from associating with such efforts.

Expert Review Comments

Expert review comments on the draft report were received from four reviewers, with an additional informal review. The comments provided were detailed and constructive, enabling the study contractors to respond accordingly in preparation of the final report.

Key suggestions by the reviewers included further clarification and focus on sustainably produced biomass, further emphasis on accounting issues and policy incentives, and more detailed analysis of biomass pricing. These comments are addressed in the final report, including the addition of a text box (Box 1, p31 – 32) on sustainability criteria biomass production, sensitivity analysis of biomass pricing, the addition of further text on policy incentives and accounting such as within Drivers and Barriers, and increased discussion within the report.

Further comments discussed preference for comparison with gas-fired plants which has been addressed with additional text and reference, and potentially optimistic co-firing percentages and efficiencies though those used within the report are within the range provided by cited literature and as a response to one specific comment the study now reflects a higher energy penalty of 10% for a CFB CCS 500MWe plant.

The contractors have provided a detailed tabulated summary of the comments and their actions to address these comments which may be made available to interested parties.

Conclusions

This study has shown the value of a first order techno-economic assessment of BE-CCS technologies which is currently under wide debate due to its potential for negative emissions. The global *Technical Potential* for BE-CCS technologies is found to be large and, if deployed, can result in negative emissions up to 10 Gt of CO_2 equivalent annually; or a more conservative *Economic Potential* of up to 3.5 Gt of CO_2 equivalent of negative emissions per year; which compared to the IEA ETP (2010) estimate of 43 Gt of global CO_2 emissions reductions required from the energy sector by 2050, shows significant potential. Given the impact such could have on atmospheric CO_2 reduction targets, it is important IEAGHG continues to expand upon this study to further assess these results.

The key obstacle to the implementation of the technology is identified as the absence of a price for stored biomass based CO_2, hence an economic value on ‘negative emissions’, in for example the EU ETS; and BE-CCS needs inclusion into the CDM if this option is to be taken up by developing countries such as Brazil where early opportunities exist. There is therefore, a need for policy developments in this area to assist global take-up of the technology. This is of course not an area IEAGHG covers directly, and the policy implications of this study will be discussed with the IEA CCS Unit.

The study raises the importance of further definition of what constitutes sustainable biomass, and IEAGHG should ensure to keep abreast of advancements in international efforts to establish sustainability criteria, in addition to further detailed regional and focussed potential assessment of BE-CCS. IEAGHG should consider a focussed study to provide insight into the economic and infrastructure boundary conditions for CO_2 capture from bio-ethanol production, as bio-ethanol appears to be a route which has short-term opportunities for BE-CCS; consideration of the co-utilisation of biomass and coal in existing and new Fischer Tropsch facilities that are planned or operating worldwide; and additional assessments to include other potential biomass supply options not included in this study, such as aquatic biomass from algae, with a particular emphasis on potential secure sustainable biomass sources. The study also further highlights the need for consistent and detailed storage capacity estimates and linking any such further assessments to developments in estimates will be necessary.

Recommendations

There are a number of recommendations resulting from this study, the most important of which highlights the need for an economic incentive for producing negative emissions, without which BE-CCS will not have an economic potential.

- Stored CO_2 originated from biomass will require an economic value to stimulate the introduction of this technology. CO_2 price in combination with low cost sustainable biomass are the key drivers for BE-CCS.

- Further research should be focussed on assessing the BE-CCS potential per region and in greater detail through regional specific cost supply curves for CO_2 transport and storage, including source sink matching.

- State-of-the-art sustainability criteria should be applied when assessing the potential for BE-CCS technologies, and additional research should verify these results with a more detailed assessment of factors that limit sustainable supply of biomass at a regional level and assess actions to increase this supply, which was out of the scope of this first level assessment.

- Further assessment of the effect of (co-)firing biomass on the performance of CO_2 capture options in pilot/demonstration plants is needed, particularly in terms of potential effects of increasing biomass fractions, and after such any potential technical barriers can be identified and removed to facilitate deployment.

- A BE-CCS option not considered in this study is the co-utilisation of biomass and coal in existing and new Fischer Tropsch facilities that are planned or operating worldwide. In conjunction with CO_2 capture from bio-ethanol production, this could provide early opportunities for BE-CCS at relatively low cost; and examination of such on a case-by-case basis could be a valuable next step. Research should be focussed on further insight into the economic and infrastructure boundary conditions for CO_2 capture from bio-ethanol production, using detailed case studies. This seems to be economically attractive for the short to medium term, and it is likely short-term opportunities exist in Brazil and the USA, which are the largest producers of bio-ethanol with considerable CO_2 storage potential.

- Short and long-term price estimations are pivotal to assessing economic potential and, insights and quantification of key factors influencing trade volume and price of biomass would provide a more robust economic potential assessment.

- Further research should take into account assessments of other potential biomass supply options not included in this study, such as aquatic biomass from algae.

Potential for Biomass and Carbon Dioxide Capture and Storage

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Potential for Biomass and Carbon Dioxide Capture and Storage

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IEA Greenhouse Gas R&D Programme

Executive summary

Carbon capture, transport and storage (CCS) is often associated with the use of fossil fuels and most notably, with the use of coal. However, CCS can also be combined with biomass fuels (BE-CCS) where short-cycle carbon is harvested, converted, captured and stored deep underground. Effectively, this suggests that carbon dioxide is removed from the atmosphere resulting in negative greenhouse gas (GHG) emissions.

One major drawback to the use of CCS in combination with biomass is that there is considerably less information available than there is for fossil fuel based CCS systems. There is currently no complete overview of the technical and economic differences between fossil fuel and biomass fired energy conversion technologies in combination with CCS. A comparative overview of global and regional biomass potential and global and regional CCS potential (e.g. storage potential) has also not been published. The global potential of the BE-CCS options and the drivers and obstacles that accelerate or limit the future implementation of this potential is also not yet clear.

The aim of this study is to fill these knowledge gaps and provide a first order assessment of the potential for BE-CCS technologies to 2050, with an additional focus on the medium term, i.e. 2020 to 2030. We make a distinction between *technical potential* (the potential that is technically feasible and not restricted by economical limitations), *realisable potential*[1] (the potential that is technically feasible and takes future energy demand and scenarios for capital stock turnover into account) and *economic potential* (the potential at competitive cost compared to alternatives). The difference between these potentials can be large and it is therefore imperative to understand these differences and identify the restrictions that constrain the deployment of the full potential. Next to quantitative estimates of these potentials, in the form of regional and global supply curves, we present recommendations to overcome the possible deployment obstacles and enhance drivers to stimulate the deployment of BE-CCS technologies.

Six BE-CCS routes have been selected for detailed analysis

The two major sectors we focus on for the possible application of BE-CCS technologies are: large scale electricity generation and biofuel production. We have selected six technology routes for a detailed assessment, considering the entire biomass supply and CCS chain, see Table 1. For these routes we have performed a techno-economic assessment and have calculated the technical, realisable and economic potential. It should be noted that we do not use an economic optimisation in our model, but

[1] The realisable potential is factually a limitation applied to the technical potential by including the demand for final energy, capital stock turnover and possible deployment rate. This means that the realisable potential increases over time according to the possible deployment rate. The scenario approach for the realisable potential is different compared to the approach used to determine the technical (and economic) potential. The technical potential is estimated in a static way looking at the view years 2030 and 2050 and does not depend on capital stock turnover, energy demand and deployment rate.

calculate the maximum potential as if all biomass were allocated to a specific BE-CCS route. We distinguish three categories of sustainable biomass potential: energy crops, forestry residues and agricultural residues.

Table 1 BE-CCS technologies assessed in this study

Route name	**Technology description**	**Feedstock and CO_2 capture principle**
Electricity production		
PC-CCS co-firing	Pulverized Coal fired power plant with direct biomass co-firing	Co-firing share[1] is 30% in 2030 and 50% in 2050. *Post-combustion*
CFB-CCS dedicated	Circulating Fluidised Bed combustion power plant	100% biomass share. *Post-combustion*
IGCC-CCS co-firing	Integrated Gasification Combined Cycle with co-gasification of biomass	Co-firing share[1] is 30% in 2030 and 50% in 2050. *Pre-combustion*
BIGCC-CCS dedicated	Biomass Integrated Gasification Combined Cycle	100% biomass share. *Pre-combustion*
Biofuel production		
Bio-ethanol-advanced generation	Advanced production of Bio-ethanol through hydrolysis + fermentation	100% biomass share *Nearly pure CO_2; only drying and compression.*
FT biodiesel	Biodiesel based on gasification and Fischer Tropsch-synthesis	100% biomass share *Nearly pure CO_2 from Pre-combustion; only compression*

[1]Share of biomass on a primary energy basis.

We combine existing studies on sustainable biomass potentials and CO_2 storage potentials to estimate the regional potential of the selected BE-CCS routes. We divide the world into seven regions; Africa & Middle East, Asia, Oceania, Latin America, Non-OECD Europe & the Former Soviet Union, North America and OECD Europe.

The most eminent results following from this assessment are summarised in Table 2, Figure 1 and Figure 2, and are discussed here.

The technical potential for achieving negative CO_2 emissions is significant

The global **technical** potential for BE-CCS technologies is found to be large and, if deployed, can result in negative greenhouse gas emissions up to 10 Gt CO_2 eq., annually. Negative emissions are the largest for the dedicated routes with CCS; Biomass Integrated Gasification Combined Cycle (BIGCC) and Circulating Fluidised Bed (CFB). The potential for negative emissions for the biofuel routes with CCS are the lowest, ranging between 0.5 and 6 Gt, because a smaller fraction of the CO_2 is captured and stored. Deploying the full technical potential[2] equates to up to 16 PWh (59 EJ) of bio-electricity or 1.1 Gtoe (47 EJ) of biofuels.

Comparing the world regions, we found the **technical** potential to be the greatest in Asia and Latin America. The potential is the lowest in Oceania, Non-OECD Europe & the Former Soviet Union (FSU) and OECD Europe. The results also show a vast storage potential in North America, Non-OECD Europe and FSU and Africa and Middle East[3]; and the technical BE-CCS potential is in those regions limited by the supply of sustainable biomass. For almost all regions, there is likely to be enough storage capacity to store the captured CO_2 and definitely for the 100% biomass fired routes. Only where depleted hydrocarbon fields are used solely, storage capacity may become a limiting factor. Inter-regional transport can contribute to match biomass availability with storage capacity.

Table 2 Overview of global technical, realisable and economic potential per BE-CCS route for the view years 2030 and 2050

Technology route	**Year**	**Technical potential[1]**				**Realisable potential**			**Economic potential**	
		Final energy EJ/yr	Final energy EJ/yr	CO_2 stored Gt/yr	GHG balance Gt/yr	Final energy EJ/yr	Final energy EJ/yr	GHG balance Gt/yr	Final energy EJ/yr	GHG balance Gt/yr
Electricity generation		Bio share	Total	Total	Total	Coal share[2]	Bio share	Total	Total	Total
PC-CCS co-firing	2030	27	90	19.0	-4.3	34	15	-2.3	0	0.0
	2050	54	108	20.9	-9.9	43	20	-3.2	7	-0.6
CFB-CCS dedicated	2030	24	24	5.9	-5.7	n/a	3	-0.7	1	-0.3
	2050	47	47	10.7	-10.4	n/a	6	-1.3	3	-0.6
IGCC-CCS co-firing	2030	30	99	19.0	-4.3	17	7	-1.1	33	-1.4
	2050	59	118	20.9	-9.9	26	12	-1.8	39	-3.3
BIGCC-CCS dedicated	2030	28	28	5.9	-5.7	n/a	2	-0.3	10	-1.9
	2050	57	57	10.7	-10.4	n/a	4	-0.8	19	-3.5
Biofuels										
BioEthanol	2030	19	19	0.7	-0.5	n/a	2	0.0	1.2	0.0
	2050	40	40	1.4	-1.1	n/a	8	-0.2	13.4	-0.4
FT biodiesel	2030	28	28	3.6	-3.3	n/a	2	-0.2	15.0	-1.8
	2050	47	47	6.1	-5.8	n/a	8	-1.0	25.5	-3.1

[1]The sustainable supply of biomass feedstock is equal for all selected routes: 73 and 126 EJ/yr, in 2030 and 2050, respectively.

[2] 'Coal share' is only applicable for the co-firing routes.

[2] This equals about 90% or 25% of the global production of electricity and liquids fuels in 2007, respectively.

[3] Africa and the Middle East are treated as one region.

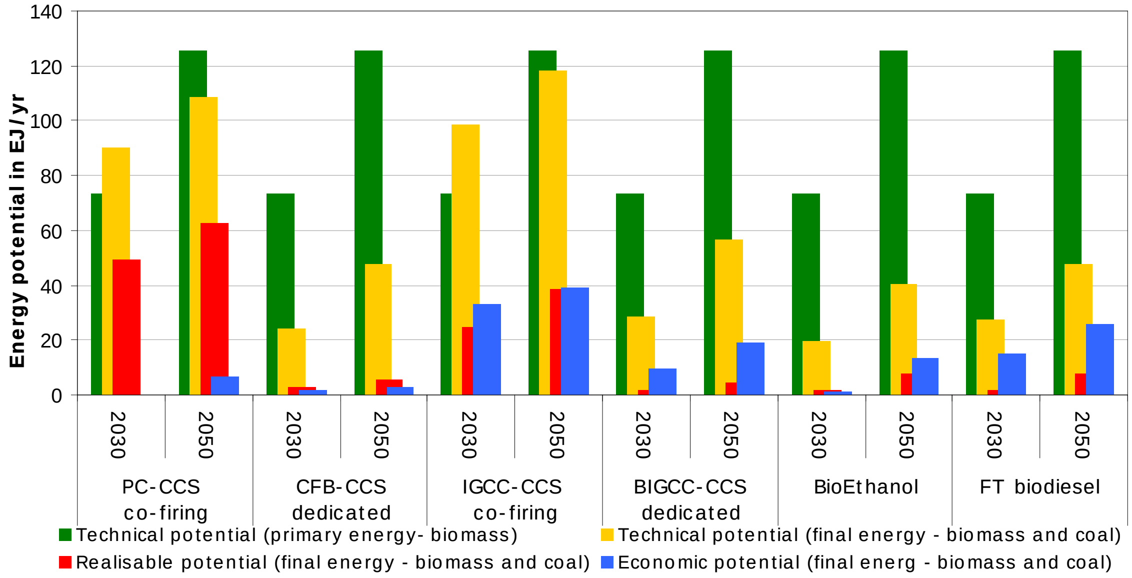

Figure 1 Global technical, realisable and economic energy potential (in EJ/yr) per BE-CCS route for the view years 2030 and 2050. Note that potentials are assessed on a route by route basis and cannot simply be added, as they may compete and substitute each other. 'Coal' is only applicable for the co-firing routes.

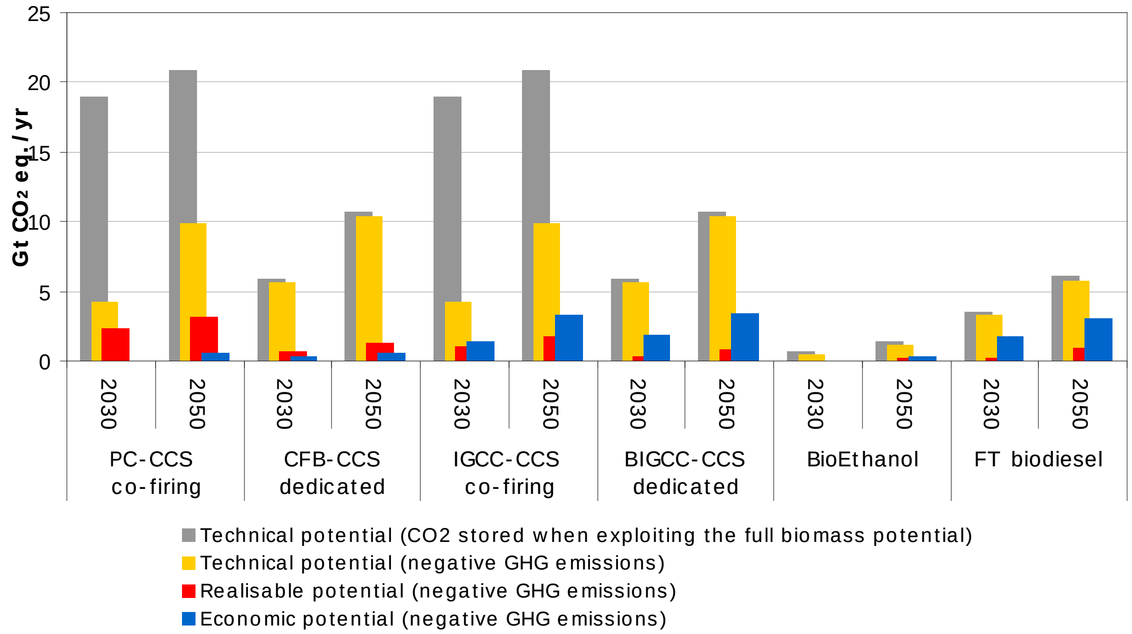

Figure 2 Greenhouse gas emission balance (in Gt CO_2 eq./yr) for the global technical, realisable and economic potential per BE-CCS route for the view years 2030 and 2050. Note that potentials are assessed on a route by route basis and cannot simply be added, as they may compete and substitute each other.

Early implementation of BE-CCS technologies is integral to the achievement of negative emissions

The **realisable** potential for the medium and long term is expected to be the largest for the Pulverized Coal (PC-CCS) route with CCS co-firing coal and biomass. Extending the lifetime of existing capacity and delaying the implementation date of CCS will have a negative effect on the annual and cumulative potential for all BE-CCS technologies; i.e. the amount of CO_2 emissions that can be avoided is reduced.

The realisable potential for the BE-CCS routes producing electricity, ranges between 2 and 15 EJ/yr (1-4 PWh) in 2030 and between 4 and 20 EJ/yr (1-6 PWh) in 2050. Negative greenhouse gas emissions associated with these potentials range between 0.3 and 2.3 Gt CO_2 eq./yr in 2030 and between 0.8 and 3.2 Gt CO_2 eq./yr in 2050.
The PC-CCS route shows the largest potential, as this route allows retrofitting of existing coal fired capacity with biomass co-firing and CCS. For 2020, the realisable potential is estimated to be small for BE-CCS technologies and is expected to be limited to the deployment of early opportunities (e.g. capture at bio-ethanol and biodiesel routes). The realisable potential for the biofuel routes will grow to 8 EJ/yr (191 Mtoe) in 2050, which is a small fraction of the technical potential and is likely to be a conservative estimate. The realisable biofuel potential in 2030 in terms of GHG performance is shown to be the highest for the FT-biodiesel route at 0.2 Gt CO_2 eq./yr. In 2050, the potential in annual negative emissions is between 0.2 and 1 Gt CO_2 eq.

The economic potential of BE-CCS reaches up to 3.5 Gt of negative emissions

When assuming a CO_2 price of 50 €/tonne, the **economic** potential for BE-CCS technologies is up to 5 PWh (20 EJ) for bio-electricity routes or up to 610 Mtoe (26 EJ) for the biofuel routes. Approximately one third of the technical potential can be considered economically attractive under our assumptions, yielding a potential of up to 3.5 Gt of negative GHG emissions.

The greatest economic potential is found in the gasification-based routes (IGCC and BIGCC). The smallest economic potential is found in the PC and CFB routes; about 1 EJ/yr for the year 2030. For the biofuel routes, the economic potential is calculated to be greatest for the Fischer Tropsch (FT) biodiesel route, at 26 EJ/yr. This equates to about 3 Gt of negative greenhouse gas emissions per year.

The cost supply curves for the dedicated routes (CFB, BIGCCC, bio-ethanol and FT-biodiesel) are comparatively steeper than the supply curves of co-firing routes as the coal share suppresses the increase of production cost when biomass prices increase.

Estimates for the economic potential are highly sensitive to assumptions on the CO_2 price and biomass price. The economic potential of the PC and IGCC co-firing routes, in particular, are the most sensitive to changes in the CO_2 price. The coal price affects the production cost of the co-firing routes, but influences the economic potential[4] for all BE-CCS routes generating electricity.

We have identified important drivers and barriers that influence the deployment of BE-CCS technologies

Several technical, financial/economic and public & policy related drivers and obstacles for the deployment of BE-CCS technologies have been identified. The most important potential driver is the CO_2 price. Current CO_2 prices are, however, too low to create an economic potential for CCS technologies and substantially higher CO_2 prices require a much stricter climate policy. The position of BE-CCS technologies is even more challenging, as storing CO_2 from biomass will not 'create' sellable allowances under the current EU ETS regime. Inclusion of BE-CCS as Clean Development Mechanism (CDM) project activity would be another key driver for all BE-CCS routes as it facilitates financing of BE-CCS projects in developing countries.

The immature state of the technology is identified as a potential obstacle. Neither CCS nor advanced biomass conversion technologies (such as BIGCC) are considered to be mature technologies. The financial and technical risk of combining both can therefore be high, potentially leading to a higher financing cost.

Unsecure supply of sustainable biomass and unsecure availability of CO_2 storage capacity are also considered to be significant obstacles. The secure supply of low cost biomass will be a key driver for BE-CCS technologies. Important factors that will influence this cost are future land use scenarios and biomass price fluctuations.

Public perception is identified as another key factor in the success of BE-CCS. At various locations, local communities oppose CCS projects. Negative perception may stall CCS and can also result in higher transport and storage cost. However, BE-CCS may face less public resistance than CCS because of its association with renewable energy supply.

Further R&D and policy actions are needed to facilitate the deployment of BE-CCS

- The most significant recommendation is that stored CO_2 originating from biomass should have an economic value. The CO_2 price, in combination with low cost biomass, is the key driver for BE-CCS technologies.
- Further research should be focused on assessing the BE-CCS potential per region in greater detail through regional specific cost supply curves for CO_2 transport and storage, including source sink matching.
- State-of-the-art sustainability criteria for biomass production should be applied when assessing the potential for BE-CCS technologies. It is important to

[4]Economic potential is the amount of final energy that can be produced with lower cost compared to the reference technologies (for power generation routes) or energy carriers (for biofuel routes). The reference technologies for power generation are coal fired IGCC with CCS and PC with CCS. The reference energy carriers for the biofuel routes are crude oil and diesel.

understand the implications of implementing sustainability criteria on the biomass supply potential. We recommend that additional research efforts should be employed to verify our results with a more detailed assessment of factors that limit the sustainable supply of biomass on a regional base and assess the possibilities (including policy actions) for increasing the sustainable supply.

- It is also advised to include assessing biomass supply options that are not explored in this study, such as aquatic biomass from algae and seaweed.
- Detailed and consistent storage capacity estimates for world regions are currently unavailable. Although this is not specifically a BE-CCS technologies issue, it is recommended that the large uncertainty associated with estimating global storage potentials is appropriately addressed in future BE-CCS studies and that future research efforts are aimed at decreasing this uncertainty.
- It is recommended that the effect of (co-)firing biomass on the (economic, energetic and environmental) performance of CO_2 capture options (pre- post- and oxyfuel combustion) in pilot/demonstration CCS plants is assessed and tested. Any technical obstacles can be indentified and removed to facilitate the deployment of BE-CCS technologies.
- A BE-CCS option that is omitted in this study is the co-utilisation of biomass and coal in existing and new Fischer Tropsch facilities that are planned or currently operating worldwide. In conjunction with CO_2 capture from bio-ethanol production, this could provide early opportunities for BE-CCS at relatively low cost. Mapping these opportunities and examining technological and cost aspects in greater detail, on a case-by-case basis could be a valuable next step.
- Short and long-term price estimations are pivotal to assessing the economic potential of biomass and CCS. Insights and quantification of the key factors that influence the trade volume and price of biomass would be a valuable next step for a more robust assessment of the economic potential of BE-CCS technologies.
- The final recommendation is to focus research on gaining insight into the economic and infrastructural boundary conditions for CO_2 capture from bio-ethanol production, such as maximum economical transport distance and/or the minimal required CO_2 capture capacity. Detailed case studies can provide an insight into these boundary conditions. This option seems an economically attractive option for the short to medium-term. It is likely that short-term opportunities exist in Brazil and the USA, which are the largest producers of bio-ethanol and have considerable storage potential.

Table of contents

1 Introduction

Carbon Dioxide Capture, Transport and Storage (CCS) can potentially reduce emissions of CO_2 considerably over the next few decades. It is considered a key technology, amongst many other GHG reduction options such as energy savings and renewable technologies, to allow reaching the 2 degrees target.

CCS is often associated with the use of fossil fuels and most notably, with the use of coal. However, CCS can also be combined with bioenergy production. Short-cycle carbon is harvested and stored deep underground. Effectively, this suggests that carbon dioxide removed from the atmosphere, leading potentially to negative GHG emissions, see Figure 1 - 1. It is therefore, one of the few options that make reduction of global CO_2 concentrations in the atmosphere possible. Several mitigation scenarios show that biomass, in combination with CCS, is likely to be required to meet low GHG stabilisation concentrations (Azar, Lindgren et al. 2006; IEA/OECD 2008; IEA 2009; Luckow, Dooley et al. 2010).

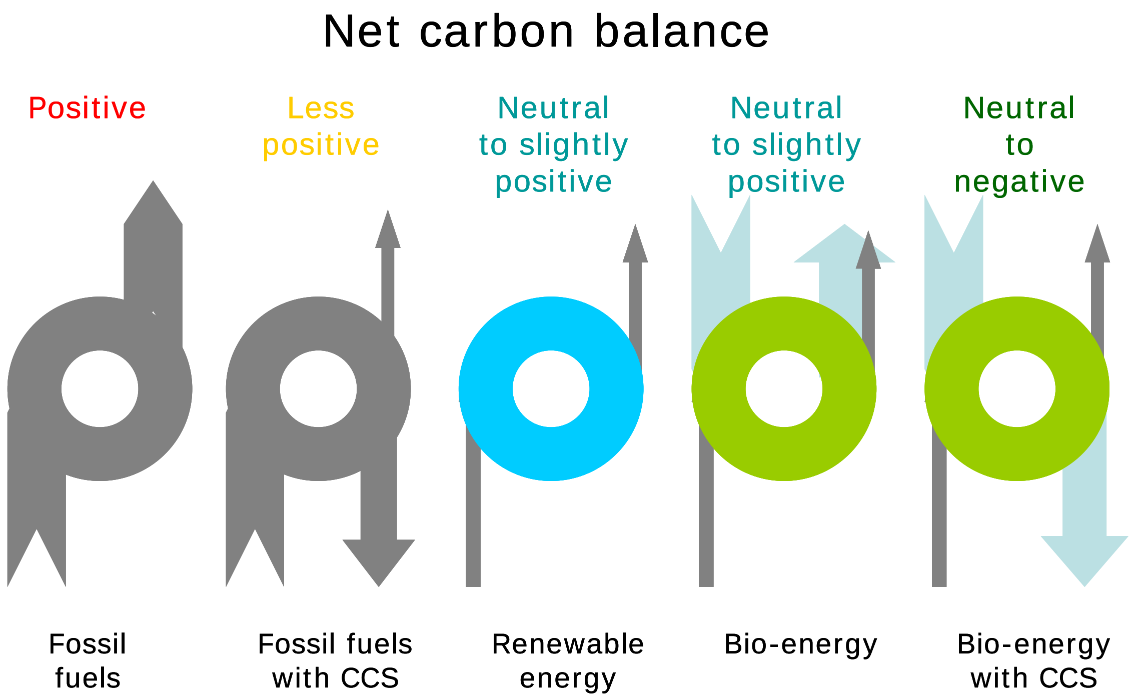

Figure 1 - 1 Carbon balance for different energy systems (adapted from (www.ecofriendlymag.com 2010). Note that grey arrows indicate CO_2 originated from fossil energy carriers and turquoise arrows indicate CO_2 from biogenic origin.

The combined application of biomass and CCS in energy conversion technologies has many technological similarities with CCS applied to fossil fuel energy conversion. Biomass can, for instance, be converted into electricity and heat in coal fired power plants equipped with CCS. Electricity generation using biomass alone will make use of conversion technologies (i.e. combustion and gasification) that also allow capturing the CO_2. However, there are also differences between biomass and fossil fuels when they are used for the production of electricity and heat. Biomass fuels typically have other combustion/gasification properties, lower energy density and greater variation in fuel properties. This may require modifications (e.g. pre-treatment and feeding, boiler design and burner configuration) in the energy conversion process to allow large scale use of biomass. Biomass plants are also typically smaller than plants fed with fossil fuels. This will have an effect on the economies of scale, particularly when applying CCS.

Biomass and CCS is not restricted to the production of electricity or heat. Some production processes for biofuels such as bio-ethanol and Fischer-Tropsch diesel manufacturing, produce (pure) CO_2 streams as a by-product that can easily be separated and captured.

The combined application of CCS and biomass (BE-CCS) has many advantages. As biomass use is expected to increase in the future, the potential application of CCS will also increase. This may lead to reduced costs and improved use of the (local) CO_2 infrastructure. CO_2 emission reduction with biomass and CCS is a very effective option to remove CO_2 from the atmosphere, in contrast with the use of fossil fuels in combination with CCS, which will result in an increase in global CO_2 concentration. Another possible advantage of the use of CCS with biomass is that its application is less controversial than that of fossil fuels. Many NGOs are opposed to CCS with coal but less opposed to CCS in combination with CCS, leading to potentially less (public) opposition to the application of CCS. An early deployment of CCS combined with biomass may facilitate a faster implementation of CCS policy. CCS can then be applied more broadly once the technological aspects are understood and (storage) safety is proven.

In summary, BE-CCS technologies may play a considerable role in the future of a low-carbon energy supply. The IEA foresees that the majority of CCS projects in 2050 will be established in various sectors in developing countries and not just in developed countries. Considering this envisaged worldwide deployment of CCS projects it is therefore also of eminent interest to create a good understanding of global and regional potential of biomass and which aspects of that potential may be used in BE-CCS technologies.

A major drawback for the deployment of BE-CCS is that there is considerably less information available for this technology than for fossil fuel based CCS systems. There is currently no comprehensive overview available of the technical and economic differences between fossil fuel, and biomass-based energy conversion technologies in combination with CCS. An overview of global and regional biomass potential has not yet been published. Also an assessment on the match of BE-CCS with global and regional CCS storage potential has not yet been published. In addition, the global potential of the BE-CCS option and the drivers and obstacles that will accelerate or limit the implementation of this potential in the future, are also not well defined.

The aim of this study is to provide an understanding and assessment of the potential for BE-CCS technologies up to 2050. We make a distinction between:

- *Technical potential* (the potential that is technically feasible and not restricted by economical limitations),
- *Realisable potential* (the potential that is technically feasible and takes into consideration the demand for energy and more realistic scenarios for capital stock turnover),
- *Economic potential,* (the potential at an economic cost compared to alternatives).

In some circumstances the difference between these potentials can be large and it is imperative, for the deployment of BE-CCS, to understand these differences. Next to the quantitative estimates of these potentials, in the form of regional and global supply curves, this study will present recommendations to solve possible obstacles and enhance drivers to stimulate the deployment of BE-CCS technologies.

2 General approach

2.1 Classification of potentials

There is no common terminology for energy potentials (Resch, Held et al. 2008). Therefore, it is imperative to understand the definitions and classification of potentials we use in this study. The results of our study can then be compared to other studies on a parallel basis.

The deployment and possible use of energy technologies fundamentally depends on the availability of resources and the cost of those resources. The difference in various terms used to define potentials lies in the limitations or constraints that have been applied to the 'availability of resources'. The different potentials are illustrated in Figure 2 - 1. If there were no constraints on using all available resources then this is the maximum potential. This is the **theoretical potential.** If we apply current or future technical constraints, then we derive the **technical potential**. This potential indicates the amount of resources that can be maximally used or converted, depending on the technical status of conversion technologies. This is a constraint that varies over time due to technological progress. For Biomass and CCS technologies, the technical potential[5] is constrained only by the availability of sustainable biomass and CO_2 storage capacity, and the (future) technological performance of the technology. The **realisable potential** is the technology potential, but with an additional constraint determined by the possible deployment rate and expected (energy) demand. This means that the realisable potential increases in time, in accordance with the possible deployment rate. The deployment rate is constrained by the possibility of applying BE-CCS to existing energy conversion technologies and the retirement rate of existing technologies. The **economic potential** is the subset of the technical potential that can be realised at acceptable costs. This potential takes into consideration the cost of the use of resources and the cost of competing technologies. The **market potential** is also referred to as a variant of the economic potential. It indicates the proportion of the technical potential that is attractive to realise from the perspective of private investors. The market potential also includes obstacles and drivers (for example subsidies, taxes or regulation). A visual representation of market drivers and obstacles is provided in Figure 7 - 1. One can speak of the enhanced market potential if possible drivers are included, such as higher carbon prices and obligations.

Potentials therefore indicate the possibility for growth of technologies or measures depending on the removal of constraints. In this study we distinguish between the following potentials:

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[5] In some studies the technical potential of biomass supply is considered the global potential of biomass supply without sustainability criteria applied (see for instance (EC 2009)). Throughout this report, we only consider the sustainable biomass supply potential. When we refer to the 'Technical potential', sustainability criteria are already taken into account.

1 Technical potential
2 Realisable potential
3 Economic potential

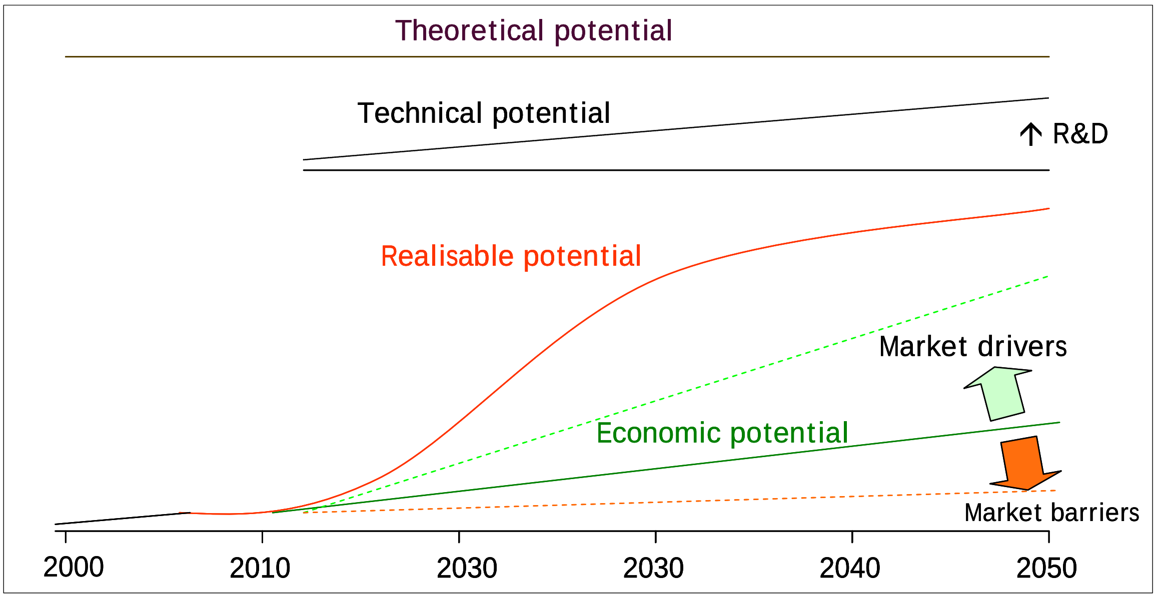


Figure 2 - 1 Graphical representation of the definitions for potentials used in this study (adapted from (Resch, Held et al. 2008))

2.2 General methodology and chapter overview

In this study, the potential for CCS and biomass (BE-CCS) are assessed step-by-step for the view years, 2030 and 2050. Figure 2 - 2 shows the tasks identified in the study. These tasks are described further below. In this chapter, we discuss only the general approach. Detailed methodologies for the calculation of potentials are presented in separate chapters.

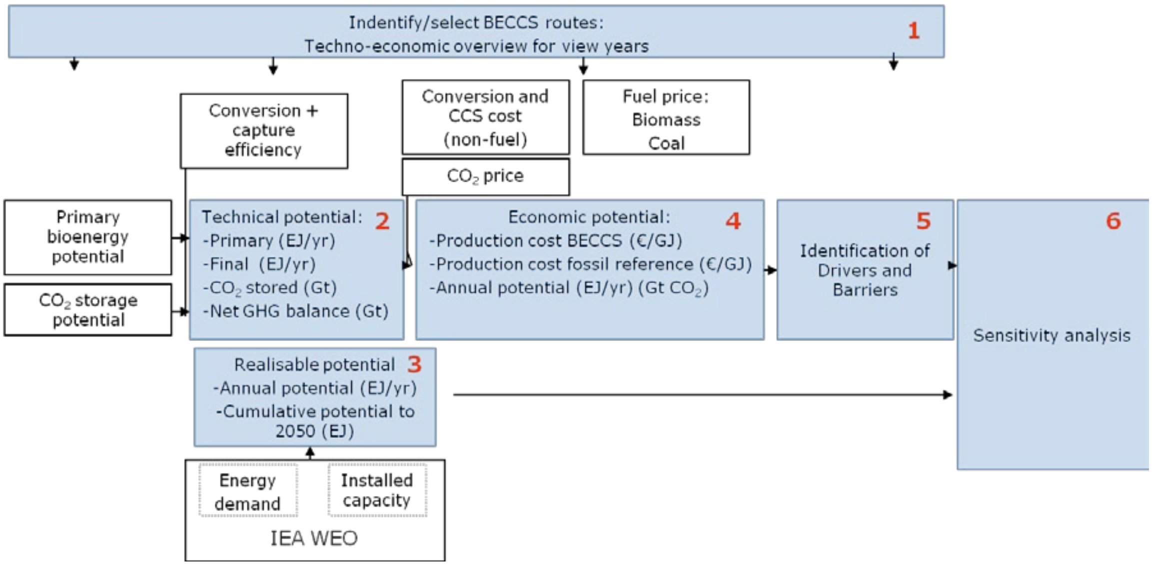


Figure 2 - 2 Overview of research steps in this study. EIA WEO stands for World Energy Outlook 2009 by the IEA, which is used to determine the realisable potential

In chapter 3 - indicated by the red number 1 in Figure 2 - 2 - we identify possible technological routes for combining biomass energy conversion systems with CO_2 capture, transport and storage. This includes the main biomass conversion technologies (biomass for large–scale electricity production (both 100% biomass and co-firing); bio-fuel production (i.e. bio-ethanol and Fischer Tropsch bio-diesel); and other large-scale biomass conversion technologies generating CO_2). In this task also six BE-CCS technologies are selected for further analysis.

In chapter 4, we perform a technical analysis on the selected combinations of biomass with CCS. We discuss (technological) differences between BE-CCS and fossil-fuel based technologies and we provide an analysis on BE-CCS technologies with respect to the development status & prospects, typical scale and efficiency of conversion units. We estimate the technical performance of the selected BE-CCS technologies in the view years 2030 and 2050. We estimate the storage potential and CO_2 storage capacity for seven world regions. The technical potential of BE-CCS (expressed in EJ-final energy) is determined by the availability of sustainable biomass and the net energy conversion of each of the selected BE-CCS route, including energy requirements for CCS. The technical potential can also be restricted by CO_2 storage availability. Chapter 4 provides the methodology, explained in detailed, and the results.

In chapter 5, we estimate the realisable potential for the selected BE-CCS routes with a separate model. The realisable potential for the electricity producing BE-CCS routes is determined through the IEA World Energy Outlook Reference scenario (IEA 2009). To estimate the potential (in EJ/yr) of BE-CCS we take into account the expected growth in capacity due to increased global demand, replacement of existing stock and retrofit of existing stock with BE-CCS.

In chapter 6, we present a detailed overview of the cost of various steps in the BE-CCS routes. We determine the annual economic potential of BE-CCS routes by combining the fuel price, conversion cost, cost of CCS and the CO_2 price. We also present the cost of the reference technologies. The economic BE-CCS potential arrived at is the total final energy that can be annually converted at lower cost than the competing (fossil) reference technologies. Results are presented in the form of cost supply curves for the selected BE-CCS routes.

In chapter 7, we focus on key drivers and obstacles that will impact the deployment (rate) of BE-CCS technologies. We identify drivers and obstacles and characterise these as technical, financial/economic and public & policy related factors. We present an overview of these drivers and obstacles and describe a conceptual model that explains how these factors influence the technical, realisable or economic potential, including the linkages between the drivers and obstacles.

In chapter 8, we apply a sensitivity analysis (task 6 in Figure 2 - 2), which is used to assess the effect of uncertainties on the outcomes presented in the preceding chapters. The sensitivity analysis shows the variation of one parameter/assumption in the model and the effect of this on the outcomes of the model. We selected relevant parameters/assumptions based on the expected uncertainty of input data and the overview of drivers and obstacles for BE-CCS routes presented in chapter 7. Detailed methodology and results are given.

In chapter 9, we discuss the pivotal results of our study and compare these with the outcomes of earlier studies. The most significant limitations of our methodology and results are discussed in this chapter.

We conclude with chapter 10 where our key findings are summarised and we formulate recommendations for further research and policy actions.

A quick reference to the overall results of this study can be found in Appendix D.

3 Possible technologies for biomass conversion and CO_2 capture

This chapter presents available technology routes that combine biomass conversion and CO_2 capture, based on a literature review. We also provide an overview of the potential available technologies to capture, transport and store carbon dioxide and indicate how these can be applied to biomass conversion technologies. Finally, we select six BE-CCS technologies for further analysis.

3.1 Introduction CCS

CCS is the acronym for carbon dioxide capture and storage. It is an umbrella term for a wide variety of technologies that aim to reduce anthropogenic CO_2 emissions to the atmosphere. It comprises three distinctive steps: CO_2 capture, transport and storage.

Generally, four categories of CO_2 capture are distinguished:

1. Post-combustion capture;
2. Pre-combustion capture;
3. Oxyfuel combustion capture.
4. Capture from industrial processes.

Below, we describe these technologies briefly.

Post-combustion

CO_2 can be captured from the flue gas of a combustion process. This can be flue gas coming from any (pressurised) combustion in a boiler, gas turbine or industrial process yielding CO_2. Various capture mechanisms, or combinations of them, can be applied; phase separation, selective permeability and sorption (see Table 3 - 1). The last mechanism, sorption, is the most widely recommended mechanism to be used at large point sources.

Pre-combustion capture

Pre-combustion capture comprises a group of technologies that remove CO_2 before the combustion of the fuel. This requires a carbonaceous fuel to be broken down into hydrogen (H_2) and carbon monoxide (CO), i.e. syngas. This process is referred to as reforming or partial oxidation for gaseous fuels and gasification for solid fuels.

For CO_2 capture of the highest possible efficiency, the syngas formed after steam reforming or partial oxidation/gasification must be shifted after it is cleaned. The 'shift reaction', or 'water gas shift' (WGS) reaction, yields heat and a gas stream with high CO_2 and H_2 concentrations. The CO_2 can then be removed with chemical and physical solvents, adsorbents and membranes.

Table 3 - 1 CO_2 separation techniques

Separation techniques	Post-combustion	Oxyfuel - combustion	Pre-combustion
Chemical and physical absorption	chemical solvents[1]	-	Physical solvents chemical solvents[1]
membranes	Polymer Ceramic Hybrid Carbon	polymer	Polymer ceramic palladium
adsorption	Zeolites active carbons sorbents type: “molecular basket”	Zeolites active carbons adsorbents for separation O_2/N_2	Zeolites active carbons aluminium and silica gel
cryogenic	-	Distillation[1]	-

[1] Separation techniques currently used on a commercial scale. Source: (Majchrzak-Kucęba 2008)

Oxyfuel combustion

Oxyfuel combustion is based on denitrification of the combustion medium. The nitrogen is removed from the air through a cryogenic air separation unit (ASU) or through the use of membranes. Combustion therefore takes place with almost pure oxygen. The final result is a flue gas containing mainly CO_2 and water. The CO_2 is purified by removing water and impurities. The production of oxygen and the purification and compression of CO_2 stream require a significant amount of energy, which reduces the efficiency of the power plant.
Combustion with oxygen is currently applied in the glass and metallurgical industry (Buhre, Elliott et al. 2005; IPCC 2005; M. Anheden, Jinying Yan et al. 2005). However, the concept has not been applied in large utility scale boilers for steam generation and power production. Oxyfuel combustion using solid fuels has only been proven in test and pilot facilities. It can also be applied in natural gas fired concepts. Power cycles for gaseous and solid fuels, however, vary significantly.

Capture from industrial processes

This group of technologies is often mentioned as an early opportunity for CCS at relative low cost. The total reduction potential due to CO_2 capture from these point sources is considered rather limited however. Examples of industrial processes are the production of cement, iron and steel, ethylene (oxide), ammonia and hydrogen. CO_2 can also be captured from natural gas sweetening processes and from refineries (IPCC 2005). The capture processes applied are generally the same technologies already described. However, some industrial processes yield nearly pure CO_2 streams. This reduces energy and capital requirements compared to capture from streams with low CO_2 concentrations. The production of bio-ethanol is a good example of an industrial process that yields nearly pure CO_2.

3.2 Biomass conversion technologies with CO_2 capture

Biomass is by far the largest contributor to renewable energy production in the world. A large part is the non-commercial use in developing countries. Biomass is also widely used as a commercial power production source, either in dedicated biomass plants or by co-firing with fossil fuels in large scale coal fired power plants (Junginger, Lako et al. 2008). Biomass has integral similarities with fossil fuels (particularly coal) and uses the same conversion technologies for power production, i.e. combustion and gasification concepts. The three capture technologies could theoretically all be applied to biomass conversion technologies for power production. Due to technical and economical reasons, CO_2 capture is generally considered to be feasible at industrial scale energy conversion technologies.

Industrial scale power and heat production can be found in several sectors providing opportunities for BE-CCS technologies. These sectors are the power sector where biomass is co-fired on a relative large scale; pulp and paper production where combustion and gasification of biomass residues provides power and heat; and in large scale CHP applications for, among others, district heating (currently predominantly found in Scandinavian countries).

Another large scale conversion route for biomass is the conventional production of “first generation” biofuels derived from starch (e.g. corn), sugar (e.g. sugarcane) and oil crops (e.g. palm and rapeseed oil). High production levels of these fuels occur in Brazil and the United States (mainly ethanol) and also in Europe (predominantly biodiesel). The production of, “advanced generation” biofuels is still in an early commercial stage. Examples include ethanol production from ligno-cellulose biomass through hydrolysis and fermentation and Fischer-Tropsch biodiesel production. Relatively pure streams generated during biofuel production facilities provide an additional opportunity to capture CO_2 with relative ease (Mollersten, Jinyue Yan et al. 2003; Rhodes and Keith 2008).

This results in several routes for integrating biomass energy conversion systems with CO_2 capture, transport and storage. These routes are presented in the figure below and encompass both dedicated biomass firing routes as routes that allow co-utilization (co-firing and co-gasification) of biomass and fossil energy carriers:

1 Biological processing (e.g. fermentation) for fuel production with the capture of CO_2.
2 Biomass gasification with shift and pre-combustion CO_2 separation to produce hydrogen rich syngas, which can be used for the production of chemicals, fuels and power.
3 Production of power and heat by combustion combined with post-combustion capture;
4 Production of power and heat based on oxyfuel combustion.

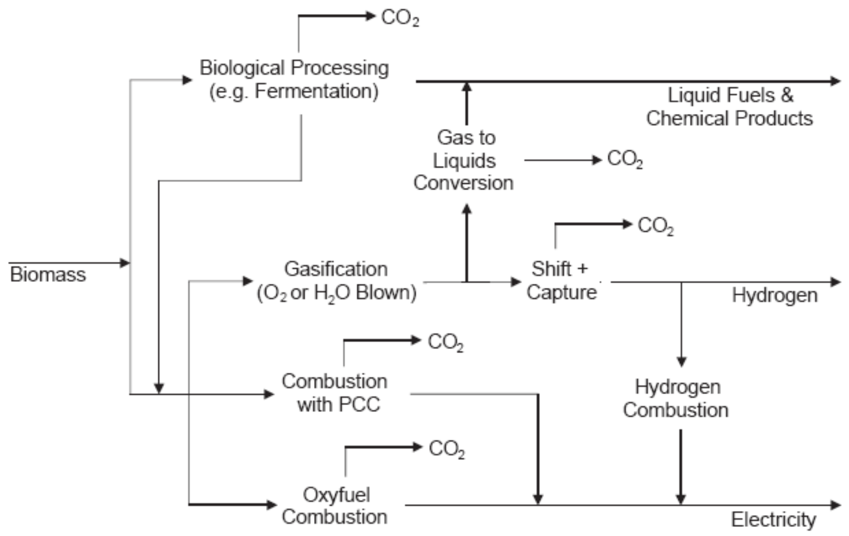


Figure 3 - 1 Routes for biomass conversion with CO_2 capture (Source: (Rhodes and Keith 2005)) PCC = post-combustion capture.

3.3 BE-CCS technologies assessed in this study

These basic methods described above can be combined and integrated with other technologies, for example, by gasification of residual biomass from biological processes with CCS, by syngas conversion to liquid fuels with CCS or by burning hydrogen-rich syngas to produce electricity with CCS. Not all possible BE-CCS technologies are incorporated in this study. Examples are oxyfuel conversion and the application of BE-CCS technologies in the pulp and paper sector. Here, we focus on technologies that have been described in literature as BE-CCS technologies with the greatest anticipated potential.

Mollersten et al. (Möllersten, Yan et al. 2003) suggest that CO_2 capture from bio-ethanol production and from chemical pulp mills are promising market niches for BE-CCS. In recent studies, the BE-CCS potential is estimated to be greatest when combining CCS with the production of power and biofuels (IEA 2009; Luckow, Dooley et al. 2010). Promising technologies mentioned for the production of power with biomass and CCS are co-firing biomass in coal fired power plants with post-combustion CCS and the dedicated firing of biomass in fluidised bed combustion technology with CCS (IEA GHG 2009). In addition to combustion, (co-)gasification of biomass in combination with pre-combustion CCS in an (B)IGCC is also widely proposed in literature as a possible option for the production of power (Rhodes and Keith 2005; Luckow, Dooley et al. 2010).

For the production of biofuels, two technologies are being proposed: CO_2 capture from ethanol production and from synthetic biodiesel production using biomass gasification and Fischer – Tropsch synthesis (Möllersten, Yan et al. 2003; Ecofys 2007; Larson, Fiorese et al. 2009; van Vliet, Faaij et al. 2009; Luckow, Dooley et al. 2010; Xu, Isom et al. 2010).

Here we focus on the two major sectors for the application of BE-CCS technologies, large-scale electricity generation and biofuel production. For the latter we have selected the advanced generation of bio-ethanol and synthetic diesel production as key technologies. For the power sector, we have selected energy conversion technologies based on gasification and combustion of biomass. For these two types of conversion technologies, we distinguish between co-firing and dedicated firing. This results in the BE-CCS technologies summarised in Table 3 - 2. The technical and economic performance of these technologies is presented in chapters 4 and 6. More details are discussed in the Factsheets provided in Appendix E to Appendix H.

Table 3 - 2 BE-CCS technologies assessed in this study

Conversion technology	CO_2 capture principle	Route reference
Electricity production		
Pulverized Coal fired power plant with direct biomass co-firing	Post-combustion	PC-CCS co-firing
Circulating Fluidised Bed combustion power plant with 100% biomass	Post-combustion	CFB-CCS dedicated
Integrated Gasification Combined Cycle with co-gasification of biomass	Pre-combustion	IGCC-CCS co-firing
Biomass Integrated Gasification Combined Cycle with 100% biomass	Pre-combustion	BIGCC-CCS dedicated
Biofuel production		
Advanced production of bio-ethanol through hydrolysis + fermentation	Nearly pure CO_2 only drying and compression. (+ post-combustion)[1]	Bio-ethanol advanced generation
Biodiesel based on gasification and Fischer Tropsch-synthesis	Nearly pure CO_2 from Pre-combustion; only compression[2]	FT biodiesel

[1]CO_2 from the fermentation step is nearly pure and only requires drying and compression. No capture process is required. Residues from ethanol production can be used to generated heat and power in a boiler. Off-gases from combustion can be captured using post-combustion technologies. This is not taken into account in this study.

[2]Pre-combustion capture technology is already applied in the FT-concept to optimize the conversion of syngas from gasification into biofuels (including biodiesel). CO_2 capture then only requires drying and compression compared to a FT-plant without CO_2 capture.

4 Technical potential

In this chapter, we discuss the technical status and position of the steps within the entire BE-CCS chain, including biomass and CO_2 storage potentials. We present the results of the (annual) technical potential for the BE-CCS conversion routes. The technical potential is presented as the primary and final energy potential and the potential in terms of net GHG emissions. The technical potential is constrained by either the storage or sustainable biomass potential. This constraint is dependent on the capture and conversion efficiencies. The technologies have different conversion and CO_2 capture efficiencies, which result in a range of technical potentials. The biomass potentials are provided in Appendix B and CO_2 storage potential estimations are in Appendix C. Overall results are presented in Appendix D. The technical potential is assessed over medium (2030) and long term (2050).

4.1 Summary

An overview of technical potentials is provided in Table 4 - 1, Figure 4 - 1 and Figure 4 - 2. All routes have a similar potential in terms of primary energy. The results show that in most regions the potential is limited by the availability of sustainable biomass as there is sufficient CO_2 storage capacity available (see Figure 4 - 1). The technical potential of BE-CCS routes is thus most often limited by the biomass potential. Less storage capacity is required for the routes producing biofuels and for the routes of power generation that only use biomass. In the biofuel routes a relatively small fraction of CO_2 is captured, therefore a relatively small storage capacity is required. In the 100% biomass routes for power generation, less storage capacity is required, as this route does not have to store CO_2 originated from coal conversion; this is the only the case in the co-firing routes. Only in the instance where depleted hydrocarbon fields are used alone, storage capacity may become a limiting factor. Inter-regional transport can contribute to match biomass availability with storage capacity.

The technical potential expressed in final energy is solely dependent on the conversion efficiency of the BE-CCS technologies. This is greatest for the IGCC co-firing route and the lowest for the advanced generation of ethanol.

The amount of CO_2 stored is dependent on the primary energy potential and the CO_2 capture efficiency. This amount increases towards 2050, as both biomass supply and capture efficiency is estimated to increase. Another important factor is the co-firing of coal. This CO_2 is also stored which explains the significantly higher amounts of CO_2 stored in the co-firing routes (see Figure 4 - 2). Co-firing also affects the net GHG balance (in CO_2 eq.) for the routes. The negative emissions are the largest for the dedicated routes, BIGCC and CFB with CCS. The negative emissions for the biofuel routes with CCS are the lowest because a smaller fraction of the CO_2 is captured.

Table 4 - 1 Overview of technical potentials per conversion routes

BE-CCS route	Year	Technical potential				
Electricity generation		Primary energy EJ/Yr	Final energy (biomass share) EJ/yr	Final energy (total) EJ/yr	CO_2 stored Gt/yr	net GHG emissions Gt/yr
PC-CCS co-firing	2030	73	27	90	19.0	-4.3
	2050	126	54	108	20.9	-9.9
CFB-CCS dedicated	2030	73	24	24	5.9	-5.7
	2050	126	47	47	10.7	-10.4
IGCC-CCS co-firing	2030	73	30	99	19.0	-4.3
	2050	126	59	118	20.9	-9.9
BIGCC-CCS dedicated	2030	73	28	28	5.9	-5.7
	2050	126	57	57	10.7	-10.4
Biofuels						
BioEthanol	2030	73	19	19	0.7	-0.5
	2050	126	40	40	1.4	-1.1
FT biodiesel	2030	73	28	28	3.6	-3.3
	2050	126	47	47	6.1	-5.8

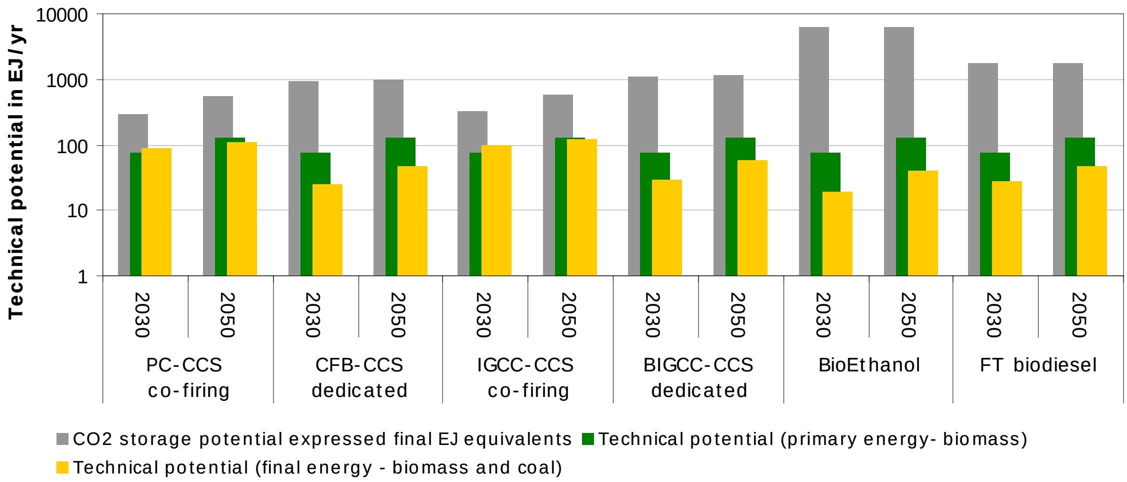


Figure 4 - 1 Technical potential for the six BE-CCS routes showing the primary biomass potential, final energy potential and the CO_2 storage potential expressed in final energy equivalents per route. Note the logarithmic scale.

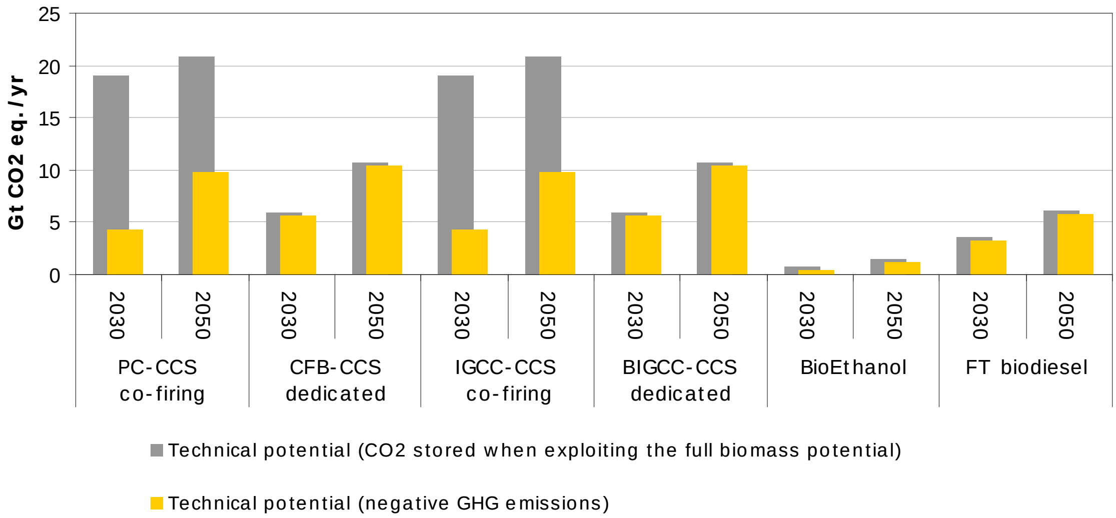


Figure 4 - 2 Technical potential for the six BE-CCS routes showing the amount of CO_2 stored when fully exploiting the biomass potential in one single route and the technical potential expressed in net negative greenhouse gas emissions.

4.2 Determining the technical potential

To determine the technical potential, we combine existing studies on biomass potentials (in EJ/yr primary energy) and CO_2 storage potentials (in total Gt CO_2). The net energy conversion efficiency (including the energy penalty) and the carbon removal efficiency of the BE-CCS route then determine the technical potential for biomass CCS in terms of primary energy converted, final energy and net (negative) GHG emissions. In some regions, the CO_2 storage capacity may be a constraint and in others the availability of sustainable biomass. In this study, we therefore distinguish various regions for which the BE-CCS potential is assessed.

A geographic breakdown is used to show the availability of sustainable biomass resources and storage capacity per region. The breakdown allows the regional assessment of the potential for the selected BE-CCS routes.

We divided the world into seven regions:

- Africa & Middle East (AFME)
- Asia (ASIA)
- Oceania (OCEA)
- Latin America (LAAM)
- Non-OECD Europe & the Former Soviet Union (NOEU)
- North America (NOAM)
- OECD Europe (OEU)

We then calculate the global potential, determined by the global storage and biomass potential assuming that inter-regional transport of biomass and CO_2 is allowed. Secondly, we exclude inter-regional transport of biomass. In the latter case, the BE-CCS potential may be lower as regional biomass availability may pose a constraint to the implementation of BE-CCS technologies.

Before estimating the technical potential, we first discuss the status and technical performance of biomass conversion routes that we have estimated to be available in the view years, 2030 and 2050. We will describe the technical development expected to occur per step in the full chain of the selected BE-CCS routes, see Figure 4 - 3. We focus on scale, conversion efficiency and the technical performance of CO_2 capture options applied to these conversion technologies. More details on these BE-CCS technologies are presented in the factsheets provided in Appendix E to Appendix H. A detailed overview of results can be found in Appendix D.

4.3 Technical performance of steps in the BE-CCS routes

In Figure 4 - 3, we show the steps in the BE-CCS routes that are analysed in detail in this study. In the sections below we discuss the technical performance of these steps and the assumptions that were made for the calculation of the technical potential.

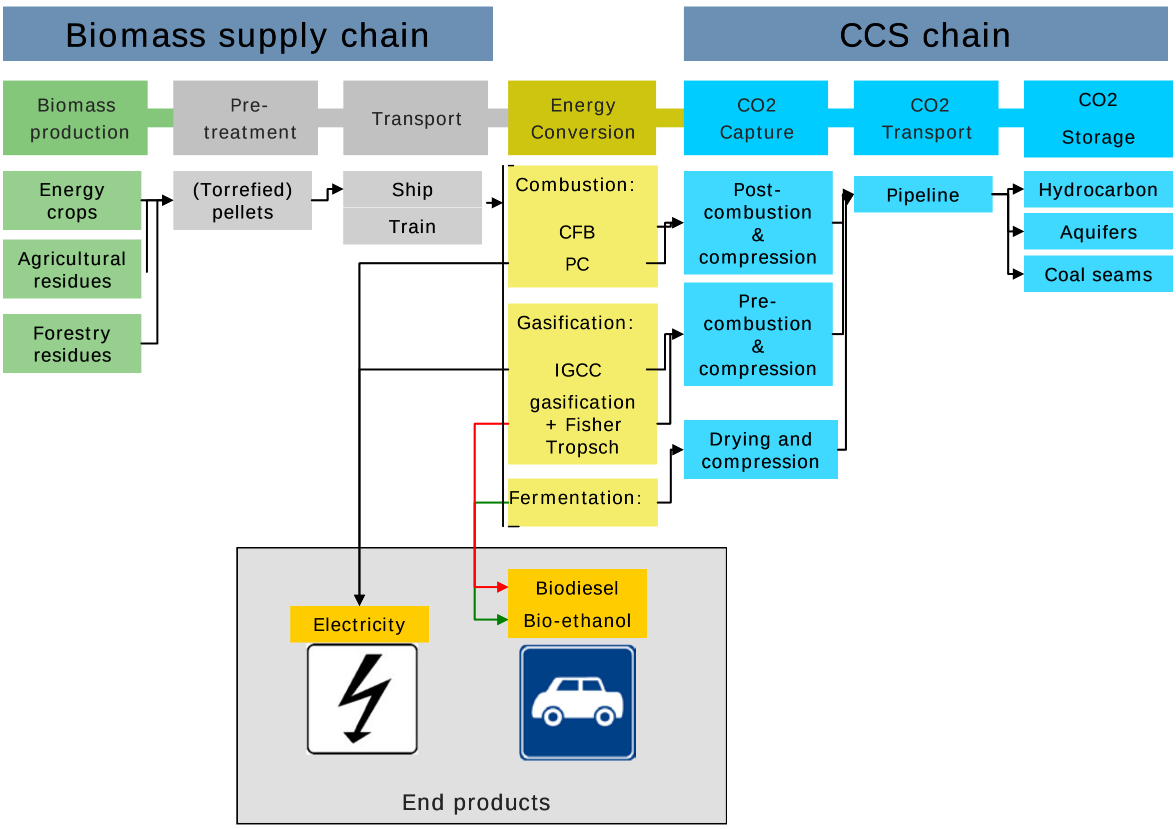


Figure 4 - 3 Steps in the BE-CCS routes. Per step the options researched in this study are indicated.

4.3.1 Sustainable biomass potential

Many routes can be followed to convert a broad range of raw biomass feedstock into intermediate and final energy products and along these routes, biomass can take different forms. Not all biomass forms are suitable for long distance transport and international trade.

Biomass for bioenergy production stems from plant or animal matter. Plant biomass originates from crops, but also from residues, intermediate (e.g. sugar, vegetable oil) and intermediate energy carriers (e.g. pellets, biofuels). In this study we focus on ligno-cellulose biomass such as wood and grass, vegetable oil, sugar and starch crops.

Biomass resources are available from a large range of different feedstock. Many of them are or can be traded on the international market. However, due to economical considerations, not all of them can be transported over longer distances.

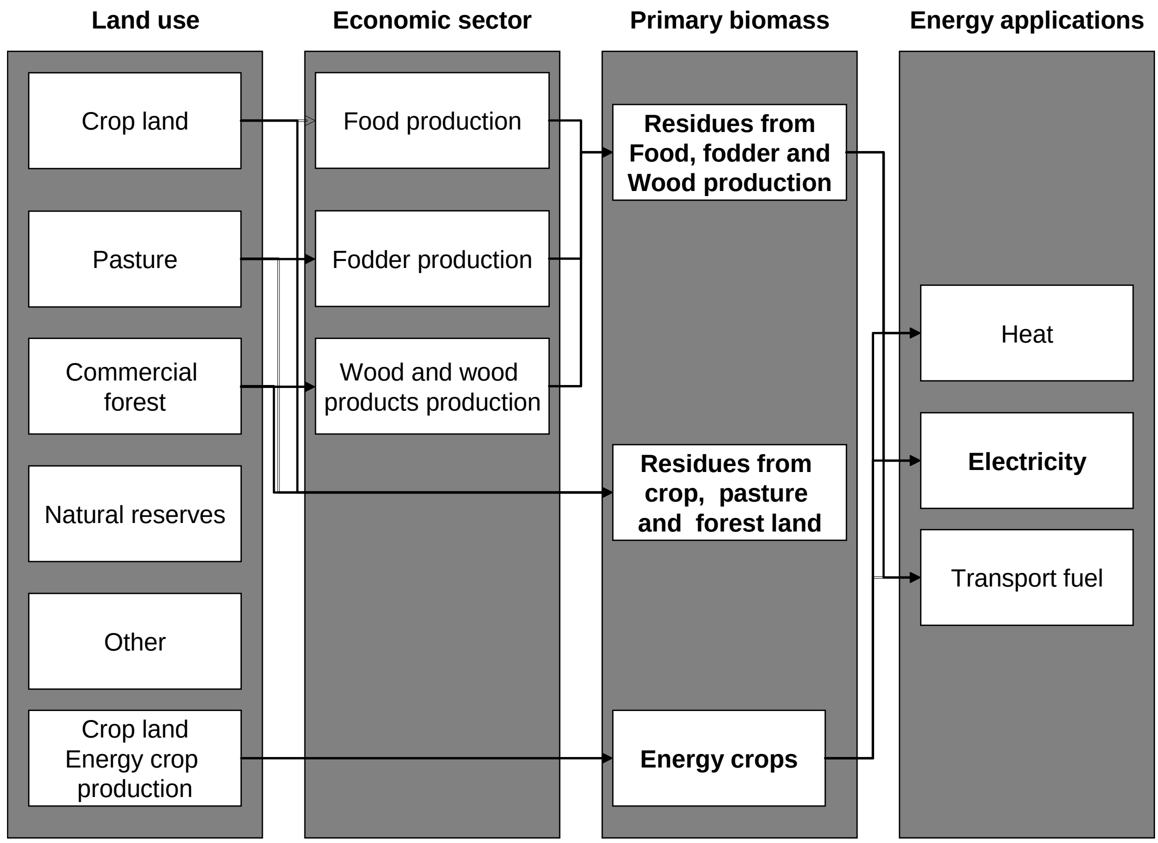


Figure 4 - 4 Schematic representation of the type of primary biomass feedstock and the conversion to energy applications. Note that the production of energy carriers (here the final part of the chain) often results in the production of valuable by-products.

Figure 4 - 4 gives a schematic representation of biomass and conversion to energy applications, i.e. heat, electricity and transport fuel. In this study we focus on the production of electricity and transport fuels.

In our study, we examine three categories of biomass further, which together represent at least more than 50% of land-based biomass resources:

- Energy crops
- Forestry residues
- Agricultural residues

Worldwide sustainable biomass potential for the selected categories is estimated based on data from van Vuuren et al. (van Vuuren, Vliet et al. 2009) and Hoogwijk (Hoogwijk 2004) (Hoogwijk et al. 2010). Potentials for forestry residues and agricultural residues are taken from (Hoogwijk et al. 2010). The potential for agricultural residues is estimated at 42 EJ. For forestry residues UNFCCC reports a range between 19 and 35 EJ. We use the lowest values to produce a conservative estimate for the potential of BE-CCS technologies. The energy crop potential is taken from (van Vuuren, Vliet et al. 2009). In that assessment, sustainability criteria are included. They indicate a biomass potential for energy crops that range between 65 and 148 EJ in 2050, depending on the set of sustainability criteria (see Box 1 for a more detailed discussion on sustainability criteria). The sustainability criteria they consider relate to water scarcity, biodiversity conservation and land degradation risk. They apply these criteria to assess the global availability of land for bio-energy production:

1. **Strict** set of criteria: Land occupied by expanding nature reserves, land areas that face mild risk for water scarcity and mildly degraded areas are excluded.
2. **Mild** set of criteria: New nature reserves, water scarce areas and severe degraded areas are excluded.
3. **No criteria**: The full technical potential without sustainability criteria applied.

Van Vuuren et al. estimate the full technical biomass potential **without** such criteria applied at 148 EJ in 2050. If they apply the full set of sustainability criteria the biomass potential for energy crops is about 65 EJ. We used the numbers derived by the application of the **strict criteria**. Although we do not take into account all sustainability criteria that are currently being discussed (see Box 1) we consider this set to be appropriate to estimate the sustainable production of bio-energy with BE-CCS technologies (see section 9 for a discussion on sustainable biomass potentials estimated in other studies). Appendix B gives an overview of the biomass potentials used in this study. All potential estimates are based on the potential given for 2050. The total potential for energy crops in 2030 is approximately 40% lower. For forestry residues, we have used the same 40% reduction for 2030 compared to 2050. For agricultural residues, we have used a linear extrapolation of the potential between 2005 and 2050 to estimate the potential in 2030.

Our selection excludes categories such as organic waste, animal dung/matter and the potential of aquatic biomass production in form of (micro or macro) algae or seaweed. Recent studies have estimated that the potential of this category of biomass may be in the order of several hundreds or even thousands of EJ on the longer term (Florentinus, Hamelinck et al. 2008; Bauen, Berndes et al. 2009). This aquatic biomass has been excluded from the current analysis as it is less extensively studied compared to land-based biomass resources. The relative low dry matter and uncertainties in the sustainability and logistics of offshore cultivation are aspects that have to be assessed in more detail before this category of biomass could be included as suitable feedstock in the selected BE-CCS routes.

Box 1 Sustainability criteria biomass production (Smeets, Faaij et al. 2005; Dehue 2006; EC 2008; EC 2009; WBA 2009; Dehue, Meyer et al. 2010; EC 2010)

In the past decade, the number of countries exploiting biomass opportunities for the provision of energy has increased rapidly. However, large scale biomass production for bioenergy has met concerns about sustainability. Sustainable development of biomass is considered a major challenge in increasing the production of biomass and is part of extensive public debate. The sustainable development debate focuses around topics to ensure that biomass production meets economical, social and environmental standards.

Social and economic standards or principles include:

- Maintain and enhance the economic viability of biomass production;
- Labour conditions including wages and health & safety of workers;
- Respect indigenous/local people and their traditions & customs. This includes the protection of areas with high historical, cultural and spiritual values;
- Acknowledge land rights of local communities;
- Rise in agricultural commodity prices, with potential consequences for food prices and security.

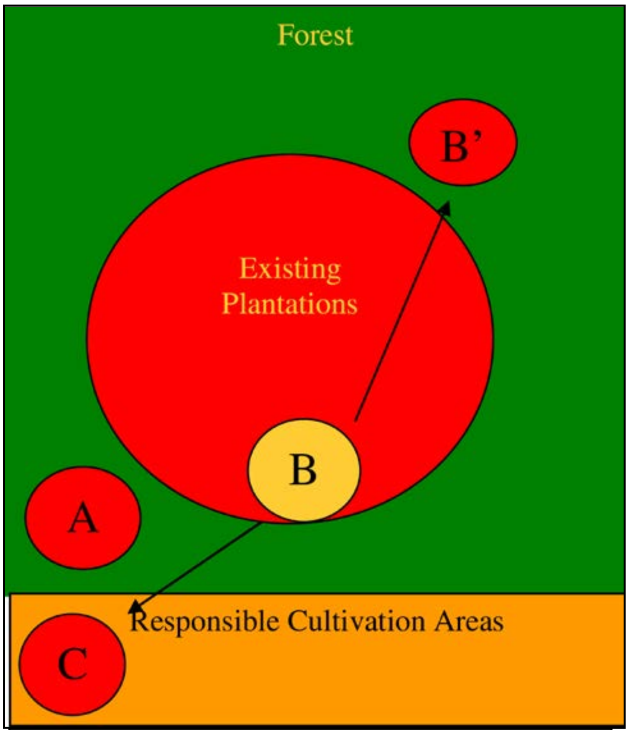
Next to socio-economic principles and associated criteria, also the principles related to producing biomass in an environmental responsible way are very important. They include:

- Minimum greenhouse gas savings including effects of land use change;
- Soil quality and erosion aspects;
- The use of chemicals and fertilizers;
- Water depletion and water quality;
- Protection or enhancement of air quality;
- Protection of areas with high ecological value and biodiversity;
- Avoidance of (indirect) land use change (ILUC and LUC) including, for instance, deforestation.

Especially competition for land (and food prices) as well as ILUC and LUC are on top of the list of items being discussed within the public and scientific arena (see for instance (EC 2010)). Below we explain LUC and ILUC in somewhat more detail.

Direct land use change (LUC)

A direct LUC occurs when new areas (e.g. forest areas or Responsible Cultivation Areas[6]; see the circles A and C in the figure) are taken into production to produce the additional feedstock demand for bioenergy. LUC can cause negative effects such as loss of biodiversity, loss of carbon stocks and land right conflicts as well as positive effects such as an increase in soil carbon, rural development and a change to more sustainable agricultural practices. Direct LUC effects and other direct effects of crop production can generally be measured and attributed to the party that caused them. These properties make direct LUC relatively easy to control. The development of voluntary certification schemes such as the Roundtable on Sustainable Palm Oil and the Round Table on Responsible Soy aim to prevent negative direct effects from crop cultivation.



Adapted from (Dehue 2006)

Indirect land use change (ILUC)

ILUC can occur when existing plantations (see circle B) are used to cover the feedstock demand of additional biofuel production. This displaces the previous productive function of the land (e.g. food production). This displacement can cause an expansion of the land use for biomass production to new areas (e.g. to forest land or to Responsible Cultivation Areas, see circles B´and C) if the previous users of the feedstock (e.g. food markets) do not reduce their feedstock demand and any demand-induced yield increases is insufficient to produce the additional demand.

Since land requirements are a key concern for both environmental and social sustainability issues, controlling direct and indirect LUC effects is a major challenge to ensure a sustainable energy crop production. Mitigation measures are in theory available to prevent or minimize unwanted indirect impacts from bioenergy. Development and implementation of these measures and certification systems are important for achieving sustainable bioenergy.

There are international efforts underway for several years to guide (formally or voluntary) the production and trade of bioenergy by establishing sustainability criteria. This includes sustainability criteria for biofuels in the EU Renewable Energy Directive and criteria proposed by, inter alia, the World Biomass association, Roundtable on Sustainable Biofuels (RSB), Roundtables on Sustainable Palm Oil (RSPO), Round Table on Responsible Soy Association (RTRS) and the Better Sugarcane Initiative (BSI).

[6] Areas where biofuel feedstock can be cultivated without risks of other farming activity being displaced, or of negative effects on biodiversity, the environment or local communities.

4.3.2 Pre-treatment and transport

Most forms of biomass tend to have a relatively low energy density per unit of volume or mass. Long distance transport and international trade is limited to commodities that have sufficient energy densities. Pre-treatment of biomass is therefore required to make transport economic and energetic viable.

Woody energy crops may be transported internationally, predominantly by ship as chips, pellets or briquettes. According to van Vliet et al. (2009), conversion of biomass feedstock to intermediate products such as pellets and torrefied pellets has been the subject of extensive study. In this study, two processes are assumed to be available in the view years:

- Biomass pellet production through heating followed by compression and cooling resulting in densities of 600-700 kg/m^3. Figure 4 - 5 shows that pellisation is currently in the commercial phase of development and is widely applied.
- Biomass pellet production through torrefaction. In this process the biomass is heated to produce a material similar to charcoal, which can be compressed to form pellets with a typical density of up to 800 kg/$m^{3.}$ The specific heating value of the biomass increases with this process, but at the expense of some energy that is required in the process. Torrefaction is currently in the R&D phase entering the demonstration phase of development, see Figure 4 - 5.

The pre-treatment of raw biomass feedstock into (torrefied) pellets comes with an energy penalty. That is, during the heating and densification energy is consumed, which is estimated in the range of 10-20% of the primary energy of the biomass input (van Vliet, Faaij et al. 2009). Here we assume an energy and carbon efficiency of 90%.

It should also be noted that dried and densified biomass still has a lower energy density than fossil fuels, which makes handling, storage and transportation more costly per unit of energy.

4.3.3 Technology status and prospects for biomass power plants

In Figure 4 - 5 the development status of biomass conversion technologies is presented. It is shown that direct co-firing (combustion) is currently a commercial technology. Biomass co-firing in modern, large scale coal fired power plants is widely applied and is the single largest growing conversion route for biomass in many EU countries. There are several technical options to co-fire biomass in coal fired boilers:

1. The milling of biomass pellets (see section 4.3.2) through modified coal mills;
2. the pre-mixing of the biomass with coal, and subsequent milling of and firing of the coal-biomass mix in the existing coal firing system;
3. The direct injection of pre-milled biomass into the pulverized coal pipework;

4. The direct injection of pre-milled biomass into modified coal burners;
5. The direct injection of pre-milled biomass through dedicated biomass burners or directly into the furnace;
6. The gasification of the biomass, with combustion of the product gas in the PC boiler.

The choice for one of the options above depends strongly on the properties of the biomass (heating value, particle size, combustion properties such as reactivity and grindability of the biomass) and the design of the PC power plant (e.g. fuel feeding system and burners). In this study we consider the second technical options as we assume that biomass is converted into (torrefied) pellets before feeding it into the power plant.

Typical large scale (up to GWe) combustion technologies available for biomass co-firing are pulverized coal power plant and fluidised bed combustion. No significant further scale up is expected for these technologies and these are expected to remain in the size range up to 1 GWe. Low co-firing shares (up to ~20%) have limited consequences on the performance of the boiler, flue gas treatment and maintenance. Going to higher shares (40-50%), which is the subject of current development efforts, requires technical modifications in boiler design (burner configuration), biomass feeding lines (pre-treatment) and may result into fouling, slagging and corrosion problems. It is expected that co-firing shares of 50% can be reached in the coming decades. The conversion efficiency (35%-45%) in large-scale coal plants is generally higher in comparison with dedicated firing of biomass. This is due to the size of the power plant and associated benefits, such as higher steam parameters and lower heat losses. Increase in conversion efficiency is expected for the coming decades with RD&D efforts aimed at reaching higher steam parameters (temperature and pressure) from the current sub- and supercritical towards ultra-supercritical steam conditions. This will increase the thermodynamic efficiency of the steam cycle.

Dedicated biomass fired power plants are currently also in the commercial phase of the development. A technology currently widely used for 100% biomass firing is fluidised bed combustion. Biomass-based power plants are typically in the size range between 20–50 MWe. Technologies are available up to 100 MWe and further scale up is deemed possible to several hundreds of MWe. We assume scales of dedicated power plants of approximately 500 MWe to be very likely in the coming decades (IEA GHG 2009).

Conversion efficiencies for smaller dedicated biomass plants are in the range between 25-30%, for larger plants of about 50-80 MWe efficiencies in the 30-36% range are possible. As for fossil fired power plants with co-firing, it is expected that conversion efficiencies will increase in the coming decades due to the development of ultra-supercritical steam cycles for dedicated biomass power plants. Nevertheless, conversion efficiencies are expected to be below that of fossil fired power plants due to a higher energy requirement for on-site pre-treatment and due to the lower heating values of the feedstock[7]. Furthermore, in fluidised bed combustion technologies endogenous energy demand is typically higher compared to pulverized coal power plants due to the parasitic load for fluidisation of the bed material and fuel, and recirculation of the bed material.

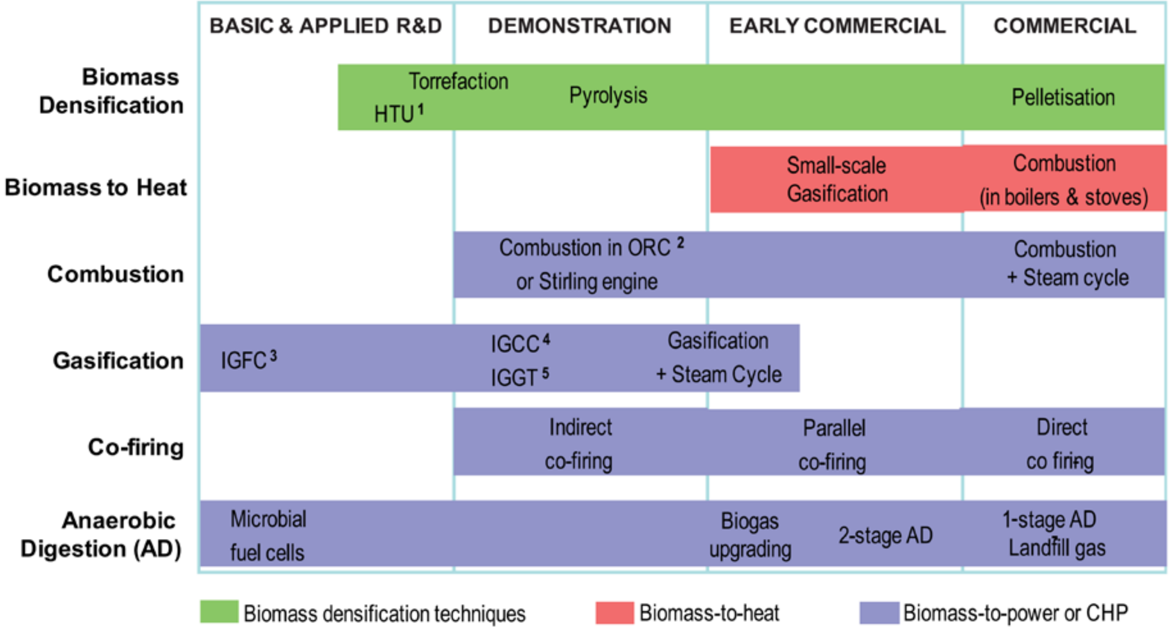


Figure 4 - 5 Development status of main biomass upgrade (densification) and conversion technologies (from: (Bauen, Berndes et al. 2009)) (1 = Hydrothermal upgrading, 2= Organic Rankine Cycle, 3 = Integrated gasification with fuel cell, 4 and 5 = Integrated Gasification with combined cycle/gas turbine)

Gasification of carbonaceous fuels is a commercial technology. However, the IGCC concept based on fossil fuels can be characterised as 'early commercial'. Only several (demonstration) IGCC power plants have been operating in the last decades. In addition, there is relative little experience with co-gasification of biomass and fossil fuels compared to co-firing in combustion concepts (Fernando 2009). The co-gasification of coal and biomass has been demonstrated in several types of gasifiers in several countries. It is expected that co-gasification rates in the order of 20-30 % (on energy basis) are technically feasible. Higher rates may be possible depending on the feedstock quality (e.g. high heating value, low moisture content).
The scale of IGCC power plants is currently up to approximately 300 MWe. Current reference design plants are available at the scale of 600 MWe up to over one GWe. Scale up is expected to be possible by installing multiple gasifier trains feeding multiple gas turbine combined cycles (GTCC). Current conversion efficiencies of IGCCs are found up to 45% (LHV). Co-gasification of biomass has typically a negative impact on overall generating efficiency. Improvement in efficiency in IGCC on the longer term

[7] A lower heating value of the feedstock results in a higher mass and volume handling (fuel and flue gas) per unit of primary energy input, resulting in relatively higher parasitic load; and with it reducing the overall efficiency. Lower heating values also affect the combustion characteristics and heat transfer.

is expected through increased conversion efficiency of the gas turbine, higher operating pressure in the gasifier, process integration and hot syngas cleaning. In this study we assume that conversion efficiencies of the IGCC can be increased towards ~55% in the longer term.

Dedicated gasification of biomass for power production is successfully demonstrated in the range of several MWe. Nevertheless this technology is considered the least mature conversion technology (see Figure 4 - 5). Dedicated BIGCC plants are possible in the scale range of ~30 MWe on the shorter term increasing to ~100 MWe size range on the mid-term. Following developments in the scale of gasifiers and fossil fired IGCCs we expect that BIGCC at a size of 500 MWe can become available in the longer term. Near future generating efficiencies are estimated at around 30-40% (LHV) for the size range of tens of MWe. Although extensive RD&D is required, we expect that conversion efficiencies above 50% can be achieved on the longer term.

4.3.4 CO_2 capture from biomass power plants

In theory, all capture principles can be applied to biomass power plants. In general, the same CO_2 capture technologies that can be applied to pulverised coal fired power combustion plants are suitable for equivalent biomass fired systems considered here, being: post-combustion capture and oxyfuel combustion. Post-combustion CO_2 capture is the most likely near term option for both co-firing and dedicated firing in concepts based on combustion. Oxyfuel combustion is also an option, but this technology has not been extensively demonstrated and should be regarded as a technology available in the mid-term. In this study we therefore focus on post-combustion capture.

Capture efficiencies mentioned in literature for the post-combustion option are generally in the range of 85-95%. It is possible to reach nearly 100%. This is however not attractive from a thermodynamic point of view. Increase in capture efficiency will result in disproportional higher energy demands for CO_2 capture. The energy demand for CO_2 capture, resulting in an efficiency penalty up to 10% pts as estimated here, is expected to decrease in the future. With a reduction in energy requirement for capture it becomes increasingly attractive to go to higher capture efficiencies. This is shown in Table 4 - 2.

Co-firing biomass will likely not have severe influences on the application of post-combustion CO_2 capture. Possible effects on the capture process are that co-firing results in relative higher volumes of flue gas exiting the boiler (this depends on moisture content), which results in a more dilute stream of CO_2. It is more difficult to capture CO_2 with low partial pressure and the energy penalty will increase, resulting in an overall lower generating efficiency. In addition, the concentration and composition of impurities that may affect post-combustion operation may change due to co-firing.

Capturing CO_2 with post-combustion from dedicated firing of biomass in fluidised bed combustion systems results in a higher loss in generating efficiency compared to coal-fired installations due to

1) the installation of additional flue gas cleaning equipment[8] such as flue gas desulphurisation (FGD) and a direct contact cooler;
2) the lower CO_2 concentration in the flue gas;
3) the lower heating value of biomass resulting in heat generation at lower heat; and
4) the lower generating efficiency without capture[9] (Horssen, Kuramochi et al. 2009; IEA GHG 2009).

Table 4 - 2 Overview of technical performance of BE-CCS technologies for electricity generation assessed in this study based on (Hendriks et al. 2004; IEA GHG 2009).

Technology	View year	Capacity (MW_e)[1]	Biomass share[2]	Capture efficiency	Efficiency penalty (% pts.)	Generating efficiency (LHV)
PC-CCS co-firing	2030	1000	Up to 30%	90%	10%	41%
CFB-CCS dedicated	2030	500	100%	90%	10%	37%
IGCC-CCS co-firing	2030	1000	Up to 30%	90%	7%	45%
BIGCC-CCS dedicated	2030	500	100%	90%	7%	43%
PC-CCS co-firing	2050	1000	Up to 50%	95%	6%	48%
CFB-CCS dedicated	2050	500	100%	95%	8%	42%
IGCC-CCS co-firing	2050	1000	Up to 50%	95%	4%	52%
BIGCC-CCS dedicated	2050	500	100%	95%	4%	50%

[1]Capacity is defined as the total output from biomass and coal.

[2]Defined as share in primary energy input.

Pre-combustion capture is currently the most promising option to capture CO_2 capture with high efficiencies in the range of 85-95% from either dedicated biomass BIGCCs or IGCCs with co-firing of biomass. The technology to capture CO_2 from the syngas generated in a gasifier can be considered proven technology and is commercially available in other applications (e.g. hydrogen production from natural gas or coal for the production of ammonia) than for electricity production. Due to the typically higher CO_2 partial pressure in the shifted syngas, the energy penalty for pre-combustion capture is theoretically lower compared to other capture concepts, see Table 4 - 2.

When applying pre-combustion CO_2 capture on IGCC facilities, or gasifiers in general, the basic processes involved in CO_2 capture are considered to be the same

[8] In a dedicated biomass fired CFB/BFB power plant generally no FGD is installed as sulphur emissions are controlled by limestone injection in the combustion boiler. The (post-combustion) CO_2 capture process requires low to nihil sulphur compounds in the flue gas as these results in operational complications of the capture solvent and process.

[9] A low generating efficiency without capture results in higher efficiency penalty when the power plant is equipped with CO_2 capture as per kWh net output relatively more CO_2 is captured, which results in a higher energy requirement. This in turn results in a percentage higher loss in generating efficiency.

independently of the type of fuel input (oil, coal, biomass and waste) (ZEP 2006). The type of fuel(s) used has an impact on the composition of the syngas exiting the gasifier. This will in turn affect for instance the shift process and CO_2 capture energy requirement. As far as we can ascertain, it is currently not known whether biomass (co-)gasification has a positive or negative influence on the efficiency penalty. The relative energy penalty for capture increases when applied to power plants with lower generating efficiencies. The lower conversion efficiency of dedicated BIGCCs does thus together with the capture penalty result in a lower conversion efficiency compared to co-gasification.

4.3.5 Technology status and prospects for bio-ethanol production

A by-product the bio-ethanol production process is pure CO_2. This production process is therefore an interesting option to combine with CCS. Figure 4 - 6 shows the development status of routes to produce transport fuels from biomass. The first generation ethanol production from sugar and starch crops is currently a mature and commercial technology. The ethanol production is based on the enzymatic conversion of biomass into sugars, and/or fermentation of 6-carbon sugars with final distillation of ethanol to fuel grade. Technical and economical improvements can still be made by using improved enzymes and bacteria, process & plant optimization, improved water separation methods and by producing value-added by-products. Typical conversion efficiencies for conventional bio-ethanol production depend on the feedstock. In an Ecofys report (Ecofys 2007) conversion efficiencies for bio-ethanol production are reported to vary significantly per feedstock and are expected to be between 11 and 59% (HHV) in the coming decades. A typical plant size is at a scale of 200 MW_{final}, which equates to an annual production of approximately 250 million litres. In this study, first generation bio-ethanol production is assumed to phase out over time as this route relies on feedstock that are generally also used for food (Bauen, Berndes et al. 2009). This option is therefore not considered in detail in further analyses for the view years 2030 and 2050.

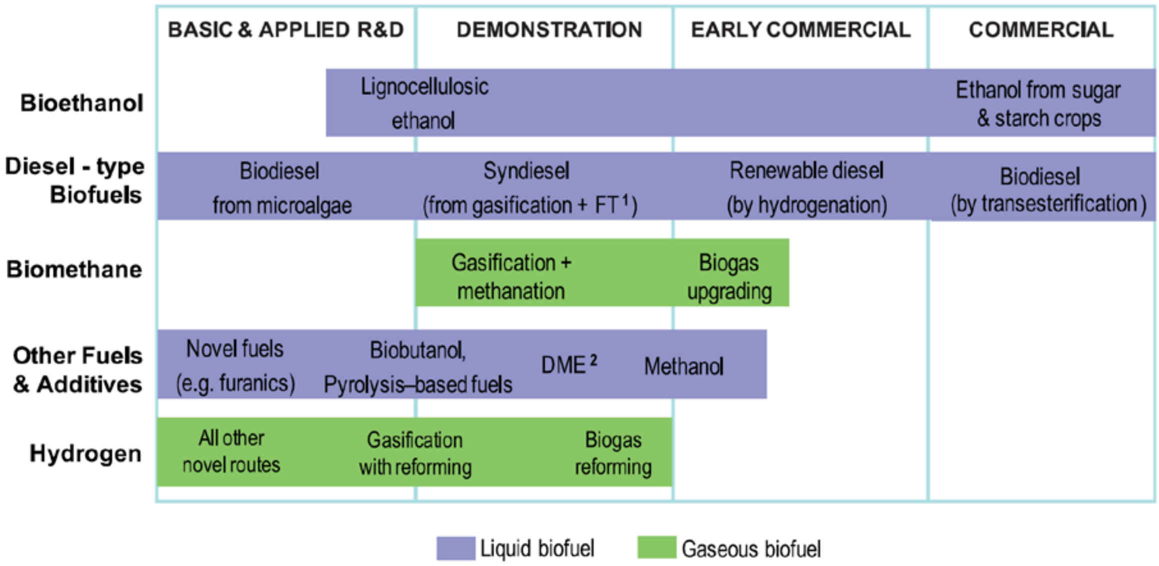


Figure 4 - 6 Development status of main conversion routes to produce transport fuels from biomass (source: (Bauen, Berndes et al. 2009)) (1 = Fisher Tropsch, 2= Dimethylether)

Second or advanced production of bio-ethanol from ligno-cellulosic biomass is in the applied R&D phase and entering the commercial demonstration phase. It is more difficult to break down the ligno-cellulosic biomass into sugars than starch, and therefore the production of ethanol requires advanced pre-treatment and conversion processes. Most process steps are relatively similar though, such as the fermentation step. Currently, large production of second generation bio-ethanol on a commercial scale does not exist. However, developments in the production of ligno-cellulose ethanol have accelerated in recent years and it is considered to be likely that commercial scale plants will become available in the coming decade (Bauen, Berndes et al. 2009). Here it is assumed that this technology comes available in the range of 200-400 MW_{final} (230 – 470 ktonnes/year) in the coming decades with conversion efficiencies of up to 36% (LHV), see Table 4 - 3.

4.3.6 CO_2 capture from bio-ethanol production

One large source of biogenic CO_2 is the fermentation step (see figure below), where sugars are converted into ethanol. This is a process that results in a high purity CO_2 stream. As mentioned earlier, the fermentation step of both conventional and advanced bio-ethanol production is quite similar. Depending on the conversion efficiency of the process, about 11-13% of biogenic CO_2 in the advanced bio-ethanol production route is produced in the form of high purity CO_2. The remaining carbon ends up in the product, in residues or is emitted within the flue gas. Besides drying, further treatment of the CO_2 from the fermentation step is not deemed necessary.

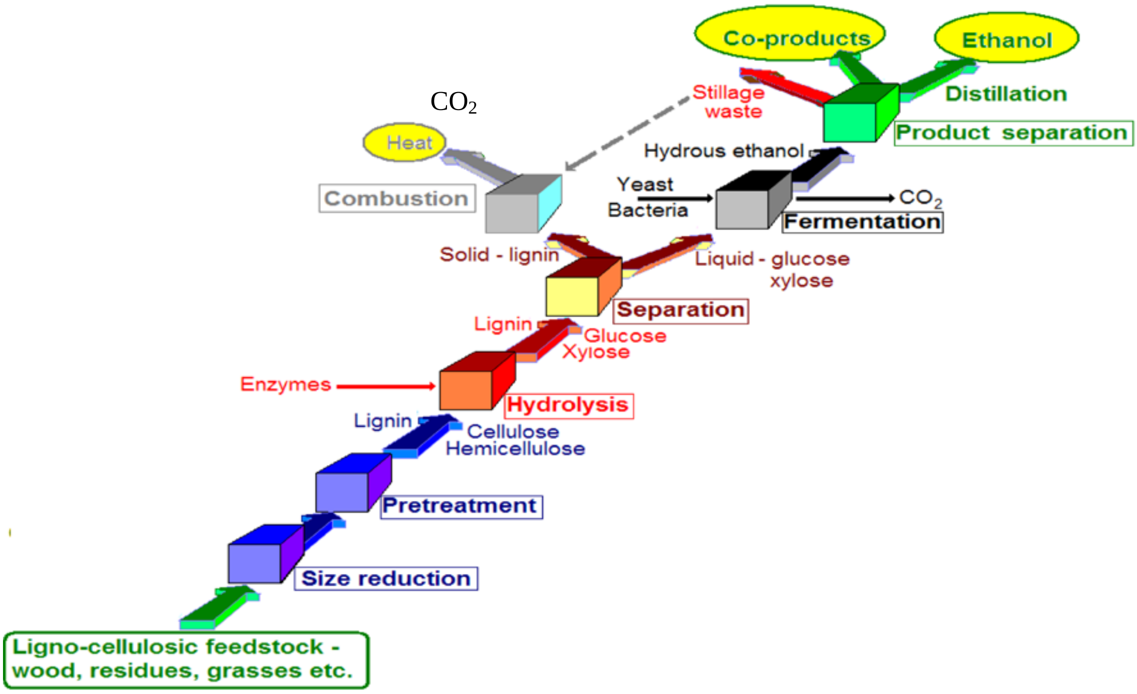


Figure 4 - 7 Ethanol production from ligno-cellulose via the bio-chemical route (after (IEA/OECD 2008))

Table 4 - 3 Overview of technical performance of BE-CCS technologies for biofuels production assessed in detail in this study

Technology	View year	Capacity (MW_{final})	Net conversion efficiency		Capture efficiency
			(kg_{fuel}/ $kg_{feedstock}$)	(MJ_{fuel}/ $MJ_{feedstock}$)	
Bio-ethanol-advanced generation (ligno cellulosic)	2030	200	20%	29%	11%
Bio-ethanol-advanced generation (ligno cellulosic)	2050	400	25%	36%	13%
FT biodiesel	2030	200	14%	42%	54%
FT biodiesel	2050	400	14%	42%	54%

4.3.7 Technology status and prospects for FT biodiesel production

Combining CCS with biodiesel production is interesting because CO_2 removal is already part of the biodiesel production process. With the use of thermochemical conversion process, a wide range of feedstock can be converted in a wide range of transport fuels, including synthetic diesel and gasoline, methanol, dimethylether (DME), methane, and hydrogen. In this study, the conversion process for biomass feedstock into bio-diesel with the use of Fischer Tropsch (FT) synthesis is further assessed. Gasification (see Gasification discussion in section 4.3.3) combined with FT synthesis is an advanced technology for the conversion of biomass into liquid biofuels. After gasification of biomass and cleaning of the produced syngas, the CO and H_2 in the syngas can be catalytically converted in a FT-reactor to hydrocarbons of various chain lengths, i.e. lighter and heavier hydrocarbons. Several types of FT process are commercially available and are being used - for instance - to convert on a large scale coal into hydrocarbons. FT-diesel production with biomass is currently in the demonstration phase with a plant capacity of about 15,000 ton of biodiesel per year.

The FT process has become much more efficient and more economic since it was invented in the 1920s. Also, the selectivity of the process has significantly increased. On the longer term this selectivity can be further increased (van Vliet, Faaij et al. 2009; Vrijmoed, Hoogwijk et al. 2010). Overall conversion of feedstock to product is expected to be in the range between 44 and 52% (LHV) based on available literature. In this study we assume a rather conservative conversion efficiency in the view years of 42%.

4.3.8 CO_2 capture from FT-biodiesel production

CO_2 removal is already an important part of the gas cleaning process that is required before the syngas can be fed into the FT process (see figure below). Before removal the H_2/CO ratio is adjusted to an optimal ratio for the FT process with the use of the water gas shift process. The CO_2 must be removed to increase the partial pressure of CO and H_2 to assure a high synthesis efficiency of the FT process. The capture technology applied is in fact a pre-combustion capture technology. About 90% of the CO_2 in the syngas can typically be removed with this technology. Approximately 54% of the total carbon in the feedstock is captured according to literature with the use of this technology. In (Larson, Fiorese et al. 2010) approximately 51-54% of the CO_2 is captured and stored. The largest remainder (23-32%) of the carbon content is embodied in the FT product, i.e. bio-diesel (van Vliet, Faaij et al. 2009). The remaining carbon is emitted with the combustion of the tail gas of the FT process. This CO_2 can be removed as well using a post-combustion technology (Dooley and Dahowski 2009; Larson, Fiorese et al. 2010). This requires however more energy compared to pre-combustion capture of CO_2 from the syngas and is considered to be more costly per tonne of CO_2. Although in principle possible, because of economics-of-scale reasons, it is assumed here that the capture of CO_2 coming from the combustion of the tail gas combustion is not implemented.

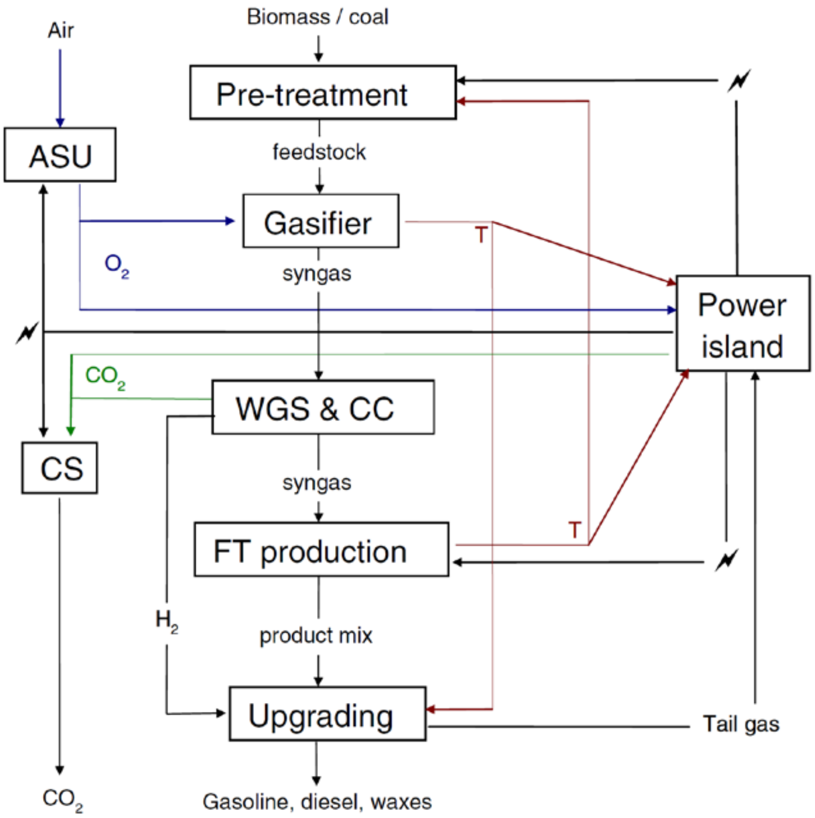


Figure 4 - 8 General layout of an Fischer Tropsch plant (ASU = air separation unit, WGS = water gas shift, CC = CO_2 capture, CS = CO_2 storage) after van Vliet, Faaij et al. (2009)

4.3.9 CO_2 compression and transport

To make the separated CO_2 suitable for transport and sequestration, the CO_2 typically has to be dried and compressed. The technology required to remove the CO_2 and to subsequently compress and dry it, is commercially available and proven. Technological bottlenecks are not expected for the additional processes that are required to make CO_2 available for sequestration.

CO_2 can be transported as a solid, gas, liquid and supercritical fluid. The desired phase depends mainly on the distance to transport the CO_2 and the mode of transport, i.e. by pipeline, ship, train or truck. Of these options, transport by pipeline is considered the most cost-effective one. Transport by ship can be economically favourable when large quantities have to be transported over long distances (>1000 km) (IPCC 2005) or to smaller storage sites. Transport by train or truck is not considered cost-effective for large-scale transport of CO_2 (IPCC 2005).

In this study, it is assumed that CO_2 will be transported by pipelines only. CO_2 transport by pipeline is considered a mature technology. There is worldwide experience in transporting CO_2 using the transport modes mentioned above. CO_2 is currently transported on large-scale by pipeline to supply the oil industry with CO_2 for enhanced oil recovery (EOR). CO_2 transport by ship is being conducted on a small scale, but is being researched as a possibility to reach offshore storage capacity or as a temporary substitute for pipelines (IEA GHG 2004; Aspelund, Molnvik et al. 2006). CO_2 is being transported by trucks from CO_2 point sources to for instance, the horticulture, and food and beverage industry.

The transport of CO_2 by pipeline in the gas phase is not favourable for projects that require the transport of significant amounts of CO_2 over longer distances. The disadvantageous economics (large pipeline diameter) and relative high energy requirement (due to the large pressure drop) are the main reasons for this (IPCC 2005; Zhang, Wang et al. 2006). Increasing the density of CO_2 by compression renders the possibility to transport the CO_2 with less infrastructural requirements and at lower cost.

The CO_2 is compressed in a multistage compressor to the required transport pressure, which is typically above 100 bars. CO_2 is typically released at atmospheric pressures from post-combustion and bio-ethanol routes. The energy requirement for compression from atmospheric pressure to 100 – 140 bars amounts to about 0.11-0.12 MWh_e/tonne CO_2. For the FT-biodiesel route the CO_2 is released at higher pressures which reduces the energy requirement for compression to about 0.1 MWh_e/tonne (van Vliet, Faaij et al. 2009). Compression is considered a mature technology with modest possibilities for future improvements.

4.3.10 CO_2 storage potential

The next step in the BE-CCS chain is the storage of CO_2 by injecting it into geological formations. It encompasses the injection of CO_2 into porous rocks that may hold or have held gas and or liquids. In literature, several storage media are proposed, especially: deep saline formations (aquifers); (near) empty oil reservoirs; combined with enhanced oil recovery (EOR); (near) empty gas reservoirs; combined with enhanced gas recovery (EGR) and deep (unminable) coal seams combined with enhanced coal bed methane production (ECBM) (Van Bergen, Pagnier et al. 2003; IPCC 2005).

CO_2 injection in underground formations is used in the oil and gas industry to enhance production. Part of the CO_2 that is used for this purpose is produced from natural CO_2 accumulations in geological formations. US DOE/NETL (Kuuskraa and Ferguson 2008) reports 51 Mt of CO_2 being injected[10] annually for EOR purposes, 11 Mt of which comes from anthropogenic sources (coal gasification, ammonia production, fertilizer production and gas processing). Experience with injecting CO_2 with the purpose of storing it for geological times can build upon the vast experience with the injection of fluids into the underground. Currently, several CO_2 injection projects with the objective of long-term storage are operating worldwide since 1996 with a maximum injection rate per project of approximately 1.2 Mt per year.

[10] All CO_2 is produced from natural or anthropogenic sources in the USA. 2.8 Mt of the total of 51 Mt is injected in Canada and the remaining part in the US.

RD&D efforts regarding the storage of CO_2 are focused on a more detailed assessment of storage capacities going from theoretical capacity, via technical capacity to realisable or matched capacity (Bradshaw, Bachu et al. 2006). In practice, matching the temporal and geographical availability of sources and sinks may become a bottleneck. Matched capacity is therefore typically much lower than the theoretical capacity.

The CSLF taskforce (CSLF 2008) has proposed the following characterisation of CO_2 storage potentials:

1 **Theoretical Storage Capacity** is the total resource. It is the physical limit of what the geological system can accept. It assumes that the storage system's entire capacity to store CO2 (in pore space, or dissolved at maximum saturation in formation fluids, or adsorbed at 100% saturation in the entire coal mass) is accessible and utilized to its full capacity.
2 **Effective Storage Capacity** represents a subset of the theoretical capacity and is obtained by considering that part of the theoretical storage capacity that can be physically accessed and which meets a range of geological and engineering criteria.
3 **Practical Storage Capacity** is that subset of the effective capacity that is obtained by considering technical, legal and regulatory, infrastructural and general economic barriers to CO2 geological storage. The Practical Storage Capacity corresponds to the term 'reserves' used in the energy and mining industries.
4 **Matched Storage Capacity** is that subset of the practical capacity that is obtained by detailed matching of large stationary CO2 sources with geological storage sites that are adequate in terms of capacity, injectivity and supply rate to contain CO2 streams sent for storage from that source or sources. This capacity is at the top of the resource pyramid and corresponds to the term 'proved marketable reserves' used by the mining industry.

It should be stressed that high uncertainties still persist regarding the estimation of storage capacity due to the use of incomplete data or simplified assumptions on geological settings, rock characteristics, and reservoir performance (Bradshaw, Bachu et al. 2006).

For the CO_2 storage potential we have updated estimates from Hendriks et al. (Hendriks et al. 2004) which gives storage estimates for 17 world regions. These storage estimates reflect the theoretical storage capacity for three types of reservoirs:

1 Depleted hydrocarbon fields (oil & gas fields)
2 Aquifers
3 Unmineable coal seams

The potential assessment includes these three types of reservoirs. As a sensitivity analysis, we also included assessments that only consider hydrocarbon fields to be available in a certain view year. Appendix C gives an overview of the estimated CO_2 storage potential.

We brought the number of regions back to the same seven regions we derived for the biomass potential. For North America we used the updated storage resource estimates from the second edition of NETL-DOE's Carbon sequestration Atlas (NETL/DOE 2008). This corresponds best to the effective capacity (CSLF 2008). For Europe, we updated the CO_2 storage estimates with more detailed results from (GeoCapacity 2009). The conservative GeoCapacity estimates consider that the full storage capacity can not be exploited. Thus, it does not correspond to theoretical capacity, but more to the effective storage capacity as defined above. Overall, hydrocarbon estimates corresponds best to theoretical storage capacity estimates[11] reported in (IEA GHG 2009). The global storage capacity used here corresponds best to the theoretical or effective capacity.

Because the estimations on global storage potential are first estimations (storage sites have to be assessed individually to assess the capacity more accurately and to know whether they are suitable for CO_2 storage), we included three estimations for each region: Low, Best, High following (Hendriks et al. 2004). For Europe, we used the results from (GeoCapacity 2009) and categorised this as a 'Best'-estimation. As default we used the 'Best' estimate to determine the technical BE-CCS potential.

4.3.11 Combining biomass and CO_2 storage potential

Combining biomass resource and storage capacity to determine the technical potential yields a challenge. The biomass potential is given as an annual potential (see Figure 4 - 9). The storage potential however is a finite resource which is given as the total amount of CO_2 that can be stored (see Figure 4 - 10). To estimate the amount of CO_2 that we can store on an annual basis, we need to convert this total amount of storage capacity to an annual storage capacity. In other words, we needed an approach to convert total CO_2 storage capacity estimates to an annual storage capacity estimate. For the technical potential, we therefore assumed that 1/50 of the total storage capacity can be used annually, i.e. the saturation period of the total capacity is 50 years (at immediate full deployment). The annual storage potential derived using this approach is shown in Figure 4 - 11. This is based on the conservative assumption that a project developer does not start a CO_2 injection activity if storage capacity is not assured for at least the entire lifetime of the energy conversion facility generating the CO_2. As this rough assumption is likely to have considerable impacts on the assessment of the technical potential we include an uncertainty range for this factor and assess its impact on the results. The uncertainty range for this is chosen to lie between 30 and 70 years.

[11] In (IEA GHG 2009) the matched capacity for depleted gas fields in 2050 is estimated to be approximately 20% of the total theoretical storage capacity.

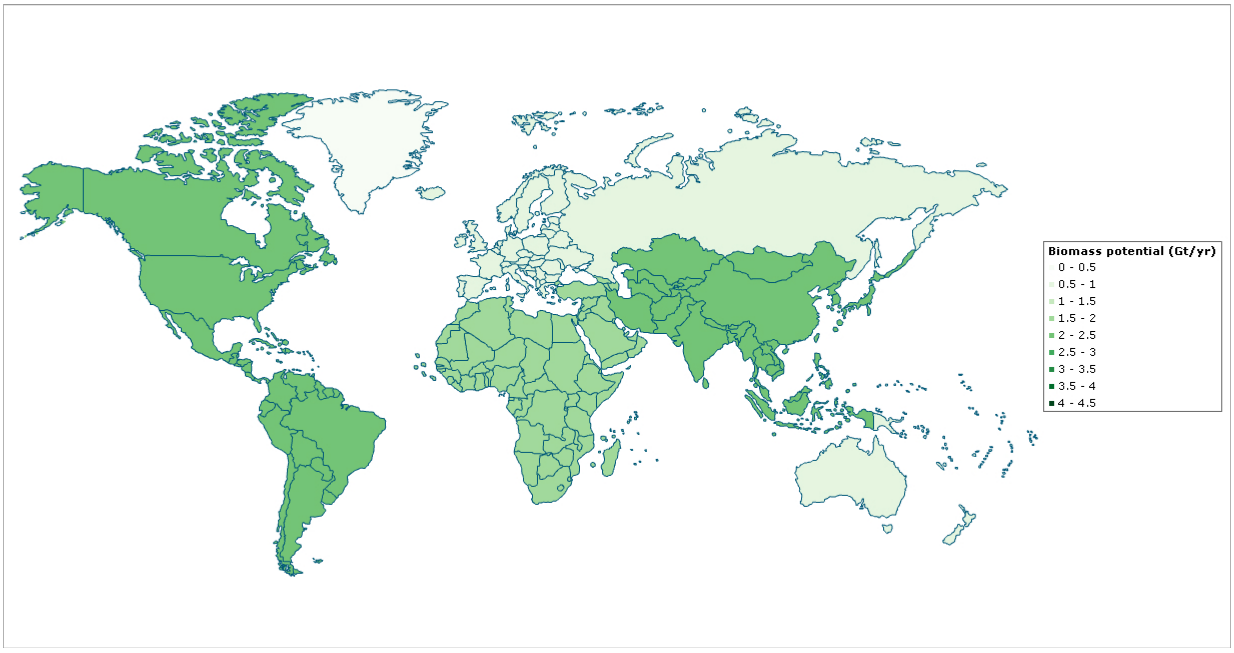


Figure 4 - 9 Global map showing annual biomass potential expressed in Gt CO_2 /yr for the seven world regions. Note that in reality biomass potential is not equally distributed within a region, this is merely a graphical representation to show the difference in estimated capacity between regions.

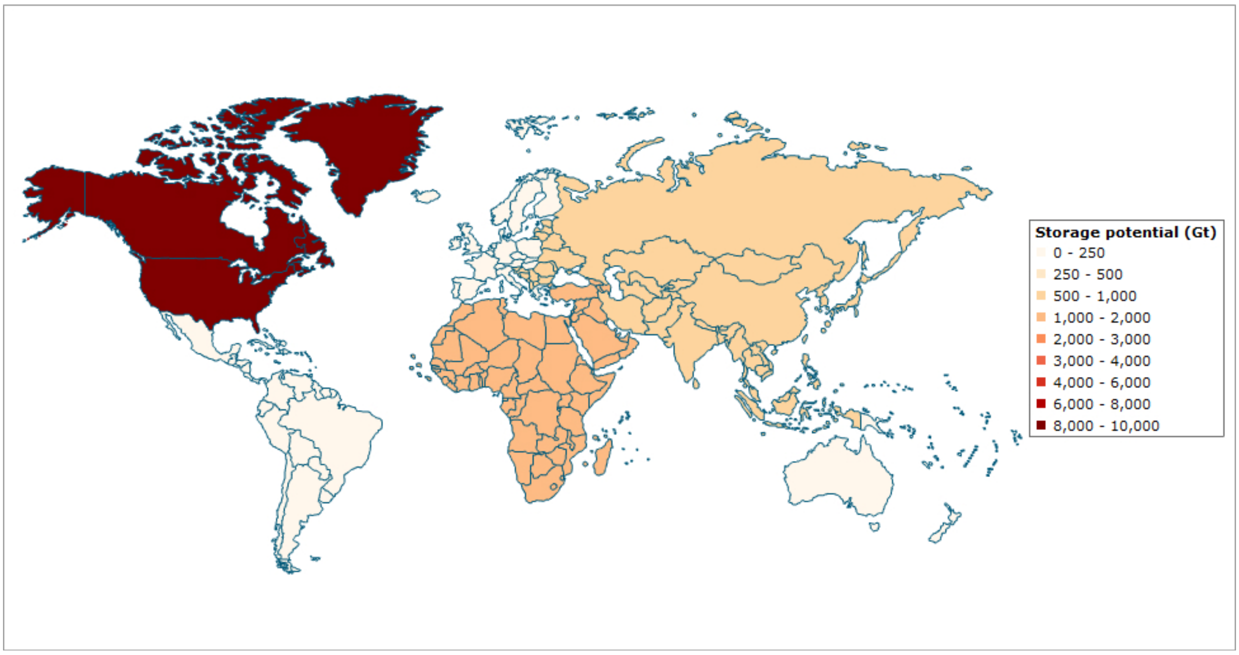


Figure 4 - 10 Global map showing total CO_2 storage potential expressed in Gt CO_2 for the seven world regions. Note that in reality storage potential is not equally distributed within a region, this is merely a graphical representation to show the difference in estimated capacity between regions.

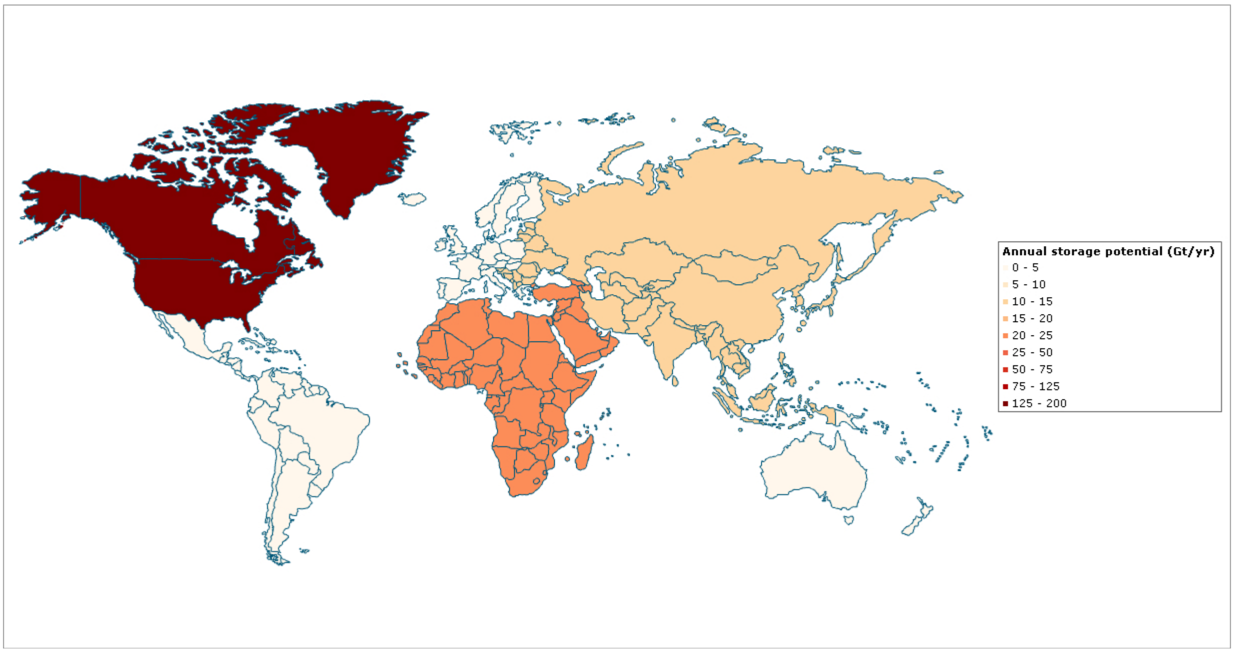


Figure 4 - 11 Global map showing annual CO_2 storage potential expressed in Gt CO_2 /yr for the seven world regions. Note that in reality storage potential is not equally distributed within a region, this is merely a graphical representation to show the difference in estimated capacity between regions.

4.3.12 Direct and indirect greenhouse gas emissions

The technical BE-CCS potential is determined by assessing the amount of biomass that can be converted into secondary energy carriers, i.e. electricity and biofuels. During this conversion, CO_2 is generated which can be captured; transported and stored. It is thus imperative to know how much CO_2 is generated in the conversion step. This is determined by the direct emission factor. This together with the capture efficiency determines the amount of CO_2 that can be captured.

In order to estimate the net greenhouse gas balance of BE-CCS routes we also need to know the indirect emission factor, which quantifies the GHG emissions in the fuel supply chain. This indirect emission factor cannot be easily standardised by biomass resource as this depends on the fuel supply chain.

The net greenhouse gas balance is calculated by the sum of direct and indirect non-biogenic GHG emissions and the amount of biogenic CO_2 stored, which counts as negative emissions. In the co-firing routes we count the fraction of CO_2 from the coal share that is captured, transported and stored as not emitted. The fraction not captured, in the case of coal, obviously adds to the direct emissions of non-biogenic GHG.

Direct emission factor

The direct emission factor is arguably assumed to be equal for all biomass resources and is set at 100 kg CO_2 /GJ (IPCC 2006)[12]. An uncertainty range between 85 and 117 kg CO_2 /GJ is assumed, reflecting lower and higher estimates given in (IPCC 2006). Direct emissions of other GHG emissions (e.g. CH_4 and N_2O) from the conversion processes are not included as they are assumed to be negligible.

Indirect emission factor - Greenhouse gas emissions in biomass supply chains

An example of a biomass supply chain is given in the figure below. Most common steps in this supply chain are production, transport and conversion. Since CCS takes place during the conversion step, the emissions of the biomass supply are analysed until the gate of the conversion facility.

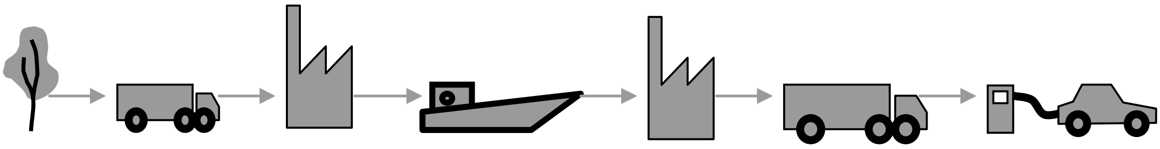


Figure 4 - 12 Example of biomass supply chain for transport fuels

First, the range of greenhouse gas emissions for a number of biomass supply chain is given, after which possible alterations towards 2020 are indicated, resulting in a range of supply chain emissions that is used for the overall evaluation of biomass and CCS combination.

Current chain emissions biomass supply chains

Supply chain emissions of biomass are analysed in several international initiatives. In this way a better comparison can be made between the greenhouse gas emissions from biomass routes and from fossil fuels. The Renewable Energy Directive (RED) from the EC (EC 2009) indicates the expected greenhouse gas emission reductions for a set of biomass supply chains (mostly focusing on end use as biofuel). The following section is based on the Well to Wheel studies as constructed by the Joint Research Centre of the European Commission (JRC 2008) on which the EC bases the typical values which should be used for the calculations of the greenhouse gas emissions for each biomass chain.

Main emissions in the supply chain of biomass occur during production, transport and conversion. Inputs like fertilizers and use of diesel during production and agricultural part of the supply chain cause greenhouse gas emissions attributed to the biomass.

[12] IPCC, 2006. 2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 2 – Energy. Internet: http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html [Accessed 31-05-2010]

Since the agricultural processes of the feedstock are very different, the greenhouse gas burden of the various supply chains is very different.

Since none of the advanced chains (producing biofuel from residues and ligno-cellulose material) are currently commercially produced, the supply chain emissions as indicated for them can be regarded as indications what is expected towards the commercialization of these chains (towards 2020).

Table 4 - 4 Overview of well-to-gate emissions biomass supply chains (JRC 2008). All figures are in kg CO_2 eq./$GJ_{primary}$.

Feedstock	Cultivation	Processing	Transport & distribution	Overall supply chain emissions
Sugar cane	5.1	0.3	3.2	8.7
Wheat	12.3	17.2	1.1	30.6
Straw	1.2	2.1	0.8	4.2
Farmed wood to ethanol	2.1	4.1	0.7	6.9
Farmed wood to diesel	2.4	0.0	1.0	3.4
Wood residues to ethanol	0.3	4.1	1.4	5.8
Wood residues to diesel	0.5	0.0	1.9	2.4

Trends in supply chain emissions towards 2020 and beyond

A recent study by the COWI Consortium (COWI 2009) indicated possible trends in emission reductions for relevant parts of the biomass supply chains. The main expected reductions are given in the table below.

Table 4 - 5 Main expected emissions reductions biomass supply chains towards 2020 (COWI 2009)

Emission reduction in sector / substance	2017	2018	2020
N_2O in N fertilizer production	81%	90%	90%
CO_2 in N fertilizer production	19%	21%	25%
Overall GHG in agriculture	3.8%	4.2%	5%
CO_2 in biofuels processing industry	7.5%	10%	10%

As indicated in Table 4 - 5, the main reductions in greenhouse gas emissions are expected in the fertilizer production and processing industry.

Not for all chains analysed in this study, the reductions will have impact on the expected supply chain emissions in 2020. For example, chains with no agricultural component will not be influenced by currently expected reductions.

Range supply chain emissions 2020

The combination of the expected emissions reported by Joint Research Centre of the European Commission (JRC 2008) and the expected trends in emission as reported by COWI (COWI 2009) give a range for the biomass supply chain emissions as expected towards 2020.

The three main groups of feedstock under review within this study are:

- Agricultural residues ;
- Forest residues;
- Ligno-cellulose energy crops (like willow, poplar or perennial grasses).

For the biomass supply chains of ligno-cellulose energy crops (farmed wood) the expected emission reductions related to the use of fertilizer will have an impact on the 2020 supply chain emissions (see Table 4 - 5). For part of the chains of agricultural residues or forest residues no emissions are attributed, as – for instance - fewer fertilizers are used during production (like wood residues). For straw, the overall 5% efficiency improvement in agricultural practices is taken into account. For the wood chips from forest residues case no emission reductions are expected towards 2020.

Table 4 - 6 presents the range of biomass supply chain emissions for the well to gate part of the supply chain as expected in 2020.

Table 4 - 6 Range for biomass supply chain emissions 2020. All figures are in kg CO_2 eq./$GJ_{primary}$.

Feedstock	Cultivation	Processing	Transport & distribution	Overall supply chain emissions
Straw (agricultural residues)	1.1	2.1	0.8	4
Farmed wood to ethanol (energy crops)	0.9	4.1	0.7	6
Forest residues to ethanol	0.3	4.1	1.4	6
Farmed wood to diesel (energy crops)	1.3	0.0	1.0	2
Wood residues to diesel	0.5	0.0	1.9	2

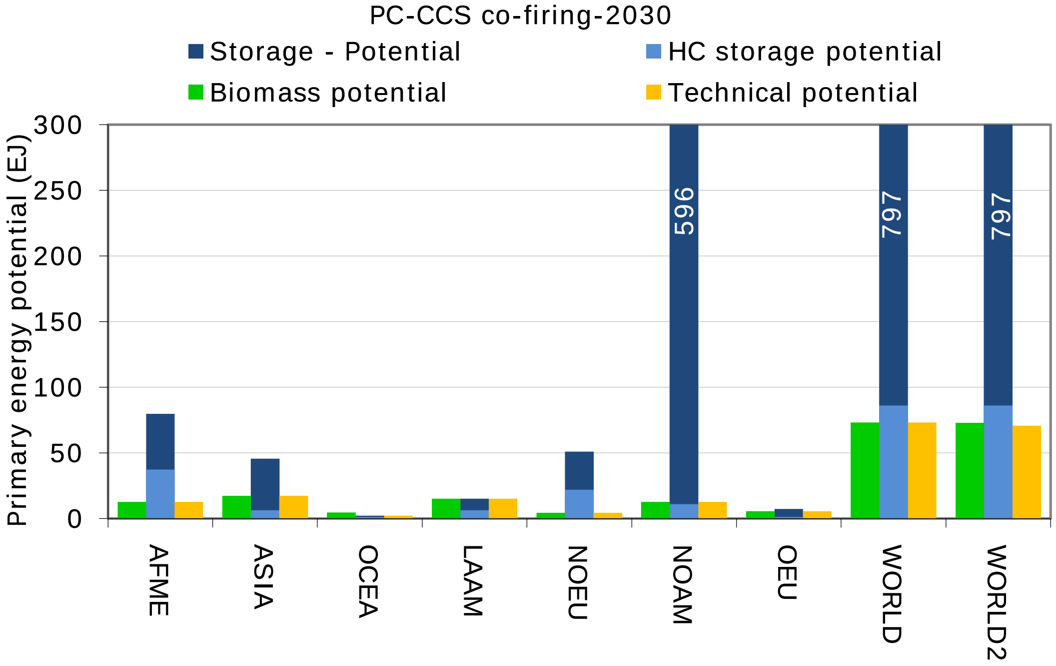
No detailed assessments are available for the longer term, i.e. towards 2050. We therefore use the 2020 figures also for the view years 2030 and 2050.

4.4 Results for the technical potential

Below, we present the technical potentials for the selected BE-CCS routes. The technical potential is expressed in primary and final energy (EJ/yr) and net greenhouse gas balance (Gt CO_2-eq.). The technical potentials include only the biomass-part in the conversion route and do not include the (possible) energy from the coal share. The GHG balance does take into account the direct emissions from fossil fuels, when applicable.

4.4.1 PC-CCS co-firing

The primary biomass potential for PC-CCS co-firing is given in Figure 4 - 13.



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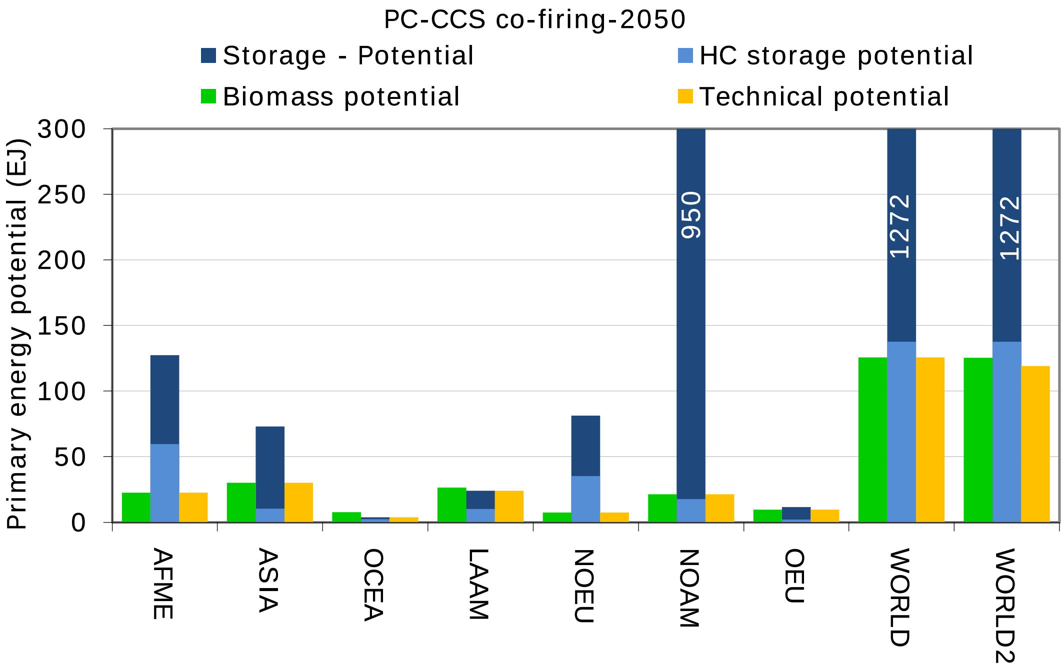
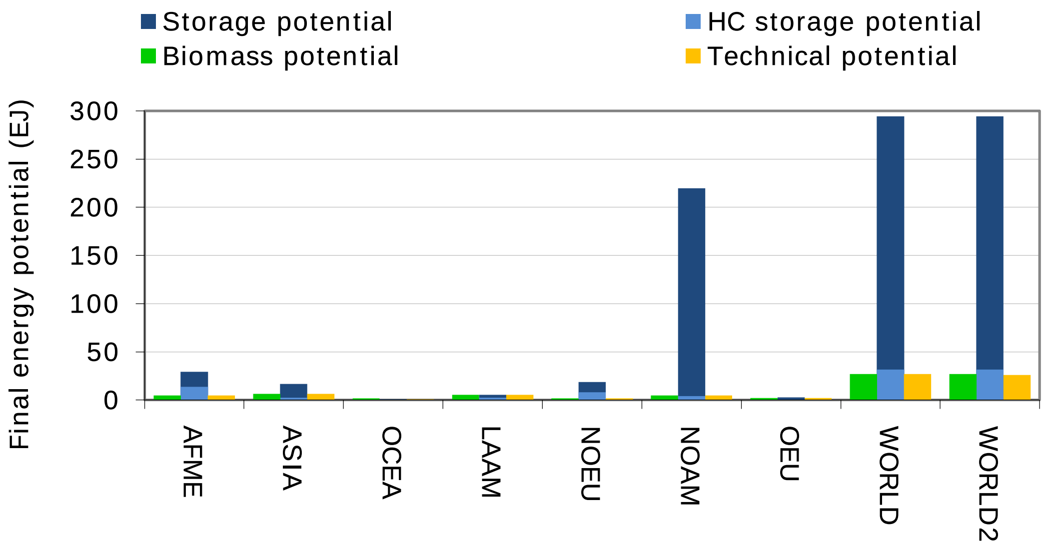


Figure 4 - 13 Primary energy potential (EJ/yr) for the PC-CCS co-firing route in 2030 and 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.

We see that the global primary energy potential ranges between 73 EJ/yr in 2030 and 126 EJ/yr in 2050 (today's global industrial biomass energy use is about 9 EJ/yr; the global primary energy use in 2008 was about 500 EJ). As can be seen in the graph, the potential is restricted in all regions but one by the availability of biomass. Excluding inter-regional transport of biomass (indicated as 'World2' in the figure) results in a technical potential of 71 and 119 EJ/yr in 2030 and 2050, respectively. The reason for this reduction of 7 EJ/yr in 2050 is that the storage capacity in Oceania is the limiting factor in the BE-CCS potential. As such, 7 EJ/yr of biomass potential can not be used. The technical potential is the largest in the regions Asia and Latin America (LAAM). The figure also shows that there is a vast storage potential in the regions North America, Non-OECD Europe and FSU, and Africa and Middle East which is not used.



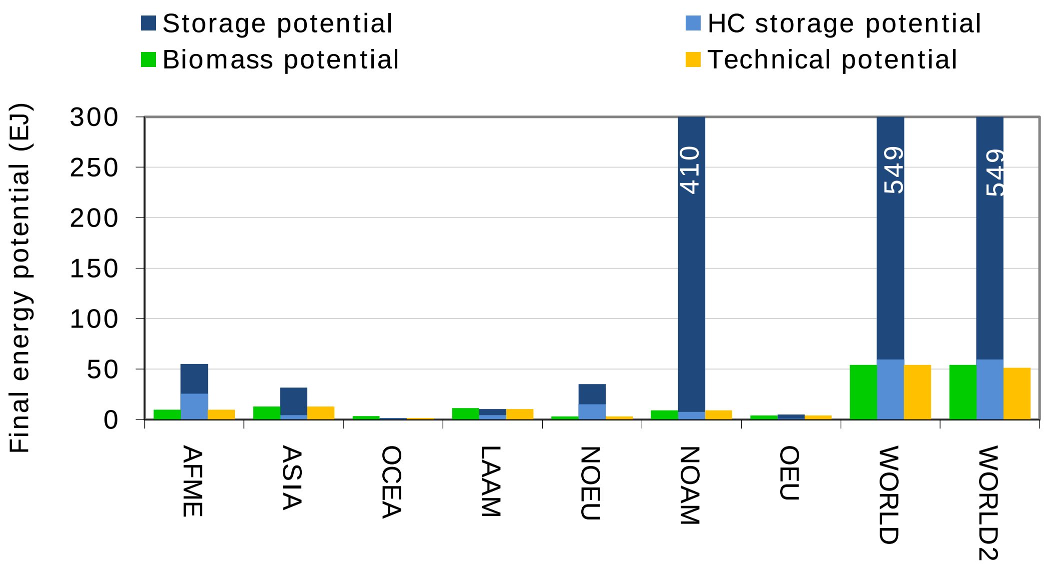
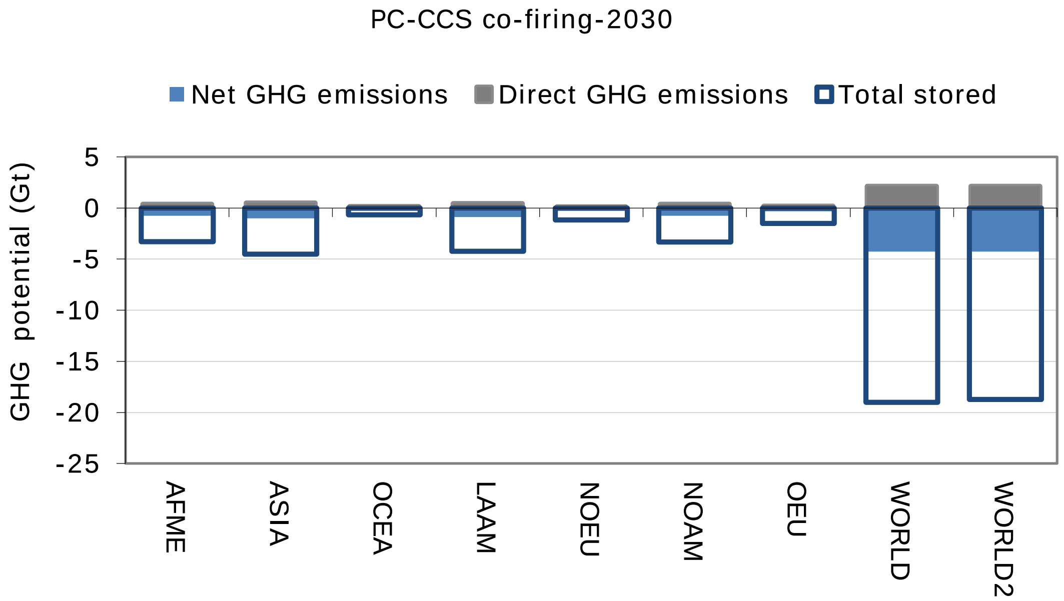


Figure 4 - 14 Final energy potential (EJ/yr) for the PC-CCS co-firing route in 2030 and 2050 (biomass share only). Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.

The global potential in terms of final energy is given in Figure 4 - 14. The potential increases from 27 to 54 EJ/yr from 2030 to 2050. This increase is due to the increase of biomass potential as well as the improvement of conversion efficiency. As for the primary energy potential, the final potential is somewhat lower when inter-regional transport is not included.



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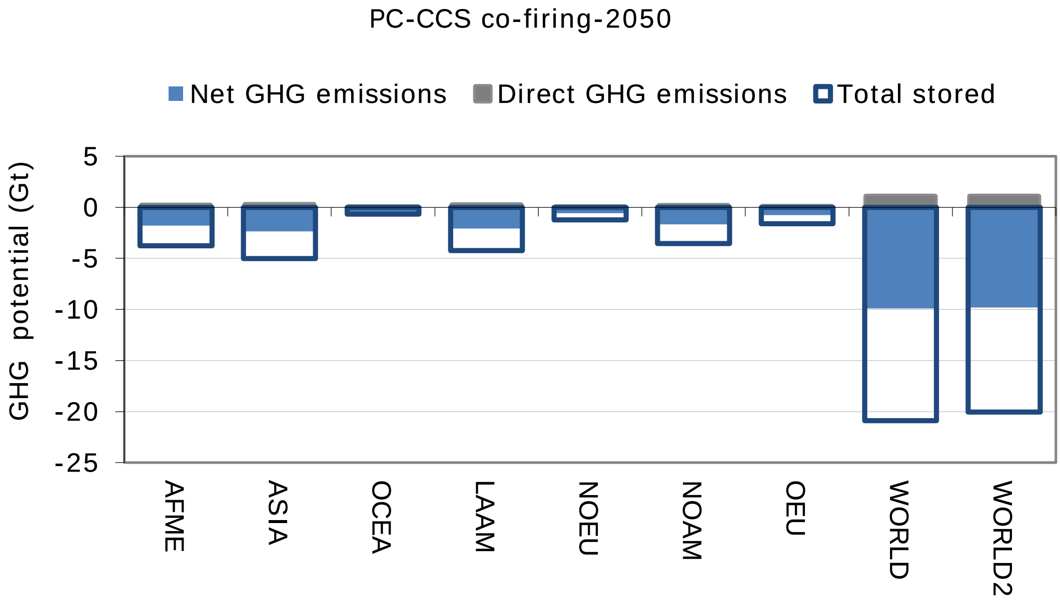
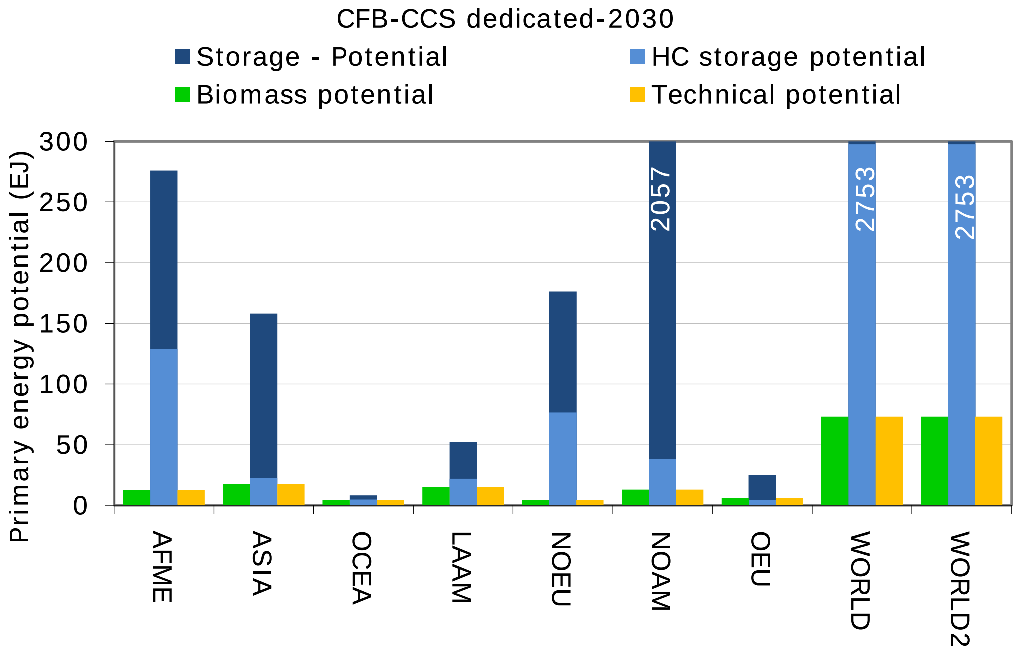


Figure 4 - 15 Net GHG emissions in Gt CO_2 eq. for the PC-CCS co-firing route in 2030 and 2050. Blue bars indicate the net emission balance. Grey bars indicate the direct GHG emissions in the supply chain. Dark blue lined boxes indicate the amount of CO_2 stored.

Figure 4 - 15 shows that negative emissions can be achieved in the co-firing route. The reduction in global emissions (if the full potential is harvested) range between 4.3 and 9.9 Gt annually. This means that an amount of CO_2 can be removed from the atmosphere that is equal to up to one third of the present annual CO_2 emissions if the full technical potential is harvested.

4.4.2 CFB CCS dedicated firing

The global primary energy potential estimates for the CFB-CCS route range between 73 EJ/yr in 2030 and 126 EJ/yr in 2050. The global potential is here restricted in all regions by the availability of biomass. A difference compared to the PC-co-firing route is that the storage potentials, expressed in EJ/yr, are much higher. The reason for this is that CO_2 from coal does not fill storage capacity in this route. The storage potential expressed in primary biomass is therefore higher.



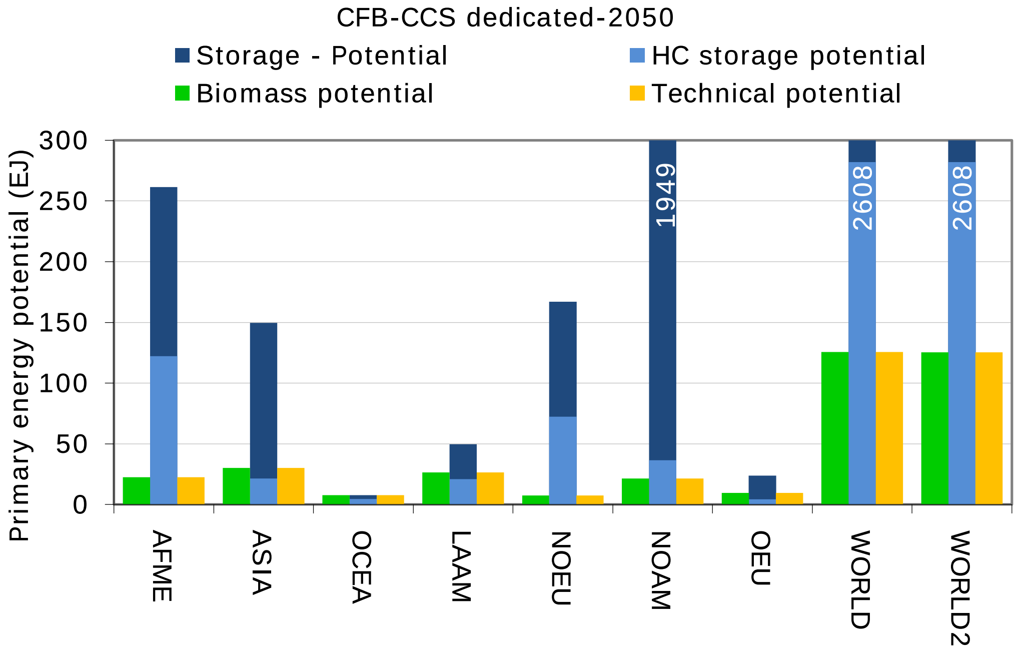
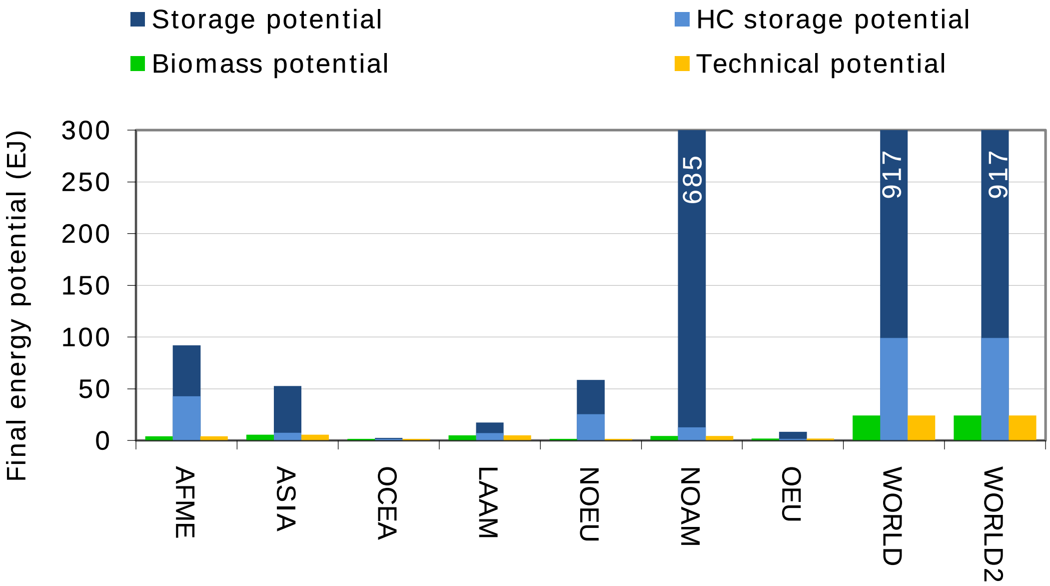


Figure 4 - 16 Primary energy potential (EJ/yr) for the CFB-CCS route in 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.

When inter-regional transport of biomass can not take place ('World2'), the technical potential remains 73 and 126 EJ/yr in 2030 and 2050, respectively. These latter potentials are somewhat higher when compared to the PC co-firing route as storage potential is not a constraint in the CFB route.



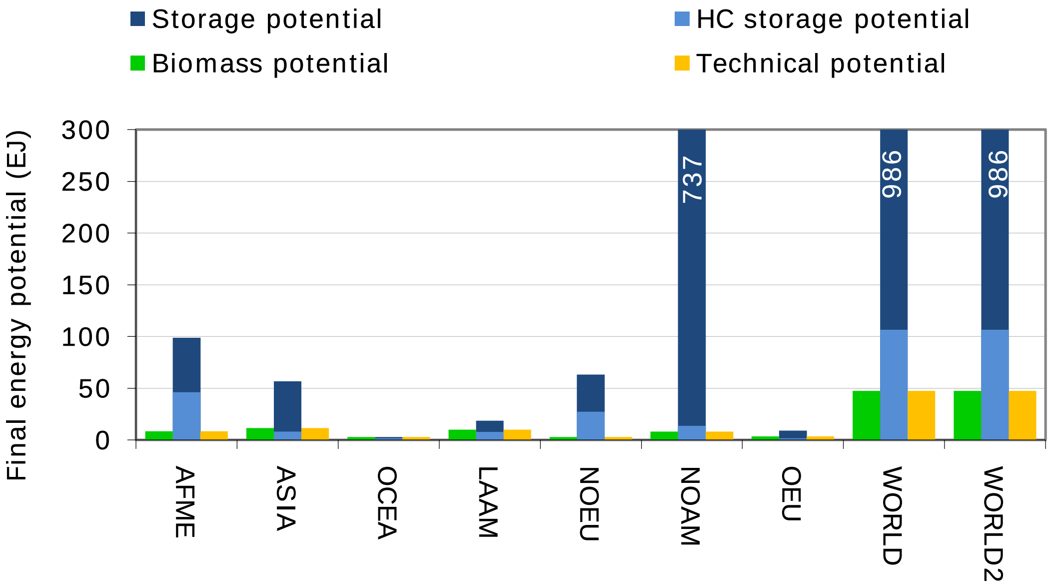
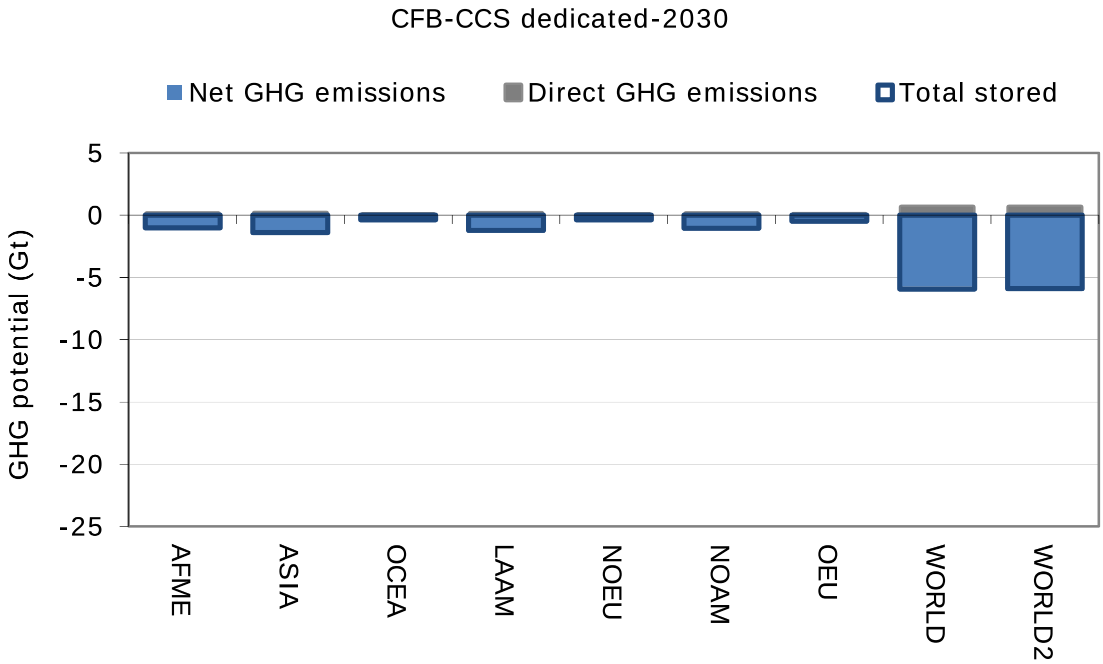


Figure 4 - 17 Final energy potential (EJ/yr) for the CFB-CCS route in 2030 and 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.

The global potential in terms of final energy, shown in Figure 4 - 17, increases from 24 to 47 EJ/yr from 2030 to 2050. This is lower compared to the PC co-firing route due to the lower conversion efficiency.



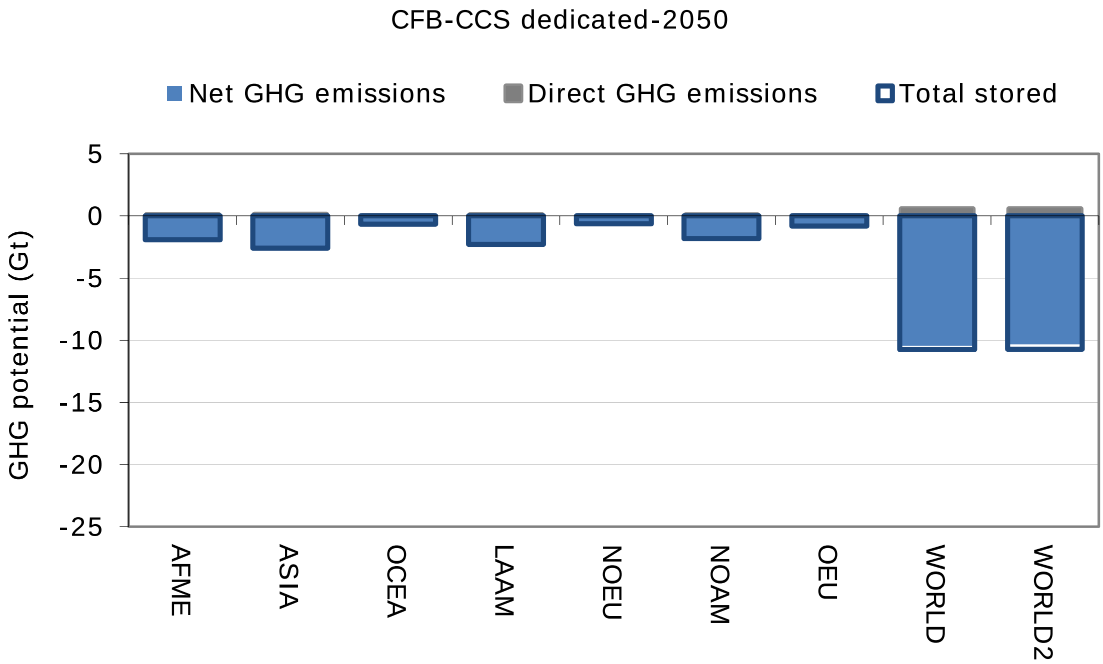
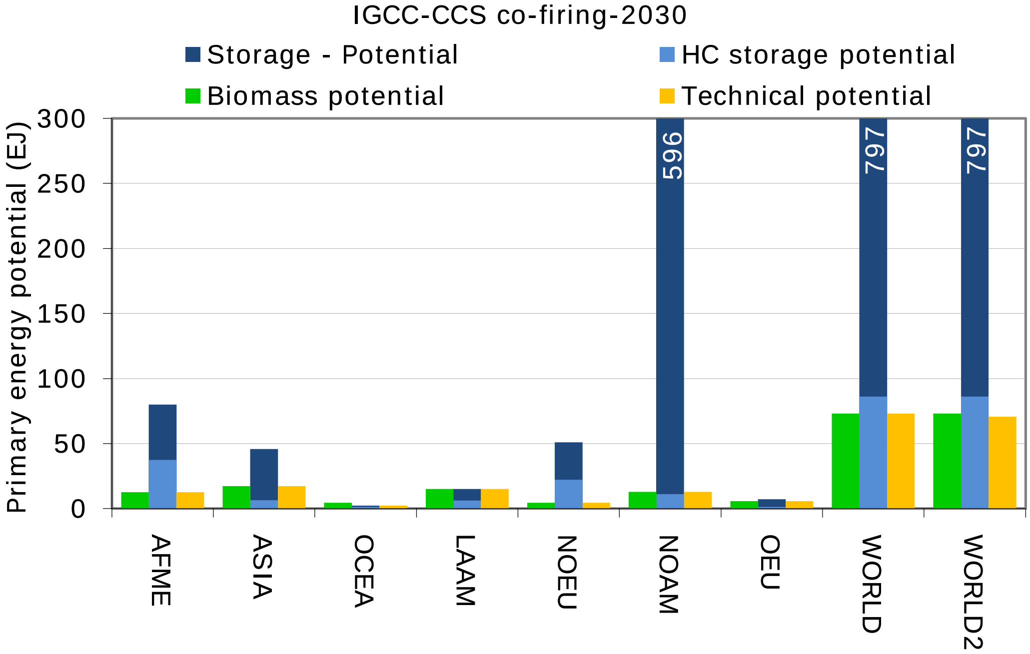


Figure 4 - 18 Net GHG emissions in Gt CO_2 eq. for the CFB-CCS route in 2030 and 2050. Blue bars indicate the net emission balance. Grey bars indicate the direct GHG emissions in the supply chain. Dark blue lined boxes indicate the amount of CO_2 stored.

Figure 4 - 18 shows that negative emissions are higher, between 5.7 and 10.4 Gt per year (negative), for the biomass share in the dedicated compared to the co-firing route. This shows that deeper emission reductions can be achieved by only implementing dedicated BE-CCS routes.

4.4.3 IGCC-CCS co-firing

In the figure below, we see that the global primary energy potential ranges between 73 EJ/yr in 2030 and 126 EJ/yr in 2050, which is comparable to the potential for the PC co-firing route.



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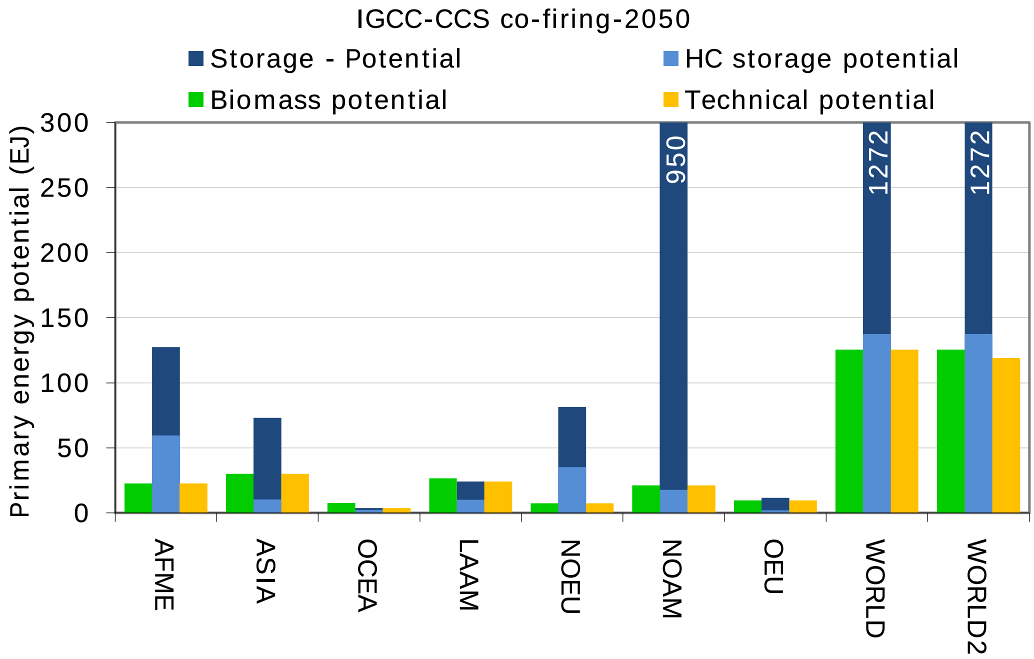
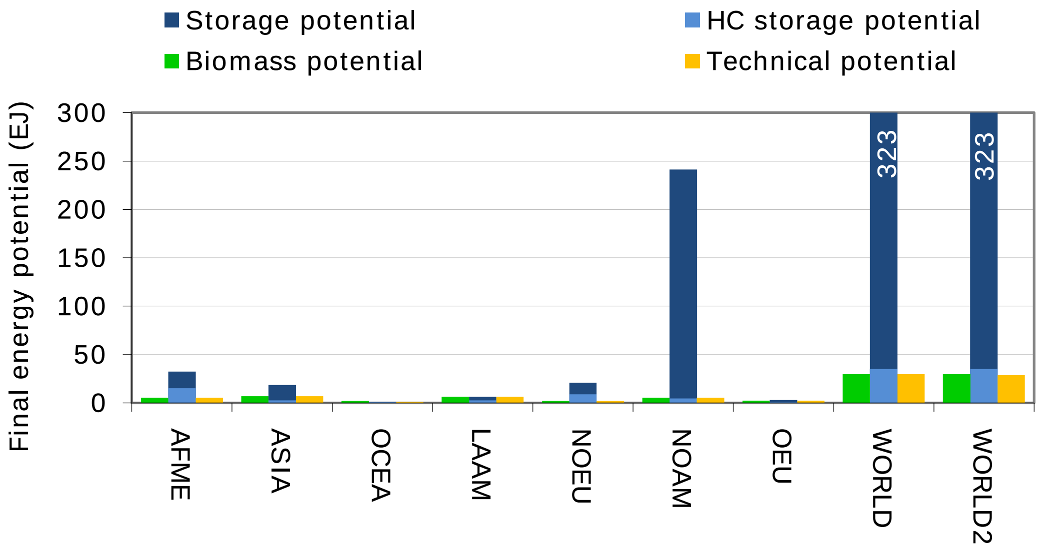


Figure 4 - 19 Primary energy potential (EJ/yr) for the IGCC-CCS co-firing route in 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.

The global potential is here also restricted in all regions except Oceania by the availability of biomass. When we exclude inter-regional transport of biomass ('World2'), then the technical potential is 71 and 119 EJ/yr in 2030 and 2050, respectively. Again, this is equal to the PC co-firing case as the co-firing shares are assumed to be equal.



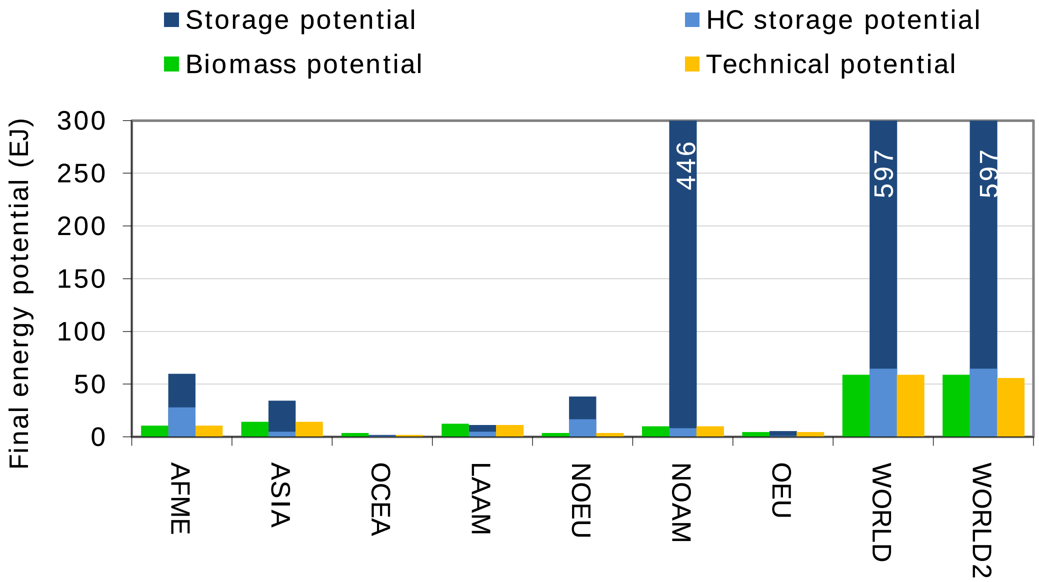
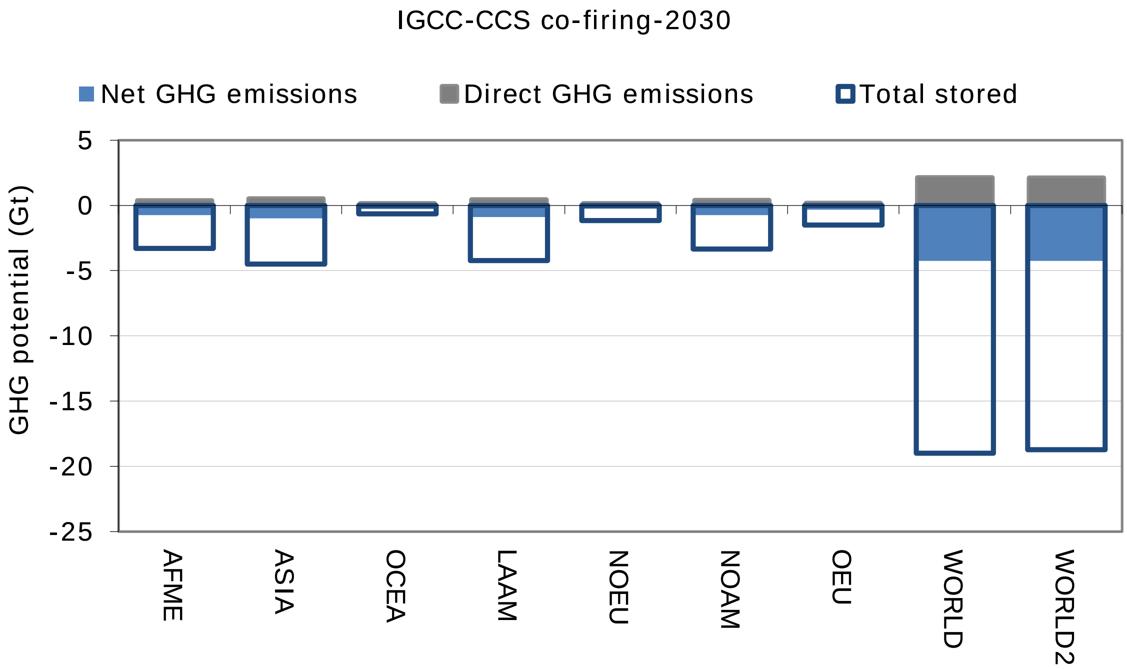


Figure 4 - 20 Final energy potential (EJ/yr) for the IGCC-CCS co-firing route in 2030 and 2050 (biomass share only). Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on ‘best’ estimate. “World2” technical potential excludes the possibility of inter-regional transport of biomass and CO_2.

The global potential in terms of final energy, shown in Figure 4 - 20, increases from 30 to 59 EJ/yr from 2030 to 2050. This is minimally 10% higher compared to the PC co-firing and CFB routes due to the higher conversion efficiency for IGCC power plants with co-firing.



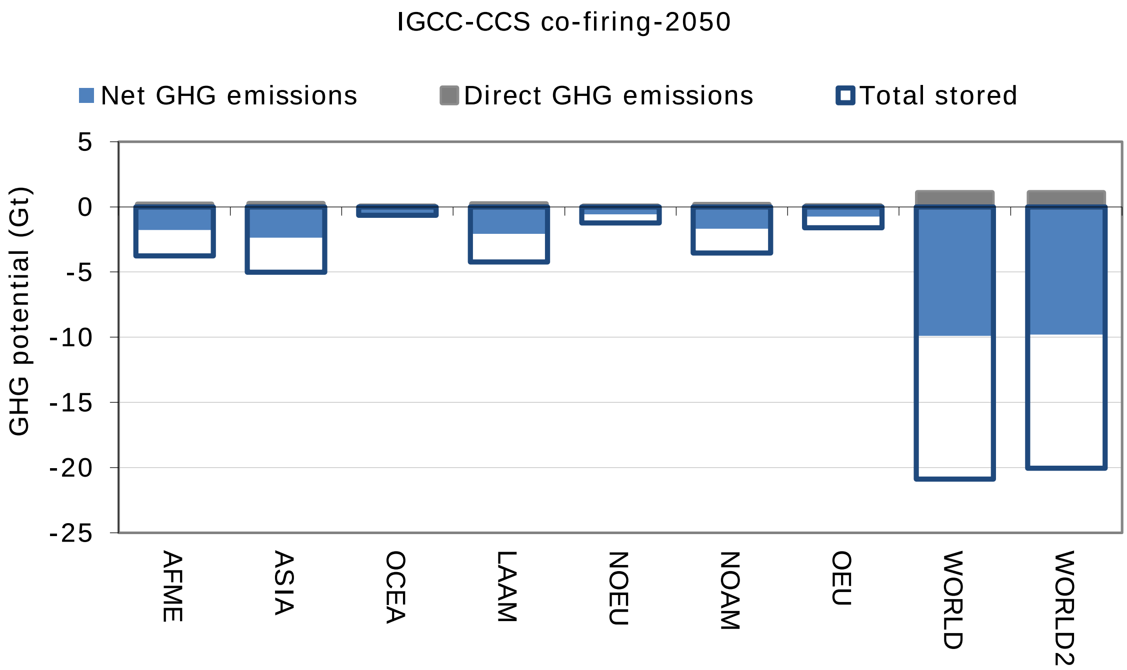
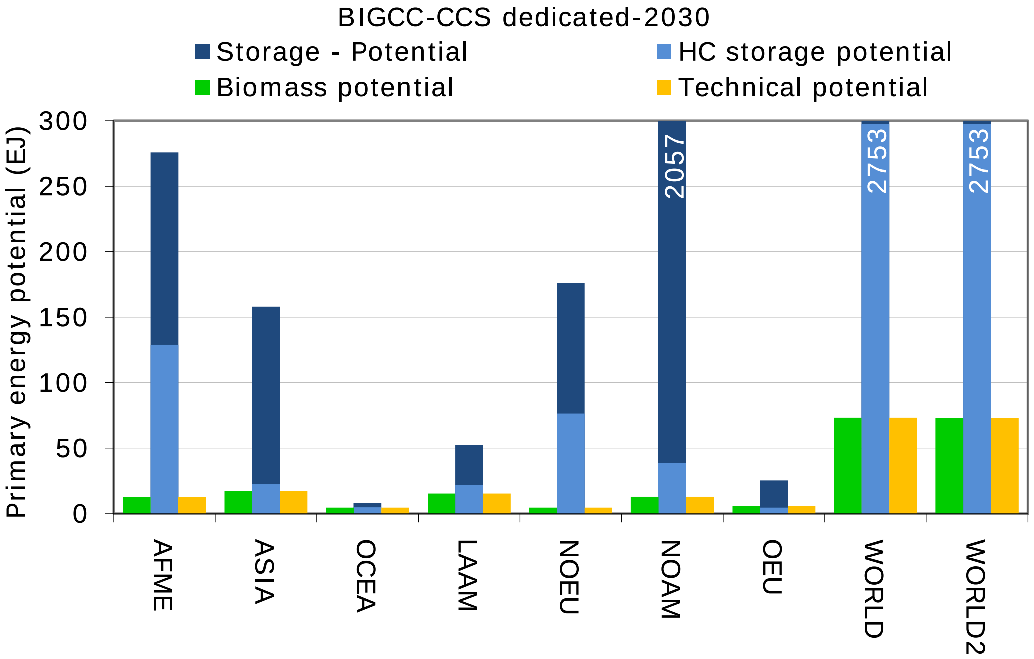


Figure 4 - 21 Net GHG emissions in Gt CO_2 eq. for the IGCC-CCS co-firing route in 2030 and 2050. Blue bars indicate the net emission balance. Grey bars indicate the direct GHG emissions in the supply chain. Dark blue lined boxes indicate the amount of CO_2 stored.

Figure 4 - 21 shows that negative emissions are approximately the same as for the PC co-firing route, namely between 4.3 (in 2030) and 9.9 (in 2050) Gt per year (negative).

4.4.4 BIGCC-CCS dedicated

In Figure 4 - 22, we see that the global primary energy potential increases from 73 EJ/yr in 2030 and 126 EJ/yr in 2050, which equates to the estimate for the CFB-CCS case.



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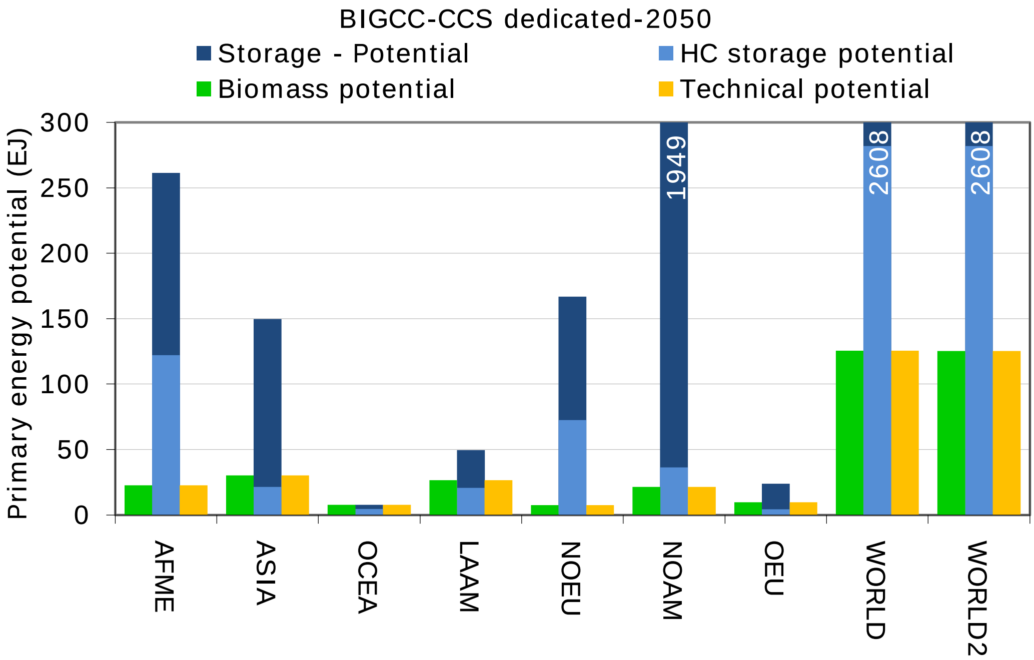
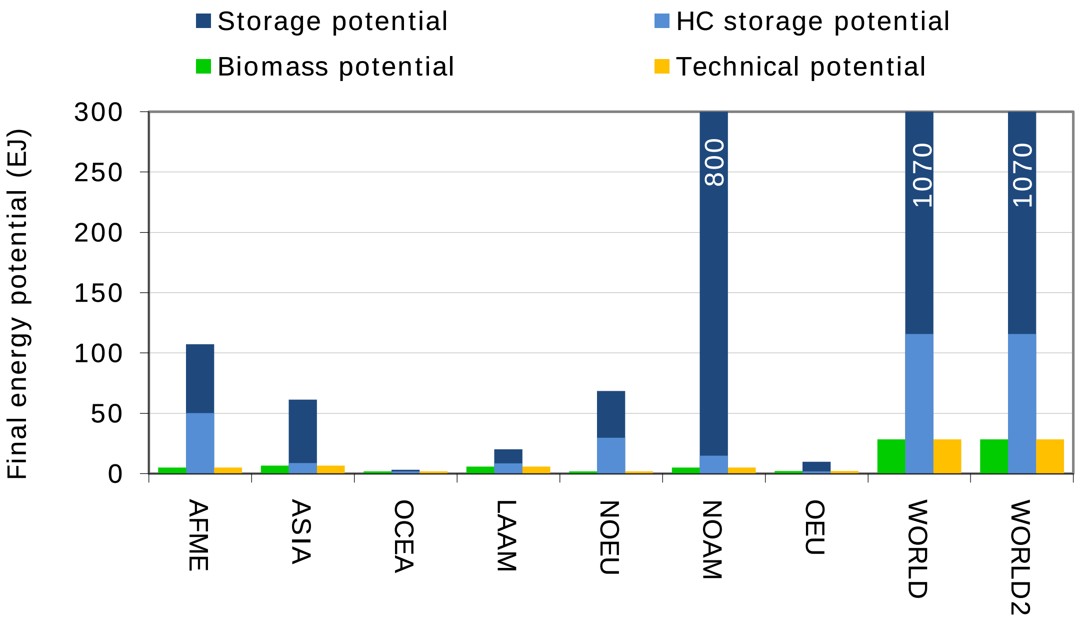


Figure 4 - 22 Primary energy potential (EJ/yr) for the BIGCC-CCS route in 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.

The global potential is as in the CFB-CCS route restricted by the availability of biomass in all regions. Exclusion of inter-regional transport of biomass ('World2') will not change the technical potential in 2030 and 2050.



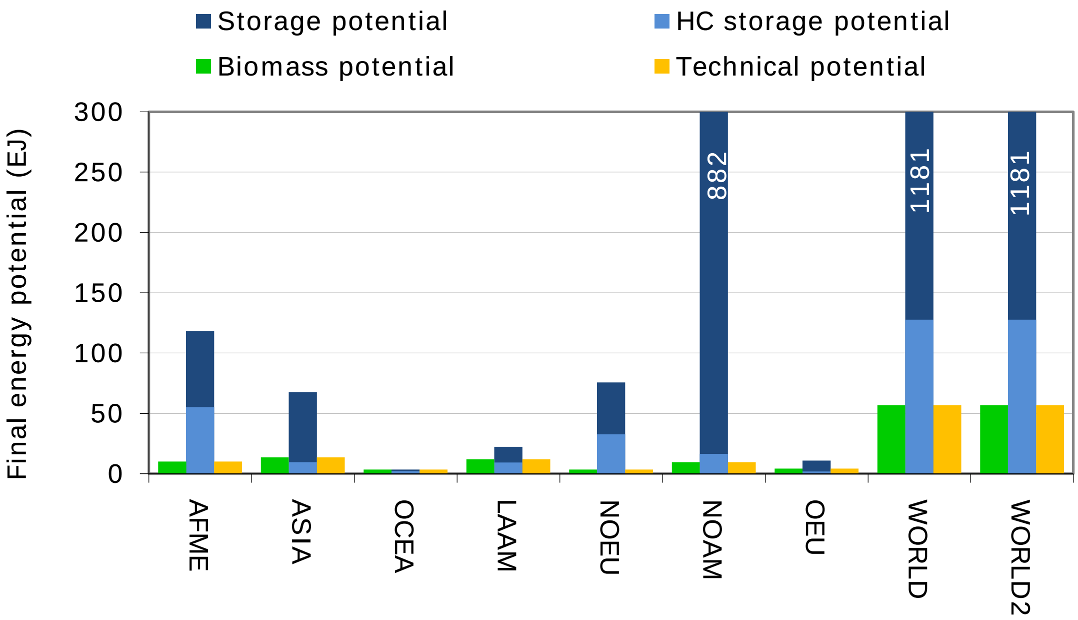
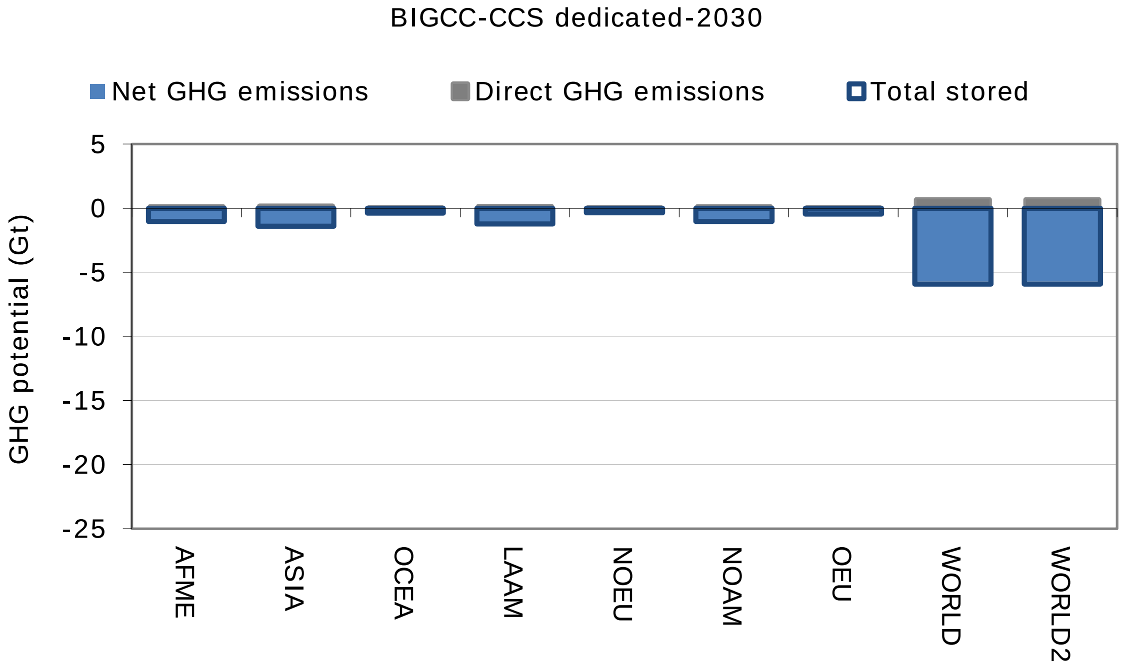


Figure 4 - 23 Final energy potential (EJ/yr) for the BIGCC-CCS route in 2030 and 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on ‘best’ estimate. “World2” technical potential excludes the possibility of inter-regional transport of biomass and CO_2.

The global potential in terms of final energy, shown in Figure 4 - 23, increases from 28 to 57 EJ/yr from 2030 to 2050. This is higher compared to the PC co-firing and CFB routes due to the higher conversion efficiency. It is however slightly lower than for IGCC power plants with co-firing.



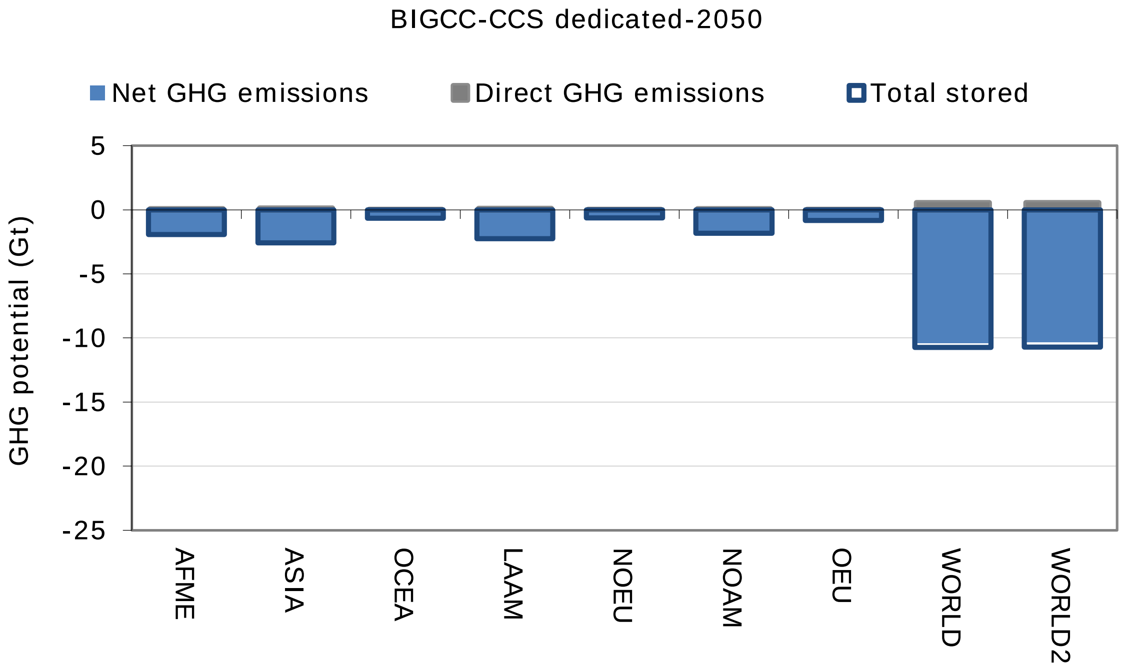
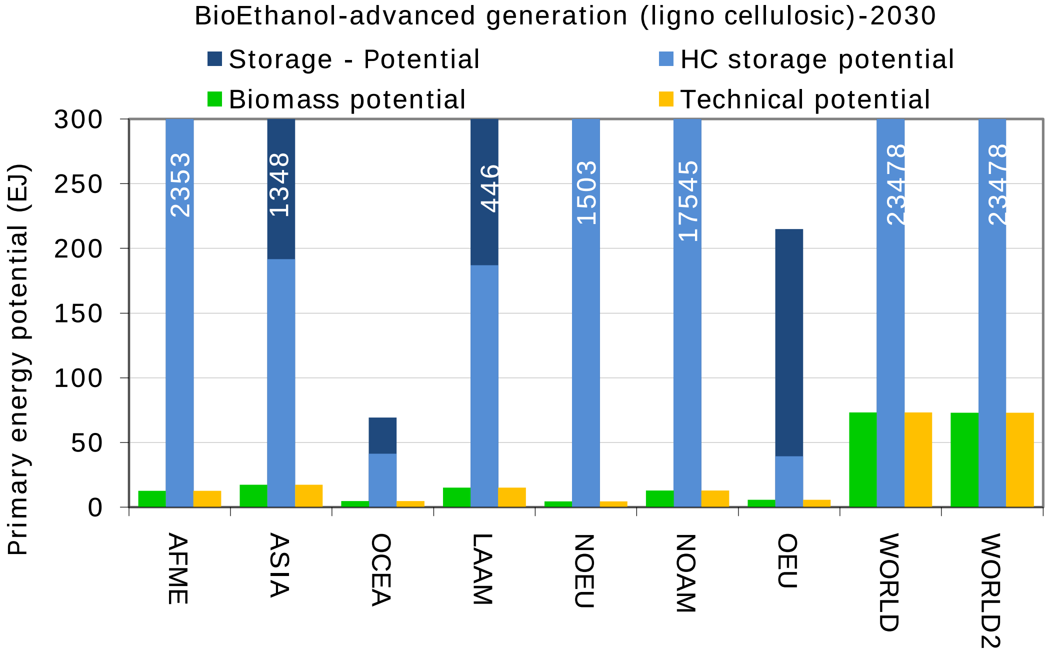


Figure 4 - 24 Net GHG emissions in Gt CO_2 eq. for the BIGCC-CCS route in 2030 and 2050. Blue bars indicate the net emission balance. Grey bars indicate the direct GHG emissions in the supply chain. Dark blue lined boxes indicate the amount of CO_2 stored.

Figure 4 - 24 shows that negative emissions in the view years are comparable to those of the other dedicated route using solely biomass, between 5.7 and 10.4 Gt per year (negative).

4.4.5 Bio-ethanol - advanced generation (ligno-cellulosic)

The primary energy potential for bio-ethanol is given in Figure 4 - 25.



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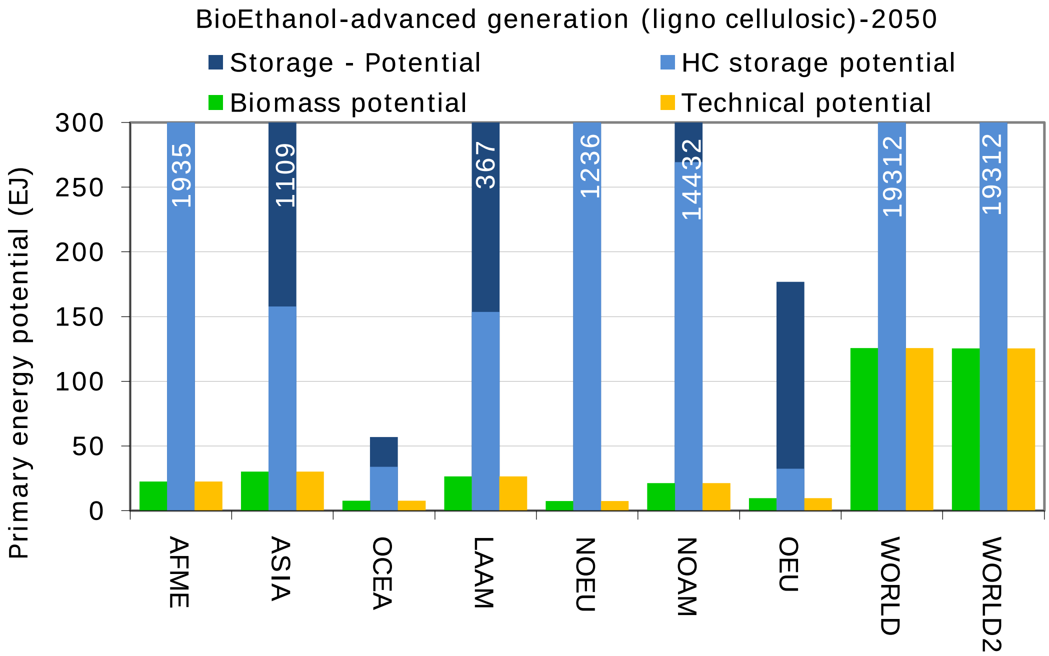


Figure 4 - 25 Primary energy potential (EJ/yr) for the advanced bio-ethanol route in 2030 and 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.

The global primary energy potential is estimated to be 73 EJ/yr in 2030. In 2050 this is 126 EJ/yr. The potential is restricted by the availability of biomass. This is understandable, as only a small fraction (11% in 2030 and 13% in 2050) of CO_2 is captured (only CO_2 from the fermentation process is captured) and thus a relative small storage capacity is required. When biofuels are combusted (for example in transport vehicles), the emissions are not captured.

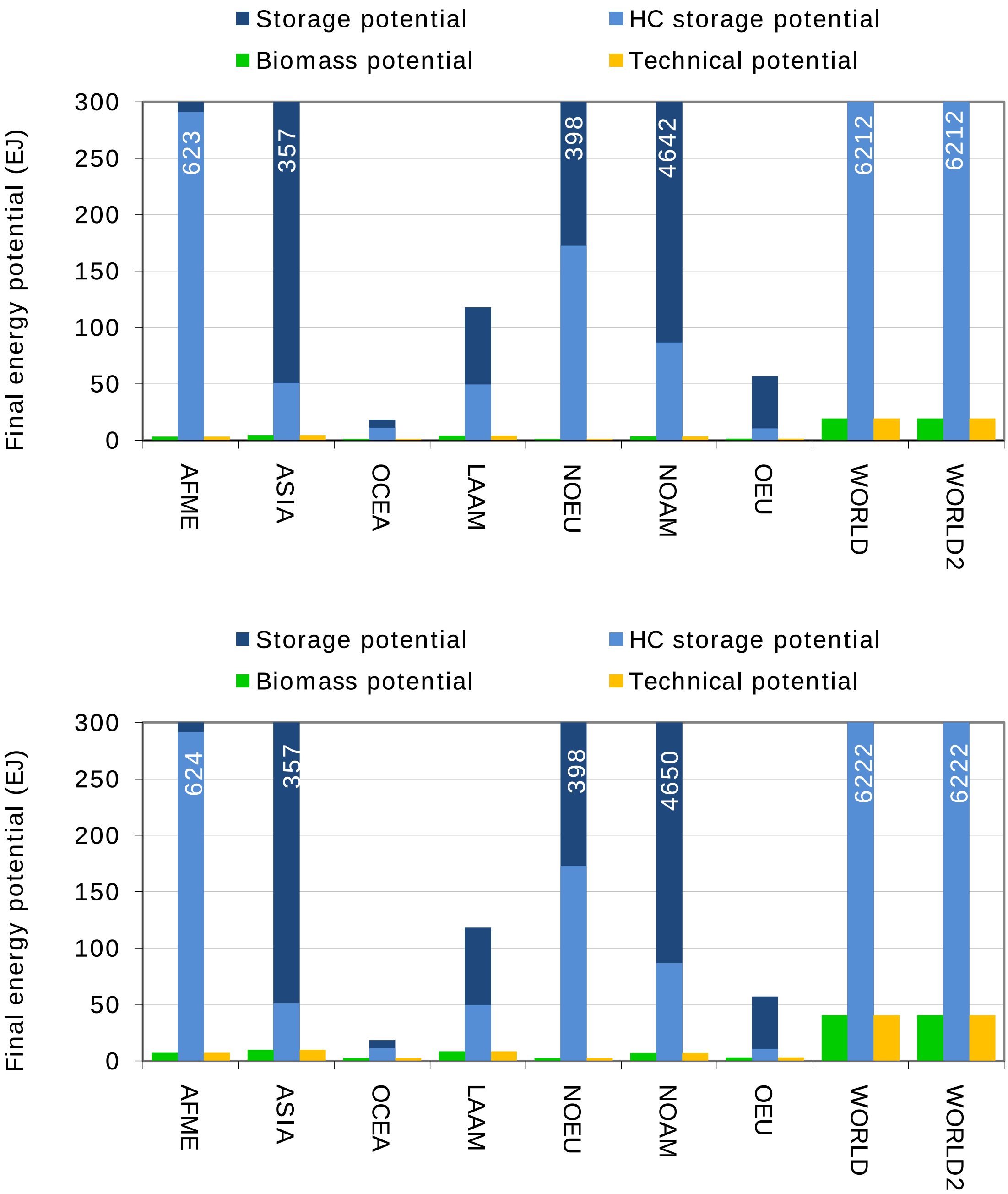
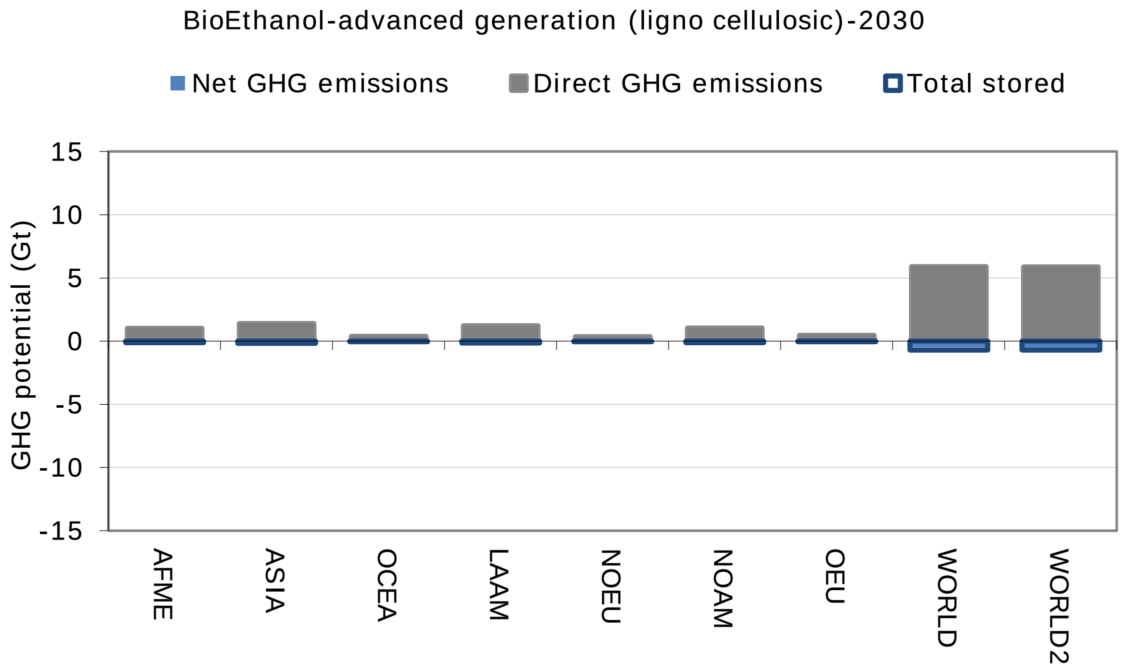


Figure 4 - 26 Final energy potential (EJ/yr) for the advanced bio-ethanol route in 2030 and 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.



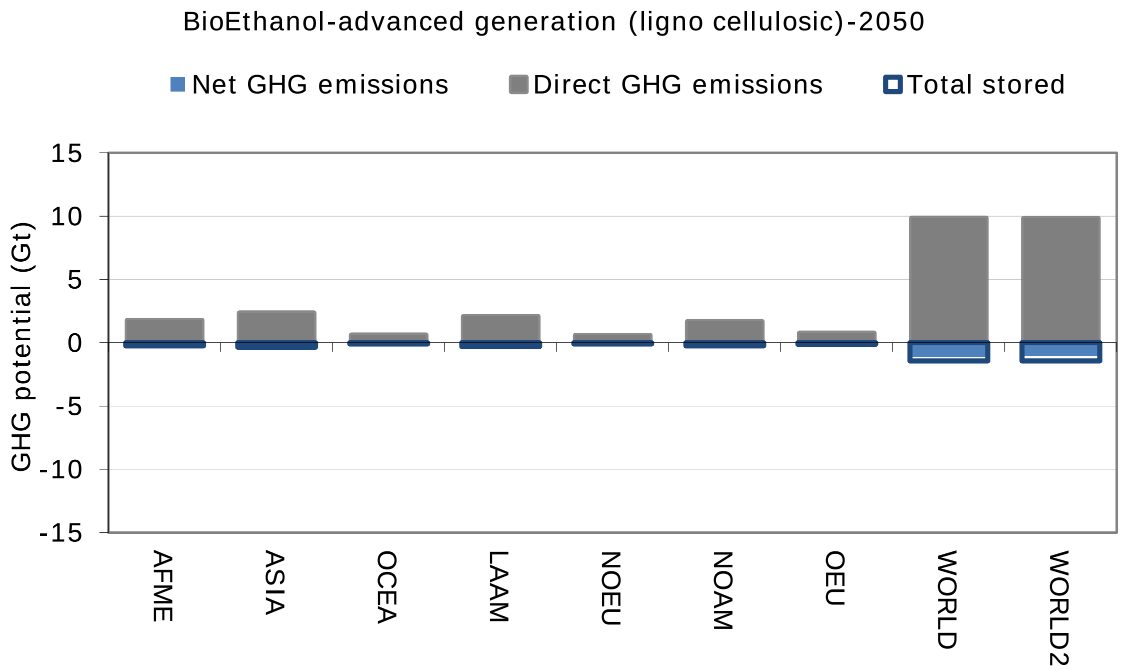


Figure 4 - 27 Net GHG emissions in Gt CO_2 eq. for the advanced bio-ethanol route in 2030 and 2050. Blue bars indicate the net emission balance. Grey bars indicate the direct GHG emissions in the supply chain. Dark blue lined boxes indicate the amount of CO_2 stored.

The final energy potential, see Figure 4 - 26, is estimated to be 19 EJ/yr in 2030. In 2050 this is estimated at 40 EJ/yr. This potential in final energy is comparable to the potential for the CFB-CCS route for power generation, but the net GHG emission balance is different. The balance for this route is just negative at 0.5 Gt and 1.1 Gt in 2030 and 2050, respectively, at full deployment of the potential. This includes the combustion of the biofuels. This is a significantly lower reduction compared to the power generation routes. Emissions are slightly negative as only a small fraction of the carbon in the feedstock is captured which just offsets the emissions in the supply chain (see Figure 4 - 27).

Box 2 Short term technical potential (in Mt CO_2) from bio-ethanol production

Throughout the main body of this report emphasis is placed on *advanced* bio-ethanol production based on lignocellulosic feedstock. The *conventiona*l production of bio-ethanol based on maize and sugarcane currently dominates the production share worldwide however.

A large source of biogenic CO_2 within the production process of ethanol is the fermentation step where sugars are converted into ethanol. The fermentation step produces a high purity CO_2 stream that can be captured with relative low specific cost. For every litre of ethanol produced, 765 g of CO_2 is generated. Figure 4 - 28 shows the CO_2 emissions coming from the fermentation step from bio-ethanol produced in 2008. In 2008, worldwide 50 Mt of CO_2 (with biological origin) is produced by this fermentation process.

As can be seen in Figure 4 - 28, the largest producers of conventional bio-ethanol are Brazil (dominantly sugarcane ethanol) and the United States (dominantly maize ethanol). The storage potential in both countries is assessed in detail and is estimated to be large compared to the amount of CO_2 emitted every year. This production capacity of bio-ethanol can be seen as early opportunities for BE-CCS provided that CO_2 storage capacity is available and located in the near vicinity of the ethanol production plant.

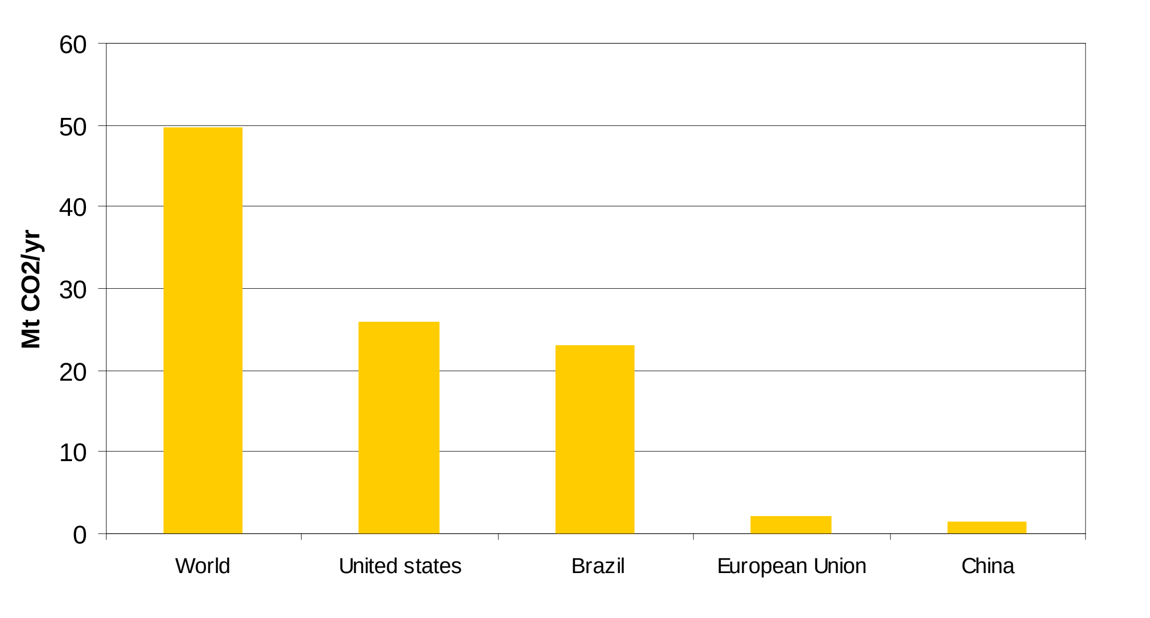
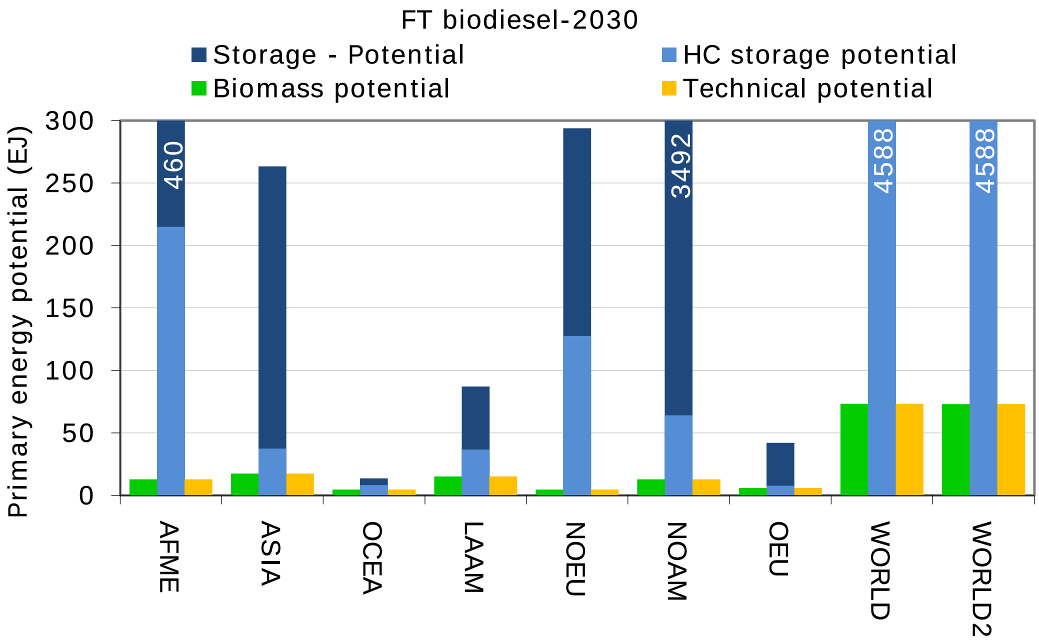


Figure 4 - 28 Worldwide CO_2 emissions from ethanol fermentation in the year 2008 (data for Brazil are for the year 2009)(GEF 2009; Xu, Isom et al. 2010).

4.4.6 Fischer-Tropsch (FT) diesel

The primary energy potential for FT-diesel is given in Figure 4 - 29.



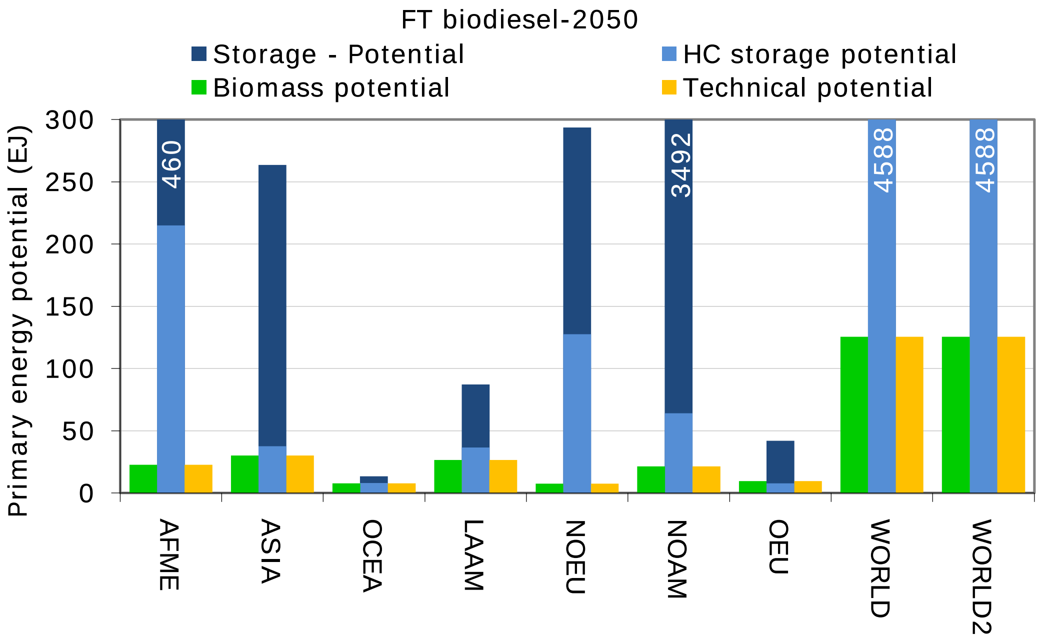
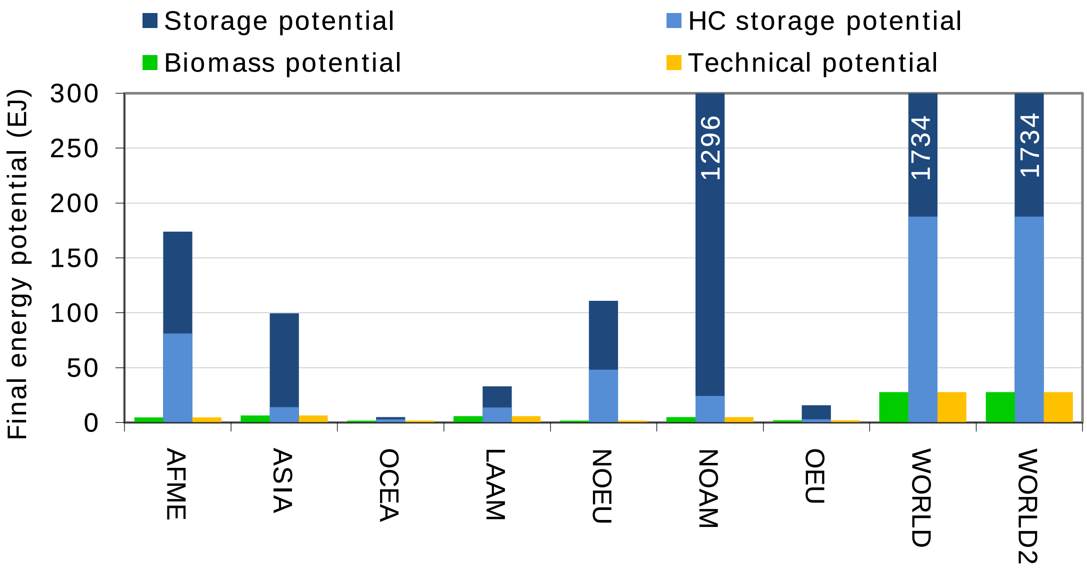


Figure 4 - 29 Primary energy potential (EJ/yr) for the FT-biodiesel route in 2030 and 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.



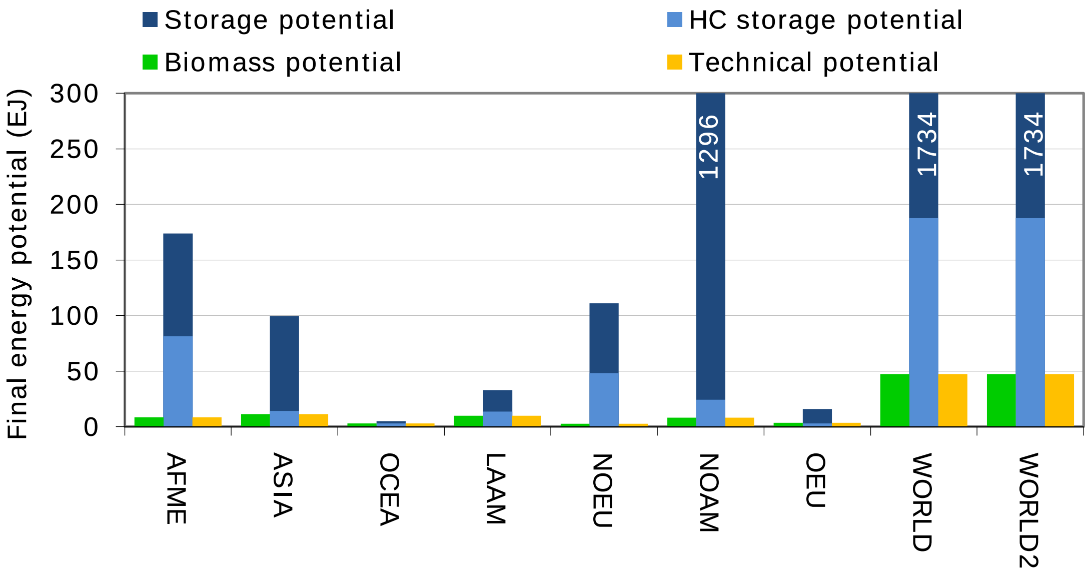
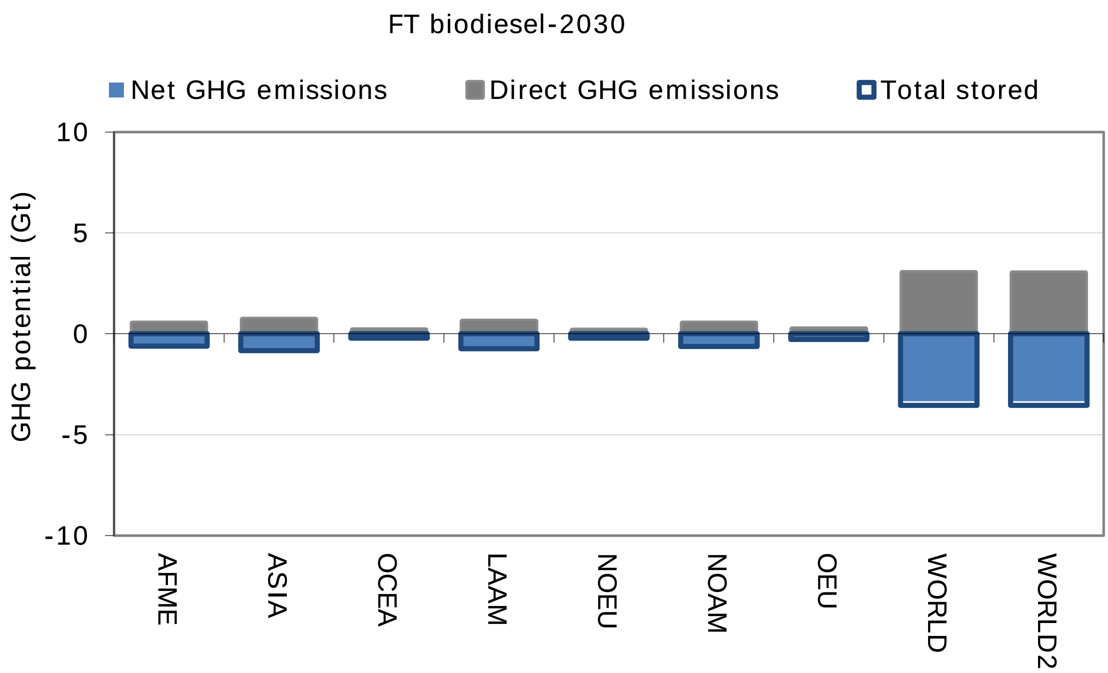


Figure 4 - 30 Final energy potential (EJ/yr) for the FT-biodiesel route in 2030 and 2050. Orange bars indicate the resulting technical potential which is either limited by biomass (green bar) or total storage capacity (dark blue bar). The numbers in the figure represent the total storage potential in EJ/yr. Light blue share represents the hydrocarbon storage potential. Storage capacity is based on 'best' estimate. "World2" technical potential excludes the possibility of inter-regional transport of biomass and CO_2.



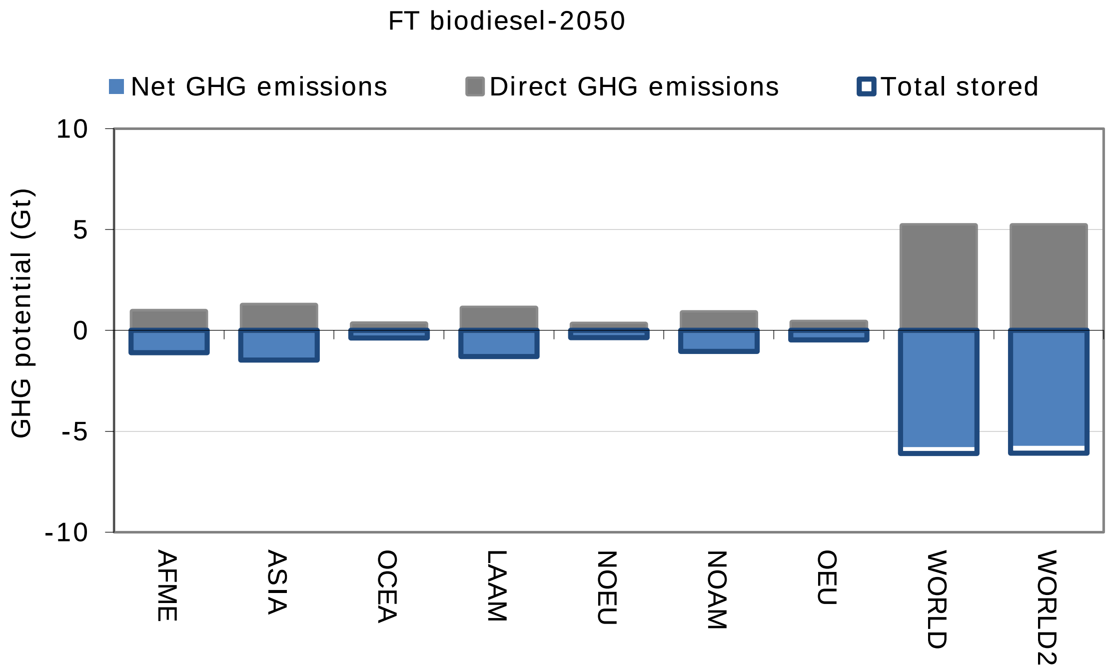


Figure 4 - 31 Net GHG emissions in Gt CO_2 eq. for the FT-biodiesel route in 2030 and 2050. Blue bars indicate the net emission balance. Grey bars indicate the direct GHG emissions in the supply chain. Dark blue lined boxes indicate the amount of CO_2 stored.

We see that the global primary energy potential ranges between 73 and 126 EJ/yr. The potential is in all regions restricted by the biomass availability, although Oceania has little storage capacity left when all biomass is employed. In the FT-biodiesel technology route, a smaller fraction of the emitted CO_2 is captured compared to the power generation routes, but a larger fraction compared to advanced bio-ethanol production. This results in the possibility that storage potential becomes a constraint sooner compared to the advanced ethanol route with capture.

The final energy potential, see Figure 4 - 30, is estimated to range between 28 and 47 $EJ_{biofuel}$/yr. This potential is higher compared to the technical potential of the advanced bio-ethanol route due to the higher conversion efficiency.

More CO_2 is also captured in the conversion process than in the bio-ethanol route and larger negative emissions are thus a possibility with this route: annually up to 3.3 Gt of CO_2 is net removed from the atmosphere if the full potential in 2030 is deployed. In 2050 this can be technically increased to 5.8 Gt, due to the higher primary biomass potential.

5 Realisable potential

In this chapter we present the results of the realisable potential for the BE-CCS routes. The realisable potential for the BE-CCS routes is determined with a separate model using the IEA World Energy Outlook Reference scenario. The maximum share and potential of BE-CCS is estimated based on increased capacity due to increased global demand, replacement of existing stock and retrofit of existing stock with CCS. Important factors influencing the realisable potential are stock turnover rates and timing of the introduction of CCS. The realisable potential is presented in annual and cumulative final energy production for the period 2020-2050. Overall results are also presented in Appendix D.

5.1 Summary

Table 5 - 1 shows the realisable potential per conversion technology. Both annual and cumulative potential in **final energy** in the view years are given. The results show that the realisable potential for 2020 is estimated to be non existent or very small for the selected BE-CCS technologies.

Table 5 - 1 Overview of realisable potential for the selected BE-CCS routes under default assumptions. Note that potentials are assessed on a route by route basis and cannot simply be added, as they may compete and substitute each other.

BE-CCS route		**Potential in EJ final energy**		
	View year	**2020**	**2030**	**2050**
PC-CCS co-firing (biomass share)	Annual	0	15	20
	Cumulative	0	92	440
PC-CCS co-firing (coal share)	Annual	0	34	43
	Cumulative	0	214	1,014
CFB-CCS dedicated	Annual	0	3	6
	Cumulative	0	17	102
IGCC-CCS co-firing (biomass share)	Annual	0	7	12
	Cumulative	0	36	238
IGCC-CCS co-firing (coal share)	Annual	0	17	26
	Cumulative	0	129	846
BIGCC-CCS dedicated	Annual	0	2	4
	Cumulative	0	7	66
Bio-ethanol-advanced generation (ligno cellulosic)	Annual	0	2	8
	Cumulative	0	9	123
FT biodiesel	Annual	0	2	8
	Cumulative	0	9	123

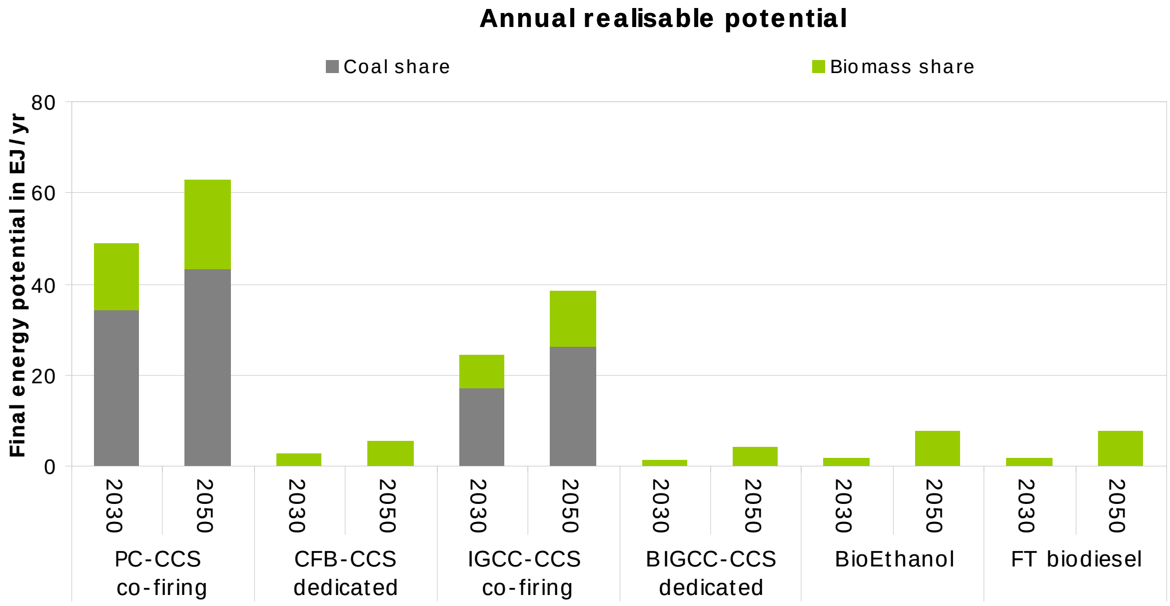


Figure 5 - 1 Annual realisable potential (in EJ/yr) for the selected BE-CCS routes. Note that potentials are assessed on a route by route basis and cannot simply be added, as they may compete and substitute each other.

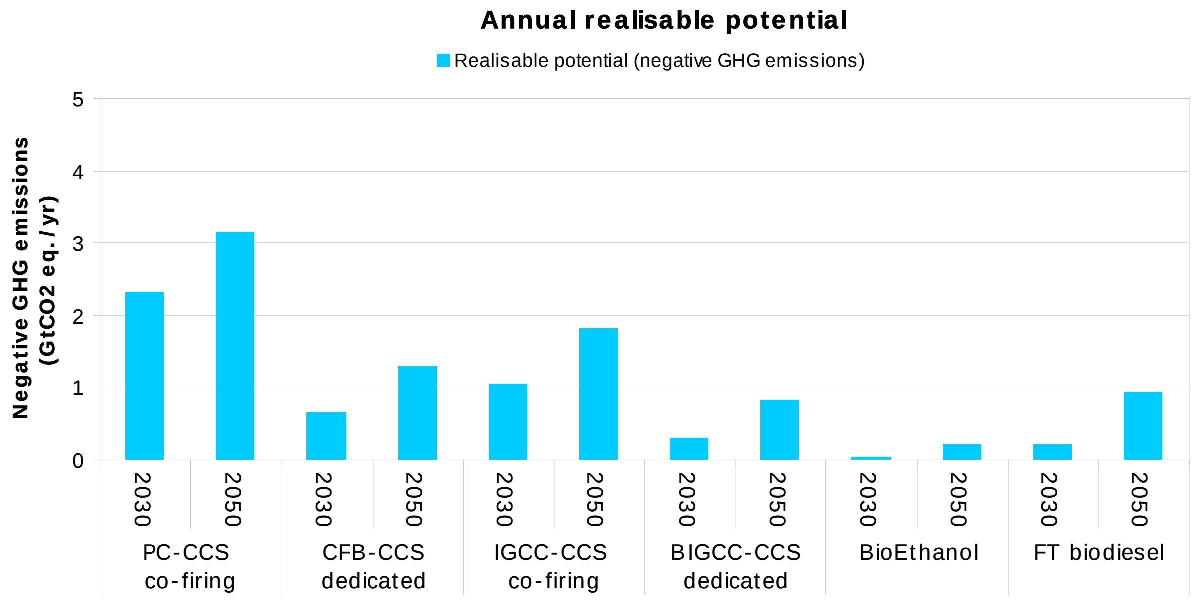


Figure 5 - 2 Overview of GHG performance of the realisable potential for the selected BE-CCS routes. Note that potentials are assessed on a route by route basis and cannot simply be added, as they may compete and substitute each other.

The realisable potential for the BE-CCS routes producing electricity ranges between 2 and 15 EJ/yr in 2030 and between 4 and 20 EJ/yr in 2050. Negative GHG emissions associated with these potentials range between 0.3 and 2.3 Gt CO_2 eq./yr in 2030 and between 0.8 and 3.2 Gt CO_2 eq./yr in 2050. The largest realisable potential for the medium and long term is found in the scenario for the PC-CCS co-firing route. In this route, all new power plants are assumed to be equipped with CCS after 2020, and existing power plants and newly added power plants without CCS may be equipped with CCS at a later date. This advantage over, for instance, the dedicated and gasification routes explain why the realisable potential is considerably higher for this route. Where the realisable potential in final energy produced with dedicated routes is estimated considerably lower compared to the co-firing routes; the potential in terms of GHG performance is relatively better. The dedicated routes result in higher negative emissions per EJ than the co-firing routes and require less storage capacity to achieve those negative emissions.

The realisable potential for both biofuel routes is equal at 2 EJ/yr in 2030 and 8 EJ/yr in 2050. The potential in 2030 in terms of GHG performance is shown to be the highest for the FT-biodiesel route at 0.2 Gt CO_2 eq./yr. In 2050, the potential in annual negative emissions is between 0.2 and 1 Gt CO_2 eq. The cumulative potential of both routes is estimated at 123 EJ up to 2050.

Further, we found that both extending the lifetime of existing installed capacity as extending the implementation date of CCS will have negative influence on the potential for BE-CCS technologies. The rationale behind this is that CCS, and with it BE-CCS, is not likely to be installed at old coal fired power plants.

5.2 Determining the realisable potential

The realisable potential is factually a limitation applied to the **technical potential** by including the demand for final energy, capital stock turnover and possible deployment rate. This means that the realisable potential increases over time according to the possible deployment rate. Based on existing scenario studies we assess the capital stock turnover and final demand on a global scale for the view years. This assessment is done separately for electricity production routes and routes for biofuel production.
The scenario approach for the realisable potential is different compared to the approach used to determine the technical (and economic) potential. The technical potential is estimated in a static way looking at the view years 2030 and 2050 and does not depend on capital stock turnover, energy demand and deployment rate.

Electricity supply

The realisable potential estimates for the electricity supply BE-CCS routes are based on the reference scenario in the IEA World Energy Outlook (IEA 2009). The scenario stretches to 2030. We have adapted the scenario to include the view year 2050. In the model we created, the growth rates of energy conversion technologies from 2007-2030 are used to estimate the shares in electricity supply in 2040 and 2050, see Table 5 - 2. Electricity demand is assumed to grow further from 2030 to 2050 in the same pace as the average growth from 2007-2030, i.e. 2.4 % per year. The results of this calculation are shown in Table 5 - 3.

Table 5 - 2 Shares and average annual growth rate of energy conversion technologies in the adapted WEO reference scenario (figures in *italic* are Ecofys estimations, based on extrapolation of the WEO scenario). In the WEO reference scenario, the total power production increases. A number of conversion technologies will have a decreasing share in total production, while their absolution production increases.

Conversion technology	**Share (%)**			**Average annual growth rate (%)**
	2007	**2030**	***2050***	**2007-2030**
Total generation	100	100	*100*	2.4
Coal	42	44	*32*	2.7
Oil	6	2	*1*	-2.2
Gas	21	21	*14*	2.4
Nuclear	14	11	*6*	1.3
Hydro	16	14	*8*	1.8
Biomass and waste	1	2	*3*	5.2
Wind	1	4	*12*	9.9
Geothermal	0	1	*1*	4.6
Solar	0	1	*24*	21.2
Tide and wave	0	0	*0*	14.6

Table 5 - 3 Electricity generation by conversion technology in the period 1990-2050 based on the IEA World Energy Outlook Reference scenario (figures for 2040 and 2050 (in *italic*) are Ecofys estimations, based on extrapolation of the WEO scenario)

Electricity generation (EJ/yr final)	**1990**	**2007**	**2015**	**2020**	**2025**	**2030**	***2040***	***2050***
Total generation	42.5	71.1	87.7	98.0	110.4	123.5	*160.9*	*198.4*
Coal	15.9	29.6	37.7	42.3	48.4	54.9	*58.9*	*62.9*
Oil	4.8	4.0	3.1	2.8	2.6	2.4	*1.7*	*1.0*
Gas	6.2	14.9	17.9	20.2	22.6	25.4	*26.6*	*27.9*
Nuclear	7.2	9.8	11.2	11.7	12.7	13.2	*12.4*	*11.5*
Hydro	7.7	11.1	13.3	14.5	15.7	16.8	*16.5*	*16.1*
Biomass and waste	0.5	0.9	1.5	1.9	2.4	3.0	*4.3*	*5.6*
Wind	0.0	0.6	2.4	3.6	4.6	5.5	*15.0*	*24.4*
Geothermal	0.1	0.2	0.3	0.4	0.5	0.6	*0.8*	*1.0*
Solar	0.0	0.0	0.2	0.5	0.9	1.4	*24.4*	*47.4*
Tide and wave	0.0	0.0	0.0	0.0	0.0	0.0	*0.2*	*0.4*

Biomass and CCS routes for electricity production are assumed to be applied in two energy conversion processes:

- Electricity production with coal: a share of the existing power plants is assumed to be equipped with CCS and is assumed to be co-firing biomass. Depending on the

BE-CCS route chosen new and replacement capacity is assumed to be co-firing biomass or firing 100% biomass.

- Electricity production with biomass and waste: a share of the existing plants is assumed equipped with CCS and all new capacity is assumed equipped with CCS.

The share of other conversion technologies in the total of power generation is assumed to be fixed. The maximum share of BE-CCS is then estimated based on increased capacity due to increased demand, replacement of existing stock and retrofit of existing stock with CCS.

For the PC-CCS co-firing route we assume that all existing coal fired capacity built after 2007 can be retrofitted with CO_2 capture before the year 2025. Existing coal fired capacity is assumed to be able to co-fire 30% biomass. All newly added capacity after 2020 is assumed to be equipped with CO_2 capture and is able to co-fire 30% biomass. Power plants installed in 2050 are assumed to co-fire 50% biomass in combination with CO_2 capture.

For the dedicated BE-CCS routes we assume that all newly added capacity in the group ‘biomass and waste’ is replaced by BE-CCS capacity with 100% biomass firing. All existing capacity built after 2007 is retrofitted with CO_2 capture before 2025.

To date, only a few IGCCs are operating worldwide. The possibility for retrofitting of existing IGGC co-gasification capacity is therefore very limited. All newly added coal-fired capacity after 2020 are assumed to be IGCCs equipped with CO_2 capture and are able to co-fire 30% biomass. Power plants installed in 2050 are assumed to co-fire 50% biomass in combination with CO_2 capture.

For the dedicated BE-CCS routes we assume that all newly added capacity in the group ‘biomass and waste’ is equipped with CCS and with 100% biomass firing.
Existing capacity which uses ‘biomass and waste’ for power generation is also primarily based on combustion, although a small fraction is based on gasification. We therefore assume that retrofitting of existing capacity with pre-combustion CO_2 capture is limited and is therefore omitted here.

The most important assumptions are summarised in Table 5 - 4.

Table 5 - 4 General assumptions in the realisable potential model

Assumption	Default value
Annual electricity demand growth - global	2.4%
Share of existing stock (built before 2007) replaced every 5 years	20%
New (BE-)CCS will be implemented on power generation installed from year	2020
Retrofitted CCS will be implemented on power generation installed from year	2007
Power plants will be retrofitted before year	2025
Fraction of retrofitted power generation equipped with CCS	100%
Biomass input in final energy in BE-CCS routes replacing 'Coal'	30% from 2020 onwards 50% in 2050
Biomass input in final energy in BE-CCS routes replacing 'Biomass and Waste'	100%
Coal input in final energy in BE-CCS routes replacing 'Coal'	70% from 2020 onwards 50% in 2050

Important variables that can be altered in the model are the expected increase in electricity demand and the expected rate of stock turnover. The latter determines how much capacity is replaced and thus how much BE-CCS capacity can be added in a period. As a default we assume that every 5 year 20% of the existing stock (capacity installed before 2007) is decommissioned and replaced by new power plants.

It should be stressed that the model does not determine the techno-economic optimum. It merely gives insight into the possible share BE-CCS routes could reach based on general trends in the global electricity sector sketched in the IEA WEO reference scenario (IEA 2009).

Supply of transport fuels

The realisable potential estimates for the supply of biofuels with BE-CCS routes are also based on the *Reference scenario* in the IEA World Energy Outlook (IEA 2009). For biofuels we have adapted the reference scenario to include the view year 2050. In the model we created, the growth rates of energy conversion technologies from 2007-2030 are used to estimate the shares in the supply of transport fuels in 2040 and 2050. The demand for transport fuels is assumed to grow from 2030 to 2050 in the same pace as the average growth from 2007-2030, i.e. 1.6 % per year.

Table 5 - 5 Supply of transport fuels by source in the period 1990-2050 based on the IEA World Energy Outlook Reference scenario (figures in *italic* are Ecofys estimations, based on extrapolation of the WEO scenario) in EJ/yr

Fuels	1990	2007	2015	2020	2025	2030	*2040*	*2050*
Oil	62.2	90.5	97.8	105.7	115.7	127.8	*147.9*	*152.4*
of which marine bunkers	4.7	8.0	8.3	9.0	9.5	10.2	*11.5*	*11.8*
of which aviation bunkers	3.6	5.8	6.4	7.0	7.7	8.5	*10.1*	*10.4*
Biofuels	0.3	1.4	3.2	4.4	5.0	5.6	*10.0*	*11.3*
Other fuels	3.6	4.2	4.9	5.2	5.7	6.1	*7.1*	*7.4*
Total transport	66.1	96.1	105.9	115.3	126.4	139.5	*165.1*	*171.0*

Table 5 - 6 Shares and average annual growth rate of transport fuel supply technologies in the adapted WEO reference scenario (figures in *italic* are Ecofys estimations, based on extrapolation of the WEO scenario)

Fuels	Shares (%)			Average annual growth rate
	2007	2030	2050	2007-2030
Oil	94	92	89	1.5
of which marine bunkers	8	7	7	1.1
of which aviation bunkers	6	6	6	1.7
Biofuels	1	4	7	6.1
Other fuels	4	4	4	1.6

BE-CCS routes for transport fuels are assumed to replace the share of 'biofuels' in the above scenarios based on the IEA WEO Reference scenario. As in the model for electricity supply, important variables in the model are the turnover of existing capacity and the increase in demand for biofuels. This determines how much new capacity can be added and whether this is first or second generation biofuel production. The most important assumptions are presented in the table below.

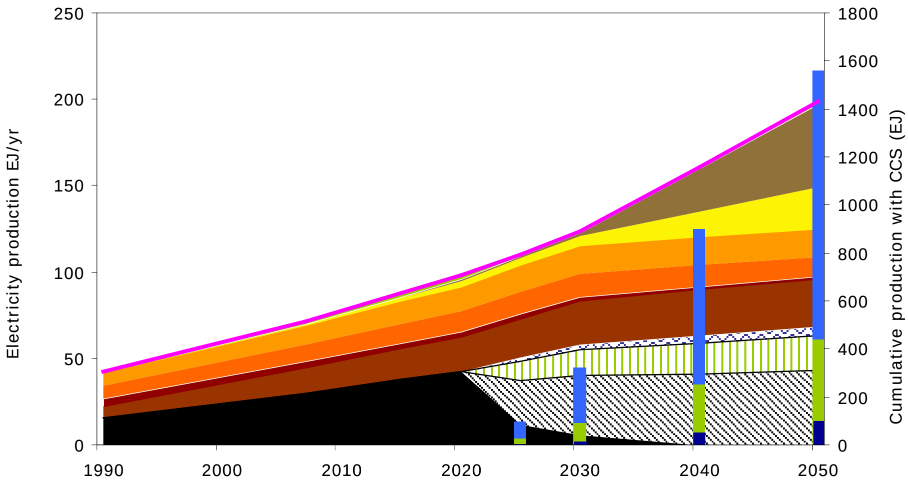
Table 5 - 7 General assumptions in the realisable potential model for transport fuels

Assumption	Default value
Annual transport fuel demand growth -global	1.6%
Existing stock (built before 2007) replacement in 5 years	20%
CCS will be implemented on first generation biofuel (bio-ethanol) plants from year	2015
Fraction of first generation biofuels that can be equipped with CCS	85%
Replaced capacity and new capacity due to increase in demand is all second generation biofuel production from year	2020

5.3 Results for the realisable potential

5.3.1 Realisable potential for BE-CCS routes producing electricity

In Figure 5 - 3 the realisable potential for BE-CCS routes is shown. The graph shows that coal fired generation (i.e. based on combustion) without CCS grows until 2020 and then phases out due to the implementation of new power plants with CCS and biomass co-firing/co-gasification and due to the retrofit of existing generating capacity with CCS. More details on this assumed implementation path are discussed below.

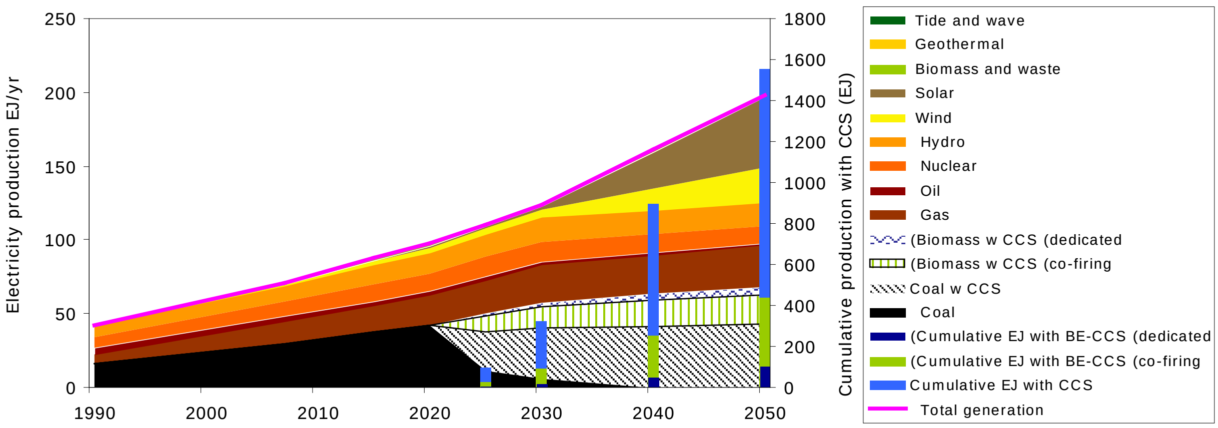


	1990	2007	2015	2020	2025	2030	2040	2050
Tide and wave	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4
Geothermal	0.1	0.2	0.3	0.4	0.5	0.6	0.8	1.0
Biomass and waste	0.5	0.9	1.5	1.9	0.4	0.2	0.0	0.0
Solar	0.0	0.0	0.2	0.5	0.9	1.4	24.4	47.4
Wind	0.0	0.6	2.4	3.6	4.6	5.5	15.0	24.4
Hydro	7.7	11.1	13.3	14.5	15.7	16.8	16.5	16.1
Nuclear	7.2	9.8	11.2	11.7	12.7	13.2	12.4	11.5
Oil	4.8	4.0	3.1	2.8	2.6	2.4	1.7	1.0
Gas	6.2	14.9	17.9	20.2	22.6	25.4	26.6	27.9
(Biomass w CCS (dedicated	0.0	0.0	0.0	0.0	2.0	2.8	4.3	5.6
(Biomass w CCS (co-firing	0.0	0.0	0.0	0.0	11.0	14.7	17.7	19.7
Coal w CCS	0.0	0.0	0.0	0.0	25.6	34.3	41.2	43.2
Coal	15.9	29.6	37.7	42.3	11.8	5.9	0.0	0.0
(Cumulative EJ with BE-CCS (dedicated	0.0	0.0	0.0	0.0	5.0	17.0	52.7	102.0
(Cumulative EJ with BE-CCS (co-firing	0.0	0.0	0.0	0.0	27.5	91.7	253.6	440.3
Cumulative EJ with CCS	0.0	0.0	0.0	0.0	96.5	322.6	897.9	1556.5

Figure 5 - 3 Assumed implementation path for BE-CCS technologies in global electricity supply determining the annual (left axis) and cumulative realisable potential (stacked bars – right axis) up to 2050.

5.3.2 PC-CCS co-firing and dedicated firing routes

In the Figure 5 - 4, we can see that the annual BE-CCS potential for the co-firing route increases towards 20 EJ/yr in 2050 and the dedicated route towards 6 EJ/yr. The cumulative potential grows significantly in the period 2030-2050 and totals at 542 EJ for the total biomass share. The total cumulative potential, which also represents how much CO_2 is stored in this scenario, is 1556 EJ in 2050. The negative emissions associated with these potentials are presented in Table 5 - 8 and show that annual negative emissions for combustion based routes are maximally 3.2 Gt CO_2 eq. per year in 2050 for the PC-CCS co-firing route. The dedicated route has somewhat lower (0.7-1.3 Gt CO_2 eq./yr) GHG potentials in 2030 and 2050, but the relative performance in terms of negative GHG emissions per EJ is better.



All figures in EJ	2020	2030	2050
Annual BE-CCS potential (co-firing biomass share)	0	15	20
Annual BE-CCS potential (dedicated)	0	3	6
Annual BE-CCS potential (coal share)	0	34	43
Annual CCS potential	0	52	68
Cumulative EJ with BE-CCS (co-firing)	0	92	440
Cumulative EJ with BE-CCS (dedicated)	0	17	102
Cumulative EJ with BE-CCS (coal)	0	214	1,014
Cumulative CCS potential	0	323	1,556

Figure 5 - 4 Annual (left axis) and cumulative realisable potential (stacked bars – right axis) up to 2050 for co-firing and dedicated combustion BE-CCS technologies in global electricity supply.

The annual technical potential (biomass share) for these routes has been estimated in section 4 at 24-47 and 27-54 EJ/yr for the dedicated and co-firing routes, respectively. The realisable potential of 20 EJ/yr for the co-firing routes is thus up to almost a factor three lower than the technical potential. The 6 EJ/yr, estimated for the dedicated routes, is approximately factor 8 lower than the technical potential. It can thus be concluded that if full global biomass supply and storage capacity is allocated to these routes only that there is enough biomass and storage capacity to accommodate the implementation path sketched in Figure 5 - 4.

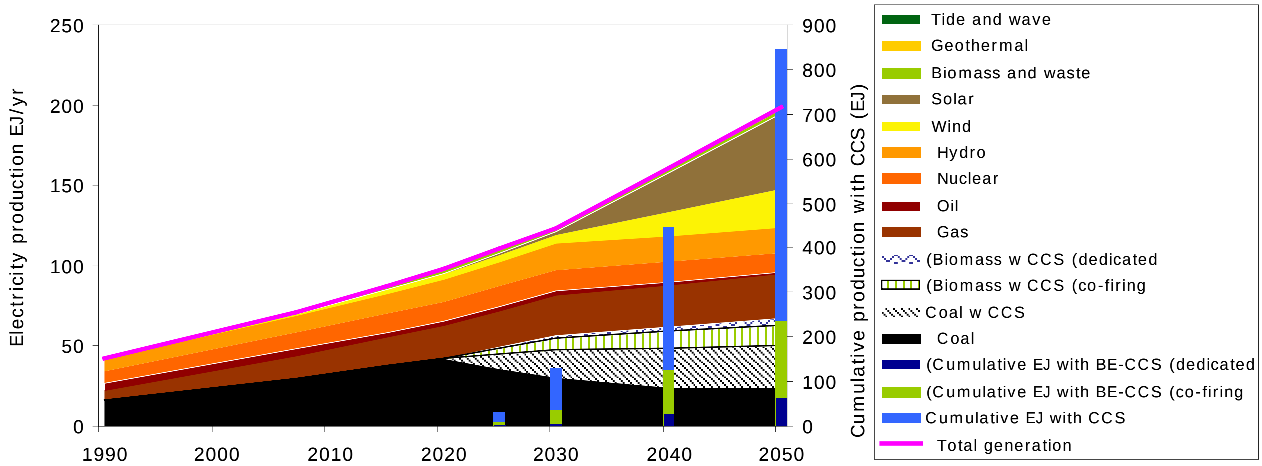
Table 5 - 8 Greenhouse gas emissions for co-firing and dedicated combustion BE-CCS technologies in global electricity supply.

Technology route	Year	Net GHG Emissions ($Gt\ CO_2$ eq./yr)
PC-CCS co-firing	2030	-2.3
	2050	-3.2
CFB-CCS dedicated	2030	-0.7
	2050	-1.3

5.3.3 (B) IGCC co-gasification and dedicated gasification routes

In Figure 5 - 5, we see that the annual BE-CCS potential for the co-gasification route increases towards 12 EJ/yr in 2050. For the dedicated route this is 4 EJ/yr. The cumulative potential here also grows significantly in the period 2030-2050 and totals at 304 EJ for the total biomass share in both routes. The total cumulative potential, which also represents how much CO_2 is stored in this scenario, is 846 EJ in 2050. These numbers are significantly lower than estimated for the routes based on combustion. The overall GHG reduction that can be achieved with implementing these routes is thus also estimated lower. The dominant reason for this is the fact that we assume that retrofitting of existing generating capacity with CO_2 capture is not possible for these routes.

The negative emissions associated with these potentials are presented in Table 5 - 9 and show that annual negative emissions for combustion based routes are maximally 1.8 Gt CO_2 eq. per year in 2050 for the IGCC-CCS co-firing route. The dedicated route has somewhat lower GHG potentials (0.3-0.8 Gt CO_2 eq./yr) in 2030 and 2050, but the relative performance in terms of negative GHG emissions per EJ is better.



All figures in EJ	2020	2030	2050
Annual BE-CCS potential (co-firing biomass share)	0	7	12
Annual BE-CCS potential (dedicated)	0	2	4
Annual BE-CCS potential (coal share)	0	17	26
Annual CCS potential	0	26	43
Cumulative EJ with BE-CCS (co-firing)	0	36	238
Cumulative EJ with BE-CCS (dedicated)	0	7	66
Cumulative EJ with BE-CCS (coal)	0	85	542
Cumulative CCS potential	0	129	846

Figure 5 - 5 Annual (left axis) and cumulative realisable potential (stacked bars – right axis) up to 2050 for co-gasification and dedicated gasification BE-CCS technologies in global electricity supply.

The annual technical potential for these routes has been estimated in section 4 at 28-57 EJ/yr and 30-59 EJ/yr for the dedicated and co-gasification routes, respectively. The annual realisable potential of 12 EJ/yr for the co-gasification routes is thus up to a factor 5 lower than the technical potential. The 4 EJ/yr, estimated for the dedicated routes, is approximately a factor 15 lower than the technical potential. It thus can be concluded that if full global biomass supply and storage capacity is allocated to these routes only that there is enough biomass and storage capacity to accommodate the implementation path sketched in Figure 5 - 5.

Table 5 - 9 Greenhouse gas emissions for co-firing and dedicated gasification BE-CCS technologies in global electricity supply.

Technology route	Year	Net GHG Emissions (Gt CO_2 eq./yr)
IGCC-CCS co-firing	2030	-1.1
	2050	-1.8
BIGCC-CCS dedicated	2030	-0.3
	2050	-0.8

5.3.4 Realisable potential for electricity routes– some sensitivities

The estimates for the realisable potential depend strongly on the key assumptions listed in section 5.2. Above we already have shown that the realisable potential is dependent sensitive to the assumption on whether retrofit is possible or not. Here we show the effect of changing the stock turnover rate and the year of implementation of (BE-) CCS on the annual and cumulative potential for BE-CCS routes producing electricity.

Table 5 - 10 Effect on realisable potential when changing stock turnover rate from 20% to 10% (per five years)

Result	EJ in 2030	change vs. default	EJ in 2050	change vs. default
Annual BE-CCS potential	11	-24%	17	-15%
Annual CCS potential	40	-24%	56	-18%
Cumulative EJ with BE-CCS (co-firing)	70	-24%	341	-23%
Cumulative EJ with BE-CCS (dedicated)	15	-14%	91	-11%
Cumulative EJ with BE-CCS (coal)	162	-24%	773	-24%
Cumulative CCS potential	246	-24%	1,206	-23%

In this sensitivity analysis we show that changing the stock turnover rate has large impact on the amount of EJ that can be produced with biomass and CCS. This holds for both the annual produced electricity as the cumulative produced electricity up to the year 2050. Extending the lifetime of existing installed capacity thus has a significant negative influence on the potential for BE-CCS technologies.

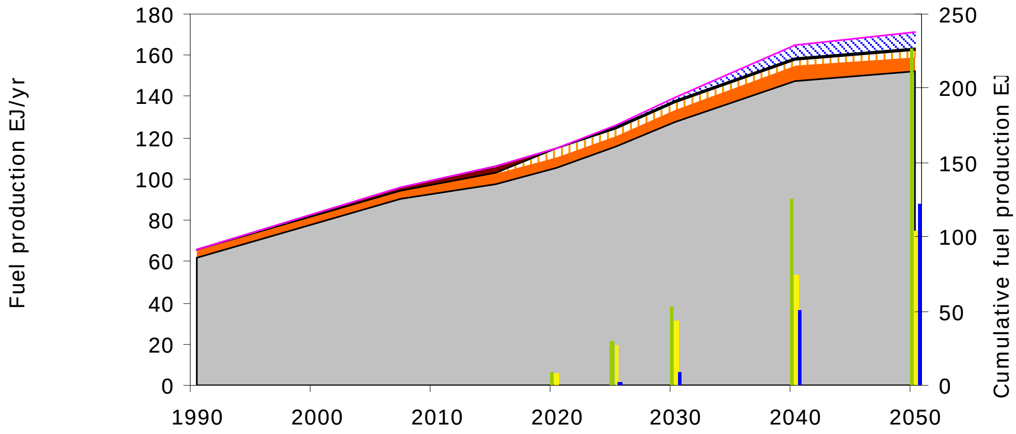
Table 5 - 11 Effect on realisable potential when changing the CCS implementation year for new installed capacity from 2030 onwards and retrofitting existing capacity before 2030

	EJ in 2030	change vs. default	EJ in 2050	change vs. default
Annual BE-CCS potential	15	0%	20	0%
Annual CCS potential	52	0%	68	0%
Cumulative EJ with BE-CCS (co-firing)	37	-60%	385	-12%
Cumulative EJ with BE-CCS (dedicated)	7	-58%	92	-10%
Cumulative EJ with BE-CCS (coal)	86	-60%	886	-13%
Cumulative CCS potential	130	-60%	1,363	-12%

In this sensitivity analysis we show that changing the year from which CCS is assumed to be ready for large scale implementation has a smaller impact on the amount of cumulative EJ that can be produced in 2050 with biomass and CCS compared to the stock turnover rate. The results show that annual production in 2050 with BE-CCS is not affected by this assumption as by that time all power plants will also have been retrofitted with CO_2 capture. However, annual production in 2030 is heavily reduced and therewith the cumulative production until 2030 and until 2050 is also negatively affected. Extending the date of large scale implementation of (BE-)CCS will have a negative influence on the cumulative potential for BE-CCS technologies and the amount of CO_2 emissions that can be avoided before 2050.

5.3.5 Realisable potential - transport fuel routes

In Figure 5 - 6, the realisable potential for BE-CCS routes is shown based on the methodology and assumptions presented in section 5.2.



	1990	2007	2015	2020	2025	2030	2040	2050
Second generation biofuels w CCS	0.0	0.0	0.0	0.0	1.0	1.8	6.5	7.8
First generation biofuels w/o CCS	0.3	1.4	3.2	0.7	0.6	0.6	0.5	0.5
First generation biofuels w CCS	0.0	0.0	0.0	3.7	3.5	3.2	3.0	3.0
Other fuels	3.6	4.2	4.9	5.2	5.7	6.1	7.1	7.4
Oil	62.2	90.5	97.8	105.7	115.7	127.8	147.9	152.4
Cumulative EJ with second gen. w CCS	0.0	0.0	0.0	0.0	2.4	9.2	50.9	122.6
Cumulative EJ with first gen. w CCS	0.0	0.0	0.0	9.3	27.2	43.8	74.8	104.6
Cumulative EJ with biofuels w CCS	0.0	0.0	0.0	9.3	29.5	53.1	125.7	227.2
Total demand	66.1	96.1	105.9	115.3	126.4	139.5	165.1	171.0

Figure 5 - 6 Assumed implementation path for BE-CCS technologies in global supply for transport fuels determining the annual (left axis) and cumulative realisable potential (stacked bars – right axis) up to 2050.

The figure clearly shows that fossil oil based transport fuels will dominate the supply in the IEA WEO Reference scenario up to 2030 and also to 2050. Biofuels represent about 7 % of the supply for transport fuels, which equates to about 7.5 % of road transport fuels in 2050. It can be seen that first generation biofuel production is gradually phased out and that second generation biofuels (ligno-cellulosic bio-ethanol or FT-biodiesel) are dominant in 2050 with 7.8 EJ/yr. Due to our assumptions, conventional and advanced technologies for the generation of biofuels with CCS have comparable cumulative production over the period up to 2050, i.e. between 104 and 123 EJ.

The negative GHG emissions associated with these estimates are highest for the FT biodiesel route (1 Gt of negative emissions) as the amount of CO_2 that is captured and stored per EJ of final energy is higher. This results in more negative emissions compared to the bio-ethanol route. The latter shows a maximum of 0.2 Gt of negative emissions in the year 2050.

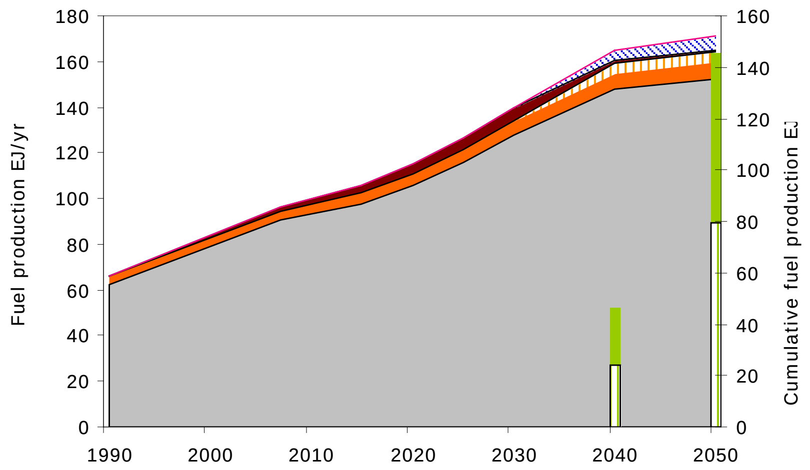
Table 5 - 12 Greenhouse gas emissions for BE-CCS technologies in global supply for transport fuels.

Technology route	Year	Net GHG Emissions (Gt CO_2 eq. / yr)
BioEthanol	2030	0.0
	2050	-0.2
FT biodiesel	2030	-0.2
	2050	-1.0

The results of the simple model depend strongly on the assumptions. To assess the impact of the assumptions we conducted a sensitivity analysis. We have adjusted the assumptions to represent a scenario where CCS is implemented later and where the lifetime of the production capacity of biofuels is extended (see table Table 5 - 13). The latter adjustment results in a lower stock turnover rate. The results of this exercise are presented in Figure 5 - 7.

Table 5 - 13 Assumptions in the realisable potential model for transport fuels – sensitivity analysis

Assumption	Alternative value
Annual transport fuel demand growth -global	1.6%
Existing stock (built before 2007) replacement every 5 years	10%
CCS will be implemented on first generation biofuel (bio-ethanol) plants from year	2030
Replaced capacity and new capacity due to increase in demand is all second generation biofuel production from year	2030



	1990	2007	2015	2020	2025	2030	2040	2050
Second generation biofuels w CCS	0.0	0.0	0.0	0.0	0.0	0.0	4.8	6.3
First generation biofuels w/o CCS	0.3	1.4	3.2	4.4	5.0	5.6	0.8	0.7
First generation biofuels w CCS	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.2
Other fuels	3.6	4.2	4.9	5.2	5.7	6.1	7.1	7.4
Oil	62.2	90.5	97.8	105.7	115.7	127.8	147.9	152.4
Cumulative EJ with second gen. w CCS	0.0	0.0	0.0	0.0	0.0	0.0	23.8	79.2
Cumulative EJ with first gen. w CCS	0.0	0.0	0.0	0.0	0.0	0.0	22.5	66.2
Cumulative EJ with biofuels w CCS	0.0	0.0	0.0	0.0	0.0	0.0	46.3	145.3
Total demand	66.1	96.1	105.9	115.3	126.4	139.5	165.1	171.0

Figure 5 - 7 Results of sensitivity analysis for transport fuel model.

The figure shows that the cumulative production of biofuels with CCS has decreased significantly from 123 to 79 EJ and from 105 to 66 EJ for second and first generation, respectively. The timing of the implementation of CCS and the stock turnover of existing capacity is thus critical for the amount of biofuels that can be produced when equipped with CCS.

6 Economic potential

In this chapter, we present the results of the economic potential for the BE-CCS conversion technologies. The economic potential is determined by combining the cost supply curves for biomass resources with the conversion and CCS cost of the selected BE-CCS routes. We assess the cost of producing electricity of biofuels with and without CCS, including the CO_2 price. This yields supply curves for the selected BE-CCS routes. We also present the cost of the reference technologies. The economic BE-CCS potential is then the total final energy that can be converted at lower cost than the (fossil) reference technologies. Important factors influencing the economic potential are the CO_2 price, fuel price (development) and discount rate (to determine the annualised investment cost). Assumptions on these factors should be acknowledged when reviewing the results in this section.

6.1 Summary

Under the assumptions presented Table 6 - 1, we have estimated the cost supply curves and the economic potential of the selected BE-CCS routes. The results are summarised in Table 6 - 2, Figure 6 - 1 and Appendix D, and show the economic potential and the production cost of electricity and transport fuels for the first two 'steps' of the supply curve.

Table 6 - 1 General assumptions for the calculation of the economic potential

General assumptions	2030	2050
Discount rate	Medium (10%)	Medium (10%)
Forestry residues scenario	Low	Low
Criteria biomass	Strict	Strict
CO_2 Reservoirs type	All	All
Storage potential estimation	Best	Best
Storage capacity saturation period (years)	50	50
CO_2 price (€/tonne)	50	50
Biomass densification cost (€/GJ)	1.0	1.0
Biomass transport cost (€/GJ)	0.4	0.4
Average CO_2 storage costs (EUR/tonne CO_2)	5.0	5.0
Average CO_2 transport distance (km) and cost (EUR/tonne CO_2)	200-500 km 5.0	200-500 km 5.0
Coal price (€/GJ)	3.7	3.7

The results show that for the view years 2030 and 2050, the route using the BIGCC with CCS has the lowest cost of electricity production when using low cost biomass. This despite the higher specific investment cost and lower conversion efficiency compared to the other BE-CCS technologies. The low cost biomass and relative high CO_2 price of 50 euro/t offsets these disadvantages.

With higher cost for biomass resources the production cost increase for all routes, though the most for the dedicated routes (BIGCC and CFB with CCS). These routes are more sensitive for changes in biomass prices compared to the co-firing routes. In the co-firing routes the coal represents a large share of the primary energy input and thus of the fuel cost. This suppresses the increase of production cost when biomass prices increase. The cost supply curves are thus steeper for the dedicated routes.

The dedicated route using the CFB technology is the only route where the conversion costs for power production are overall lower when the plant is **not** equipped with CCS. The cost difference is the largest for the medium term, i.e. for 2030. In the other routes the production costs are predominantly lower when CCS is implemented compared to the same technology not equipped with CCS.

The economic potential is found to be the largest for the routes based on gasification. The largest potential is found for the IGCC co-firing route for 2050 summing to approximately 39 EJ/yr (20 EJ/yr biomass share). This equates to more than 3 Gt of negative GHG emissions. The smallest economic potential is found for the PC-CCS co-firing route and CFB-CCS route of about ranging between 0 and 1 EJ/yr for the year 2030.

For biofuels, the economic potential is calculated to be the highest for the FT-biodiesel route at 26 EJ_{final}/yr, which equates to about 3 Gt of CO_2 eq. removed from the atmosphere per year in 2050. The bio-ethanol route shows a low economic potential in 2030 of 1.2 EJ/yr but grows significantly to about 13 EJ/yr in 2050. This equals maximally 0.4 Gt of net negative GHG emissions.

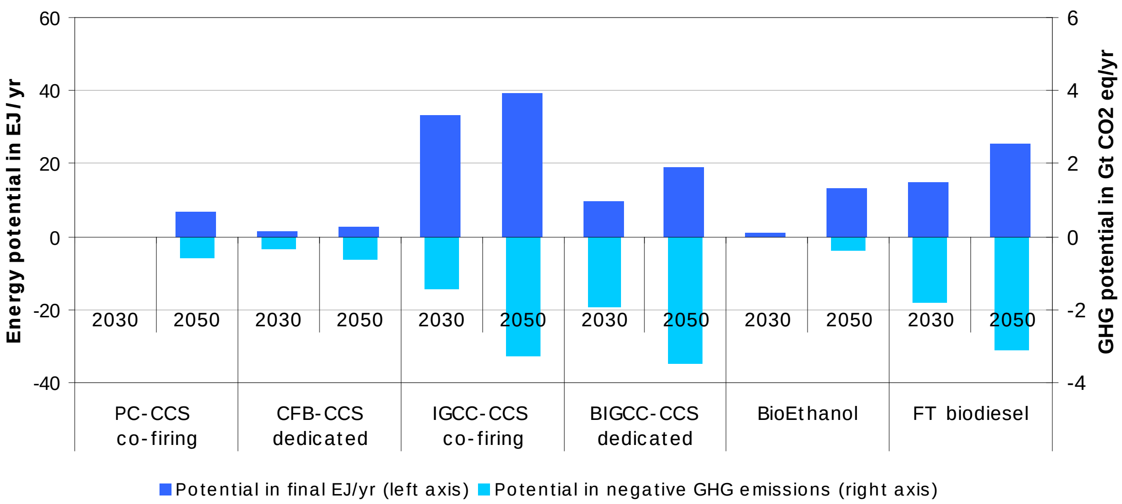


Figure 6 - 1 Maximum annual economic potential expressed in EJ/yr (left axis) and Gt CO_2 equivalents (right axis) for the selected BE-CCS routes.

Table 6 - 2 Overview of economic potential and production cost of selected BE-CCS routes

Technology	Year	Economic Potential[1]			Production cost			
		min	max	GHG	Lowest cost category[2] for biomass supply		Second cost category[3] for biomass supply	
Electricity generation		EJ/yr	EJ/yr	Gt/yr	€/GJ$_{final}$	€/MWh	€/GJ$_{final}$	€/MWh$_{l}$
PC-CCS co-firing	2030	0	0	0.0	21.7	78.2	23.2	83.6
	2050	7	7	-0.6	15.8	56.9	17.9	64.6
CFB-CCS dedicated	2030	1	1	-0.3	19.8	71.4	25.4	91.3
	2050	3	3	-0.6	15.4	55.4	20.2	72.9
IGCC-CCS co-firing	2030	33	33	-1.4	19.6	70.7	21.0	75.6
	2050	39	39	-3.3	14.2	51.0	16.1	58.0
BIGCC-CCS dedicated	2030	10	10	-1.9	15.7	56.6	20.5	73.7
	2050	19	19	-3.5	11.4	41.0	15.4	55.6
Reference technologies								
PC coal with CCS	2030	na	na	na	21.2	76.2	na	na
	2050	na	na	na	17.3	62.2	na	na
IGCC coal with CCS	2030	na	na	na	21.1	76.1	na	na
	2050	na	na	na	16.9	60.7	na	na
Biofuels					€/GJ$_{final}$	€/l[4]	€/GJ$_{final}$	€/l[4]
BioEthanol	2030	0	1.2	0.0	24.4	0.78	31.4	1.00
	2050	0	13.4	-0.4	18.0	0.58	23.7	0.76
FT biodiesel	2030	0	15.0	-1.8	16.2	0.59	21.1	0.77
	2050	0	25.5	-3.1	14.4	0.52	19.2	0.70
Fossil fuel references								
Crude oil price	2010	na	na	na	8.7	na	na	na
Crude oil price	2030	na	na	na	13.7	na	na	na
Crude oil price	2050	na	na	na	17.8	na	na	na
Diesel - High	-	na	na	na	26.4	na	na	na
Diesel price - Low	-	na	na	na	16.1	na	na	na

[1]Economic potential is the amount of EJ/yr that can be produced with lower cost compared to the reference technologies (for power generation routes) or energy carriers (for biofuel routes). The maximum economic potential is determined by comparing the production cost with the cost of the most expensive reference technology, and the minimum potential by comparing with the cheapest reference technology.

[2]Lowest cost category represents a biomass price at factory gate of 5.2 €/GJ and CO_2 price of 50 €/t.

[3]Second cost category represents a biomass price at factory gate of 7.0 €/GJ and CO_2 price of 50 €/t.

[4]Production cost per litre is based on the heating value of gasoline (32 MJ/l) for bio-ethanol and for diesel (36.4 MJ/l) for the FT-biodiesel route.

6.2 Determining the economic potential

The economic potential is determined by combining the price of biomass resources with the costs for biomass conversion and CCS for the selected BE-CCS routes. We assess the cost of producing electricity and biofuels - with and without CCS - taking the CO_2 price into account. This yields supply curves for the various BE-CCS routes. With the use of the cost assumptions for the BE-CCS and reference technologies (PC and IGCC with CCS) presented in section 6.3 we also calculate the cost of the reference technologies. The economic BE-CCS potential is then the biomass potential, presented in final or primary energy that can be converted at lower cost than the fossil reference technologies.

6.3 Economic performance of BE-CCS routes

Here the economic performance of BE-CCS technologies in the view years is presented. We distinguish between several steps in the BE-CCS production chain. The chain starts with the biomass supply chain, which includes the production, transport and pre-treatment of the biomass. This is followed by energy conversion, which is linked to the conversion step in the CCS chain which includes the capture, transport and storage of CO_2. The cost of these steps and whether they differ per BE-CCS technology will be discussed below.

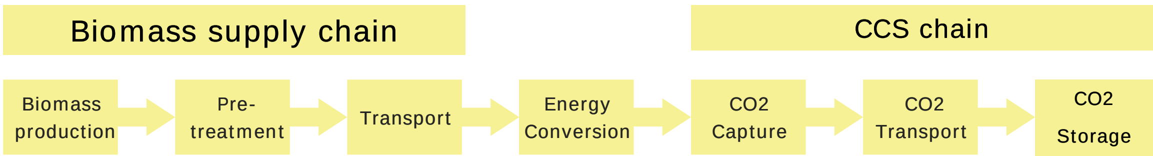


Figure 6 - 2 General overview of BE-CCS supply chain.

6.3.1 Cost and price of (fossil) fuel supply

For energy crops, we combined the cost-supply curves of biomass production from Hoogwijk (2004) with the sustainable biomass potential estimates by van Vuuren et al. (2009). The cost-supply curves are specified on a regional level. The cost-supply curves in Hoogwijk (2004) are based on four steps, or cost categories (<1$/GJ, 1-2 $/GJ, 2-4 $/GJ and >4$/GJ). The cost curves used in this study are presented in Table 6 - 3, which gives an overview of the potential that can be delivered below certain costs and price. Every cost category represents a ‘step’ in the supply curve. For example, at a global level in 2030 about 24 $EJ_{primary}$/yr can be produced per year at a cost below 1.7 €/$GJ_{primary}$.

For residues, both agricultural and forestry, we used the assumption from Hoogwijk et al. (2010)[13] that 10% of the potential fulfilling certain sustainability criteria is available at costs below 1 $/GJ and 100% below 50 $/GJ. With an extrapolation we have

[13] Hoogwijk et al. (2010) applied this cost-curve solely to forestry residues, but we assumed this for both agricultural and forestry residues.

estimated what share of the potential can be produced in a certain cost category. This yields that 10% of the potential falls within the first cost category, 26% within the second, 42% within the third and 22% within the fourth category. For residues, the shape of the cost-supply curves is the same for all regions.

All potential estimates are based on the potential given for 2050. The cost supply curves for 2030 for energy crops are based on the potential estimates by Van Vuuren. They estimate a similar shaped cost supply curve for 2030 when compared to the curve for 2050. However, the total potential is approximately 40% lower. Thus, the cost supply curve for biomass supply in 2030 has the same cost categories and shape, only the potential per category is reduced by 40%. For forestry residues, we have used the same 40% reduction for 2030 compared to 2050; the breakdown of potential into the cost categories remains the same. For agricultural residues, we have used a linear extrapolation of the cost supply curves estimates between 2005 and 2050 to estimate the potential in 2030.

To calculate the economic potential, the price of biomass is also relevant. We therefore assumed a ratio to convert biomass production cost into the price of biomass on the market. The ratios for the cost categories are based on figures reported by the IEA (Bauen, Berndes et al. 2009). The difference between cost of biomass production and price is estimated in that study to vary between a factor 2 to 5. This factor is not assumed to be equal for all cost categories as the relative margins on high cost biomass are most likely to be lower. The price to cost ratio assumed here are presented in Table 6 - 3. We apply this ratio and this yields the price and associated potential of biomass before pre-treatment and transport.

Table 6 - 3 Estimates for regional cost and price of biomass potential.

	Unit	Cost category biomass potential			
		1	**2**	**3**	**4**
Biomass production cost	€/$GJ_{primary}$	0.8	1.7	3.3	41.5
Ratio price/cost	-	4	3	2.5	1.2
Price	€/$GJ_{primary}$	3.3	5.0	8.3	49.8
Price (incl. densification and transport	€/$GJ_{primary}$	4.7	6.3	9.6	51.2
Price of biomass at factory gate	€/$GJ_{pellets}$	5.2	7.0	10.7	56.9
2030					
Region					
AFME	$EJ_{primary}$	1	5	6	13
ASIA	$EJ_{primary}$	1	5	8	17
OCEA	$EJ_{primary}$	0,3	2	2	5
LAAM	$EJ_{primary}$	0,4	3	11	15
NOEU	$EJ_{primary}$	0,3	2	2	5
NOAM	$EJ_{primary}$	1	4	7	13
OEU	$EJ_{primary}$	0,4	1	3	6
WORLD	$EJ_{primary}$	4	24	40	73
2050					
AFME	$EJ_{primary}$	2	8	10	23
ASIA	$EJ_{primary}$	2	9	14	30
OCEA	$EJ_{primary}$	0,5	3	4	8
LAAM	$EJ_{primary}$	0,8	5	19	27
NOEU	$EJ_{primary}$	0,5	3	4	7
NOAM	$EJ_{primary}$	1	7	12	21
OEU	$EJ_{primary}$	0,7	2	5	10
WORLD	$EJ_{primary}$	8	42	68	126

Assuming a price to cost ratio is highly subjective, but more accurate statistics on current prices (in relation to cost) and certainly accurate estimates on developing prices towards 2050 are lacking. Given the uncertain relationship between the cost and price of biomass and the volatility of biomass prices[14] (see also Box 3 below) we will further assess the impact of our assumptions related to biomass prices in the sensitivity analysis (see section 8).

Box 3 Biomass price

When reviewing the prices of biomass pellets, is important to emphasize that we have to distinguish between different price categories. CIF stands for Costs, Insurance and (sea) Freight. The (overseas) seller pays these. Inland transport by road or river ways and power plant handling are excluded. Commonly terms used for export prices are: FAS (Free Alongside Ship) i.e. excluding the costs of loading; and FOB (Free On

[14] See (Bauen, Berndes et al. 2009) for a more detailed discussion on price volatility and uncertainty of future biomass prices.

Board), i.e. including loading costs. FOB prices are commonly used for dry bulk in export harbours. Finally, CIF and FOB prices do not necessary reflect the real market, as pellets are more and more frequently purchased on longer term contracts (up to 3 years).

On a worldwide basis several indices exist that map the trade of, for instance, biomass pellets. Examples of these indices are APX Endex (Rotterdam, www.apxendex.com), FOEX Pix Pellet Nordic Index (Helsinki, www.foex.fi) and Argusmedia Argus Biomass Markets. A good overview of pellet prices and market developments is also provided within the PELLETS@LAS project (www.pelletsatlas.info)

The price of biomass pellets has shown large volatility over the last years. The price of biomass is most likely influenced by a large number of factors, including:

- The price of fossil fuels (coal, oil, natural gas etc): an increase of fossil fuel prices will likely result in an increase of biomass prices.
- Competing industries: biomass is used in a large number of industries for many purposes. The *demand* for wood and other forms of biomass in these industries affect the balance between supply and demand and will have an impact of the price of biomass on the market.

When we review the data provided by the above mentioned sources, we see that prices of biomass pellets roughly range between 7 and 8 €/GJ (CIF) and 4 and 7 €/GJ (FOB). Ranges for pellet prices found reviewing these sources is given below.

- 7.2 - 8.3 €/GJ (CIF-FOEX, period 2007-2010),
- 7.6 - 7.9 €/GJ (CIF-APX ENDEX, period 2010-2014 forward prices),
- 6.9 - 7.3 €/GJ (Argus, Q1 2011 and 2012 forward prices),
- 6.8 - 8.2 €/GJ (Pellet@tlas CIF-Rotterdam, period 2007-2009)
- 4.4 - 7 €/GJ (Pellet@tlas, FOB Riga, 2003-2007)
- 4.9 - 5.4 €/GJ (Pellet@tlas, FOB South east USA)
- 4.6 - 5 €/GJ (Pellet@tlas, FOB Vancouver, Canada)

Estimates of production cost are provided in by Bauen et al. (Bauen, Berndes et al. 2009) and provides us with some insights into the differences between production cost and prices of biomass pellets. The production cost range between 2.9 and 4.7 €/GJ (European wood pellets) and 2.6 - 3.7 €/GJ (Canadian wood pellets), and show that there is a difference between production cost in both geographical regions and that there is difference between the production cost and prices of biomass pellets.

If we compare the above CIF prices with the prices estimated in our study for the four cost categories, we see that the prices of (torrefied) pellets in categories 1 (5.2 €/GJ), and 2 (7.0 €/GJ) are in the same order of magnitude as current pellet prices. Prices assumed in categories 3 (10.7 €/GJ) are somewhat higher, and in category 4 (56.9 €/GJ) the prices are significantly higher.

Coal price

For the BE-CCS routes that co-fire biomass and coal we assume a default coal price of 3.7 €/GJ for both view years. This price is also used to determine the total production cost of electricity for the reference technologies. In the sensitivity analysis we address the impact of a variation in the coal price. The coal price is assumed to vary between 2.6 and 4.9 €/GJ based on prices reported in the World Energy outlook 2009 (IEA 2009).

6.3.2 Cost of biomass pre-treatment and transport

Biomass pre-treatment and transport makes up a significant part of the biomass supply chain cost. Using ranges presented in the study from van Vliet (2009) for the cost of local transport, densification and ocean shipping we have estimated the cost of pre-treatment to be between 0.4 and 1.7 €/GJ.[15] The cost of transport is largely determined by the distance and transport mode. The cost of inland train and push tugs (up to 300 km) ranges between 0.1 and 0.4 $€_{2005}$/GJ. Cost of ocean shipping (up to 12 000 km) is approximately 0.1-0.2 $€_{2005}$/GJ. Total costs of transport are estimated at 0.2-0.6 €/GJ. The costs for pre-treatment and transport range from 0.6 to 2.1 €/GJ. As default values we assume the average pre-treatment and transport cost adding to approximately 1.3 €/$GJ_{primary}$. Following Luckow et al. (Luckow, Dooley et al. 2010), we assume that this cost premium will apply on all biomass production. It is in practice not necessary to transport all biomass by ocean going ships as it may very well be used locally. The cost for transport can thus be considered a conservative estimate.

Table 6 - 4 Overview cost assumptions on biomass densification and transport, CO_2 transport and CO_2 storage

Assumption	Unit	Low	Base case	High
Biomass densification/pre-treatment cost	euro/$GJ_{primary}$	0.4	0.9	1.5
Biomass transport cost (local + oceanic)	euro/$GJ_{primary}$	0.2	0.4	0.6

6.3.3 Conversion of fuel and CO_2 capture

In this section we discuss the fuel conversion and CO_2 capture cost - excluding the fuel costs - of the selected BE-CCS routes. Conversion costs including the cost of fuel are presented in the results section of this chapter, in section 6.4. Conversion costs vary considerably between the routes for electricity production and transport fuel production. First, we discuss the cost for electricity production, followed by the cost of biofuel production.

[15] Cost of pre-treatment (pelletizing and torrefaction) ranges between 0.4 and 1.5 $€_{2005}$/GJ according to Van Vliet et al. (2009)

Energy conversion costs are divided into

- Cost of capital (for installation)
- Operation & maintenance
- Fuel costs
- CO_2 costs

For each part of the chain, the costs are expressed in €/GJ_{final}. Costs for the CO_2 capture and storage are also translated into the same unit. The cost calculation uses figures on annual full load hours[16] and the depreciation time. To obtain the total costs for the different technologies routes, we aggregate the CO_2 costs, conversion costs, fuel costs and CO_2 costs. The results of these calculations are shown in Table 6 - 5 and these are discussed per conversion route.

Fuel costs

Fuel costs for each GJ output are determined by the price of primary biomass supply and the conversion efficiency, which varies per conversion technology and whether the power plant is equipped with CO_2 capture or not. Transport and pre-treatment costs are also taken into account. An overview is given in Table 6 - 5.

The total cost (€/GJ) per GJ_{final} is calculated with the following formula:

$$\text{Fuel costs (€/GJ)} = \frac{FP+DC+TC}{\eta} \qquad (1)$$

With:

FP	=	Fuel price (€/$GJ_{primary}$)
DC	=	Pre-treatment costs (€/$GJ_{primary}$)
TC	=	Transport costs (€/$GJ_{primary}$)
η	=	Conversion efficiency

Installation costs

Table 6 - 5 presents the total capital costs for the power plant. In the same table, the part of the investment cost that is attributed to the CO_2 capture unit is separately depicted. By comparing the BE-CCS technologies with the reference technologies that only use coal, it is possible to derive the additional cost of biomass (co-)firing.

The cost estimates for the power generation technologies are based on earlier work by Hendriks et al. (Hendriks et al. 2004). Cost assumptions for the dedicated routes are updated with data from IEA GHG (IEA GHG 2009). Decrease in conversion cost due to technological development, i.e. learning, is taken into account by using cost development estimates published in (Hendriks et al. 2004). With the use of the discount rate and depreciation period, we can determine the annual capital charge for the initial investment.

[16] The time an installation is operational, expressed in the hours that an installation runs on full capacity per year.

Operation and maintenance costs

Operation and maintenance cost are here calculated as a percentage of investment cost. This percentage indicates the annual cost of O&M for the total power plant as well as for the capture alone. In Table 6 - 5 shows that O&M cost vary per conversion and capture technology.

The cost per GJ_{final} for installation, operation and maintenance for energy conversion and CO_2 capture is expressed as:

$$\text{Installation, O\&M cost (€/GJ)} = \frac{(IC \times \alpha + OM)}{FLH} \times C \qquad (2)$$

With:

IC = Conversion installation and CO_2 capture installation costs (€/kW)
α = Annuity
OM = O&M costs per kW per year (for CO_2 capture installation and conversion installation)
FLH = Full Load Hours
C = Conversion factor to GJ: 1000/3.6 = 278

Electricity production

PC-co-firing

For the PC route, it is shown that co-firing requires additional investment costs compared to coal firing alone, but this cost premium is assumed to decrease on the longer term. When co-firing biomass is applied in a coal fired power plant the capital cost increase, as investments are required for biomass treatment and feeding facilities. In the table it is shown that the cost level (in €/kWe) of adding CO_2 capture is independent of whether or not co-firing is applied. Overall capital cost and O&M cost are assumed to decrease significantly towards the year 2050.

CFB-dedicated

Dedicated firing requires higher specific investment cost compared to co-firing, which is mainly due to more extensive fuel treatment methods required for 100% biomass combustion and due to the lower conversion efficiency. The capital requirements for adding CO_2 capture to CFB power plants is assumed to be significantly higher. The main reason for this is that post-combustion capture requires more extensive flue gas treatment which is not required in CFB power plants without capture. For dedicated power plants the specific investment cost for conversion and CO_2 capture are assumed to decrease with the same rate as for co-firing technologies. Hence, the conversion and capture cost, and associated O&M cost, are significantly decreasing towards 2050. Dedicated power plants are assumed to remain more costly than PC power plants with co-firing, but the difference in specific investment cost is assumed to reduce over time.

IGCC-co-firing

For the IGCC routes with co-firing, Table 6 - 5 shows that specific investment cost for IGCC power plants with and without CO_2 capture are estimated in the view years to be lower than for PC power plants with and without CO_2 capture. This trend is in line with recent estimates by van den Broek (van den Broek 2010) who takes into account learning effects of both conversion technologies with and without CO_2 capture. She states that learning has a big impact on IGCCs with CO_2 capture due to its current low level of maturity, i.e. there are more possibilities for improvement and cost reduction compared to the relative mature PC power plant. In IEA (IEA/OECD 2008), cost of IGCC with CO_2 capture are estimated to be slightly lower in 2030 compared to PC power plants with CO_2 capture. In studies reviewed by Davison and Thambimuthu (Davison and Thambimuthu 2009) investment cost of IGCC without capture are estimated to be higher compared to that of PC without capture, but slightly lower when equipped with CO_2 capture. They state further that - within the range of uncertainty of cost estimates currently- the investment cost with CO_2 capture is about equal for IGCC and PC technologies, but that relative economics depend on future technology improvements (Davison and Thambimuthu 2009).

BIGCC

The specific investment cost of BIGCC with and without CO_2 capture are in (IEA/OECD 2008) estimated to be significantly higher than both other conversion routes (IGCC and PC). This is also shown in Table 6 - 5, where BIGCC has 16% higher investment cost in 2030 and 9% in 2050. The relative and absolute difference in investment cost between IGCC and BIGCC is decreasing over time due to technology development. For the BIGCC, which is a less mature technology, the possibilities for improvement are considered more extensive and therefore a higher cost reduction is foreseen. This holds also for O&M cost, which are typically higher for the BIGCC compared to the IGCC. The additional cost of CO_2 capture is estimated to be equal for both the IGCC as BIGCC technology.

Overall, the conversion cost per GJ_e, excluding fuel cost and including CO_2 capture, are expected to be the lowest for the IGCC technology. The highest costs are expected for the dedicated CFB route. This is expected for both view years. A difference between the view years is that conversion costs for the PC route are assumed to be lower compared to BIGCC in 2030. In 2050, technical improvements and deeper cost reductions in the BIGCC route have reduced its conversion cost and it has become lower than that of the PC route.

Post-combustion vs. pre-combustion

Another important difference between the routes is the type of CO_2 capture that is applied. In the PC routes we have assumed post-combustion CO_2 capture. In the IGCC routes pre-combustion CO_2 capture is applied. The cost of pre-combustion capture is assumed to be lower, which is primarily because of the relative lower capital requirements for this capture route. Here it is assumed that post-combustion capture has approximately 10% higher capital requirements compared to pre-combustion, in the co-firing routes. In the dedicated routes, post-combustion has significantly (i.e. a factor two) higher capital requirements compared to pre-combustion.

Davison and Thambimuthu (Davison and Thambimuthu 2009) have presented an overview of cost estimates and note that cost may vary significantly depending on the sources, time of publication and economic assumptions (e.g. the discount rate). They conclude also that future cost estimates are inherently uncertain. This should be kept in mind when comparing cost estimates presented here with figures presented elsewhere. However, based on a rough comparison, our cost estimates agree well with earlier published estimates in literature. For example, our estimates are within the cost ranges presented in IEA (IEA/OECD 2008). Our estimates are however somewhat higher than estimated by van den Broek (van den Broek 2010, chapter 3), who estimates future cost based on learning rates. The cost estimate for BIGCC with and without capture are in line with estimates by Rhodes and Keith (Rhodes and Keith 2005). Cost estimates for dedicated power plants without CO_2 capture are lower compared to estimates in (IEA ETSAP 2010).

A more detailed discussion of the economic performance assumed in this study compared to the pertaining literature is presented in the Factsheets provided in Appendix E to Appendix H.

Table 6 - 5 Overview of performance and cost of biomass fired conversion technologies for power generation with CO_2 capture and compression

Technologies with CO_2 capture	View year	Capture technology	Biomass Share[1]	Conversion Efficiency (LHV)		Capture efficiency	Specific investment cost €/kWe		Annual operation and maintenance cost €/kWe		Operation and maintenance cost (in % of investment cost)		Total generation cost[2] (fuel excluded) €/GJe	
	Year	Capture		w/o capture	With capture		Total	Capture	Total	Capture	Power plant	Capture	Total	Capture
PC co-firing	2030	Post	30%	51%	41%	90%	2152	675	111	50	4%	7%	12.1	4.3
CFB dedicated	2030	Post	100%	47%	37%	90%	2978	1397	137	84	3%	6%	16.1	8.3
IGCC co-firing	2030	Pre	30%	52%	45%	90%	1930	615	100	37	5%	6%	10.9	3.6
BIGCC dedicated	2030	Pre	100%	50%	43%	90%	2231	615	116	46	4%	7%	12.6	4.0
PC co-firing	2050	Post	50%	54%	48%	95%	1782	422	79	31	4%	7%	9.5	2.7
CFB dedicated	2050	Post	100%	50%	42%	95%	2329	873	108	52	4%	6%	12.6	5.1
IGCC co-firing	2050	Pre	50%	56%	52%	95%	1518	385	75	23	5%	6%	8.4	2.3
BIGCC dedicated	2050	Pre	100%	54%	50%	95%	1657	385	80	29	4%	8%	9.1	2.5
Reference technologies[3]														
PC coal	2030	Post	0%	52%	43%	90%	2000	675	80	40	3%	6%	10.4	4.0
PC coal	2050	Post	0%	55%	49%	95%	1643	422	59	25	3%	6%	8.3	2.5
IGCC coal	2030	Pre	0%	52%	45%	90%	1930	615	100	37	5%	6%	10.9	3.6
IGCC coal	2050	Pre	0%	56%	52%	95%	1518	385	75	23	5%	6%	8.4	2.3

[1]Biomass share on an energy basis.

[2]Based on a depreciation period of 30 years, a discount rate of 10% and 7800 full load hours per year.

[3] Gas fired power plants (NGCC) with post-combustion capture could theoretically also be used as a reference technology. MottMacdonnald (Mott MacDonald 2010) has estimated the specific investment cost of this option to be between 640 and 740 €/kWe without capture and 950 and 1190 €/kWe with capture and would thus results in lower capital cost compared to the other reference technologies. However, fuel cost in NGCC power plants dominate the production cost and NGCC technology is often not used as a base load power generation option. The latter aspect is the main reason for excluding this technology as a reference technology in this study.

Table 6 - 6 Overview of performance and cost of biomass fired conversion technologies for biofuel production with CO_2 capture and compression

Technologies with CO_2 capture	Year	Capture type	Biomass Share	Conversion efficiency (LHV)	Capture efficiency	Specific investment cost €/kW$_{net\ output}$		Annual operation and maintenance cost €/kWe		Operation and maintenance cost in % of investment cost		Total generation cost[3] (fuel excluded) in €/GJe	
						Conv. plant	Capture	Conv. plant	Capture	Conv. plant	Capture	Conv. plant	Capture
Bio-ethanol-advanced generation (ligno cellulosic)	2030	Post[1]	100%	29%	11%	1580	36	79	7	5%	6%	8.9	0.4
Bio-ethanol-advanced generation (ligno cellulosic)	2050	Post[1]	100%	36%	13%	1064	37	38	7	4%	6%	5.6	0.4
FT biodiesel	2030	Pre[2]	100%	42%	54%	1615	78	71	23	4%	6%	9.5	1.1
FT biodiesel	2050	Pre[2]	100%	42%	54%	1296	62	57	22	4%	6%	7.7	1.0

[1]Capture of CO_2 only from fermentation step, CO_2 capture from conversion of fossil fuels or residues into power and heat is not included.

[2]Capture of CO_2 from tail gas is not included.

[3]Based on a depreciation period of 30 years, a discount rate of 10% and 8000 full load hours per year.

Biofuel production

Table 6 - 6 presents the conversion cost for production routes for biofuel (excluding the costs for the fuel). The conversion cost estimates are primarily based on earlier work by Hamelinck and Hoogwijk (Ecofys 2007). Cost estimates for CO_2 capture are based on work by Ecofys and van Vliet (Ecofys 2007; van Vliet, Faaij et al. 2009).

The production cost of biomass-to-liquid (BTL) depends mainly on the costs of biomass, the energy conversion efficiency from biomass to biofuel and the size of the plant. Unit costs for larger plants are lower due to economy–of-scale effects. Numerous cost estimates can be found in literature showing a wide range of outcomes, see Appendix H. Van Vliet et al. (van Vliet, Faaij et al. 2009) argue therefore that cost estimates should be interpreted as best-guess values and attention should be paid to uncertainties in those estimates. Uncertainties stem mainly from assumptions on feedstock price, the chosen technology, its configuration and performance, the equipment costs, and on the basic economic assumptions such as economic lifetime and interest rate. Another aspect is the production of value added by-products. This is not taken into account in this study, but is likely to influence the economics of biofuel production. From this perspective it is likely that we overestimate the cost of biofuel production.

<u>Bio-ethanol</u>

There is a clear difference between conventional and advanced bio-ethanol production. Experts believe that commercial scale plants for advanced production will become available in the coming years (Bauen, Berndes et al. 2009). The specific investment cost of advanced bio-ethanol plants based on ligno-cellulosic biomass are estimated to be significantly higher than that of conventional bio-ethanol plants using sugar and starch based feedstock. It is estimated to be 3-5 times higher (see Appendix G for more details). Capital cost reductions due to economies of scale and lower feedstock cost makes the ligno-cellulosic option competitive in the longer run, according to several estimates in literature. This however strongly depends on the price of (fossil) alternatives. The potential development in terms of cost is shown in Table 6 - 6, where we can see that a cost decrease of 500 €/kW is expected over time. Long term cost estimates for conventional bio-ethanol are not shown here as this technology is assumed to phase out towards 2050. In earlier studies current bio-ethanol conversion cost in 2008 are estimated to range between 4.7 and 8.6 €/GJ (Bauen, Berndes et al. 2009). The conversion cost of advanced production of bio-ethanol is estimated between 4 and 6.7 €/GJ. The lowest figure represents cost in 2050. In earlier studies these cost are estimated at 7.8 and 11 €/GJ for the view years 2022 and 2015, respectively. This compares reasonably with our estimates for future conversion cost.

The costs of CO_2 capture from the fermentation step are in general low as investment cost, operational costs and the energy requirement for drying and compression are relatively small. Additional investment costs are estimated at 36-37 €/kW$_{output}$[17], together with the O&M cost this sums up to 0.3 €/GJ. This investment cost is low compared the specific investment cost for the conversion plant ranging between 1064 and 1580 €/kW$_{output}$.

Biodiesel

Next to bio-ethanol production, we also estimated the cost of biodiesel (FT-biodiesel) production with CO_2 capture. Here it is estimated that biomass conversion into FT-biodiesel requires specific investment cost of approximately 1600 €/kW$_{output}$ in 2030, which is assumed to decrease on the long term towards 1300 €/kW$_{output}$. The cost of CO_2 removal largely depends on the assumptions on the energy use and equipment cost of CO_2 compression and drying. Here we assume relative small additional investment cost of 60-80 €/kW$_{output}$ in the view years. Cost of conversion and capture are expected to decrease over time due to scale up in the BTL plant. Annual O&M cost for capture are here estimated at 22-23 €/kW$_{output}$, which are dominated by the cost of electricity needed for CO_2 compression.

Overall conversion costs including CO_2 capture are then estimated to be between 6.2 and 7.5 €/GJ. Capture cost are about 1 €/GJ. When comparing these estimates with that of bio-ethanol production, FT-biodiesel production has higher conversion cost. However, the amount of CO_2 captured and the efficiency of biomass conversion are estimated much higher. Overall biofuel production cost may thus be favourable for FT-biodiesel production, depending on the cost of biomass, CO_2 price and cost of CO_2 transport and storage.

6.3.4 CO_2 transport and storage

The costs of CO_2 transport depend strongly on the mode of transport. CO_2 can be transported by truck, train, ship or pipeline. For large-scale transport, the latter is expected to be the most cost effective for distances below 1000 km. The cost per tonne of CO_2 transported by pipeline will depend strongly on the terrain conditions (including elevation and artworks), distance, and the amount of CO_2 transported. Furthermore, transporting CO_2 to offshore sites is expected to be more costly than land based pipelines. Finally, the clustering potential of sources and sinks is an important factor in reducing transport cost (IEA GHG 2009).

A typical issue that has to be addressed for CO_2 transport is designing and planning an optimal infrastructure to deploy CCS effectively and at the lowest cost possible. This should take into account: the locations involved, geographical circumstances and temporal limitations of the availability of sinks and sources (van den Broek, Ramírez et al.; Damen 2007; van den Broek, Brederode et al. 2009). Other issues are the optimal design, operation and safety of CO_2 pipelines and the development of regulatory frameworks. Last but not least, a critical issue for CO_2 transport is the need for large

[17] This number refers to the specific investment cost per output (in kW) for the whole plant. This number does not refer to the specific investment cost per kW of compression power.

upfront investments. It is a point of debate how such networks can be organised and who will be financially responsible.

A recent study by the IEA GHG (IEA GHG 2009) reports that 20 Gt[18] of CO_2 can be transported and stored for projects starting in 2030 with average cost below 5 $/tonne (~4 €/tonne) transported. Storing more than 20 Gt requires matching of sources and sinks that are economically less favourable. This will result in higher marginal cost rising to 30 $/tonne (~23 €/tonne). Over time, marginal transport cost are expected to increase with more than a factor two for projects starting in 2050 (while assuming that CCS is ongoing for decades by then). Main reasons for this cost increase are the use of less economic source-sink matching and due to the scenario assumption that CO_2 capture is applied to smaller sources and with it reducing economies of scale.

Another important result of that study is that transport cost can vary significantly per region. Reasons for this can be the limited availability of storage capacity and the larger distance between clusters of sources and sinks.

It is beyond the scope of this study to provide a detailed matching of sinks and CO_2 sources equipped with BE-CCS technologies. Instead we use a global range of CO_2 transport cost covering the range of cost found in IEA GHG (IEA GHG 2009) for the various regions. This range is estimated to be between the 1 and 30 €/tonne, see Table 6 - 7. The default value assumed here is 5 €/tonne, with an uncertainty range between 1 and 30 €/tonne.

Table 6 - 7 Cost of CO_2 transport depending on transport distance (source: Hendriks et al)

Source-sink distance	Average distance	Average cost in €/tonne transported
Short	<50 km	1
Medium	50-200 km	3
Long	200-500 km	5
Very long	500-2000 km	10
Extreme long	2000 and more	30

The costs for CO_2 storage largely depend on the drilling of wells and operational costs. The average costs range from 1 to 13 € per tonne of carbon dioxide, mainly depending on the depth, size, permeability and the type of reservoir. Onshore storage is typically less expensive than offshore storage (Hendriks et al. 2004). Here we assume a default value of 5 € per tonne with an uncertainty range between 1 and 13 €/tonne.

6.4 Results for the economic potential

Below, we present the results for the economic potential for the selected BE-CCS routes. We present cost supply curves for the biomass conversion routes with and without CCS for the years 2030 and 2050, including the cost of fossil reference

[18] This is cumulative amount of CO_2 transported and stored.

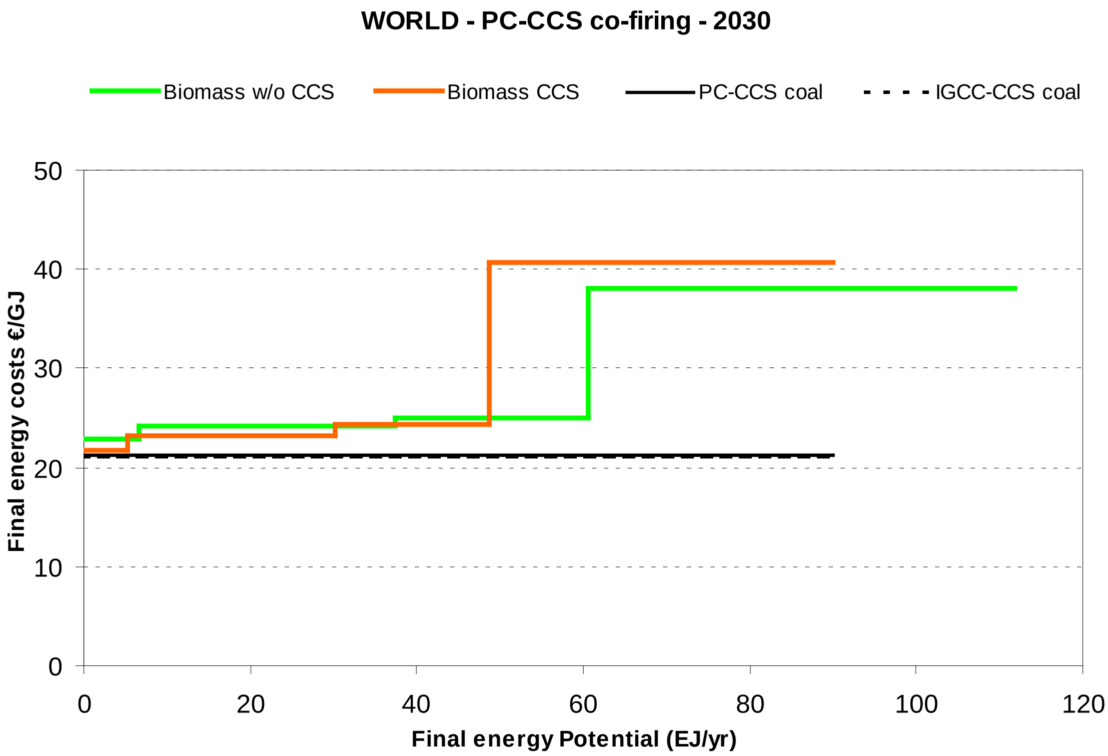
technologies. All supply curves are based on a CO_2 price of 50 euro/tonne. The effect of lower or higher CO_2 prices will be assessed in section 8.

6.4.1 PC-CCS co-firing

The supply curve and with it the economic potential of the PC-CCS co-firing route is shown in Figure 6 - 3. The economic potential in 2030 is zero. We can however see that 5 EJ/yr of BE-CCS potential can be delivered at somewhat higher prices than the reference technologies, in this case coal fired PC with CCS and the IGCC-CCS. About 2 EJ/yr of this potential is delivered by the use of biomass. The remaining part (3 EJ) is fulfilled by the coal share. The graphs also shows that additional conversion cost of CCS for biomass co-firing are small with a CO_2 price of 50 €/tonne.

In 2050, the production cost has decreased due to an increase in biomass potential at lower price and due to technological development. As a result, the economic potential has increased towards 7 EJ/yr. 36 EJ/yr can be produced at slightly higher production cost than the coal based reference, depending on the reference technology chosen. This equates to a biomass share of 18 EJ/yr.

For 2050 it can be seen that PC-co-firing with CCS is economically attractive over PC-co-firing without CCS, certainly for the lower cost biomass resources (left part of the supply curve). The figures also show that the final energy potential (on the x-axis) is reduced by applying CCS. The energy penalty results in additional demand for primary energy to deliver the same amount of final energy. As a result the supply curve shifts to the left.



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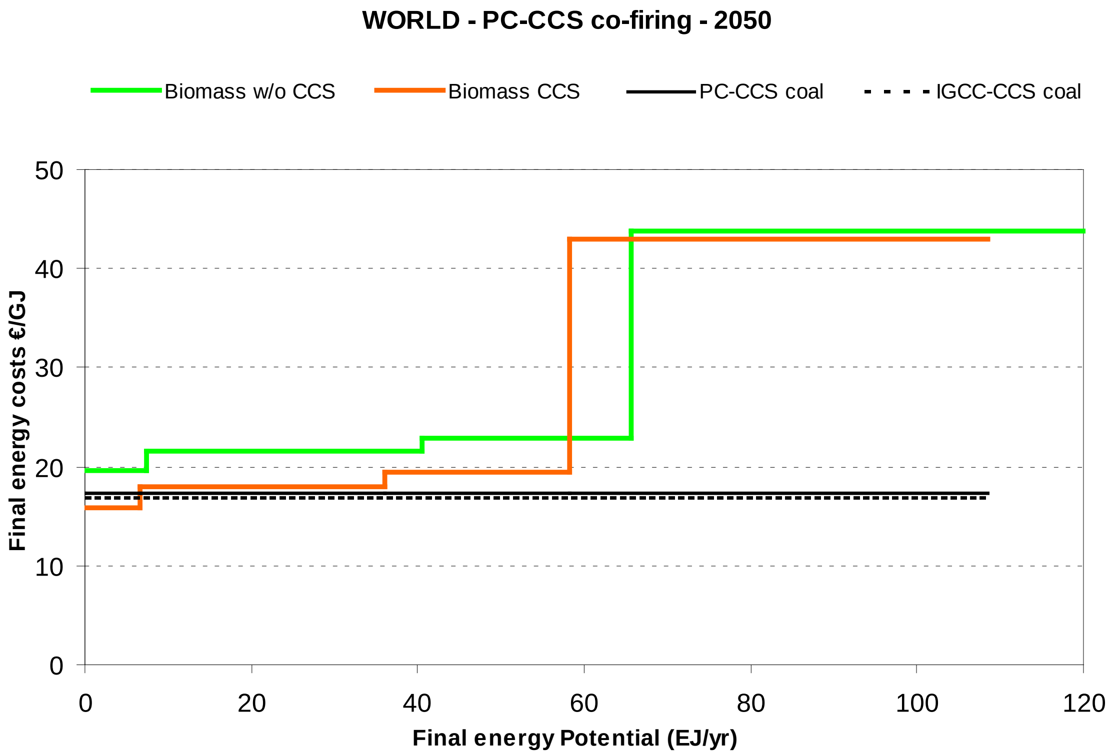
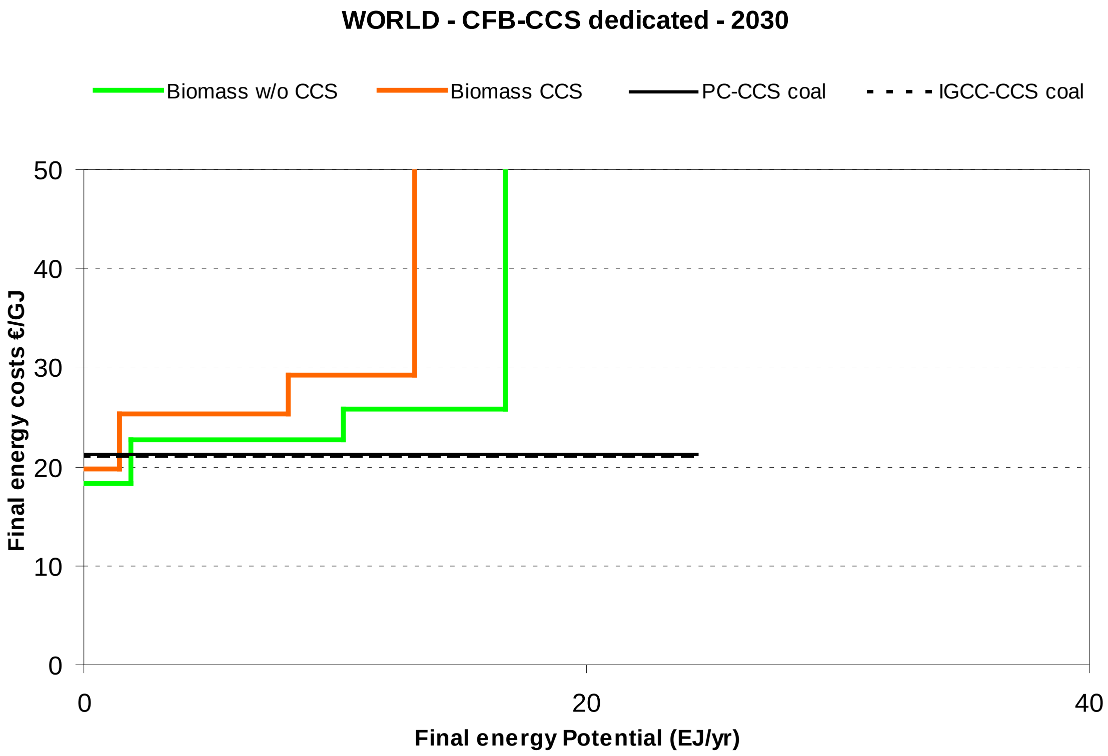


Figure 6 - 3 Supply curve for the PC co-firing route in 2030 and 2050. Y-axis shows the cost of power production (in €/GJe). X-axis shows the potential in final energy production (in EJ/yr). Final energy production includes both the biomass and coal share.

6.4.2 CFB-CCS dedicated firing

Figure 6 - 4 shows the supply curve of the CFB-CCS route. In comparison with the PC co-firing route, this route has a lower economic potential in 2050. In 2030, it can only compete with coal fired PC-CCS with the use of the lowest cost biomass resources. This amount to about 1 EJ/yr with a slightly lower production cost compare to the reference. Also, biomass conversion without CCS is economically attractive over conversion with CCS. A CO_2 price higher than 50 €/tonne would be needed in 2030 to make CFB-CCS attractive over dedicated firing without CCS.

In 2050, CFB-CCS is shown to be equally economically attractive as biomass firing without CCS and overall higher compared to the coal fired references. CFB-CCS shows then a potential of about 3 EJ/yr. The main difference with 2030 is that CFB-CCS now outperforms CFB without CCS when low cost biomass is available. This is the result of the expected decrease in investment cost for both energy conversion and CO_2 capture for dedicated power plants.



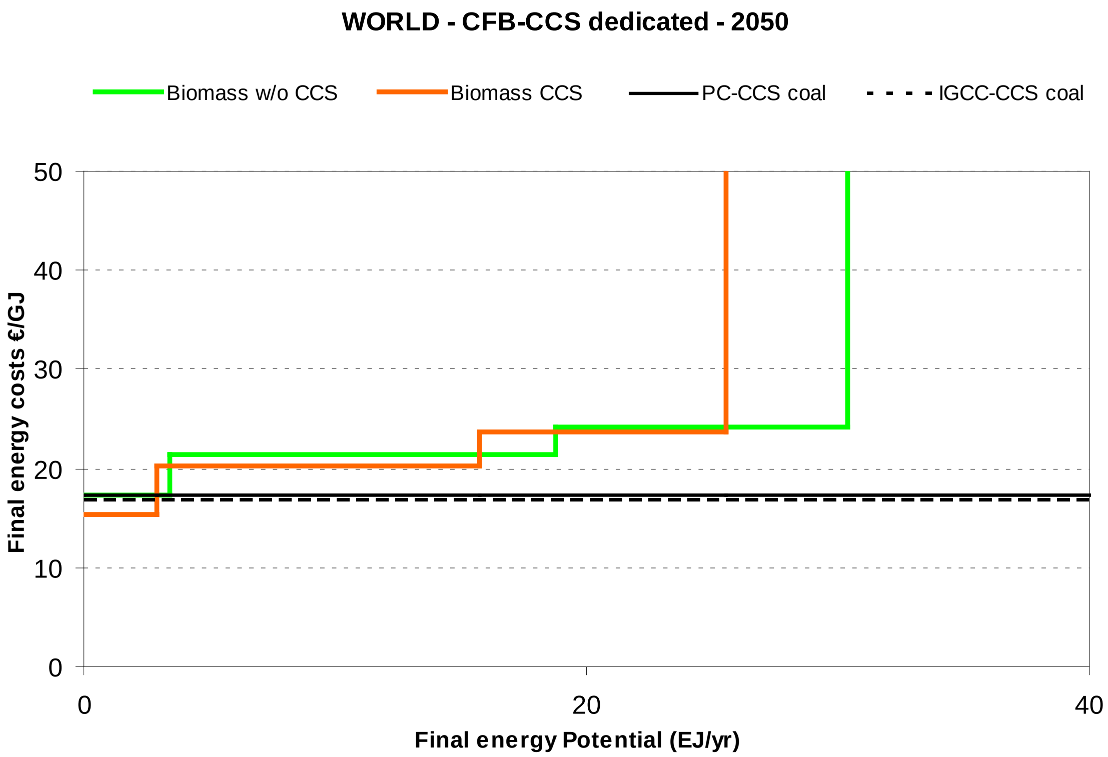
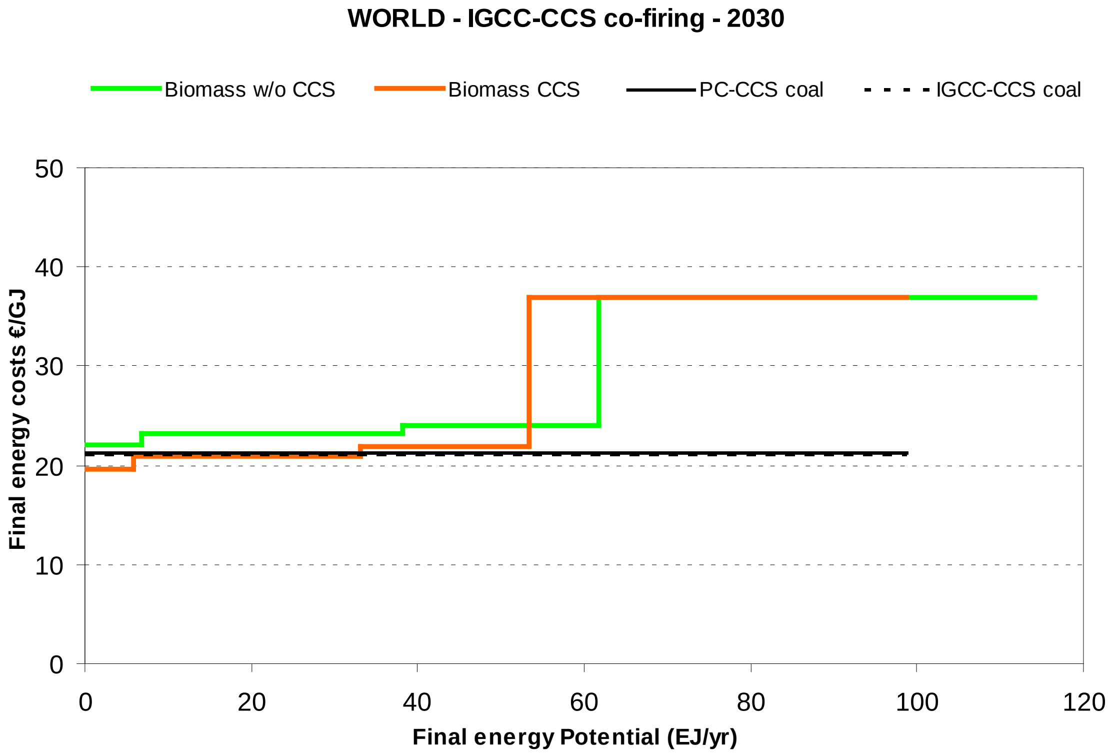


Figure 6 - 4 Supply curve for the CFB-CCS route in 2030 and 2050. Y-axis shows the cost of power production (in €/GJe). X-axis shows the potential in final energy production (in EJ/yr).

6.4.3 IGCC-CCS co-firing

Figure 6 - 5 shows the supply curve of the IGCC-CCS co-firing route. This supply curve is rather comparable to the supply curve for the PC-CCS co-firing route. It shows an economic advantage over co-firing without CCS up to about 55 EJ/yr in 2030 and above 60 EJ/yr in 2050. When compared to the coal fired IGCC the potential is 33 and 39 EJ/yr. The main differences between the IGCC co-firing and PC co-firing routes are the lower cost of production and the higher potential due to higher conversion efficiency. This is best seen for the 2050 view year where the cost of production are more than 10% higher for the PC CCS co-firing route over the full supply curve.



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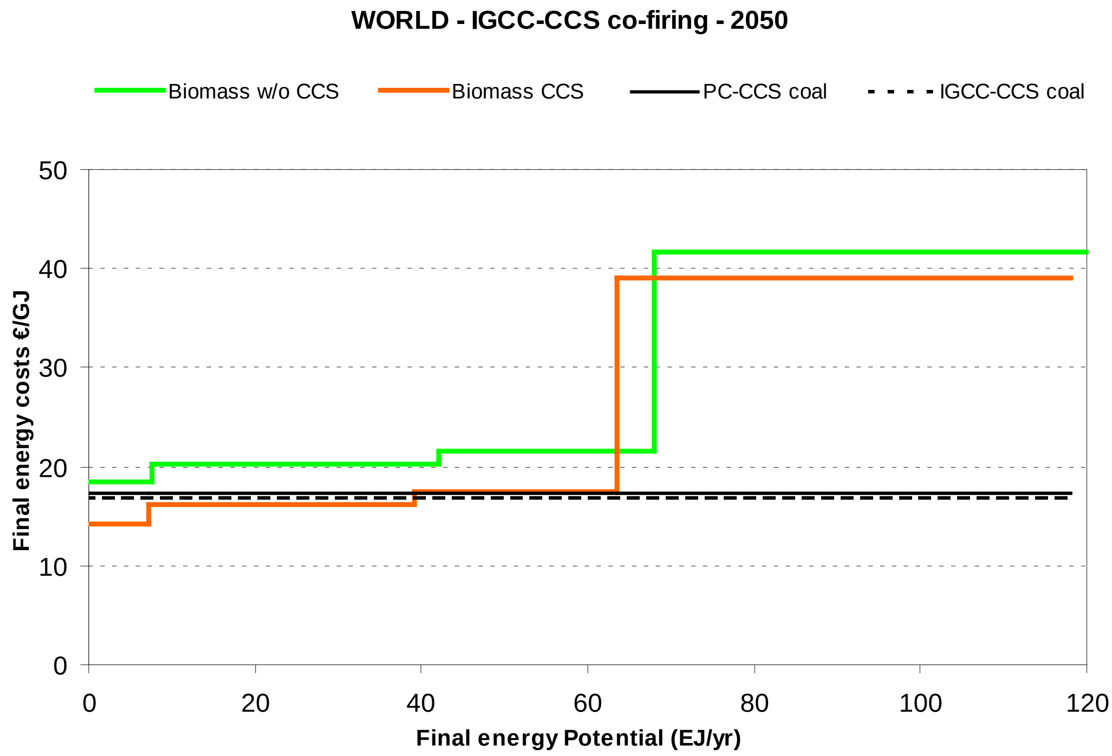
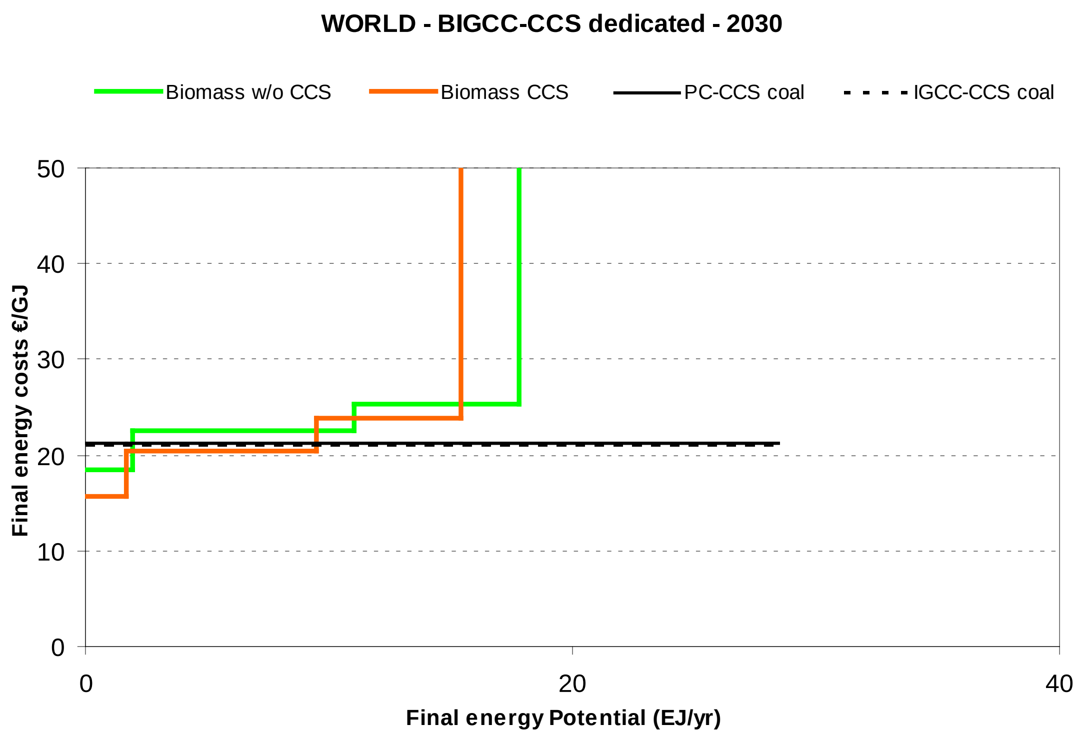


Figure 6 - 5 Supply curve for the IGCC co-firing route in 2030 and 2050. Y-axis shows the cost of power production (in €/GJe). X-axis shows the potential in final energy production (in EJ/yr). Final energy production includes both the biomass and coal share.

6.4.4 BIGCC-CCS dedicated

Figure 6 - 6 shows the supply curve of the BIGCC-CCS route. The reference technologies shown here are the BIGCC without CCS and the coal fired IGCC/PC with CCS. The supply curve is comparable to that of the CFB-CCS route. It shows a small technical potential (curve is shifted to the left) and cost increase rather steeply with increasing final energy potential. In 2030, the production costs of the BIGCC with CCS are in general lower than that of the BIGCC without CCS. The main difference with the CFB route is that in 2050 the BIGCC with CCS is anticipated to be economically attractive over the BIGCC without CCS over the largest part of the supply curve. Compared to the coal reference the BIGCC is attractive up to about 10 EJ/yr, with a CO_2 price of 50 euro.

The supply curve for 2050 shows the same trends. Only the economical supply is now larger due to an increase in low cost primary biomass supply and decrease in investment cost. This results in almost doubling of the potential to 19 EJ/yr.



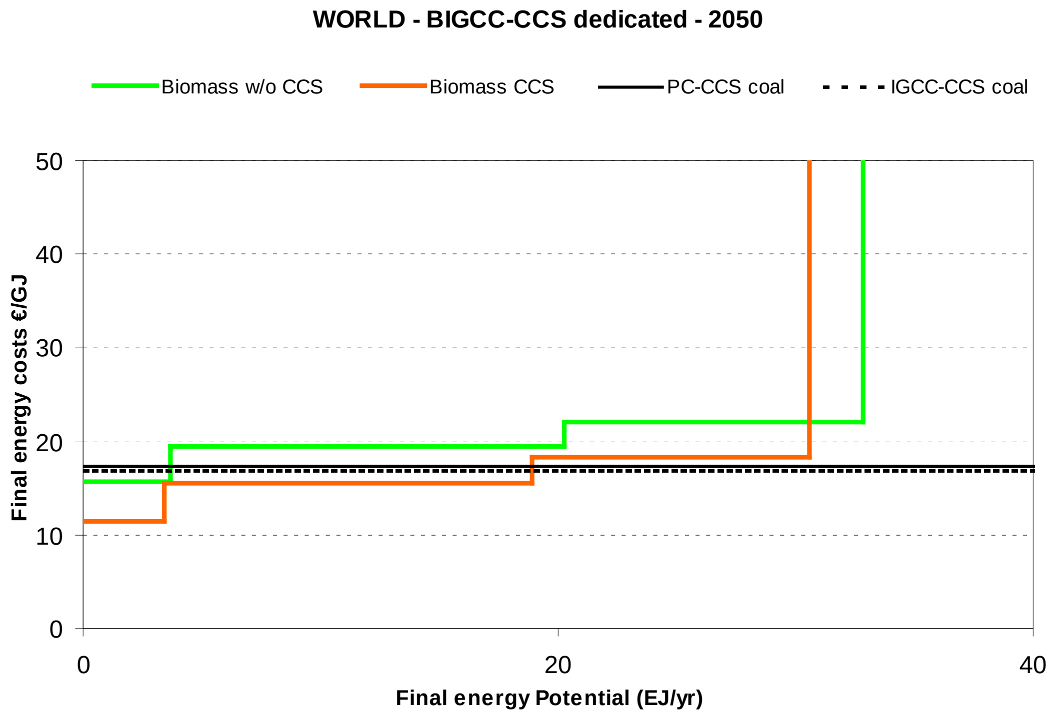
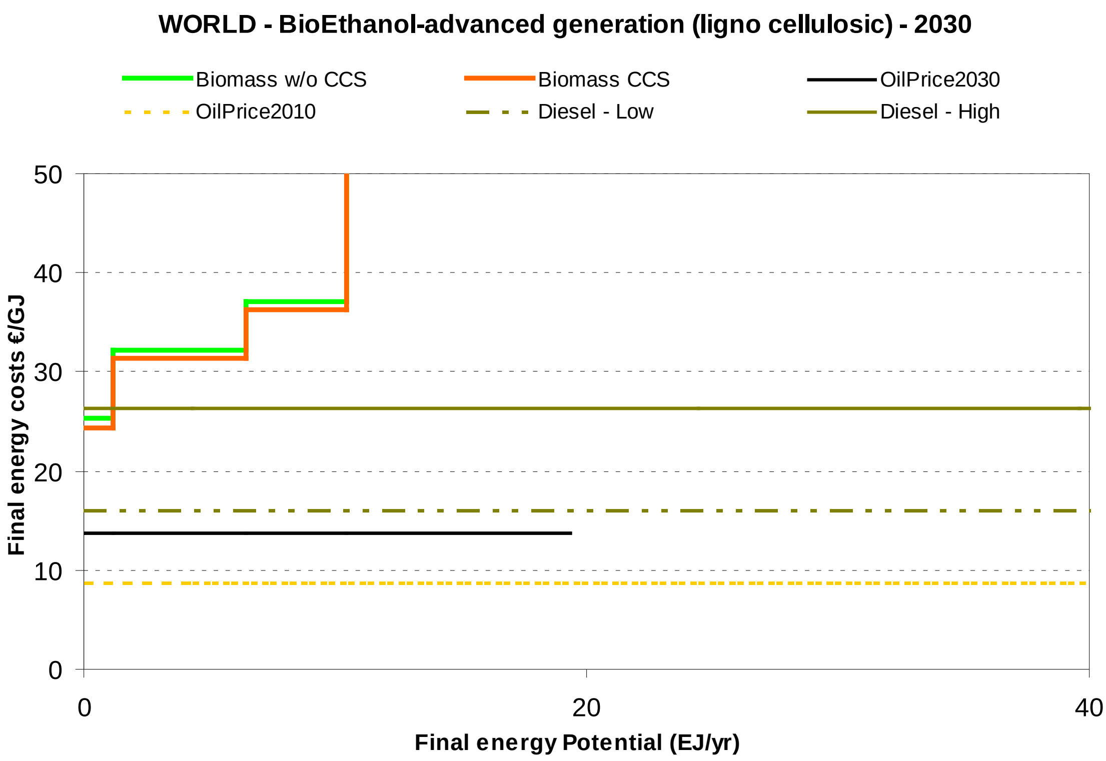


Figure 6 - 6 Supply curve for the BIGCC CCS route in 2030 and 2050. Y-axis shows the cost of power production (in €/GJe). X-axis shows the potential in final energy production (in EJ/yr).

6.4.5 Bio-ethanol - advanced generation (ligno-cellulosic)

Figure 6 - 7 shows the supply curve of the advanced bio-ethanol production route with CCS. The results indicate that CO_2 capture from ethanol is cost-effective with a CO_2 price below 50 euro. Over the full potential, the cost of ethanol production with CCS is economically attractive over production without CCS. When comparing production cost with the references (oil and diesel prices- low and high) in 2030, the results show that about 1 EJ/yr can be produced at cost below that of a high diesel price. It is thus only competitive when assuming high diesel price.

Also for 2050 we estimated that ethanol with CCS is economically attractive when compared to the ethanol production without CCS. Furthermore, due to decrease in investments cost, predominantly as a result of economies of scale, the cost of ethanol production has significantly decreased. It is in the range of diesel and oil prices when using low cost feedstock. The potential with production cost under 30 €/GJ is about 22 EJ/yr.



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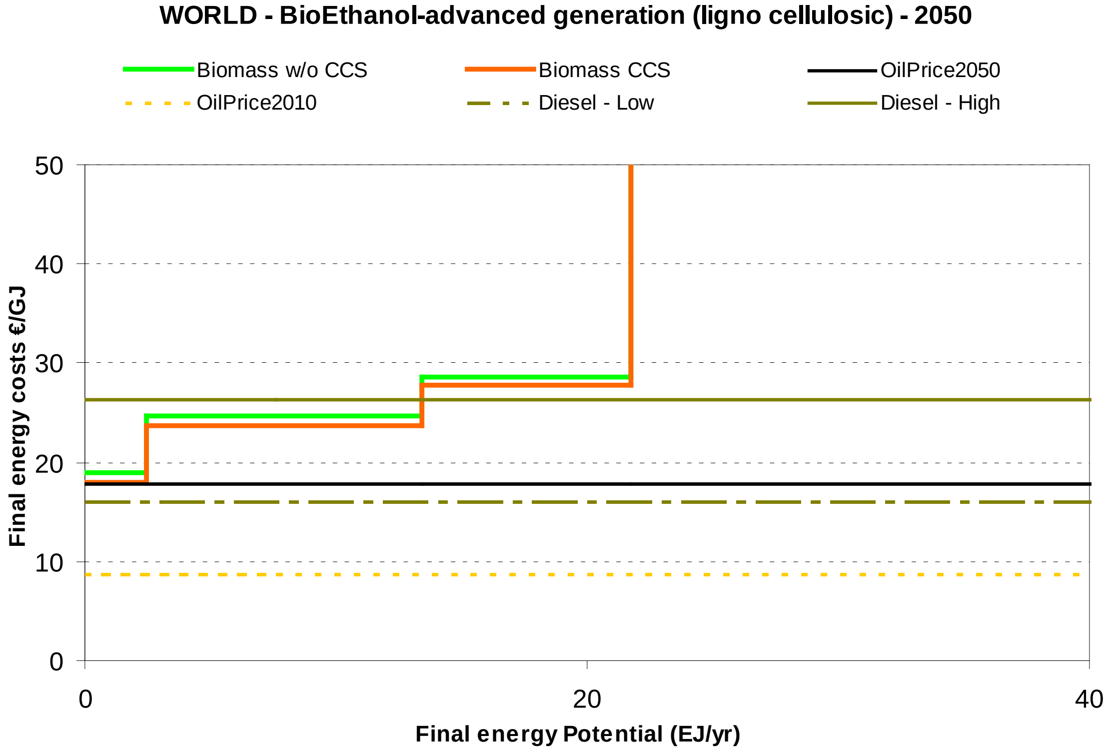


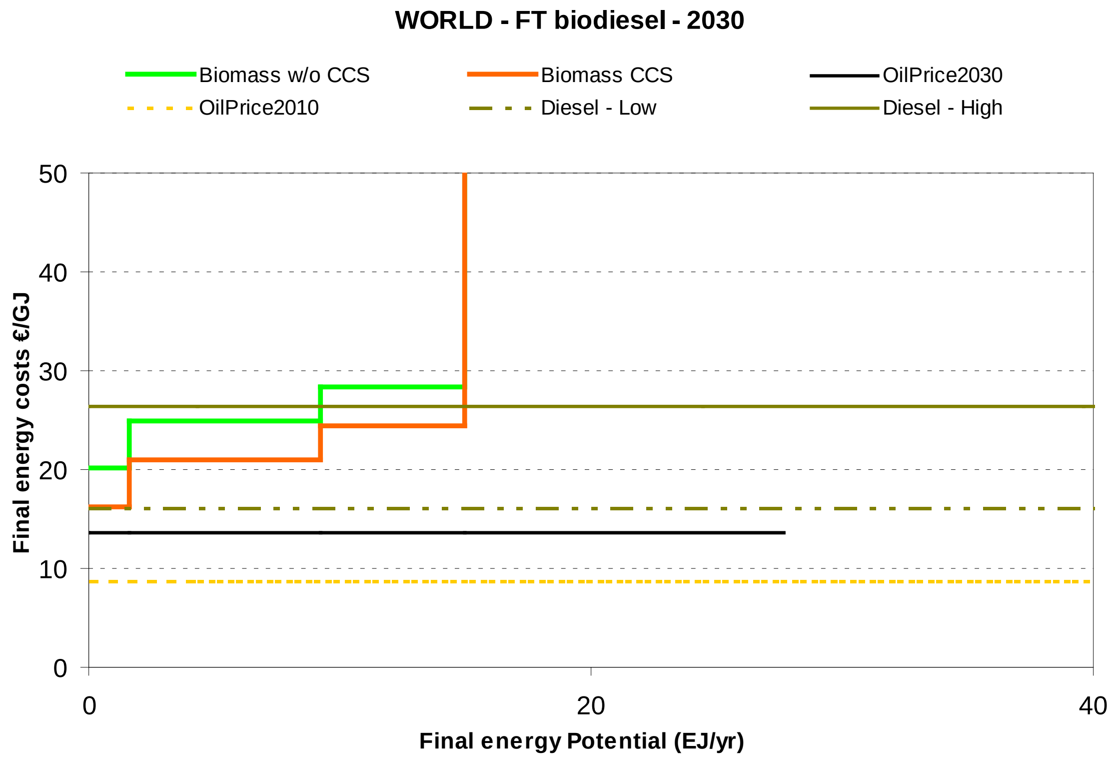
Figure 6 - 7 Supply curve for the advanced bio-ethanol route in 2030 and 2050. Y-axis shows the cost of biofuel production (in €/$GJ_{biofuel}$). X-axis shows the potential in final energy production (in EJ/yr).

6.4.6 Fischer-Tropsch (FT) diesel

Figure 6 - 8 shows the cost supply curve for the FT-biodiesel route with CCS. Like the production of ethanol, FT-biodiesel production with CCS is economically attractive over non-CCS FT-biodiesel for the total production potential. This is under the assumption of a CO_2 price of 50 €/tonne. Furthermore, the difference in FT- diesel production cost for the case with and without CCS is larger than for the bio-ethanol route. One of the reasons is that a larger fraction of the CO_2 is captured. The other is that the FT-biodiesel route has lower CO_2 capture cost compared to the bio-ethanol route.

The figure below also shows that FT-biodiesel production is already in 2030 competitive with fossil fuels if a high diesel price is assumed. With CCS, the FT-biodiesel route can achieve production of 15 EJ/yr with cost under the 25 €/GJ if low cost biomass is available for this technology route.

For 2050, the potential for production cost under 25 €/GJ has increased to 26 EJ/yr. And overall the route has become more economically attractive compared to the fossil references, as we assume an increase in oil price towards 2050 (see Appendix A).



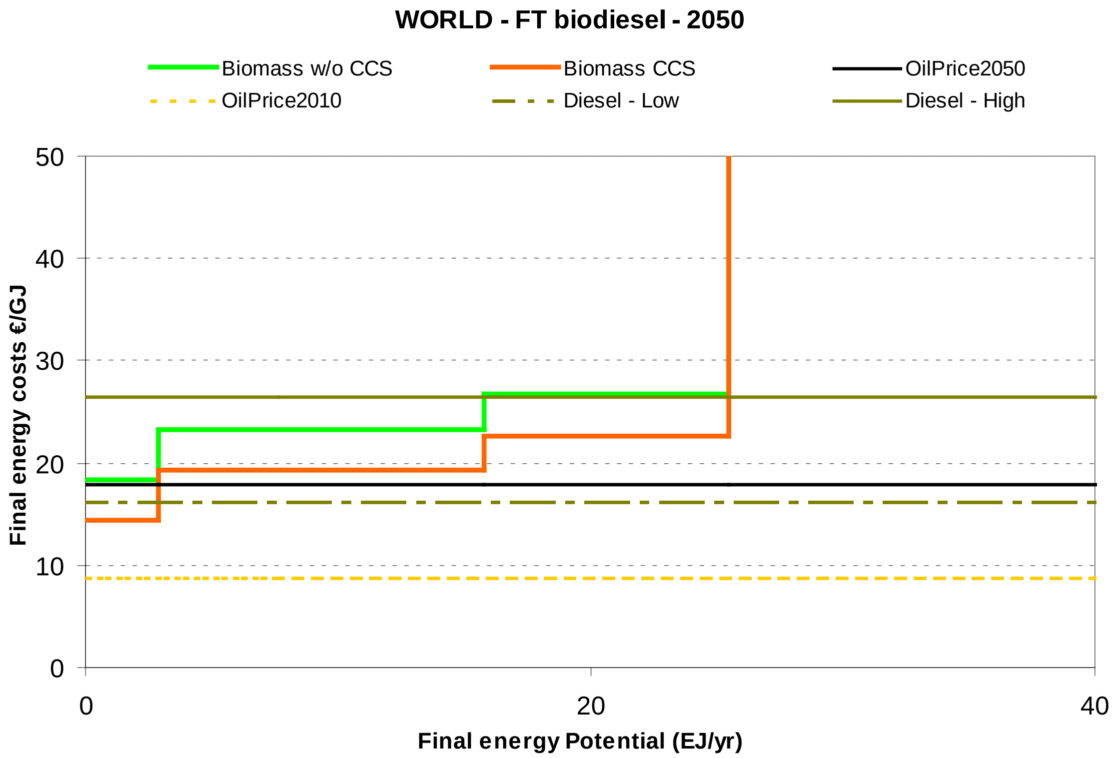


Figure 6 - 8 Supply curve for the FT-biodiesel route in 2030 and 2050. Y-axis shows the cost of biofuel production (in €/$GJ_{biofuel}$). X-axis shows the potential in final energy production (in EJ/yr).

7 Market drivers and obstacles

In this chapter, we present the key drivers and obstacles for the BE-CCS technology routes. We present a conceptual model that shows an inventory of drivers and obstacles and the relationships between them.

Typically, only part of the technical and realisable potential of a new technology can be achieved and be turned into an economic or market potential. The market potential is referred to as a variant of the economic potential, but the latter potential takes into account factors such as market obstacles, logistics, public acceptance, political and regulatory constraints or policy support. In this section the most relevant factors are identified for BE-CCS and qualitatively described. In section 8 we present a sensitivity analysis in which a quantification of drivers and obstacles is presented. For the most important drivers and obstacles we define representative variables in our model to assess the impact of the drivers and obstacles on the economic potential.

7.1 Inventory and characterization

Based on literature review we have constructed a conceptual model that shows an inventory of, and the simplified relationships between, factors that influence the potential of BE-CCS technologies. We have characterised these factors as technical, financial/economic and public & policy related. Combinations of these factors are also possible. An example of the latter is subsidies, which is a policy related economic factor. This conceptual model, including the characterization, is presented in Figure 7 - 1. In this figure, major drivers and obstacles for BE-CCS technologies are highlighted in green or red text. These drivers and obstacles describe how certain factors may influence the BE-CCS potentials calculated in this study. A more extensive overview of obstacles and drivers is presented in Table 7 - 1. There the conceptual model is used to describe how factors are related and how they influence the potential of BE-CCS technologies.

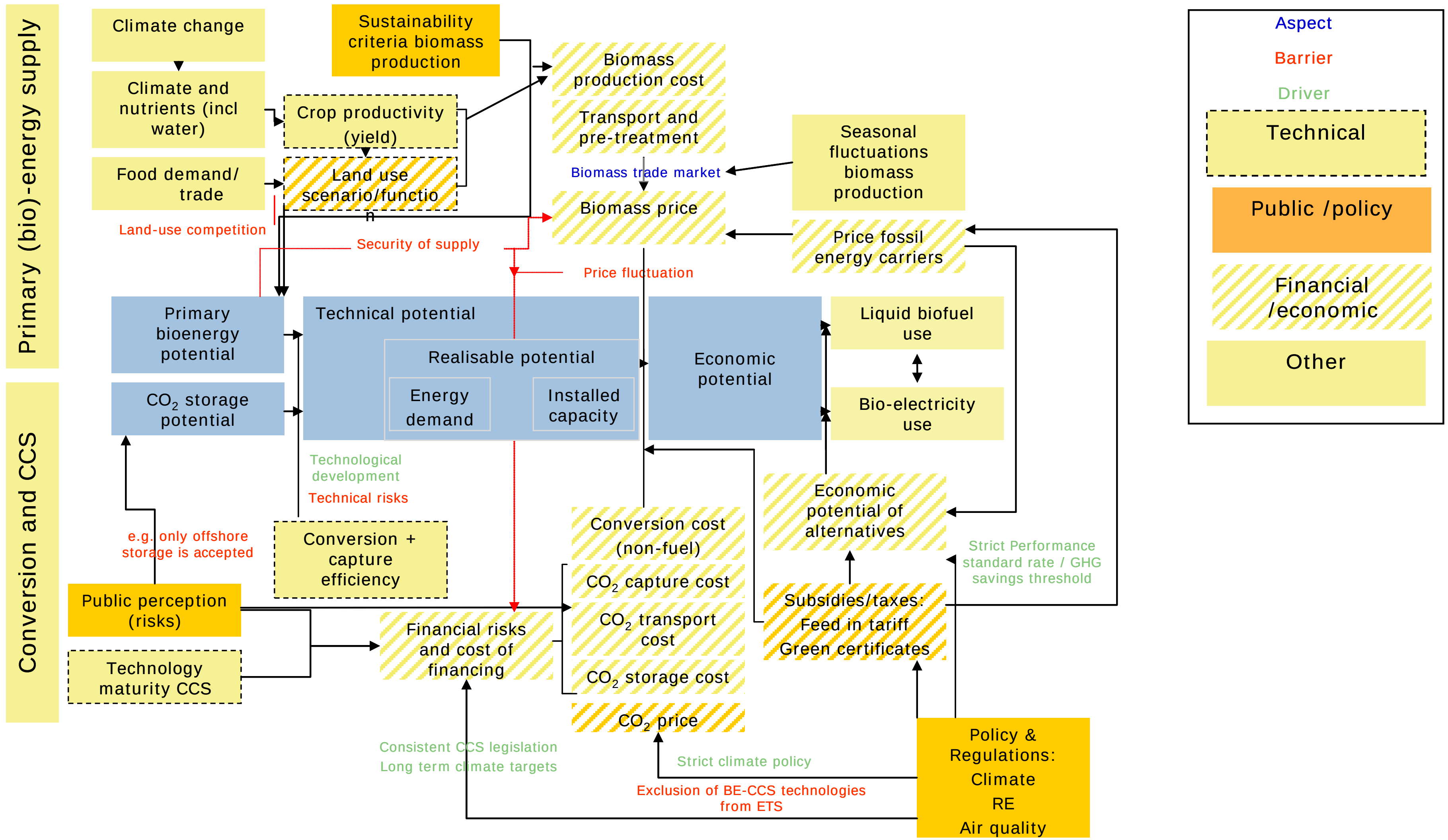


Figure 7 - 1 Conceptual model with characterization of key factors and relationships relevant for the assessment of biomass potentials with carbon dioxide capture, transport and storage. (Blue highlighted boxes indicate the most important targeted results of this study)

Table 7 - 1 Obstacles and drivers for the implementation of BE-CCS technologies.

Factor(s) in Figure 7 - 1	**Narrative**	**BE-CCS chains affected; part of the chain affected.**
food demand/trade → Land-use scenario /function → primary biomass potential	Land use for biomass production may be in competition with land use for production of food, fibre and other land use functions, such as biodiversity. This may result in lower primary biomass potential and an increase in feedstock prices due to higher land prices.	Biomass production of energy crops negatively (residues positively affected)
Food demand & Crop productivity → primary biomass potential	The biomass potential for food production is highly affected by population growth and the expected yield increase. A high population growth in combination with a low increase in yields, results in significantly lower biomass potential (i.e. > a factor 2 difference).	All chains; biomass production
Sustainability criteria → bio-energy economic potential	If bio-energy production meets the sustainability criteria, public attitude towards bio-energy may improve. This may yield a marketing advantage over non-sustainable energy production.	All chains; focus on biomass supply but the full BE-CCS chain is affected.
Sustainability criteria → financial risks and cost of financing	If sustainability criteria are not clear and too complex to comply with, investors may focus on other renewable or non-renewable energy production.	All chains; focus on biomass supply but the full BE-CCS chain is affected.
Sustainability criteria → primary biomass potential	There are risks associated with large scale production of biomass, which may result in intensive farming, use of fertilizers, water and chemicals and may have an impact on water scarcity, conservation of biodiversity and land degradation.	All chains; focus on biomass supply but the full BE-CCS chain is affected.
Security of primary biomass supply & uncertainty of CO_2 storage capacity → financial risk and cost of financing	Uncertainty in security of biomass supply and CO_2 storage capacity, in addition to uncertain/inconsistent policies, may result in higher project risks. This may be translated into higher cost of financing investments.	All chains; full chain perspective.
Seasonal fluctuations biomass supply → biomass trade & biomass price fluctuation → financial risks and cost of financing	Prices of biomass feedstock may be volatile due to seasonal variation in biomass supply. This may require storage of (pre-treated) biomass. Seasonal fluctuations in demand and supply will influence the price and the stability of the price. All in all, price volatility is considered a risk and thus a barrier for investors. This may increase the cost of financing BE-CCS projects.	All chains but most important for dedicated BE-CCS routes (co-firing less affected as they have the possibility for fuel switching, especially for IGCC); focus on

		biomass supply but the full BE-CCS chain is affected.
Crop productivity → biomass potential & biomass production cost	A higher yield increase due to improved agricultural technologies as well as 'duo cropping' may result in higher biomass production per hectare which may result in lower production cost.	All chains; biomass production.
Public perception → CO_2 storage potential & cost	Negative public attitude towards CO_2 storage may result in scenarios where: - storage on land is limited or absent; -offshore storage is most likely preferred, This leads to a lower storage potential and most likely to higher storage and transport cost.	All chains; onshore storage part of all CCS chains most likely affected.
	Negative public attitude towards CO_2 transport may result in: -non-economical route selection -increase risk mitigation efforts Both will result in additional transport cost.	All chains; onshore transport most likely affected.
	It may be that people opposing CCS may accept CCS in combination with (sustainable) biomass and those opposing biomass (because of the low GHG emission reduction potential) may support it when attached to CCS.	All chains; full chain perspective.
Policy (EU renewable energy directive) → Economic potential of alternatives	Criteria in the EU RED require that biofuels must result in at least a 35% GHG saving from 2013 onwards; 50% saving in 2017; the GHG saving threshold is 60% from 2018. The availability of CCS may prove to be an advantage for chains that need to improve their GHG performance at acceptable cost and with it will outperform chains without the possibility of CCS.	Biofuel chains with CCS; full chain is affected.
Policy: climate → Economic potential of alternatives	For example, an EPS in the form of g/kWh for new coal fired power plants will act as a driver for CCS in power generation. A very strict EPS may necessitate the use of both CCS and biomass, as CCS alone may not be sufficient. A combination of CCS (e.g. 50% capture) and co-firing (30-50%) may also be a future strategy of utilities.	Pre-dominantly coal fired power generating chains with CCS with co-firing biomass; full chain affected.
Policy: Climate → CO_2 price	1) In the EU ETS the incentive for CCS is that no emission allowances have to be surrendered for CO_2 emissions that have been stored. 2) Dedicated biomass conversion installations are currently excluded from EU ETS. Therefore no incentive exists (in the form	All chains; full chain perspective.

	of sellable allowances) in the EU to install CCS at dedicated biomass fired power plants. Installations using biomass in combination with fossil fuels are not excluded from the EU ETS. However, storing CO_2 from biomass will not 'create' sellable allowances under the EU ETS, i.e. there is no economic value attached to 'negative emissions'. There is therefore no incentive for BE-CCS technologies under the current EU ETS.	
	Inclusion of CCS as Clean Development Mechanism (CDM) project activities is a key driver for all BE-CCS routes as it facilitates financing of BE-CCS projects in developing countries. A preliminary decision has been agreed on the eligibility of CCS for CDM but detailed conditions of including CCS in CDM has to be resolved.	
Policy: Climate → CO_2 price → economic potential	A very strict climate policy which aims at large reductions and low stabilization concentrations in the order of 350 ppm will yield high CO_2 prices. This will provide an incentive for BE-CCS technologies and will increase the economic potential.	All chains; full chain perspective.
	If the international climate negotiations result in clear long term targets for GHG reduction at a level of meeting two degrees temperature raise, the implementation of BE-CCS could be inevitable. If long term targets or agreements are not agreed, the urgency for BE-CCS should come from more local or national driving forces.	Entire and all BE-CCS chains
CO_2 price → (production cost →) economic potential	A low CO_2 price does not create enough additional revenues to promote BE-CCS technologies. This results in a high production cost of final energy carriers and with a lower economic potential for BE-CCS technologies.	All chains; full chain perspective.
Policy: RET incentives →subsidies, taxes, feed-in tariffs → economic potential alternatives and BE-CCS technologies	Several instruments or mixes of instruments are used in the world to promote renewable energy technologies (RET). Examples are RET quota obligations, feed-in tariffs, feed in premiums, green certificates, tax (relief) and others. Combinations of incentives are also used and the use of incentives is very diverse. These incentives could lower end-user prices and with it promote the use of bio-energy carriers (fuels, electricity) but also that of alternative RET. The economic potential for BE-CCS could therefore be positively or negatively affected depending on the end-user prices for RET.	All chains; full chain perspective.
	Monitoring reporting and verification (MRV) guidelines for RET should be reviewed and adjusted where necessary to ensure that no double counting of GHG benefits (e.g. CO_2	

	certificates and tax relief linked to GHG performance) occurs throughout the full chain of the BE-CCS technologies.	
Policy: air quality → Economic potential alternatives → economic potential (BE-CCS) technologies	Biomass (co)firing typically results in lower NOx and SOx emissions. This may result in lower production cost for BE-CCS technologies compared to production cost of (fossil) reference technologies with CCS	Holds for PC-CCS co-firing and Dedicated CFB-CCS routes; conversion cost part of the chain.
	Due to the efficiency penalty some emissions, such as NOx, NH3 and PM may increase per kWh. This depends heavily on the conversion and capture technology.	PC-CCS co-firing, CFB-CCS dedicated, IGCC-CCS co-firing, BIGCC-CCS dedicated; conversion cost part of the chain.
	NOx and CO emissions from combustion of ethanol are typically lower compared to gasoline. High mitigation cost for these substances may result in taxes for fossil reference technologies.	Bio-ethanol routes; end-conversion part of the chain.
	Biodiesel has advantages over fossil diesel as it produces less sulphur oxides (i.e. nihil), carbon monoxide (40 to 50% less) and particulate matter (35 to 45% less) due to the absence of sulphur and better combustion characteristics. It may result in higher NOx emissions but these can typically be better controlled with end-of-pipe reduction strategies (e.g. catalysts) compared with fossil diesel. High mitigation cost for these substances may result in taxes for fossil reference technologies.	FT biodiesel; end-conversion part of the chain.
Installed capacity → realisable potential	The current installed base of coal fired power plants may be used for co-firing; at least small co-firing rates will be possible without many technical limitations. If these power plants are retrofitted with CCS, the BE-CCS potential for this chain significantly increases.	Mostly a driver for the PC-CCS co-firing route.
Technology maturity → financial risk and cost of financing	Biomass and CCS are innovative technologies. The combination of the two is new and now experiences are gained. Financial and technical risks cannot be completely overseen. This may cause failures and more time to convince financial institutes and policy makers. A consequence may be that higher financial risks are anticipated for BE-CCS projects which may result in higher costs of financing.	All chains; most impact expected on capital cost of the most capital intensive BE-CCS routes.

8 Sensitivity analysis

In this chapter, we present the results of the sensitivity analysis. The sensitivity analysis is used to assess the effect of uncertainties on the outcomes presented in the preceding chapters. In sensitivity analysis one parameter/assumption in the model is varied and the effect of this on the outcomes of the model is reported. We selected important parameters/assumptions based on the expected uncertainty of input data and on the overview of drivers and obstacles for BE-CCS routes as presented in chapter 7. Each variable is assessed separately and the relative or absolute change compared to the base case results for the technical and economic potential are reported.

8.1 Summary

We selected nine variables for the sensitivity analysis, being:CO_2 price, biomass price, coal price, discount rate, cost of CO_2 transport and storage, sustainability criteria for biomass supply, CO_2 storage capacity estimates and exclusion of possible storage reservoirs.

The results show that the economic potential is highly dependent on the CO_2 **price**. A higher CO_2 price decreases the BE-CCS production costs and increases the costs for the reference technologies, resulting in a substantial increase of competitiveness for the BE-CCS technologies.

The **coal price** directly affects the production cost of electricity for the co-firing routes and with it the economic potential. A higher coal price results in an increase of the economic potential of the BE-CCS technologies producing electricity. Indirectly the economic potential of the BIGCC route is strongly affected.

The **biomass price** affects the production cost of all routes. Halving the biomass price results in a decrease in production costs up to 39% for the dedicated routes, in 2050. The production cost of co-firing routes decrease up to 18% in 2050. If the biomass price is increased with 50%, then the production cost rise up to 28% in 2030 and up to 31% in 2050. Overall the production cost of co-firing routes are least affected depending on the co-firing share of biomass. A higher biomass price decreases the economic potential of almost all routes to zero for the year 2030.

The effect of a higher or lower **discount rate** is typically more severe for the capital intensive routes, being the dedicated routes firing only biomass. It results in a 15-20% change in production cost, but has in general a low impact on the economic potential.

Doubling the **costs of CO_2 transport and storage** leads to an increase of the production cost of maximally 16%. When the costs are halved, the production costs will decrease up to 7%. The impact on the economic potential is the largest for the co-firing routes.

The results for the technical potential, expressed in final energy and the maximum amount of CO_2 stored, are very sensitive to the set of **sustainability criteria** applied on the biomass supply. The technical potential is increased more than 60% when applying no sustainability criteria. The potential of relatively affordable biomass is also increased, which in turn leads to an increase in the economic potential. Overall, the results of our study are highly dependent on the estimates used for the primary biomass supply.

The technical and economic potential are not influenced by using lower or higher estimates for the **global storage potential**, as this is not the limiting factor in most of the regions. The technical potential of the co-firing routes is significantly reduced when storage capacity of aquifers and underground coal seams are excluded as well as excluding inter-regional transport of biomass. The impact of varying the 'annualised storage capacity factor' on the technical potential is relatively modest for the routes producing electricity. No impact is observed for the biofuel production routes.

8.2 Variables selected for analysis and base case results

We selected important parameters/assumptions based on the expected uncertainty of input data and on the overview of drivers and obstacles for BE-CCS routes as presented in chapter 7. This yields the list of variables presented in Table 8 - 1.

Table 8 - 1 Ranges used for key assumptions in the sensitivity analysis. Note that each variable is assessed separately

Variable	Unit	Base case	Variant 1	Variant 2
CO_2 price	€/tonne	50	20	100
Coal price		3.7	2.6	4.9
Discount rate (cost of financing)	%	10	6	15
Cost of transport	€/tonne	5	3	10
Cost of storage	€/tonne	5	1	13
Criteria biomass supply	-	Strict	Mild	No
Biomass price	%	100%	-50%	+50%
Storage capacity estimates	-	Best	Low	High
Annualised storage capacity factor	Years	50	70	
-CO_2 storage reservoirs -inter-regional transport of biomass and CO_2	-	-all reservoirs -inter-regional transport included	-hydrocarbon reservoirs only -inter-regional transport excluded	

For the sensitivity analysis we have chosen indicators for which we asses the change in outcome per BE-CCS route. The production of final energy and the amount of CO_2 stored are indicators for the technical potential. For the economic potential we have chosen the amount of final energy (in EJ/yr) that can be produced with lower production cost than the most expensive fossil reference technology and the production cost in €/GJ_{final}. The production cost, also used as an indicator, is shown only for the second step in the supply curve, i.e. with a biomass price at factory gate of 7.0 €/GJ. Table 8 - 2 presents the results of the base case model run for these indicators. In the sections below we discuss the effect of changing the variables.

Table 8 - 2 Results of key indicators for the base case

Technology route	Year	Technical potential		Economic potential	
		Final energy EJ/yr	Net GHG emissions Gt/yr	Final energy[1] EJ/yr	Production cost[2] €/GJ
PC-CCS co-firing	2030	90	-4.3	0	23.2
	2050	108	-9.9	7	17.9
CFB-CCS dedicated	2030	24	-5.7	1	25.4
	2050	47	-10.4	3	20.2
IGCC-CCS co-firing	2030	99	-4.3	33	21.0
	2050	118	-9.9	39	16.1
BIGCC-CCS dedicated	2030	28	-5.7	10	20.5
	2050	57	-10.4	19	15.4
BioEthanol	2030	19	-0.5	1.2	31.4
	2050	40	-1.1	13.4	23.7
FT biodiesel	2030	28	-3.3	15.0	21.1
	2050	47	-5.8	25.5	19.2

[1]Economic potential (max) is the amount of EJ/yr that can be produced with lower cost compared to the most of expensive reference technologies (for power generation routes) or fossil energy carriers (for biofuel routes)

[2]Second cost category for biomass represents a biomass price at factory gate of 7.0 €/GJ

8.3 Results of the sensitivity analysis

8.3.1 CO_2 price

The graphs below show the change in the results of the key indicators when varying the CO_2 price. The CO_2 price is varied between 20 and 100 €/tonne. For the both view years we see that a lower CO_2 price has a large impact on both the production cost and economic potential. Reducing the CO_2 price to 20 euro results in an increase in production cost of up to about 30% for the dedicated biomass routes producing electricity. The impact is lower for the co-firing routes and for the routes that capture less CO_2. When increasing the CO_2 price to 100 euro per tonne of CO_2 the opposite is seen, i.e. the production cost of final energy decrease up to about 60% for the dedicated routes in 2050.

The CO_2 price also has, by influencing the production cost, a large impact on the economic potential of the routes. A decrease in production cost leads to an increase in economic potential as the economic advantage over the reference technologies in general improves. In absolute terms, the largest impact is expected for the IGCC and PC co-firing routes in 2030. For the IGCC route a low CO_2 price results in a significantly lower economic potential and a high price in significantly higher potential. For the PC route, an increase in CO_2 price leads to a significantly higher economic potential, i.e. about 50 EJ/yr higher. Lower CO_2 prices do, however, not result in a much lower potentials, except for the IGCC and BIGCC technologies. In 2050, almost all routes react strongly to a higher CO_2 price of 100 euro/t and economic potentials increase significantly.

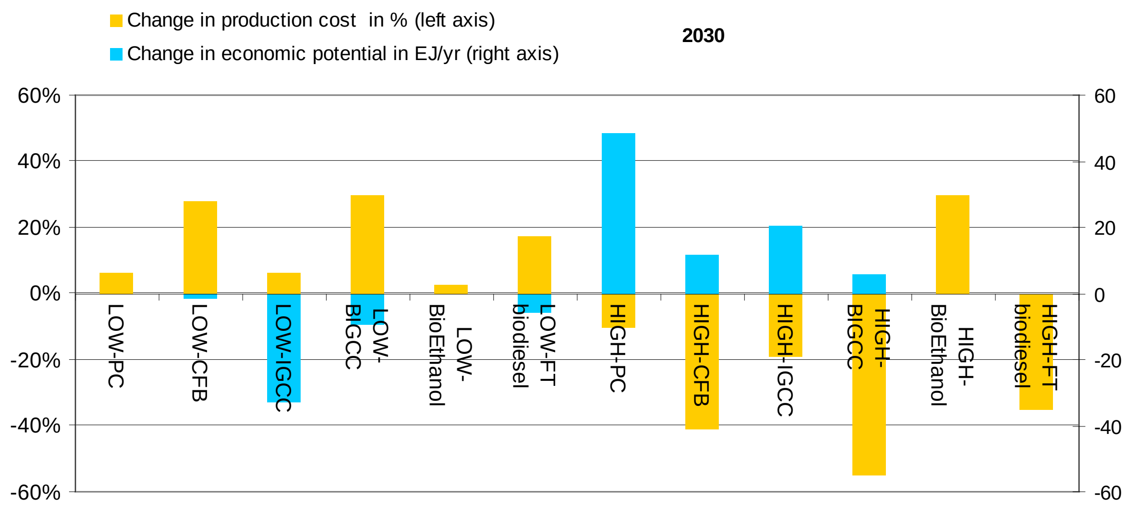


Figure 8 - 1 Impact of CO_2 price on production cost and economic potential in 2030. ‘Low’ indicates a CO_2 price of 20 €/tonne. ‘High’ indicates a price of 100 €/tonne. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

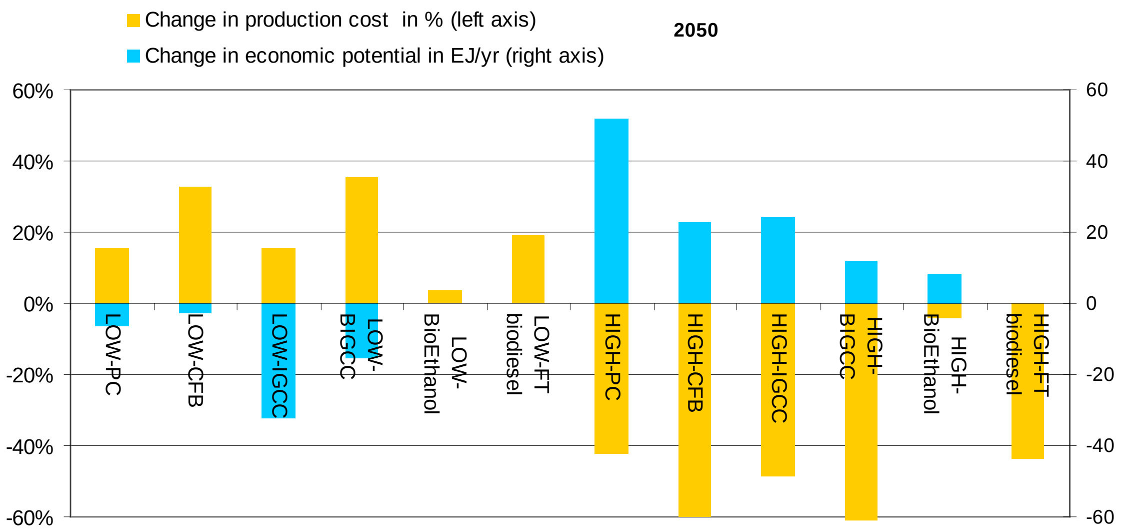


Figure 8 - 2 Impact of CO_2 price on production cost and economic potential in 2050. 'Low' indicates a CO_2 price of 20 €/tonne. 'High' indicates a price of 100 €/tonne. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

8.3.2 Coal price

Figure 8 - 3 and Figure 8 - 4 show the effect of varying the coal price on the production cost and economic potential. We did not find any impact on the other indicators. The coal price directly affects the production cost of electricity for the co-firing routes. This entails a decrease or increase of about 7-8%. With a change in the production cost also the economic potential is affected. A coal price increase, results in a higher economic potential for BE-CCS power technologies. This is shown in Figure 8 - 4 for the IGCC and the PC routes in the year 2050. The coal price also impacts the economic potential of the BE-CCS technologies only using biomass. The explanation is that the reference technologies will experience increasing production cost, while dedicated biomass plants are unaffected. As a result we see the economic potential of the BIGCC route increase in 2050 with about 12 EJ/yr with a high coal price and decreasing with 15 EJ/yr with a low coal price.

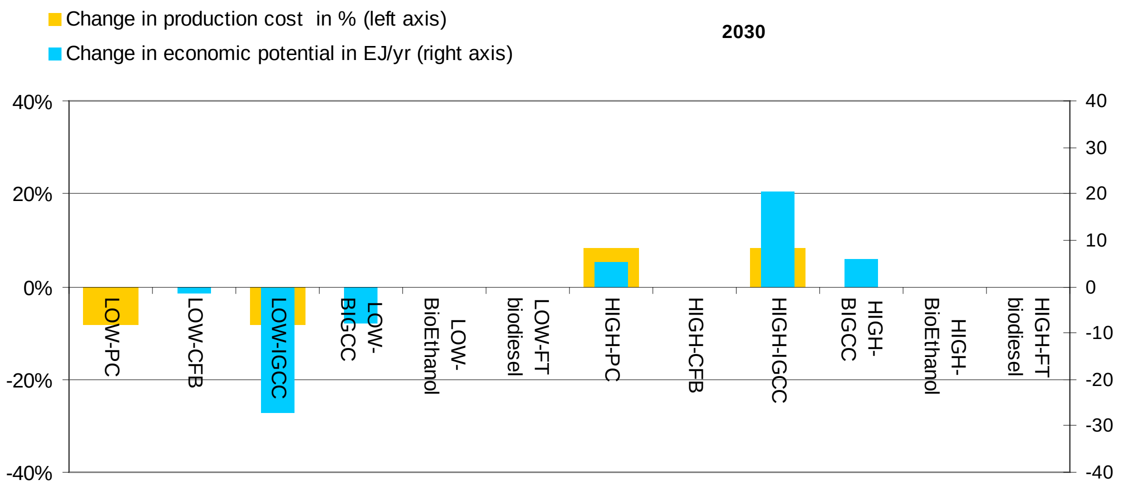


Figure 8 - 3 Impact of coal price on production cost and economic potential in 2030. 'Low' indicates a price of 2.6 €/GJ. 'High' indicates a price of 4.9 €/GJ. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

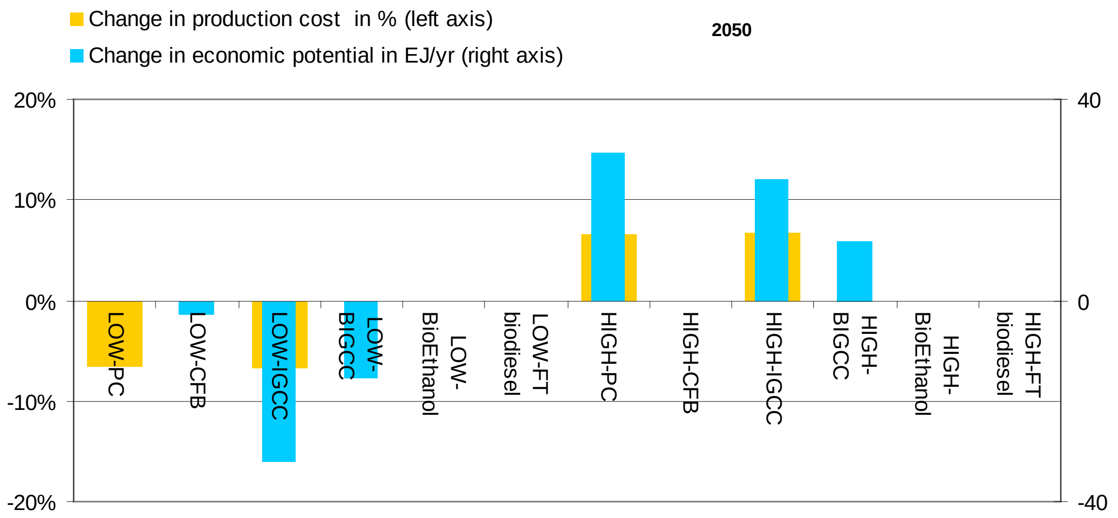


Figure 8 - 4 Impact of coal price on production cost and economic potential in 2050. 'Low' indicates a price of 2.6 €/GJ. 'High' indicates a price of 4.9 €/GJ. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

8.3.3 Biomass price

In Figure 8 - 5 and Figure 8 - 6 we show the effect on production cost and economic potential when increasing/decreasing the biomass price with 50%. This sensitivity analysis can also be used as a proxy for the estimation of the effect of economic incentives for bio-energy in the form of subsidies, tax relief or green certificates etc.

The biomass price is obviously a very important variable. If the biomass price is halved, then 100% biomass fired routes such as bio-ethanol, FT-biodiesel, CFB and the BIGCC see production cost decrease with 32-34% in 2030 and with 36-39% in 2050. The production cost of co-firing routes decrease with about 10% in 2030 and with 18% in 2050. If the biomass price is increased with 50%, then the production cost rise up to 28% in 2030 and up to 31% in 2050. Overall the production cost of co-firing routes are least affected as the coal price buffers the increase in biomass price to some extent, depending on the co-firing share of biomass.

The economic potential is in turn also significantly affected by increasing/decreasing the biomass price. For the year 2030 the effect is most prominent for the PC and IGCC routes[19], which see an increase in the economic potential of, respectively, 30 and 20 EJ/yr under a lower biomass price. For 2050, the economic potential of the PC routes even increases with over 50 EJ/yr under a low biomass price.

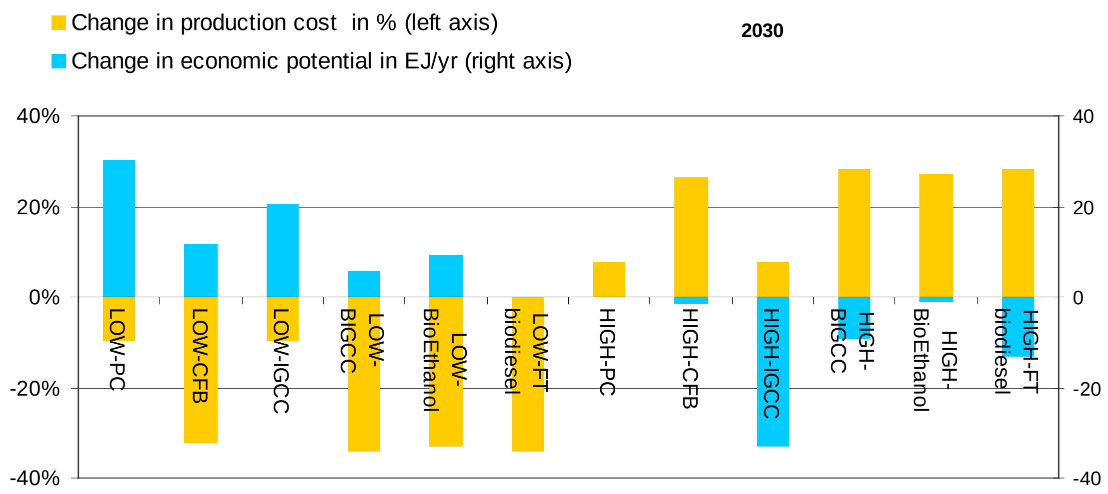


Figure 8 - 5 Impact of biomass price on production cost and economic potential in 2030. 'Low' indicates a biomass price 50% lower than used in the base case, for the full supply curve. 'High' indicates a price 50% higher. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

A higher biomass price decreases the economic potential of almost all routes to zero for the year 2030. The only exception is the FT route, which still has an economic potential of 1.5 EJ/yr in that year. For the year 2050 the effect is less dramatic but still results in the absence of any economic potential for the combustion based routes (PC and CFB). The other routes see a shear drop in the potential, but potential remains for the gasification based routes. This especially holds for the FT-biodiesel

[19] Remember that the PC and IGCC are co-firing routes also firing coal and the economic potential shows the final energy including both the biomass as coal share. Any effect on the economic potential is therefore exaggerated for these routes.

route, which still has a potential of 16 EJ/yr under a biomass price that is 50% higher across the full supply curve.

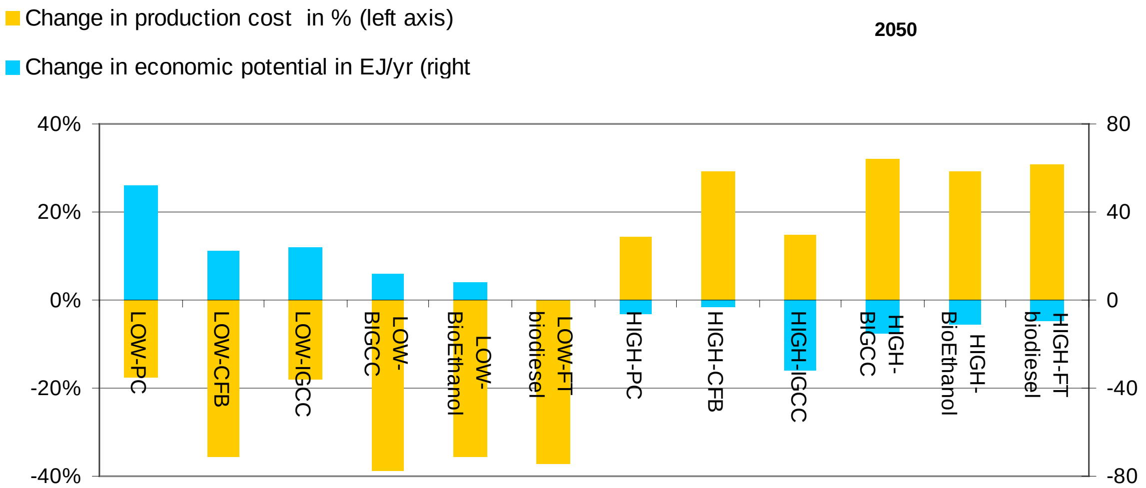


Figure 8 - 6 Impact of biomass price on production cost and economic potential in 2050. 'Low' indicates a biomass price 50% lower than used in the base case, for the full supply curve. 'High' indicates a price 50% higher. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

8.3.4 Discount rate

Varying the discount rate in fact shows what happens when the investment cost of the conversion technologies increase or when the cost of financing increase. We have varied the discount rate between 6% (low) and 15% (high). The value in the base case is 10%. The results show no effect on the technical potential. The production costs on the other hand are increased up to almost 20% due to a higher discount rate. A decrease up to almost 15% is shown for the lower discount rate. The effect is typically more severe for the capital intensive routes, being the dedicated routes firing only biomass. The economic potential is hardly influenced as also the reference technologies are affected by an increase or decrease in the discount rate. Exceptions are shown in Figure 8 - 7 for 2030, where the CFB, bio-ethanol and FT-biodiesel routes experience an increase in the production cost and as a result a lower economic potential.

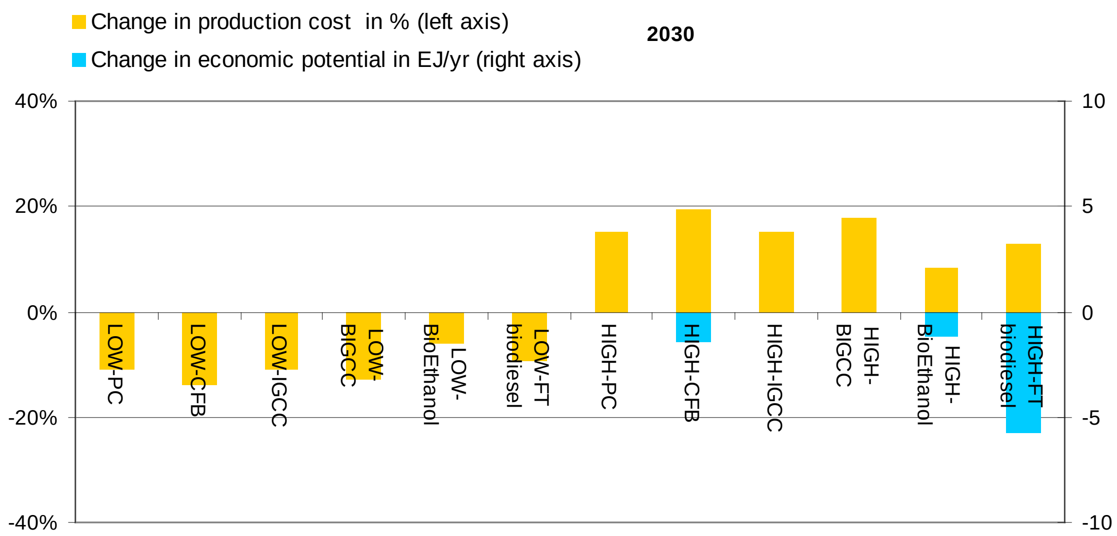


Figure 8 - 7 Impact of discount rate on production cost and economic potential in 2030. 'Low' indicates a rate of 6 %. 'High' indicates a rate of 15%. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

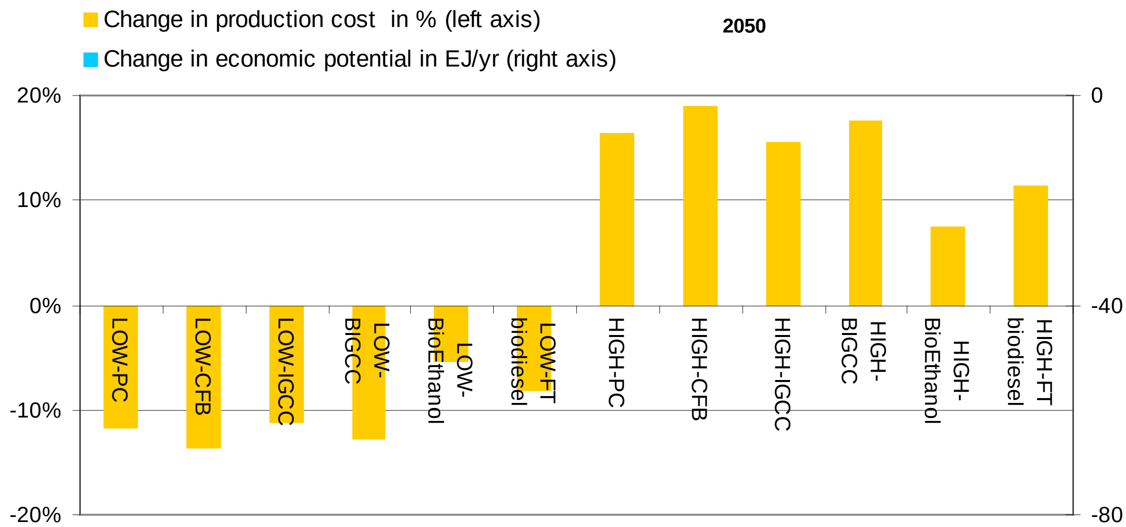


Figure 8 - 8 Impact of discount rate on production cost and economic potential in 2050. 'Low' indicates a rate of 6 %. 'High' indicates a rate of 15%. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

8.3.5 Cost of CO_2 transport and storage

Varying the cost of transport and storage of CO_2 yielded no effect on the results for the technical potential. The cost of final energy production and the economic potential are however influenced by CO_2 transport and storage cost. This is shown in Figure 8 - 9 and Figure 8 - 10.

Increasing the cost of transport and storage from 10 €/tonne to 23 €/tonne increases the production cost up to 16% for the BIGCC in 2050. A decrease of maximally 7% is found when decreasing the CO_2 transport and storage cost to 4 €/tonne. The sensitivity is higher for the results for 2050 as over time a decrease of CO_2 capture cost is expected. This increases the relative share of transport and storage cost in the total production cost.

The impact on the economic potential is clearly to see for the CFB, IGCC and BIGCC routes in 2030, where the economic potential sharply decreases with increasing cost of CO_2 transport and storage. For 2050, we can see that varying the transport and storage cost strongly influences the economic potential of co-firing routes.

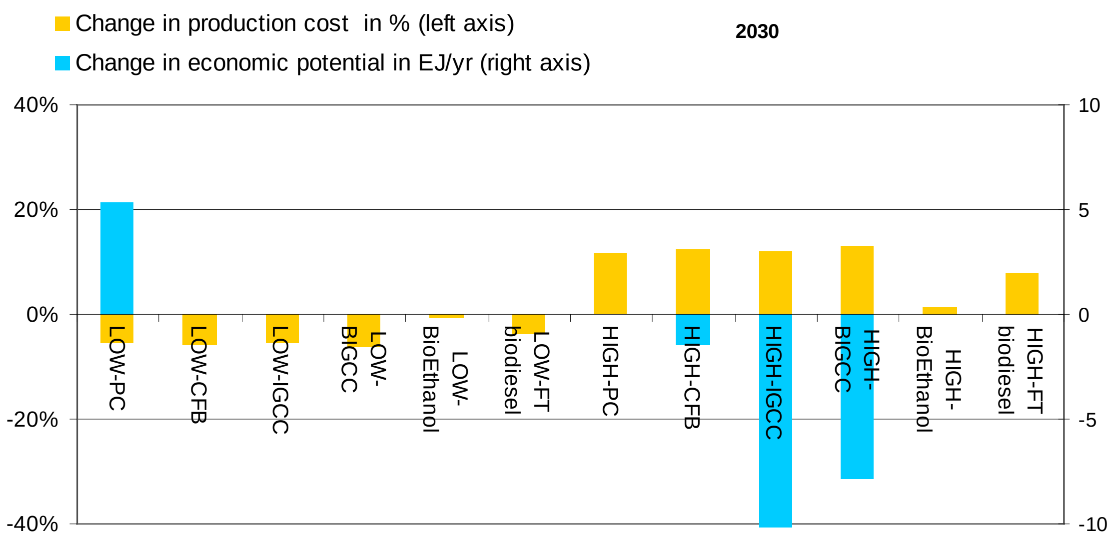


Figure 8 - 9 Impact of CO_2 transport and storage cost on production cost and economic potential in 2030. ‘Low’ indicates transport cost of 3 €/tonne and storage cost of 1 €/tonne. ‘High’ indicates transport cost of 10 €/tonne and storage cost of 13 €/tonne. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

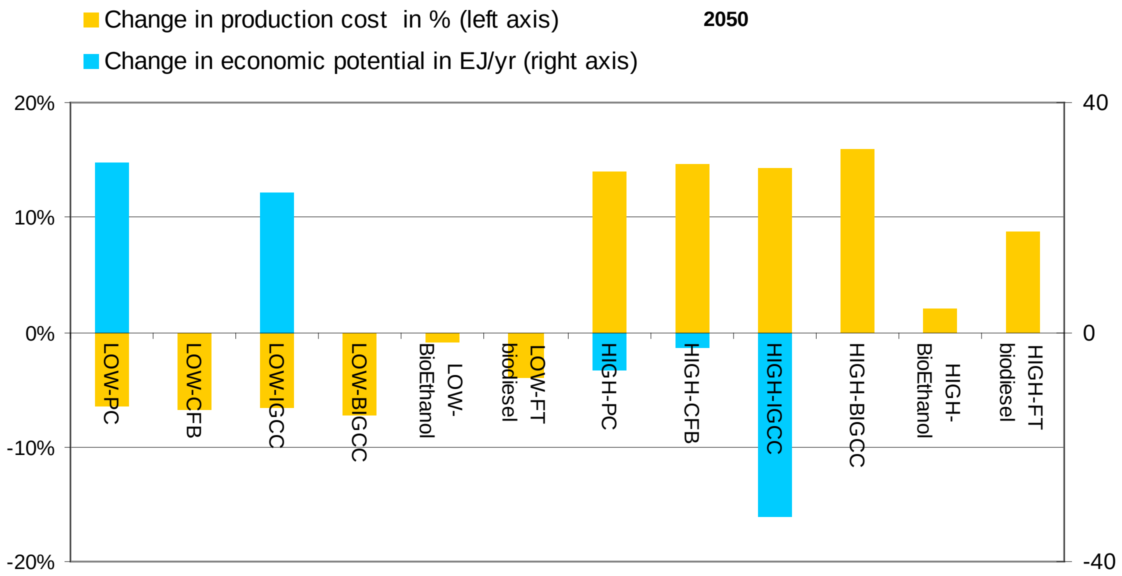


Figure 8 - 10 Impact of CO_2 transport and storage cost on production cost and economic potential in 2050. 'Low' indicates transport cost of 3 €/tonne and storage cost of 1 €/tonne. 'High' indicates transport cost of 10 €/tonne and storage cost of 13 €/tonne. Left axis shows the relative change in % for the production cost. Right axis shows the absolute change in EJ/yr for the economic potential.

8.3.6 Sustainability criteria for biomass supply

The application of sustainability restrictions on the biomass supply has severe influence on the biomass potential. By default we use the 'Strict' criteria (see Appendix B). Here we show what the effect is on the results of our study when we apply 'Mild' or 'No' criteria[20]. The results for the technical and economic potential, expressed in final energy, are very sensitive to the set of criteria applied. With no criteria applied the biomass potential is larger. And the biomass potential is the dominant constraint limiting the BE-CCS potential. These two factors combined result in an increase in the technical potential of more than 60% for both view years, when no criteria are applied. This is about 40% when the mild criteria are applied.

The economic potential is also influenced by the availability of primary biomass. In both figures, we see that the economic potential for especially the IGCC route is significantly affected by applying milder criteria, i.e. increasing the primary biomass potential. In the model, the increase of biomass supply leads to an increase of the potential in all cost categories defined for biomass supply. Therewith is the potential of relatively affordable biomass increased, which in turn leads to an increase in the economic potential.

[20] It should be noted that we not advocate the use of biomass without sustainability criteria.

Overall, these figures show that the results of our study are very sensitive to the estimated biomass supply curve and total primary biomass supply.

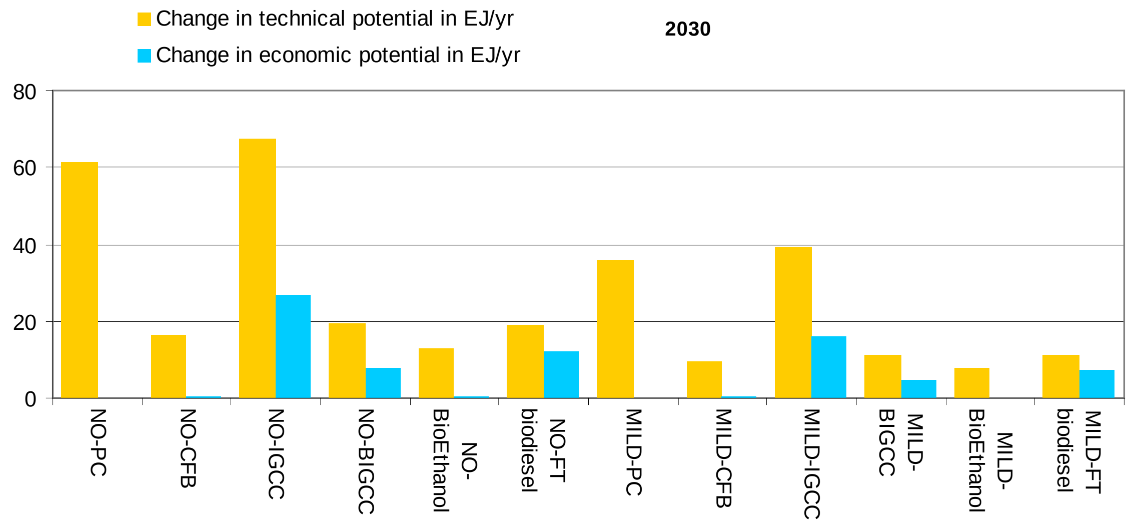


Figure 8 - 11 Impact of sustainability criteria of biomass supply on the technical and economic potential in 2030. 'Mild' indicates the application of mild sustainability criteria. 'No' indicates that no criteria are applied on the biomass potential. Axis shows the absolute change in EJ/yr.

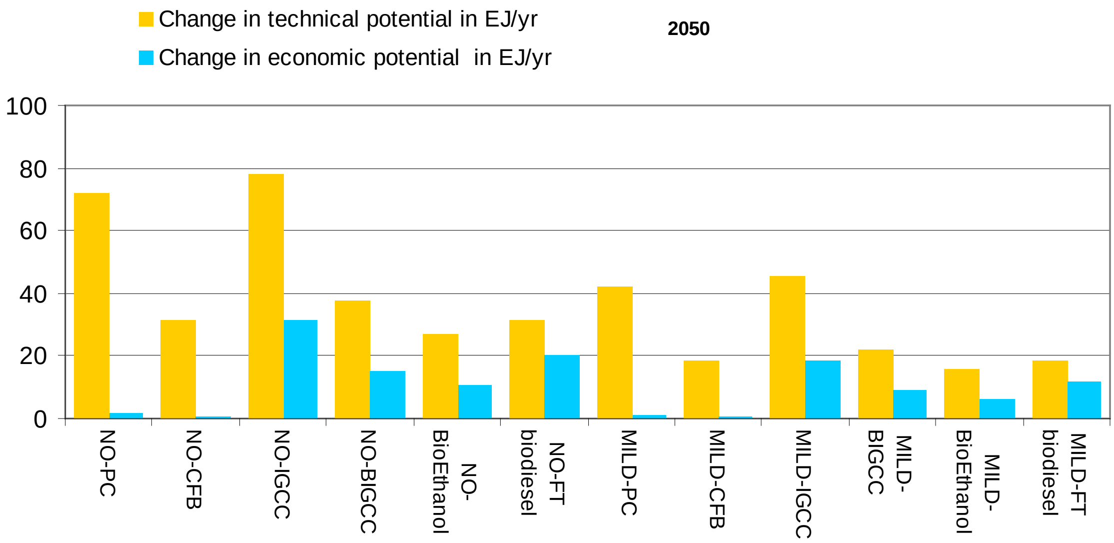


Figure 8 - 12 Impact of sustainability criteria of biomass supply on the technical and economic potential in 2050. 'Mild' indicates the application of mild sustainability criteria. 'No' indicates that no criteria are applied on the biomass potential. Axis shows the absolute change in EJ/yr.

8.3.7 CO_2 Storage potential

We assed the impact of varying assumptions regarding the CO_2 storage potential. In the base case we use the 'Best' estimates for the storage potential. In the sensitivity cases we have used the 'Low' and the 'High' estimates. The results did not show an effect on the technical and economic potential.

We also assessed the impact of increasing the "Annualised storage capacity factor" from 50 to 70 (see section 4.3.10 for explanation). This reduces only the technical potential for the BE-CCS routes for electricity production inter-regional transport is not possible. The biofuel production routes are not affected as storage capacity is not a constraint in those routes. The co-firing routes are affected the most as more storage capacity is required in those routes. The technical potential of the IGCC co-firing route in 2050 is reduced the most with 8 EJ/yr (4 EJ/yr biomass share) and the dedicated routes the least with 1 EJ/yr.

We also changed the types of reservoir that are included in the CO_2 storage potential. In the sensitivity case we have chosen 'Hydrocarbon only'. With it, we exclude the potential of aquifers and underground coal seams. This assumption does have a considerable effect on the global technical potential. However, it only has influence on the technical potential when inter-regional transport is not included. In the figure below we show the global technical potential without inter-regional transport of biomass and CO_2. It shows that reducing the storage potential leads to a constraint and limiting the overall technical potential for most of the BE-CCS routes, especially for the co-firing routes. In these routes, more CO_2 storage capacity is needed per EJ of final energy produced with biomass. These results show that globally there is assumed to be enough storage potential in hydrocarbon reservoirs for the CO_2 derived from BE-CCS technologies. However, there is a geographic mismatch between the supply of biomass and the storage capacity in hydrocarbon reservoirs in the defined regions.

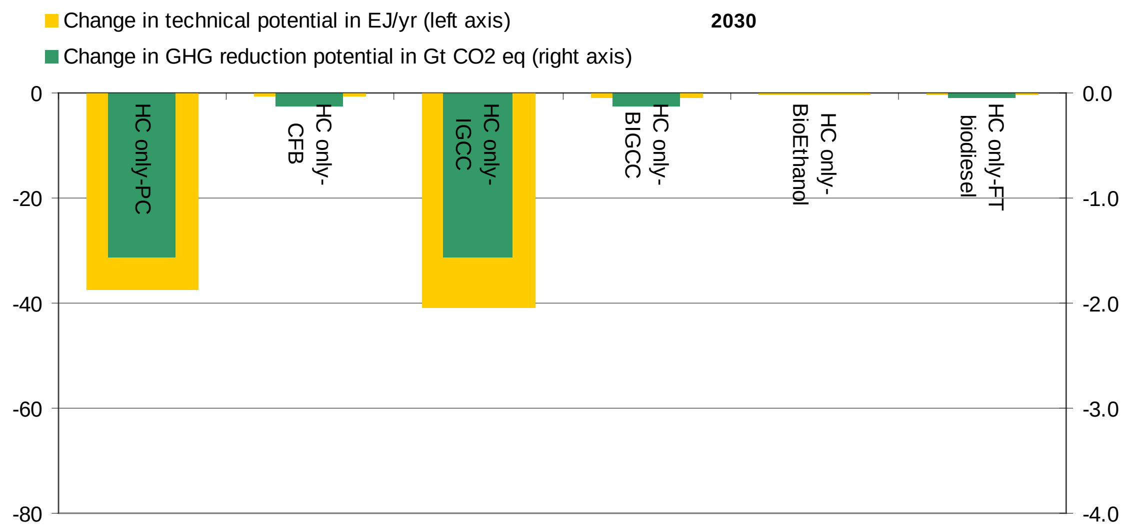


Figure 8 - 13 Impact of CO_2 storage potential (hydrocarbon reservoirs only and no inter-regional transport) on the amount of GHG emissions maximally reduced and technical potential in 2030. Left axis shows the absolute change in EJ/yr for the technical potential. Right axis shows the absolute change in Gt CO_2 eq.

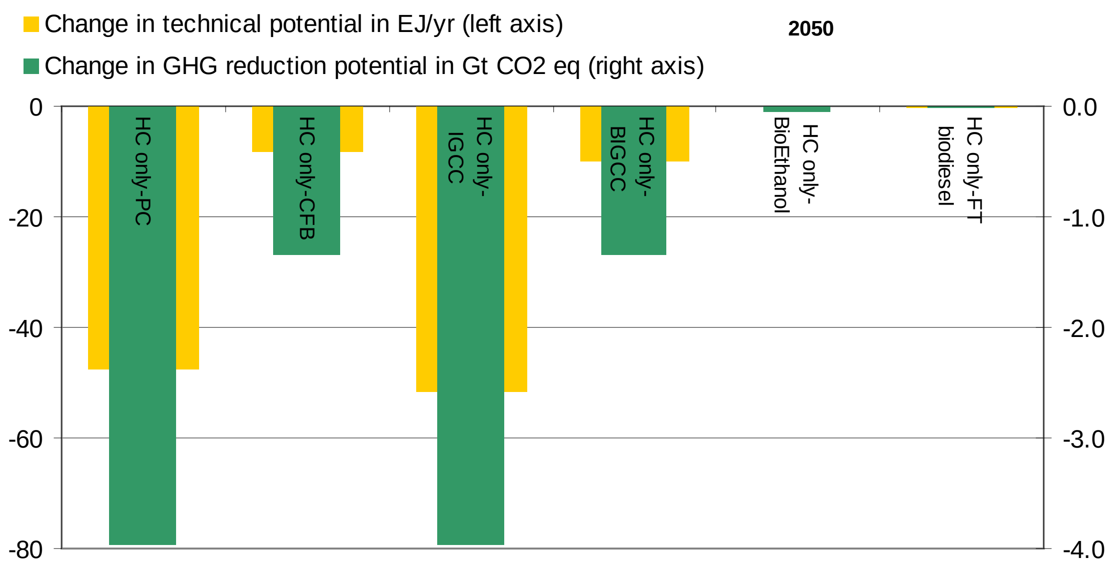


Figure 8 - 14 Impact of CO_2 storage potential (hydrocarbon reservoirs only and no inter-regional transport) on the amount of GHG emissions maximally reduced and technical potential in 2050. Left axis shows the absolute change in EJ/yr for the technical potential. Right axis shows the absolute change in Gt CO_2 eq.

9 Discussion

In this chapter, we summarise the results of the study and compare our results with those from other studies. We also discuss the impact of different assumptions on our results and highlight knowledge gaps and uncertainties that influence the outcomes.

9.1 Comparison of results with other studies

The most important results of our study are summarised in the table below. This table shows the different potentials calculated for the selected BE-CCS routes. In chapter 8 we conclude that the outcomes of our study depend strongly on assumptions on (sustainable) biomass potential available for bioenergy supply, CO_2 storage capacity, the CO_2 price, biomass price, and discount rate. It is therefore imperative to study the impacts of these assumptions on the results of our study, as we did in the previous chapter, and to compare the results with earlier (scenario) studies on the implementation of BE-CCS technologies. This comparison with earlier studies is described below.

Table 9 - 1 Overview of technical, economic and realisable potential per conversion routes under default assumptions

Technology route	Year	Technical potential[1]				Realisable potential			Economic potential	
		Final energy EJ/yr	Final energy EJ/yr	CO_2 stored Gt/yr	GHG balance Gt/yr	Final energy EJ/yr	Final energy EJ/yr	GHG balance Gt/yr	Final energy EJ/yr	GHG balance Gt/yr
Route		Bio share	Total	Total	Total	Coal share	Bio share	Total	Total	Total
PC-CCS co-firing	2030	27	90	19.0	-4.3	34	15	-2.3	0	0.0
	2050	54	108	20.9	-9.9	43	20	-3.2	7	-0.6
CFB-CCS dedicated	2030	24	24	5.9	-5.7	n/a	3	-0.7	1	-0.3
	2050	47	47	10.7	-10.4	n/a	6	-1.3	3	-0.6
IGCC-CCS co-firing	2030	30	99	19.0	-4.3	17	7	-1.1	33	-1.4
	2050	59	118	20.9	-9.9	26	12	-1.8	39	-3.3
BIGCC-CCS dedicated	2030	28	28	5.9	-5.7	n/a	2	-0.3	10	-1.9
	2050	57	57	10.7	-10.4	n/a	4	-0.8	19	-3.5
BioEthanol	2030	19	19	0.7	-0.5	n/a	2	0.0	1.2	0.0
	2050	40	40	1.4	-1.1	n/a	8	-0.2	13.4	-0.4
FT biodiesel	2030	28	28	3.6	-3.3	n/a	2	-0.2	15.0	-1.8
	2050	47	47	6.1	-5.8	n/a	8	-1.0	25.5	-3.1

[1]The sustainable supply of biomass feedstock is equal for all selected routes: 73 and 126 EJ/yr, in 2030 and 2050, respectively.

In a recent study by Luckow et al. (2010), production and utilisation of global biomass in, amongst others, the transportation and electricity sector amounted to 120-160 EJ/yr (primary) in the year 2050. In that study, both a 400 ppm and a 450 ppm target scenario was assessed. The upper value for global biomass production was found in the 400 ppm scenario. In the strict 400 ppm scenario, the dominant share of biomass is used for the production of electricity with CCS (75 EJ/yr) and without CCS (30 EJ/yr). In the 400 ppm scenario, approximately 14% of electricity supply is met by BE-CCS technologies. In that same scenario, 9% (15 EJ/yr) of the biomass potential is used for the production of refined liquids with BE-CCS technologies. In the 450 ppm scenario, the results indicate that the global biomass usage is lower in 2050 and that the share of biomass-fired conversion technologies equipped with CCS is significantly lower.

Table 9 - 2 Estimated annual economic potential in 2050 in $EJ_{primary}$ for BE-CCS technologies as reported in (Luckow, Dooley et al. 2010) (note that all numbers are read from a graph and may not be accurate)

Scenario reduction target	**400 ppm**		**450 ppm**	
	EJ/yr	**share**	**EJ/yr**	**share**
BE-CCS electricity	75	45%	20	15%
Electricity without CCS	30	18%	40	31%
BE-CCS fuels	15	9%	10	8%
Fuel without CCS	15	9%	20	15%
Other	30	18%	40	31%
Total	**165**	**100%**	**130**	**100%**

The results of Luckow et al. (2010) ranging between 20 and 75 EJ/yr are best to be compared to the economic potential estimated in our study, which ranges between 3 and 19 EJ/yr (final energy - biomass share only). This represents more than 40 EJ/yr of primary biomass. Our highest estimate is thus within the range of the results presented by Luckow et al.

Azar et al. (Azar, Lindgren et al. 2006) report the results of a scenario study in which stabilisation is achieved at 350 and 450 ppm. In their study, they have assumed a technical biomass potential of 200 EJ/yr (± 100EJ/yr), of which 100 EJ/yr is from residues. The roughly determined technical carbon capture potential is set at 18 (±9) Gt CO_2 and 100% capture efficiency is assumed. The results of their analysis show that in the 350 ppm scenario, biomass and CCS plays a small role in the energy supply mix in 2050, i.e. ~20 $EJ_{primary}$/yr. The share of BE-CCS increases from 2050 to 2100 to about 160 $EJ_{primary}$/yr. In the 450 ppm scenario, BE-CCS reaches ~70 $EJ_{primary}$/yr in 2100. The share in 2050 is about half of the maximum economic potential we estimate for the BIGCC and IGCC routes of over 40 $EJ_{primary}$/yr.

The share of biofuels is large in both scenarios, with a maximum of 160 $EJ_{primary}$/ yr by about 2050 in the 350 ppm scenario and 190 $EJ_{primary}$/yr from 2070 onwards in the 450 ppm scenario. In our study, we estimate the maximum economic potential for the advanced biofuel routes (FT-biodiesel and advanced ethanol production) to be between 13 and 26 EJ_{final}/ yr (67 $EJ_{primary}$/yr). The realisable potential was estimated at around 8 EJ_{final} /yr, which roughly equates to a potential of 20 $EJ_{primary}$/ yr. The results for both potentials are rather low in comparison with the results of Azar et al. This difference is due to the fact that we chose the IEA WEO Reference scenario with a relatively modest growth in biofuels, compared to the reduction scenarios chosen by Azar et al. stabilising at 350 and 450 ppm. Our biomass potential is also considerably lower than the 200 EJ/yr in their base case.

CCS, in combination with coal fired capacity, has a relative large share in both scenarios modelled by Azar et al., particularly in the 450 scenario, with a maximum of ~240 $EJ_{primary}$/yr. This figure is likely to be the result of the assumption that biomass is twice the cost of coal, i.e. 2 USD_{2000}/GJ (1.9 €) vs. 1 USD_{2000} /GJ (0.9 €). Capital costs are also estimated to be 13% higher (1700 vs. 1500 $\$_{2000}$/kW) for BE-CCS versus coal with CCS. Even under these assumptions, the allowance and availability of BE-CCS results in (marginally) lower overall cost to reach greenhouse gas stabilisation targets. This benefit is only significant for particularly stringent targets. This finding is supported by the results from our study. The economic potential of BE-CCS technologies does indeed depend very strongly on the price of CO_2 allowances. Very stringent climate policies may result in CO_2 prices above the 50 euro per tonne which leads, according to our results, to a considerable economic potential for BE-CCS technologies.

In an IEA study (IEA/OECD 2008), two GHG reduction scenarios are studied; the ACT and BLUE Map scenarios. In the ACT Map scenario the emissions are reduced to 2005 levels in 2050, which results in an incentive of 50$ per tonne of CO_2. In the BLUE Map scenario the emissions are reduced by 50% in 2050 compared to 2005 levels. The CO_2 price in the BLUE Map is significantly higher at 200$ per tonne of CO_2. In the BLUE Map biomass power plants are retrofitted with CCS which leads to a production of 1.4 EJ_{final}/yr with BE-CCS. The total power production in 2050 with CCS, based on coal and biomass, amounts to 22.7 EJ_{final}/yr, which is rather low compared to the economic potential of 39 EJ_{final}/yr (50%biomass, 50% coal) with a CO_2 price of 50 euro per tonne.

In the IEA Technology Roadmap for CCS (IEA 2009), it is estimated that biomass power with CCS has a relatively small share in the total global deployment of CCS technologies. In 2020, BE-CCS technologies are expected to play no significant role. In 2050, biomass fired generation in the power sector will increase to 52 GW, which equates to 4.6% of the total 1140 GW installed power generation with CCS. Of the 10 Gt captured in 2050 in various sectors, about 0.6 Gt is captured from biomass fired power generation. This number is rather low compared to our estimates for the maximum economic potential which equates to 3.6 Gt of CO_2 stored.

From this comparison we can conclude that our results are within range of other studies on the potential of BE-CCS technologies. However, the results for the maximum economic potential in this study are, in general, more optimistic compared to those in the studies reviewed above.

9.2 Main differences between estimated potentials

Table 9 - 1 shows an overview of the main results of this study. When comparing results for the technical, realisable and economic potential, clearly some important differences can be noted.

First, it should be noted that the approach for estimating the realisable potential is different compared to the approach used to determine the technical (and economic) potential. The technical and economic potential are estimated in a static way looking at the view years 2030 and 2050 and do not depend on capital stock turnover, energy demand and deployment rate. The realisable potential does take these (limiting) factors into account in a simplified scenario based approach using the IEA World Energy Outlook Reference scenario.

The technical potential thus represents the upper limit of what can technically be achieved in a certain year when using all biomass in one BE-CCS route at a time and is therefore substantially larger than the realisable and economic potential.

The realisable potential for the routes in our study represents between 5 and 58% of the technical potential. The upper limit is found for the PC co-firing route and the lower limit for the BIGCC route. The technical potential is thus not likely to be fully harvested due to limitations induced by the current energy supply mix, expected future energy demand and capital stock turnover.

The economic potential represents between 0 and 54% of the technical potential. The upper limit is found for the FT biodiesel route and the lower limits for the combustion based routes (dedicated and co-firing).

For some routes, the estimated realisable potential is lower than the economic potential. This difference can be explained by the fact that we estimate the technical and economic potential in a static way for the view years where we assess the realisable potential in a dynamic way taking into account deployment pathways. This means that we calculate the economic potential as if all capacity could be immediately be installed and used in that view year not considering the already operating and less technically advanced energy infrastructure.

In short, the realisable potential provides us with an estimate of the share of the technical potential that can be deployed given the current energy infrastructure and the economic potential indicates how much energy and negative emissions can possibly be achieved with favourable economics.

9.3 Limitations when estimating potentials

Technical potential

The main limitations, when estimating the technical potential for the selected BE-CCS technology routes in this study, are caused by the uncertainty in estimates for the global sustainable biomass potential and CO_2 storage potential.

For the biomass potential, this uncertainty is primarily caused by differences in assumptions in underlying studies on the land use scenarios, yield development, food consumption and constraints set by sustainability criteria for the supply of biomass available for energy. The latter includes issues such as water scarcity, land degradation, loss in biodiversity and (in)direct land use change (see Box 1 in section 4.3.1 for a more detailed discussion on direct and indirect land use change). Variations in land use scenarios and yield estimates result in an estimate range between 120-300 EJ/yr. Van Vuuren et al. (van Vuuren, Vliet et al. 2009) estimate the potential to be approximately 150 EJ/yr without constraints on land degradation, water scarcity and nature reserve expansion. When applying these constraints, the potential decreases to about 65-115 EJ/yr. Luckow et al (2010) cite other studies, estimating the global biomass potential to range between 100 and 400 EJ/yr. In a recent study ordered by EREC and Greenpeace (EREC and Greenpeace 2010), biomass potentials were also reviewed and assessed. Based on that review, they developed several scenarios varying food consumption, crop yields, agricultural activities and land use. Depending on the scenario this resulted in a global biomass potential estimate between 66 and 110 EJ/yr in 2020 and 94-184 EJ/yr in 2050. The overall technical potential[21] is estimated to be 102 EJ/yr in 2020, 129 EJ/yr in 2030 and 184 EJ/yr in 2050. In Figure 9 - 1, an overview of estimates for sustainable biomass potentials in 2050 is presented. The figure shows estimates of sustainable biomass potentials up to almost 500 EJ/yr.

In our study we assume a technical sustainable biomass potential of 73 EJ/yr in 2030 and 126 EJ/yr in 2050. Half of this potential is assumed to be energy crops and the remaining proportion consists of residues from agriculture and forestry. Our assumptions are supported by estimates from other studies. Referring to these studies, the estimates for biomass potentials we used can be considered slightly conservative.

For storage potential, the uncertainty arises from the difficulty of accurately estimating storage capacities. For example, the availability of detailed geological surveys of aquifers is low and not equally defined for all regions. Storage potentials are therefore uncertain, particularly for aquifers. Also, the studies that have been gathered and used to estimate the global storage potential do not use consistent methodologies to

[21] The technical potential is defined as the third order potential after 'Theoretical' and 'Conversion potential'. The **Technical potential** takes into account additional restrictions regarding the area that is realistically available for energy generation. Technological, structural and ecological restrictions, as well as legislative requirements, are accounted for.

estimate the amount of CO_2 that can be stored. It is beyond the scope of this study to perform a detailed consistency analysis on the used storage estimates. Due to the unavailability of detailed storage capacity estimates, the technical potential may be minimally higher or lower than the 'best' estimate used in our study by a factor of 2.

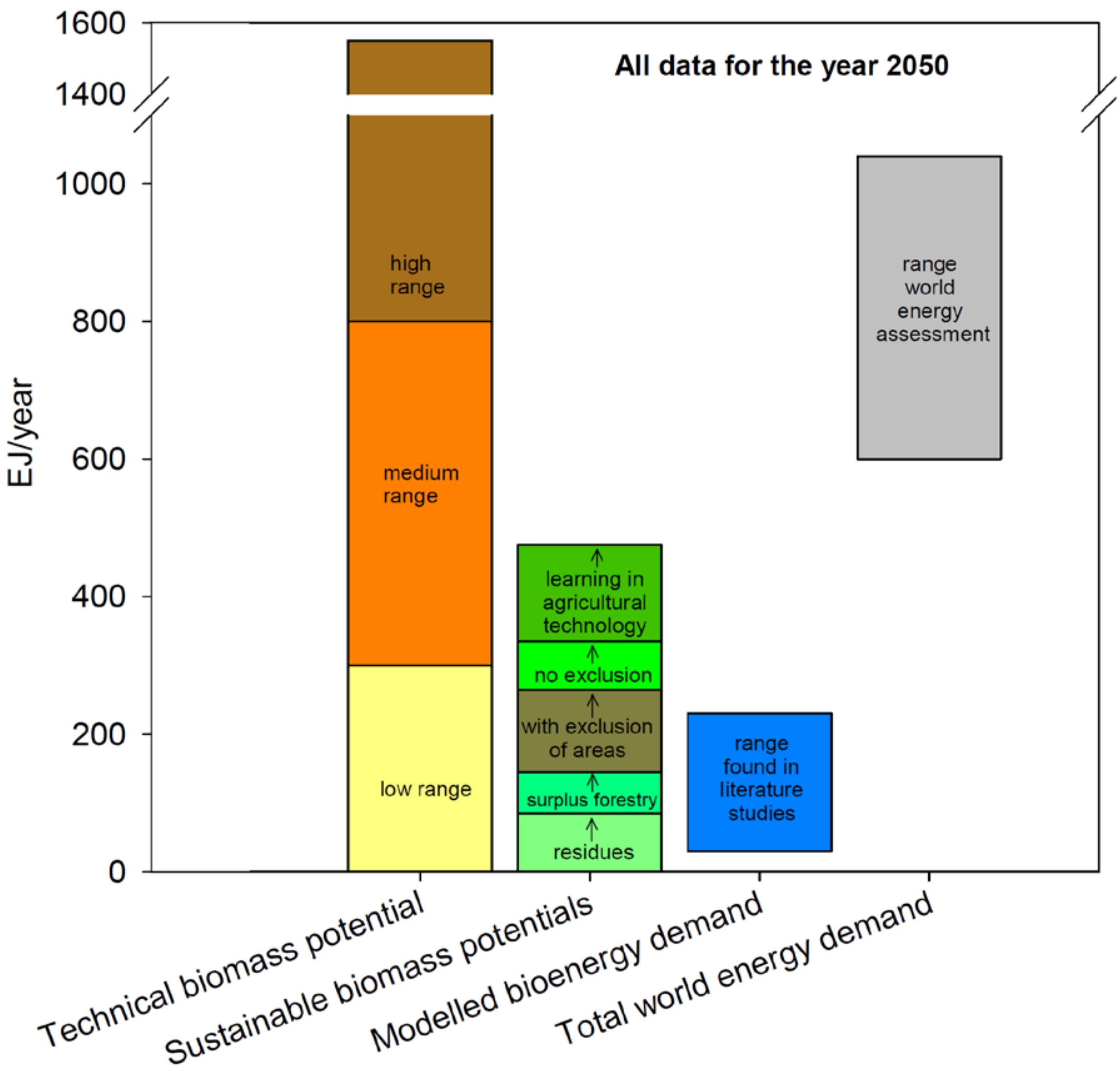


Figure 9 - 1 Comparison of ranges of technical (sustainable) biomass supply potentials in several review studies by Dornburg et al. as cited in (EC 2009). The expected demand for biomass is also shown based on global energy models and the expected total world energy demand, all for 2050.

The net greenhouse gas emissions from BE-CCS technology routes are sensitive to assumptions on the emission factor of biomass. This determines how much emissions can be captured and stored per unit of energy (primary and final energy). We have set this emission factor at 100 g CO_2/MJ (LHV). Lowering the emission factor would result in lower mitigation potential and therefore less negative emissions, and conversely when assuming a higher emission factor. In addition, we have estimated the greenhouse gas emissions in the biomass supply chain. These emissions do not however, include greenhouse gas emissions due to land use change (direct or indirect). There is extensive debate on how to include land use change in the greenhouse gas performance of bio-energy routes and which emission factor should be assumed. It is likely that the GHG performance of the full BE-CCS chain would be lower (i.e. less negative emissions) when including a GHG factor to account for land use change, but the opposite effect can also not be excluded as a possibility.

Realisable potential

The models that have been developed to asses the realisable potential of BE-CCS technology routes for electricity and biofuel are relatively simple. As previously mentioned in section 5.2, the models do not determine the techno-economic optimum energy supply mix for the view years. They are based on the IEA WEO Reference Scenario (2009). This scenario sketches the evolution of both the power and transport sector until 2030, under conservative climate policy assumptions.
"The Reference Scenario is most definitely not a forecast of what will happen but a baseline picture of how global energy markets would evolve if governments make no changes to their existing policies and measures." (IEA 2009, p. 73)

The result of this scenario is that fossil fuels (specifically coal) and conventional energy conversion technologies continue to be dominant in global energy supply. The models based on that scenario merely provide insight into how far BE-CCS may be implemented when BE-CCS technologies replace a share of energy conversion technologies in the Reference scenario. We use assumptions on the increase in energy demand and existing capacity that is replaced over time to estimate new capacity additions. Other assumptions set the date at which CCS is to be implemented for the various conversion technologies. For the electricity routes, BE-CCS is applied in electricity production with 'Coal' and with 'Biomass and Waste'. The biofuel routes with CCS are assumed to only replace biofuel production without CCS. This is rather conservative as under stricter climate regimes, the potential for BE-CCS technologies may be higher (see (Luckow, Dooley et al. 2010)). Furthermore, BE-CCS may not only compete and replace the energy conversion technologies mentioned above, but may also compete with renewable energy technologies. A larger share of electricity supply may therefore be fulfilled with BE-CCS technologies.

Economic potential

The determination of the economic potential depends on various assumptions. The most significant are future conversion cost of BE-CCS routes and their alternatives, CO_2 capture, transport and storage cost, biomass and fuel price and the CO_2 price. All of these factors are highly uncertain and estimates for each may be over 30% inaccurate. See Davison et al. (Davison and Thambimuthu 2009) for a more thorough discussion on trends in investment cost and the uncertainty of future fuel prices. We have demonstrated in our sensitivity study, the effect that variations in these factors have on our results.

The analysis showed that the production cost of the BE-CCS technologies strongly depends on the CO_2 price, biomass price, discount rate and the primary biomass potential. Coal price and cost of CO_2 transport and storage has a lesser influence on the results. Regarding the cost assumptions for CO_2 transport and storage, it should be noted that we did not take source-sink matching into consideration. In practice, matching the temporal and geographical availability of sources and sinks may become a bottleneck. Additional cost for transport and/or storage will be incurred when detailed source-sink matching is applied. In a recent IEAGHG report (IEA GHG 2009), it was reported that the cost of transport and storage in depleted gas fields may vary significantly between regions. A regional specific cost curve for CO_2 transport and storage is not applied in our study, for reasons previously discussed in section 6.3.4. Instead, we used a range of values for the cost of CO_2 transport and storage covering the range of cost estimates reported in literature and assessed the impacts of lower or higher costs on the final result. This was deemed to be appropriate, considering the scope and level of detail of this study. It is however, recommended that if the BE-CCS potential is to be estimated on a more detailed level and on a regional basis, that regional specific supply curves are used.

Another limitation of our study is that we did not take into consideration, the relationship between the scale of the CO_2 source (in Mt CO_2/yr) and the cost for transport and storage. Overall, specific transport and storage costs are higher for small point sources, i.e. the ethanol production route and to a lesser extent the FT-biodiesel route. We have assumed, in this study, that transport and storage costs for all BE-CCS routes are equal. We do however acknowledge that the capture cost for these routes is low compared to others. In that respect, they can be seen as early opportunities for BE-CCS. For these routes, with smaller but more pure CO_2 sources, it is recommended that further research is performed into which infrastructural conditions (i.e. network tie-in, sink priority for small sources) would result in an economically attractive business case. We also recommend a detailed assessment on a size of the ethanol conversion plant that will allow economical CO_2 capture, transport and storage.

In conclusion, detailed assessments of future production cost and economic potential are not possible considering the current data limitations. Despite these uncertainties and their impact on the results, we believe that the relative difference between the technology routes is appropriately assessed showing the trends and differences in outcomes. A first-order assessment of the global, technical, realisable and economic potential for BE-CCS technologies is provided, in addition to an overview of factors that will influence this potential.

10 Conclusions & recommendations

The aim of this study is to provide an understanding and assessment of the global potential for BE-CCS technologies up to 2050. We make a distinction between: *Technical potential* (the potential that is technically feasible and not restricted by economical limitations); *Realisable potential* (the potential that is technically feasible and takes into consideration the demand for energy and scenarios for capital stock turnover) and the *Economic potential,* (the potential at competitive cost compared to alternatives).

We distinguish six conversion routes to produce energy from sustainable biomass combined with capture, transport and storage of CO_2: BIGCC-CCS dedicated; bio-ethanol-advanced generation; CFB-CCS dedicated; FT-biodiesel; IGCC-CCS co-firing; and PC-CCS- co-firing. We also distinguish three categories of biomass: energy crops; forestry residues and agricultural residues. Each type of the biomass can be used in any of the energy production routes.

Below, we discuss the main conclusions of this study, highlight key uncertainties and present recommendations to solve possible obstacles and enhance drivers to stimulate the deployment of BE-CCS technologies.

Technical potential

*The global **technical** potential for BE-CCS technologies is large and, if deployed, can result in negative greenhouse gas emissions up to 10 Gt CO_2 eq. annually.*

- The amount of sustainable biomass that can be harvested and supplied greatly determines the potential for BE-CCS technologies.
- For almost all regions, there is likely to be enough storage capacity to store the captured CO_2. Only where depleted hydrocarbon fields are used in isolation, storage capacity may become a limiting factor. Inter-regional transport can contribute to match biomass availability with storage capacity.
- Up to 16 PWh (59 EJ) of bio-electricity, or 1.1 Gtoe (47 EJ) of biofuels can be produced when deploying the full potential.[22] The technical potential expressed in *final energy* is solely dependent on the available primary energy and the conversion efficiency of the various BE-CCS technologies. The conversion efficiency is the highest for the IGCC co-firing route and the lowest for the advanced generation of ethanol.
- The routes that require the lowest storage capacity are those that produce biofuels and those that use only biomass for power generation. Of the biofuel routes, a relatively small proportion (11%-54%) of CO_2 is captured and therefore,

[22] This equals about 90% or 25% of the global production of electricity and liquids fuels in 2007, respectively.

only a relative small storage capacity is required. Also, in the routes for power generation that are solely fed with biomass (no co-firing) less storage capacity is required when harvesting the full sustainable biomass potential.

- The amount of CO_2 *stored* by conversion routes ranges between 1 and 21 Gt/yr, and depends mainly on the coal share in the primary energy input, the primary energy potential and the CO_2 capture efficiency. *Negative* emissions up to 10 Gt are the greatest for the dedicated routes with CCS: BIGCC and CFB. The negative emissions for the biofuel routes with CCS are the lowest, ranging between 0.5 and 6 Gt, because a smaller fraction of the CO_2 is captured and stored. Co-firing coal has a negative effect on the net GHG balance.

Realisable potential

*The **realisable** potential for the medium and long-term is expected to be the greatest for the PC-CCS route, co-firing coal and biomass. This potential strongly depends on future energy demand, the lifetime of existing generation capacity and the implementation date of CCS.*

- The realisable potential for the BE-CCS routes that produce electricity, ranges from 2 to 15 EJ/yr (1-4 PWh) in 2030 and from 4 to 20 EJ/yr (1-6 PWh) in 2050. The PC-CCS route demonstrates the greatest potential because this route allows the retrofitting of existing coal fired capacity, with biomass co-firing and CCS.
- The realisable potential for 2020 is estimated to be relatively small for BE-CCS technologies and is limited to the deployment of early opportunities (e.g. capture at bio-ethanol and biodiesel routes).
- The realisable potential for the biofuel routes is equal at 2 EJ/yr in 2030 and 8 EJ/yr (191 Mtoe) in 2050, which is a small fraction of the technical potential and likely to be a conservative estimate.
- Extending the lifetime of existing capacity and delaying the implementation date of CCS will have a negative influence on the annual and cumulative potential for BE-CCS technologies and the amount of CO_2 emissions that can be avoided before 2050 will be reduced.

Economic potential

*The **economic** potential for BE-CCS technologies is up to 5 PWh (20 EJ) for bio-electricity routes or up to 610 Mtoe (26 EJ) for the biofuel routes. About one third of the technical potential can be considered economically attractive under our assumptions; yielding a potential of up to 3.5 Gt of negative greenhouse gas emissions.*

- For the medium to long-term, the route using the BIGCC with CCS has the lowest cost of electricity production when using low cost biomass. Considering the current maturity and scale of BIGCC technology however, significant technological development is required.

- The price for biomass at factory gate ranges, in this study, from less than 5 euro to over 50 euro per GJ. A higher cost of biomass resources increases the production cost for all routes, but most significantly for routes solely fed with biomass (CFB, BIGCCC, bio-ethanol and FT-biodiesel).
- The cost supply curves for the dedicated routes (CFB, BIGCCC, bio-ethanol and FT-biodiesel) are comparatively steeper than the supply curves of co-firing routes because the coal share suppresses the increase of production cost when biomass prices increase.
- The dedicated route using the CFB technology is the only route in 2030 where the conversion cost for power production is lower overall, when the plant is **not** equipped with CCS. In the other routes the production cost, assuming a CO_2 price of 50 euro per tonne, is considerably lower when CCS is implemented.
- The largest economic potential of about 20 EJ is in the gasification-based routes (IGCC and BIGCC) for the year 2050. The smallest economic potential is in the PC and CFB routes of about 1 EJ/yr for the year 2030.
- For the biofuel routes, the economic potential is calculated to be highest for the FT-biodiesel route, at 26 EJ/yr. This equates to approximately 3 Gt of negative greenhouse emissions per year.
- Estimates for the economic potential are highly sensitive to assumptions made for the CO_2 price and biomass price, particularly those of the PC and IGCC co-firing routes. The coal price significantly affects the production cost of the co-firing routes, but also the economic potential of all BE-CCS routes generating electricity.

Drivers and Barriers

Several technical, financial/economic and public & policy related drivers and obstacles for the deployment of BE-CCS technologies have been identified. One important driver is the CO_2 price. This price is influenced by climate policy and the development and availability of other mitigation options. Under the current EU ETS, storing CO_2 from biomass will not ‘create’ sellable allowances, i.e. there is no economic value attached to ‘negative emissions’. Current CO_2 prices are nevertheless highly unlikely to result in an economic potential for BE-CCS technologies and substantially higher CO_2 prices require a stricter climate policy.

The (lack of) maturity of the technology is identified as an obstacle. The combination of CCS and advanced biomass conversion technologies is not considered to be a mature technology. Financial and technical risk of the biomass-CCS combination can be high which could create higher financing costs. In addition, uncertainty in the (regular) supply of sustainable biomass and the availability and certainty of CO_2 storage capacity are also considered to be significant obstacles. The secure supply of low cost and sustainable biomass will be a key driver for BE-CCS technologies. Important factors that influence this are future land use scenarios and competition with other sectors using biomass.

Public perception is identified as a key factor in the success of BE-CCS. A negative perception of CCS and/or biomass will stall BE-CCS or may result in higher transport and storage costs. However, the combination of biomass conversion and CCS technologies may expect greater public support than the individual technologies.

Recommendations

Without an economic incentive for producing negative emissions, BE-CCS technologies will not have economic potential.

- The most important recommendation that follows from these conclusions is that stored CO_2 originating from biomass should get an economic value. The CO_2 price in combination with low cost biomass is the key driver for BE-CCS technologies.
- Recommendations for further research are aimed at assessing the BE-CCS potential per region on a higher level of detail through regional specific cost supply curves for CO_2 transport and storage including source sink matching. Together with a more detailed assessment of the biomass resources and regional supply constraints a more detailed cost supply curve could be derived for BE-CCS technologies.
- State-of-the-art sustainability criteria for biomass production should be applied when assessing the potential for BE-CCS technologies. The results show that the sustainable supply of biomass is in most regions the limiting factor for the technical potential. It is important to understand the implications of implementing sustainability criteria on the biomass supply potential. We recommend that additional research efforts should be employed to verify our results with a more detailed assessment of factors that limit the sustainable supply of biomass on a regional base and assess the possibilities (including policy actions) for increasing the sustainable supply.
- It is advised to also include assessing sustainable biomass supply options not explored in this study, such as aquatic biomass from algae and seaweed.
- Detailed and consistent storage capacity estimates for world regions are currently not available. Although this is not specifically an issue for BE-CCS technologies alone it is recommended that the large uncertainty associated with estimating global storage potentials is appropriately addressed in future BE-CCS studies and that future research efforts are aimed at decreasing this uncertainty.
- Although not expected to be a technical bottleneck, it is recommended to assess and test the effect of (co-)firing biomass on the performance of CO_2 capture options (pre- post- and oxyfuel combustion) in pilot/demonstration CCS plants.
- A BE-CCS option omitted, amongst others, in this study is the co-utilization of biomass and coal in existing and new Fischer Tropsch facilities that are operating or planned worldwide. Next to CO_2 capture from bio-ethanol production this could provide early opportunities for BE-CCS at relatively low cost. Mapping these opportunities and examining technological and cost aspects with more detail on a case-by-case basis could be a valuable next step.

- Short and long term price estimations are key when assessing the economic potential of biomass and CCS. Insights and quantification of the key factors that influence the trade volume and price of biomass would be a valuable next step for a more robust assessment of the economic potential of BE-CCS technologies.
- The final recommendation is to aim research at getting insight in the economic and infrastructural boundary conditions for the CO_2 capture from bio-ethanol production and get answers on the questions: what are the maximum economical transport distance and/or minimal required CO_2 capture capacity? Detailed case studies could provide insight into these boundary conditions. Although CCS in combination with bio-ethanol production is estimated to have a lower overall 'negative' emission potential, the option seems an economically attractive option for the short to medium term. Most likely short term opportunities exist in Brazil and the USA, which are the largest producers of bio-ethanol and have considerable storage potential.

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Appendix A General assumptions

In this section the most important assumptions are presented. To assess the impact of our assumptions we have determined ranges of uncertainties for dominant assumptions. The impact of these assumptions is discussed throughout the main report. The main assumptions and their range of uncertainty are presented in the table below.

Table A - 1 Overview of general assumptions used in this study (base case assumptions are highlighted)

Assumption	Unit	Low	Medium	High
Discount rate	%	6%	**10%**	15%
Coal price 2030 (at plant gate)	euro/GJ	2.6	**3.7**	4.9
Coal price 2050 (at plant gate)	euro/GJ	2.6	**3.7**	4.9
CO_2 price 2030	euro/tonne CO_2	20	**50**	100
CO_2 price 2050	euro/tonne CO_2	20	**50**	100
Oil price 2030	euro/barrel	113		
Oil price 2030	euro/GJ	14		
Oil price 2050	euro/barrel	147		
Oil price 2050	euro/GJ	18		
Biomass densification cost	euro/GJ	0.4	**0.9**	1.5
Biomass transport cost	euro/GJ	0.2	**0.4**	0.6
CO_2 transport costs	euro/tonne CO_2	1	**5**	30
CO_2 storage costs	euro/tonne CO_2	1	**5**	13
Annualised storage capacity factor	Years	30	**50**	70
Forestry residues potential	-	**Low**		High
Sustainability criteria biomass	-	**Strict criteria**	Mild criteria	No criteria
CO_2 Reservoirs type included	-	Hydrocarbon reservoirs only		**All**
Storage potential estimation	-	Low	**Best**	High

- All costs are given in euros (2010) unless otherwise stated.
- All efficiencies are based on lower heating value unless otherwise stated.

Table A - 2 SI prefixes

Prefix	Symbol	Quantity
Exa	E	1E+18
Peta	P	1E+15
Tera	T	1E+12
Giga	G	1E+09
Mega	M	1E+6
Kilo	k	1E+3

Appendix B Biomass potential

In this appendix, we give an overview of the biomass potentials as used in this study. We include energy crops, crop residues and forestry residues. The view year of the potentials is 2050.

B 1 Biomass potential – Energy crops

The potential of energy crops is taken from (vanVuuren, Vliet et al. 2009), who assessed the biomass potential under three sets of criteria:

4 **Strict:** New reserves, mildly water scarce areas and mildly degraded areas are excluded from the potential estimation
5 **Mild:** New reserves, water scarce areas and severe degraded areas are excluded from the potential estimation
6 **No criteria:** The full potential is assessed

In this study, we apply the **strict criteria** for the estimation of the potential of energy crops.

Table B - 1 Overview of energy crop potential in seven regions, using three sets of criteria. From: Van Vuuren (2009), the regions are remapped according to the regions used in this report. Energy potential is given in EJ/yr.

Regions	Strict criteria	Mild criteria	No criteria
Africa & Middle East	14.9	21.8	26.7
Asia	9.0	19.1	31.2
Oceania	6.0	8.9	10.1
Latin America	18.3	30.0	34.2
Non OECD Europe & Former Soviet Union	2.1	4.7	6.0
North America	11.6	23.7	33.0
OECD Europe	2.9	5.2	6.6
WORLD	**64.7**	**113.4**	**147.7**

B 2 Biomass potential – Agricultural residues

The potential of agricultural residues is taken from a literature assessment in (Hoogwijk et al. 2010). Agricultural residues only include residues from crops; animal waste (estimated around 11 EJ) is not included.

Table B - 2 Overview of agricultural residues (technical) potential in seven regions. From: UNFCCC (Hoogwijk et al., 2010), the regions are remapped according to the regions used in this report. Energy potential is given in EJ/yr.

Regions	Technical potential
Africa & Middle East	4.9
Asia	18.4
Oceania	0.6
Latin America	6.6
Non OECD Europe & Former Soviet Union	2.4
North America	7.4
OECD Europe	3.0
WORLD	42.0

B 3 Biomass potential – Forestry residues

The potential of forestry residues is taken from a literature assessment in (Hoogwijk et al. 2010). In the base case we use the conservative (low) estimation.

Table B - 3 Overview of agricultural residues (technical) potential in seven regions. From: UNFCCC (Hoogwijk et al., 2010), the regions are remapped according to the regions used in this report. Energy potential is given in EJ/yr.

Regions	Low	High
Africa & Middle East	0.6	1.5
Asia	2.7	4.3
Oceania	1.1	1.8
Latin America	1.6	3.8
Non OECD Europe & Former Soviet Union	3	5.4
North America	5.8	11.9
OECD Europe	3.8	6.7
WORLD	**18.8**	**35.1**

Appendix C CO$_2$ storage potential

The storage potential is taken from (Hendriks et al. 2004), which includes estimations of three categories: Low, Best and High. For Europe, estimations from (GeoCapacity 2009) are used. For North America figures are updated using data from (NETL/DOE 2008).

Table C - 4 Global CO2 storage potential for three types of resevoirs. Source: Hendriks et al. (2004) and GeoCapacity (2009). Data are given in Giga tonnes of CO2.

	Oil and gas			Unmineable coal seams			Aquifers		
	low	best	high	low	best	high	low	best	high
Africa & Middle East	209	522	1,430	-	8	46	216	588	1,736
Asia	36	91	234	-	179	967	53	370	1,614
Oceania	8	20	49	-	11	54	0	2	9
Latin America	29	89	331	-	2	12	33	121	479
Non OECD Europe & Former Soviet Union	310	310	310	25	25	25	379	379	379
North America	22	156	166	157	176	229	3,307	8,001	12,774
OECD Europe	19	19	19	1	1	1	82	82	82
WORLD	**633**	**1,205**	**2,539**	**183**	**402**	**1,333**	**4,071**	**9,542**	**17,074**

Appendix D Overview tables major results

Table D - 5 Energy - summary table of global technical, realisable and economic potential per BE-CCS route for the view years 2030 and 2050.

Technology route	Year	Technical potential			Realisable potential		Economic potential[1]	
		Primary energy EJ/yr	Final energy EJ/yr	Final energy EJ/yr	Final energy EJ/yr	Final energy EJ/yr	Final energy EJ/yr	Final energy EJ/yr
		Biomass share	Biomass share	Total	Biomass share	Total	Total Min	Total Max
PC-CCS co-firing	2030	73.1	27.0	90.0	14.7	49.0	0.0	0.0
	2050	125.6	54.2	108.5	19.7	62.9	6.6	6.6
CFB-CCS dedicated	2030	73.1	24.4	24.4	2.8	2.8	1.4	1.4
	2050	125.6	47.5	47.5	5.6	5.6	2.9	2.9
IGCC-CCS co-firing	2030	73.1	29.6	98.7	7.3	24.5	33.0	33.0
	2050	125.6	59.0	118.0	12.3	38.4	39.2	39.2
BIGCC-CCS dedicated	2030	73.1	28.4	28.4	1.5	1.5	9.5	9.5
	2050	125.6	56.8	56.8	4.3	4.3	18.9	18.9
BioEthanol	2030	73.1	19.4	19.4	1.8	1.8	0	1.2
	2050	125.6	40.5	40.5	7.8	7.8	0	13.4
FT biodiesel	2030	73.1	27.6	27.6	1.8	1.8	0	15.0
	2050	125.6	47.5	47.5	7.8	7.8	0	25.5

[1]Economic potential is the amount of EJ/yr that can be produced with lower cost compared to the reference technologies (for power generation routes) or energy carriers (for biofuel routes). The maximum economic potential is determined by comparing the production cost with the cost of the most expensive reference technology, and the minimum potential by comparing with the cheapest reference technology.

Table D - 6 Greenhouse gas performance - summary table of global technical, realisable and economic potential per BE-CCS route for the view years 2030 and 2050.

Technology route	Year	Technical potential		Realisable potential	Economic potential[2]	
		CO_2 stored[1] Gt CO_2 /yr	Net GHG Emissions Gt CO_2 eq./yr	Net GHG Emissions Gt CO_2 eq./yr	Net GHG Emissions Gt CO_2 eq./yr	Net GHG Emissions Gt CO_2 eq./yr
					Min	Max
PC-CCS co-firing	2030	19.0	-4.3	-2.3	0.0	0.0
	2050	20.9	-9.9	-3.2	-0.6	-0.6
CFB-CCS dedicated	2030	5.9	-5.7	-0.7	-0.3	-0.3
	2050	10.7	-10.4	-1.3	-0.6	-0.6
IGCC-CCS co-firing	2030	19.0	-4.3	-1.1	-1.4	-1.4
	2050	20.9	-9.9	-1.8	-3.3	-3.3
BIGCC-CCS dedicated	2030	5.9	-5.7	-0.3	-1.9	-1.9
	2050	10.7	-10.4	-0.8	-3.5	-3.5
BioEthanol	2030	0.7	-0.5	0.0	0.0	0.0
	2050	1.4	-1.1	-0.2	0.0	-0.4
FT biodiesel	2030	3.6	-3.3	-0.2	0.0	-1.8
	2050	6.1	-5.8	-1.0	0.0	-3.1

[1]CO_2 stored globally when exploiting the full global biomass potential.

[2]Economic potential is the amount of EJ/yr that can be produced with lower cost compared to the reference technologies (for power generation routes) or energy carriers (for biofuel routes). The maximum economic potential is determined by comparing the production cost with the cost of the most expensive reference technology, and the minimum potential by comparing with the cheapest reference technology.

Table D - 7 Regional breakdown technical potential in primary energy (biomass share in EJ/yr) for view years 2030 and 2050

Regions	Year	Technical potential					
		PC-CCS co-firing	CFB-CCS dedicated	IGCC-CCS co-firing	BIGCC-CCS dedicated	BioEthanol	FT biodiesel
AFME	2030	13	13	13	13	13	13
ASIA	2030	17	17	17	17	17	17
OCEA	2030	2	5	2	5	5	5
LAAM	2030	15	15	15	15	15	15
NOEU	2030	5	5	5	5	5	5
NOAM	2030	13	13	13	13	13	13
OEU	2030	6	6	6	6	6	6
WORLD	2030	73	73	73	73	73	73
WORLD2	2030	71	73	71	73	73	73
AFME	2050	23	23	23	23	23	23
ASIA	2050	30	30	30	30	30	30
OCEA	2050	4	8	4	8	8	8
LAAM	2050	24	27	24	27	27	27
NOEU	2050	7	7	7	7	7	7
NOAM	2050	21	21	21	21	21	21
OEU	2050	10	10	10	10	10	10
WORLD	2050	126	126	126	126	126	126
WORLD2	2050	119	126	119	126	126	126

NB: 'World2' represents the sum of the regional potentials which are limited by biomass or storage potential. It thus excludes transport of biomass or CO_2 between regions. 'World' estimate includes transport of biomass and CO_2 between regions.

Table D - 8 Regional breakdown technical potential in final energy (biomass share in EJ/yr) for view years 2030 and 2050

Regions	Year	Technical potential					
		PC-CCS co-firing	CFB-CCS dedicated	IGCC-CCS co-firing	BIGCC-CCS dedicated	BioEthanol	FT biodiesel
AFME	2030	5	4	5	5	3	5
ASIA	2030	6	6	7	7	5	7
OCEA	2030	1	2	1	2	1	2
LAAM	2030	6	5	6	6	4	6
NOEU	2030	2	2	2	2	1	2
NOAM	2030	5	4	5	5	3	5
OEU	2030	2	2	2	2	2	2
WORLD	2030	27	24	30	28	19	28
WORLD2	2030	26	24	29	28	19	28
AFME	2050	10	9	11	10	7	9
ASIA	2050	13	11	14	14	10	11
OCEA	2050	2	3	2	3	2	3
LAAM	2050	10	10	11	12	9	10
NOEU	2050	3	3	4	3	2	3
NOAM	2050	9	8	10	10	7	8
OEU	2050	4	4	5	4	3	4
WORLD	2050	54	47	59	57	40	47
WORLD2	2050	51	47	56	57	40	47

NB: 'World2' represents the sum of the regional potentials which are limited by biomass or storage potential. It thus excludes transport of biomass or CO_2 between regions. 'World' estimate includes transport of biomass and CO_2 between regions.

Table D - 9 Regional breakdown technical potential in negative GHG emissions (Gt CO_2 eq./yr) for view years 2030 and 2050

Regions	Year	Technical potential					
		PC-CCS co-firing	CFB-CCS dedicated	IGCC-CCS co-firing	BIGCC-CCS dedicated	BioEthanol	FT biodiesel
AFME	2030	-0,7	-1,0	-0,7	-1,0	-0,1	-0,6
ASIA	2030	-1,0	-1,3	-1,0	-1,3	-0,1	-0,8
OCEA	2030	-0,2	-0,4	-0,2	-0,4	0,0	-0,2
LAAM	2030	-1,0	-1,2	-1,0	-1,2	-0,1	-0,7
NOEU	2030	-0,3	-0,4	-0,3	-0,4	0,0	-0,2
NOAM	2030	-0,8	-1,0	-0,8	-1,0	-0,1	-0,6
OEU	2030	-0,3	-0,5	-0,3	-0,5	0,0	-0,3
WORLD	2030	-4,3	-5,7	-4,3	-5,7	-0,5	-3,3
WORLD2	2030	-4,3	-5,7	-4,3	-5,7	-0,5	-3,3
AFME	2050	-1,8	-1,9	-1,8	-1,9	-0,2	-1,0
ASIA	2050	-2,4	-2,5	-2,4	-2,5	-0,3	-1,4
OCEA	2050	-0,3	-0,7	-0,3	-0,7	-0,1	-0,3
LAAM	2050	-2,1	-2,2	-2,1	-2,2	-0,2	-1,2
NOEU	2050	-0,6	-0,6	-0,6	-0,6	-0,1	-0,3
NOAM	2050	-1,7	-1,8	-1,7	-1,8	-0,2	-1,0
OEU	2050	-0,7	-0,8	-0,7	-0,8	-0,1	-0,4
WORLD	2050	-9,9	-10,4	-9,9	-10,4	-1,1	-5,8
WORLD2	2050	-9,6	-10,4	-9,6	-10,4	-1,1	-5,8

NB: ‘World2’ represents the sum of the regional potentials which are limited by biomass or storage potential. It thus excludes transport of biomass or CO_2 between regions. ‘World’ estimate includes transport of biomass and CO_2 between regions.

Table D - 10 Regional breakdown technical potential in total CO_2 stored for view years 2030 and 2050

Regions	**Year**	**Technical potential**					
		PC-CCS co-firing	CFB-CCS dedicated	IGCC-CCS co-firing	BIGCC-CCS dedicated	BioEthanol	FT biodiesel
AFME	2030	3,3	1,0	3,3	1,0	0,1	0,6
ASIA	2030	4,5	1,4	4,5	1,4	0,2	0,8
OCEA	2030	0,7	0,4	0,7	0,4	0,0	0,2
LAAM	2030	4,2	1,2	4,2	1,2	0,1	0,7
NOEU	2030	1,2	0,4	1,2	0,4	0,0	0,2
NOAM	2030	3,3	1,0	3,3	1,0	0,1	0,6
OEU	2030	1,5	0,5	1,5	0,5	0,1	0,3
WORLD	2030	19,0	5,9	19,0	5,9	0,7	3,6
WORLD2	2030	18,7	5,9	18,7	5,9	0,7	3,5
AFME	2050	3,8	1,9	3,8	1,9	0,3	1,1
ASIA	2050	5,0	2,6	5,0	2,6	0,3	1,5
OCEA	2050	0,7	0,7	0,7	0,7	0,1	0,4
LAAM	2050	4,2	2,3	4,2	2,3	0,3	1,3
NOEU	2050	1,2	0,6	1,2	0,6	0,1	0,4
NOAM	2050	3,5	1,8	3,5	1,8	0,2	1,0
OEU	2050	1,6	0,8	1,6	0,8	0,1	0,5
WORLD	2050	20,9	10,7	20,9	10,7	1,4	6,1
WORLD2	2050	20,1	10,7	20,1	10,7	1,4	6,1

NB: 'World2' represents the sum of the regional potentials which are limited by biomass or storage potential. It thus excludes transport of biomass or CO_2 between regions. 'World' estimate includes transport of biomass and CO_2 between regions.

Appendix E Factsheet Biomass (co-)firing for power generation

Technology: Biomass (co-)firing in coal fired power plants or dedicated bioenergy plants with CO_2 capture

Output: Electricity

Feedstock:

Coal

Woody biomass: including wood chips, wood pellets, sawdust, bark from forestry operations and processing.

Agricultural residues: straw, sugar bagasse, palm kernel shells

Energy crops: including short rotation coppice or forestry (willow, poplar, eucalyptus), miscanthus, switchgrass.

Waste related streams: including RDF, municipal waste, and demolition wood.

E 1 Process and Technology Status with and without carbon capture

Biomass combustion is currently the most used conversion route to turn biomass into power and heat. In this factsheet, two main options are considered to generate power from biomass combustion: co-firing in fossil fired power plants and dedicated firing.

Co-Firing

Typically, there are two possibilities to co-fire biomass, directly of indirectly. The latter includes gasification[23] or combustion of biomass in a separate boiler[24] and is considered to be in the demonstration or early commercial phase (see Figure E - 1). Direct co-firing[25] of biomass in boiler where also the coal is converted is a commercial technology. There are several technical options to co-fire biomass directly in coal fired boilers:

1. The milling of biomass pellets (see section 4.3.2) through modified coal mills;
2. the pre-mixing of the biomass with coal, and subsequent milling of and firing of the coal-biomass mix in the existing coal firing system;
3. The direct injection of pre-milled biomass into the pulverized coal pipework;
4. The direct injection of pre-milled biomass into modified coal burners;

[23] In the case of gasification, the product gas is co-fired in coal boiler to generate steam.
[24] In this case the steam generated in the biomass boiler is used in the coal power plant's steam cycle to generate power.
[25] Direct co-firing routes may differ in whether pre-treatment facilities and for instance burners are used for both the coal and biomass.

5. The direct injection of pre-milled biomass through dedicated biomass burners or directly into the furnace.

The choice for one of the options above depends strongly on the properties of the biomass (heating value, particle size, combustion properties such as reactivity and grindability of the biomass) and the design of the PC power plant (e.g. fuel feeding system and burners).

Biomass co-firing in modern, large scale coal fired power plants is widely applied and is the single largest and fast growing conversion route for biomass in many EU countries. It is energy efficient, cost-effective[26] and requires moderate additional investment for pre-treatment and feed-in systems when using high quality fuels such as pellets. The conversion efficiency (35%-45%) in large-scale coal plants is generally higher in comparison with dedicated firing. The size of the fossil power plant (up to a GWe) results in economies of scale and high conversion efficiency for biomass compared to dedicated bioenergy plants (Faaij 2006; IEA/OECD 2007). However, co-firing biomass negatively affects the conversion efficiency of coal fired power plant due to the lower heating value of biomass, high moisture content and energy requirement of feedstock pre-treatment. With low co-firing percentages this efficiency drop is considered to be modest (NETBIOCOF 2006; COFITECK 2008). IEA ETSAP (IEA ETSAP 2010) reports conversion efficiencies for biomass co-firing between 36% and 44% and for coal firing alone 39-46 %.

The share of biomass in the power plant typically determines the additional investments required. With shares up to 20% (on a energy basis) limited consequences on the performance of the boiler, flue gas treatment and maintenance can be expected (IEA ETSAP 2010). Shares of 40 to 50 % (on an energy basis), which is the subject of current development efforts, requires technical modifications in boiler design (burner configuration), biomass feeding lines (pre-treatment) and may result into more fouling, slagging and corrosion problems. This depends strongly on the ash melting behaviour and alkali and halogen compounds in the biomass. The composition of ashes is another possible concern as biomass firing changes ash composition, which may hinder the economic use of this by-product. This depends however strongly on the type of feedstock used. In short, biomass properties[27] limit the co-firing share. However pre-treatment options such as pelletization and torrefaction improve the biomass characteristics and are thus good options to enhance the co-firing share.

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[26] Cost-effectiveness obviously depends on several factors such as the biomass price, subsidies, taxes, feed-in tariffs which varies per region.

[27] Important properties are: moisture content, particle size, structure, ash content, alkali metals content, halogen content and the heterogeneity of the biomass feedstock.

Typical large scale combustion technologies available for biomass co-firing are pulverized coal power plant and fluidised bed combustion. The circulating fluidised bed (CFB) is available on the scale of several hundreds of MWe and can typically achieve high conversion efficiencies with high co-firing shares. Pulverized coal units are available in the GWe size range. The IEA GHG (IEA GHG 2009) report a net efficiency of 45.1 % (LHV) for a supercritical 500MWe CFB co-fired plant (10% biomass/90% coal). This is somewhat higher than the pulverized coal power plant assessed in that study with the same fuel mix that shows an efficiency of 44.8 %.

The technical challenges for the future is to co-fire large shares of biomass in ultra-supercritical power plants with generating efficiencies of 50% and higher. In (IEA GHG 2009), it is however indicated that demonstration is necessary to achieve the confidence of co-firing biomass in such plants and to overcome the technology gap with regard to slagging and fouling in these plants.

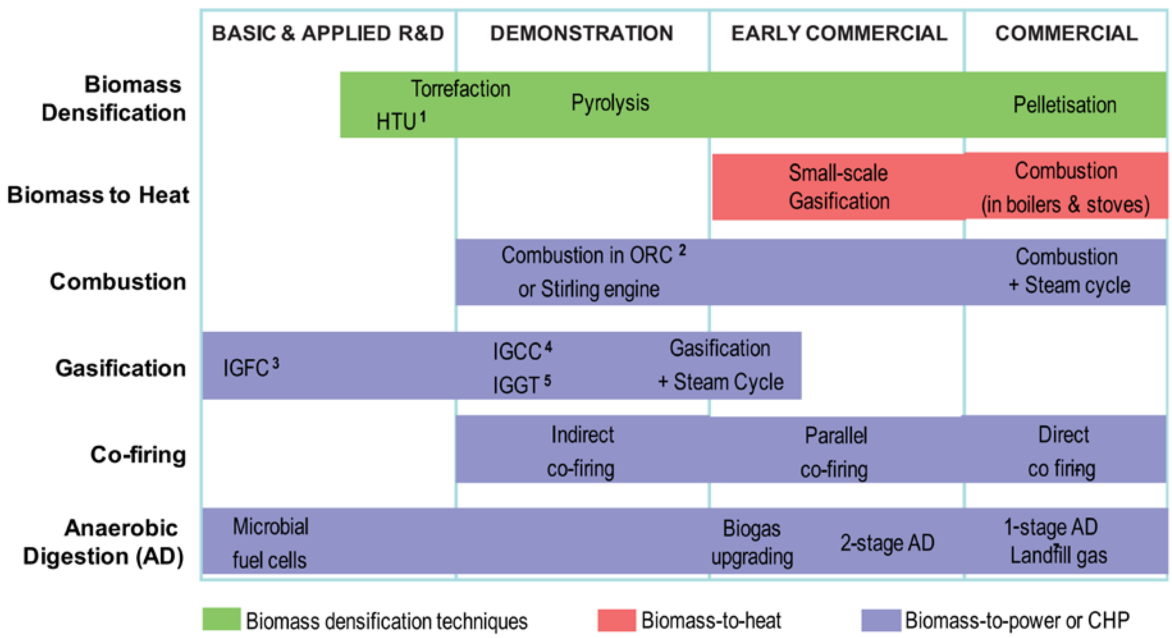

Figure E - 1 Development status of main biomass upgrade (densification) and conversion technologies (from: (Bauen, Berndes et al. 2009)) (1 = Hydrothermal upgrading, 2= Organic Rankine Cycle, 3 = Integrated gasification with fuel cell, 4 and 5 = Integrated Gasification with combined cycle/gas turbine)

Dedicated firing

Dedicated biomass-fired power plants typically perform in the size range between a few MWe and 350 MWe (IEA ETSAP 2010). Size is generally limited by the availability of biomass and high feedstock transportation cost (IEA/OECD 2007). Dedicated power plants have in general lower efficiencies compared to biomass combustion in large co-firing power plants. Energy conversion efficiencies for smaller plants are in the range between 16% and 30% for plants of about 50 MWe; however, efficiencies in the range of 30 to 36% are possible. Efficiencies for smaller plants are typically lower (Faaij 2006; IEA GHG 2009; IEA ETSAP 2010). Using municipal solid waste (MSW) as feedstock generally limits[28] steam temperature and with it efficiency to about 22%. Newer installations can reach higher efficiencies of approximately 30%, however.

To achieve commercial viability when producing electricity, economies of scale and low feedstock costs are essential. Typical feedstock that may be used are agricultural residues (e.g. bagasse), waste or wood residues and black liquor from the pulp and paper industry (Faaij 2006; IEA GHG 2009; IEA ETSAP 2010).

Technologies currently used for dedicated biomass firing are: fluidised bed combustion (BFB[29] and CFB), pile burning, various types of grate firing (stationary, moving, vibrating) and suspension firing (Faaij 2006; IEA GHG 2009). These technologies show different characteristics in terms of feedstock pre-treatment requirement and fuel flexibility (particle size, moisture content, alkali content), investment and operating cost, typical size range and conversion efficiency. In this fact sheet the fluidised bed technology is the basis as this technology is available in relative large size range up to about 100 MWe for BFB and up to 350 MWe for CFB and as it shows relatively high conversion efficiencies up to 36% (BFB) and 42% (IEA GHG 2009).

Problems with fuel properties in dedicated CFB and BFB systems related to agglomeration of the bed material. Determining factors are the ash composition together with sulphur and chlorine (halogen) content. Other feedstock related drawbacks are fouling, deposit formation, slagging, and (superheater) corrosion. Problems with low-quality fuels eventually raise costs and negatively affects the reliability of the power plant (IEA/OECD 2007; IEA GHG 2009).

E 2 CO_2 capture

In general, the same CO_2 capture technologies that can be applied to coal fired power combustion plants are suitable for biomass fired systems considered here, being: post-combustion capture and oxyfuel combustion (Möllersten, Yan et al. 2003). Retrofitting existing power plants with CO_2 capture will highly likely be done with a chemical absorption based post-combustion capture technology.

When applying post-combustion CO_2 capture, energy is needed to separate the CO_2 and compress the CO_2 to pressures required for transport. This energy consumption

[28] The issues is corrosion which depends on the composition of the feedstock (IEA/OECD 2007)
[29] Bubbling Fluidised Bed Combustion

results in a reduction of the overall efficiency of for instance a power plant. Depending on the type of solvent that is used, impurities need to be removed from the flue gas in order to limit operational problems. Examples are solvent degradation, foaming and fouling. Impurities that need to be removed are typically acid gases (NO_2, SO_2, HCl and HF) and particulate matter (PM). Power plants equipped with CO_2 capture should thus be equipped with highly efficient flue gas desulphurization (FGD), $DeNO_x$ installations and electrostatic precipitators (ESP) and/or fabric filters to remove PM. Also, the flue gas typically requires cooling before it is processed in the CO_2 capture installation (Koornneef 2010).

The RD&D focus in post-combustion capture is mainly aimed at finding and adapting solvents, optimizing the required process installations and integrating the capture system with the power generation process. This is done to reduce the energy requirement of the capture process and reduce capital cost. Furthermore, efforts are aimed at scaling up the process so that it is applicable to full scale power plants. The application of the capture process on contaminated flue gases, e.g. flue gases from coal fired power plants, is already commercially applied[30] (Strazisar, Anderson et al. 2003). However, large-scale CO_2 capture and dealing with the contaminants in the flue gas remains a challenge.

Co-firing biomass will likely not have severe influences on the post-combustion CO_2 capture process. Possible effects on capture are that co-firing results in relative higher volumes of flue gas exiting the boiler (this depends on moisture content) which results in a more dilute stream of CO_2. It is more difficult to capture CO_2 with low partial pressure and the capture penalty may thus be higher, resulting in an overall lower generating efficiency for the power plant including CO_2 capture. In addition, the concentration of impurities that may affect post-combustion operation may change due to co-firing. Typically, co-firing reduces ash, dust and SO_2 emissions from coal fired power plants (IEA/OECD 2007). NOx emissions may decrease or increase when co-firing depending on the feedstock and combustion characteristics[31] (NETBIOCOF 2006). This implies that co-firing may have a positive effect on the operation of the capture process. Other impurities such as halogens may increase due to co-firing and may affect negatively the operation of the post-combustion capture process.

Capturing CO_2 from co-firing results, according to IEA (IEA GHG 2009), in a generating efficiency between 33.8 and 34.5% (LHV) for respectively a CFB and PC[32] power plant. This means an energy penalty between 10-12% points (LHV). The

[30] In the IMC Chemicals Facility in Trona, CA, about 0.8 kt CO_2 per day is being captured since 1978 from a coal fired boiler which is being used in the production of sodium (Strazisar, Anderson et al. 2003).
[31] NOx formation is according to (NETBIOCOF 2006) a complex process depending on combustion characteristics.
[32] Pulverized Coal

higher efficiency loss estimate is found for the CFB option as equipping this power plant with capture requires additional flue gas cleaning. In the future, lower heat requirements for capture and increased generating efficiencies due to higher steam parameters may reduce capture energy requirements and improve overall generating efficiency significantly.

Capturing CO_2 with post-combustion from dedicated firing of biomass in fluidised bed combustion systems (BFB and CFB) results in a higher loss in generating efficiency, i.e. between 13-16% points. The following four factors are cause this higher loss:

1. The installation of additional flue gas cleaning equipment[33] such as FGD and direct contact cooler.
2. The lower CO2 concentration in the flue gas.
3. The lower heating value of biomass resulting in heat generation at lower temperatures.
4. The lower generating efficiency without capture[34]. This resulted in overall generating efficiencies of 25.8 % (CFB) and 23.2% (BFB) with CO2 capture.

Oxyfuel combustion is based on denitrification of the combustion medium. The nitrogen is removed from the air through a cryogenic air separation unit (ASU) or with the use of membranes. Combustion thus takes place with nearly pure oxygen. The final result is a flue gas containing mainly CO_2 and water. The CO_2 is purified by removing water and impurities. Nearly all of the CO_2 can be captured with this method.

The production of oxygen requires a significant amount of energy, which results in a reduction of the efficiency of the power plant. Further, the purification and the compression of the CO_2 stream also require energy.

The oxyfuel concept has not been applied in large utility scale boilers for steam generation and power production. Oxyfuel combustion using solid fuels has been at present only proven in test and pilot facilities and should be regarded as longer-term option (Möllersten, Yan et al. 2003).

Although there are no significant differences between oxyfuel combustion and air firing of solid fuels, the combustion characteristics (e.g. fuel to air ratio, flue gas recycling, temperature and formation of impurities) and optimal configuration of the burners are considered to be the most important hurdles to overcome. In addition, the design and configuration of the flue gas cleaning section and CO_2 purification

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[33] In a dedicated biomass fired CFB/BFB power plant generally no FGD is installed as sufur emissions are controlled by limestone injection in the combustion boiler.

[34] A low generating efficiency results in higher efficiency loss due to capture as per kWh more CO_2 is captured resulting in a higher energy requirement. This in turn results in a higher loss in generating efficiency.

section are challenges for the short-term (Koornneef 2010). The capture of CO_2 from biomass fired oxyfuel power plants have not been studied in detail and is therefore not included here.

E 3 Costs

According to the IEA, it is difficult to asses typical cost for generating electricity from biomass due to widely varying feedstock and conversion processes (IEA/OECD 2007). Typically costs of generation are determined by investment and fuel cost. Incremental investment cost required for co-firing biomass is in the range of $50 to $250/kWe (40-200 €/kWe) summing up for the total plant to 1100-1300 $/kWe (900-1000 €/kWe) (IEA/OECD 2007). In a more recent factsheet by the IEA (IEA ETSAP 2010) incremental investments of 250 €/kWe (200-350) are reported, which is in agreement with estimates by Faaij (Faaij 2006) who mentions additional investment costs for biomass co-firing of 250 euro/kWe (Faaij 2006). In (IEA ETSAP 2010) additional investment cost for co-firing in coal fired power plants in 2010 and 2020 are estimated respectively at 260 and 230 €/kWe.

In this study we assume, based on earlier work of Hendriks et al. (Hendriks et al. 2004), total specific investment cost of 1477 €/kWe for the view year 2030 and 1360 €/kWe in 2050 for co-firing biomass in coal fired power plants with co-firing rates of 30% in 2030, and of 50% in 2050 (see Table E - 10 for more details and calculations).

Compared to smaller plants, larger plants have lower specific investment costs and have on average higher efficiencies. At the other hand, large power plants require biomass transportation over long distances, which add to the costs. The cost optimal plant size depends therefore mainly on the local situation with respect to biomass supply (IEA/OECD 2007).

In Europe, the investment cost of dedicated biomass plants varies considerably from 2300 to 4600 /€/kWe, depending on plant technology, level of maturity and plant size (IEA/OECD 2007; IEA ETSAP 2010). In (IEA ETSAP 2010) total investment cost for dedicated power plants in 2010, 2020 and 2030 are estimated respectively at 2900, 2400 and 2100 €/kWe. Faaij (Faaij 2006) reports 1600-2500 €/kWe for dedicated biomass power plants. The IEA GHG (IEA GHG 2009) reports 1357 euro/kW for a CFB power plant and 2447 euro/kW for a BFB power plant. We estimate the future investment cost of dedicated power plants at about 1600 euro/kW in 2030 decreasing to approximately 1450 euro/kW in 2050.

According to the IEA GHG (IEA GHG 2009), adding post-combustion CO_2 capture to the co-firing power plants increases the specific investment cost significantly. Costs for PC increases by 63% and the costs for CFB by 73%. For biomass-dedicated power plants the capital cost increases by 126% for CFB plants and by 114% for BFB plants compared to coal-fired plant of the same size. This increase includes required additional flue gas cleaning equipment.

The cost of CO_2 avoidance for co-firing is estimated by IEA GHG (IEA GHG 2009) at 48 and 55 euro/tonne for PC and CFB co-firing, respectively. The avoidance cost for dedicated power plants is calculated higher at 65-76 euro/tonne due to higher investment and fuel cost. The higher fuel cost is a direct result of the lower net efficiency for the dedicated power plant with CCS compared to the co-firing cases.

E 4 Potential & Obstacles

In the short term it is expected that co-firing of biomass will remain the most efficient way of converting biomass into power (IEA/OECD 2007). In WEO (2009), co-firing in coal fired power plants is seen as an important area where biomass use can grow in the longer term. Worldwide about 40% of total current electricity production is produced from coal. This equates to about 0.3 TWe of power production. The potential of co-firing in this installed capacity as well as in new built coal fired power plants is very large. A co-firing rate of 5% in all coal fired power plants would result in about 40 GWe of installed 'biomass fired' capacity worldwide (IEA/OECD 2007). In addition to reduced CO_2 emissions by the use of biomass and the application of CCS this will also likely reduce other environmental emissions such as NOx[35], SOx and dust.

Typical drivers for biomass co-firing compared to dedicated firing are:
- Large installed capacity theoretically available for co-firing.
- Low capital cost for biomass to power conversion due to economies of scale
- High conversion efficiency compared to dedicated firing.
- Lower investment and operating cost of CO_2 capture.

Typical drivers for dedicated firing compared to co-firing are:
- Large negative CO_2 emissions due to 100% biomass firing with CO_2 capture.

Additional drivers for biomass combustion including CO_2 capture are:
- A high CO_2 price may create additional revenues as negative emissions represent additional value created per kWh.
- No significant technical obstacles expected compared to coal fired power plants with CCS in the case of co-firing.

Overall, potential of co-firing is estimated to be higher compared to dedicated power plants due to their lower efficiency (IEA factsheet) and higher investment cost.

[35] See earlier discussion on NOx emissions in this paper.

Main obstacles for combustion of biomass in general are:

- Feedstock availability at low cost
- Somewhat reduced generating efficiency compared to fossil fuels
- Competition on arable land with food and fibre production
- Risks associated with the large scale production of biomass, which may result in intensive farming, use of fertilizers and chemicals use and may have an impact on conservation of biodiversity
- Technical obstacles such as slagging, fouling and corrosion in advanced power plants should be eliminated before widespread deployment can be effectuated.

Main obstacles for CO_2 capture from biomass combustion are:

- Higher efficiency penalty for post-combustion capture compared to coal fired power plants
- Low generating efficiency and capacity of dedicated biomass fired power plants which reduces economies of scale for CO_2 transport and storage. Both result in higher conversion cost and cost of CCS.

Table E - 11 Summary table of cost and performance of biomass (co-)firing in coal fired power plants

View year		**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Fuel (s)		Coal	Coal	Coal/biomass	Coal/biomass	Biomass	Biomass
Type of plant		PC	PC	PC	PC	CFB	CFB
Percentage biomass	% thermal input	0%	0%	up to 30%	up to 50%	100%	100%
Net electric efficiency	%	52%	55%	51%	54%	47%	50%
Total Investment costs	€/kW	1325	1221	1477	1360	1581	1456
Total O&M costs	€/kW	40	33	53	48	61	56
Capture efficiency	%	90%	95%	90%	95%	90%	95%
Electric efficiency loss CO_2 capture	%	9%	6%	10%	6%	10%	8%
Net electric efficiency with CO_2 capture	%	43%	49%	41%	48%	37%	42%
Investment costs capture	€/kW	675	422	675	422	1397	873
Investment costs (with capture)	€/kW	2000	1643	2152	1782	2977	2329
O&M costs	€/kW	40	25	50	31	84	52

PC = pulverized coal power plant, CFB = Circulating fluidised bed combustion power plant

Calculation details: all cost data is based on Hendriks et al. and IEA GHG (Hendriks et al. 2004; IEA GHG 2009). Original cost estimates are converted to €. Cost data for PC power plants originates from Hendriks et al. Investment cost for CFB power plants are derived from IEA GHG. IEA GHG reports specific investment cost including capture of 3121 €/kWe. "The higher increase in the capital cost in the CFB case as compared to the PC case could be attributed to the additional cost associated to the installation of the external flue gas desulphurisation which was not required for the CFB power plant without CO_2 capture" (IEA GHG 2009).Technological advances, such as assumed in Hendriks et al., are expected to result in a decrease in investment cost for the years 2030 and 2050.

Appendix F factsheet Biomass (co-)gasification for power generation

Technology: (co)-gasification of biomass in IGCC power plants with CO_2 capture.

Output: electricity

Feedstock(s):

Coal

Woody biomass: including wood chips, wood pellets, sawdust, bark from forestry operations and processing. Agricultural residues: straw, sugar bagasse, palm kernel shells.

Energy crops: including short rotation coppice or forestry (willow, poplar, eucalyptus), miscanthus, switchgrass.

Waste related streams: Including RDF[36], municipal waste, and demolition wood.

F 1 Process and Technology Status with and without carbon capture

In an integrated gasification combined cycle a wide range of feedstock can be converted into electricity and heat. The concept is based on the gasification of carbonaceous fuels yielding a syngas which primarily contains carbon monoxide (CO) and hydrogen (H_2). The syngas is then cooled and cleaned, and is combusted in a gas turbine combined cycle to generate electricity. In an IGCC with CO_2 capture the process configuration will change by adding a water-gas-shift process. In the shift conversion step the CO in the syngas reacts with steam to form H_2 and CO_2. The carbon in the syngas is now predominantly in the form of CO_2 and can be removed from the gas stream. The cleaned gas flow can be used for power production in for example a (modified) gas turbine.

Gasification has several major advantages. First, gasification is a highly versatile process as virtually any carbonaceous fuel, including biomass feedstock, can be converted to fuel gas with high efficiency. Second, the use of gas turbines allows for high power generation efficiency. Third, a driver is the ability to (co-)gasify low cost fuels and wastes[37] with low emission levels (Bauen, Berndes et al. 2009).

Currently, the advanced gasification plant can be considered at the introductory commercial stage. Although hundreds of gasification plants are operating today only

[36] Refuse derived fuel
[37] Wastes may include RDF, municipal waste, demolition wood.

a few (mainly coal fired) IGCC plants designed solely for the production of electricity are operating today. Gasifiers are mainly operational in the (petro)-chemical industry and are considered a proven technology (COFITECK 2008; Harmelen, Koornneef et al. 2008).

Currently, several suppliers offer gasifier technology in three variants: the fixed bed, fluidised bed and the entrained flow gasifier. The gasification systems differ on whether air or oxygen is used as the oxidant. The method of feeding the feedstock also varies with the system. It is either fed in the lump form, as granules, as a dry powder or as slurry. (Fernando 2009) The entrained flow gasifier is seen as the most flexible technology variant, is preferred in recent IGCC applications (Minchener 2005; Beer 2007) and shows the overall most benign energetic and environmental performance (Zheng and Furinsky 2005). For the entrained flow gasifier also two basic variants exist, the dry-fed gasifiers and slurry-fed gasifiers. In general, the dry-fed gasifiers show a better energetic performance and higher flexibility. However, for IGCC applications with CO_2 capture the slurry-fed gasifiers seem to be more economical and have a lower efficiency penalty when using hard coal (Maurstad 2005).

In this factsheet, two main options are considered to generate power from biomass gasification: co-gasification in fossil fired IGCCs and dedicated gasification.

Co-gasification

There is relatively little experience with co-gasification of biomass and coal compared to co-firing in combustion concepts (Fernando 2009). The co-gasification of coal and biomass has been demonstrated in the three main types of gasifiers (fixed bed, fluidised bed and the entrained flow gasifier) in several countries. Feedstock used during demonstration included agricultural crops and wastes, wood and wood waste, sewage sludge and municipal wastes (Fernando 2009). Co-gasification rates have been applied up to 30 %wt[38] of the fuel input. It is expected that co-gasification rates in the order of 20-30 % (on energy basis) are technically feasible. Higher rates may be possible depending on the feedstock quality[39] (e.g. high heating value, and low moisture content). However, the gasifier and syngas treatment (cooling and cleaning) should be designed to cope with large amounts of biomass. Typical challenges when co-gasifying biomass are biomass pre-treatment[40] and feed systems, and fouling and corrosion due to typical characteristics of biomass. Ash

[38] It is important to note the difference between %wt (percentage by weight) and % by energy. The heating value of biomass in MJ/kg is in principle lower than that of coal, so co-firing shares expressed in %wt are in general higher than co-firing shares expressed in % by energy input.
[39] Important fuel characteristics are heating value, moisture content, alkali content and biomass structure (fibrosity).
[40] Predominantly the entrained flow concept requires small fuel particle size which should be fed into the pressurised gasifier. This requires extensive pre-treatment and sets limitations to the biomass feedstock, i.e. more fibrous feedstock are less suitable.

characteristics (melting point and aggressiveness) and halogen content are examples of the latter.

Feedstock limitations and technical issues depend on the type of gasifier applied. Entrained flow gasifiers typically require smaller fuel particles compared to fluidised bed systems.

Commercial gasification systems are available up to several GW_{th}. Currently operating coal and pet-coke fired IGCCs have a capacity of up to approximately 300 MWe with an efficiency of up to 45% (LHV). Further scale-up is limited by the availability of large scale gas turbines. Improvement in efficiency on the longer term is expected through increased conversion efficiency of the gas turbine, higher operating pressure in the gasifier, process integration and hot syngas cleaning[41]. In IEA ETSAP (IEA ETSAP 2010) an efficiency of 52% (LHV) is estimated for coal fired IGCCs in 2030. On the longer term fuel cells may be applied to generate electricity from the syngas boosting efficiencies to 50 to 55%. This requires however significant RD&D to develop, demonstrate, and commercialize these systems (Faaij 2006).

Co-gasification in large coal gasification systems will have the benefit of higher efficiencies through economies of scale. Co-gasification of biomass has typically a negative impact on overall generating efficiency. The lower heating value and higher moisture content result in a lower conversion efficiency in the gasifier, i.e. the heating value of the produced syngas is lowered.

Dedicated gasification

Most biomass gasification systems that are currently in use are based on the fluidised gasification concept, either circulating or bubbling. The circulating fluidised gasifier allows for larger scale gasification, i.e. in the range of several 10s of MWth.

Dedicated B(iomass)IGCCs for power generation with 100% biomass input are not yet in commercial operation, although demonstration plants in the range of several MWe have been successfully operated. In the pulp and paper industry black-liquor is however used in IGCC plants providing power and heat to pulp and paper mills (IEA/OECD 2007). The technology is in the early commercial phase (see Figure F - 1).

[41] Hot syngas cleaning will lower the loss of sensible heat.

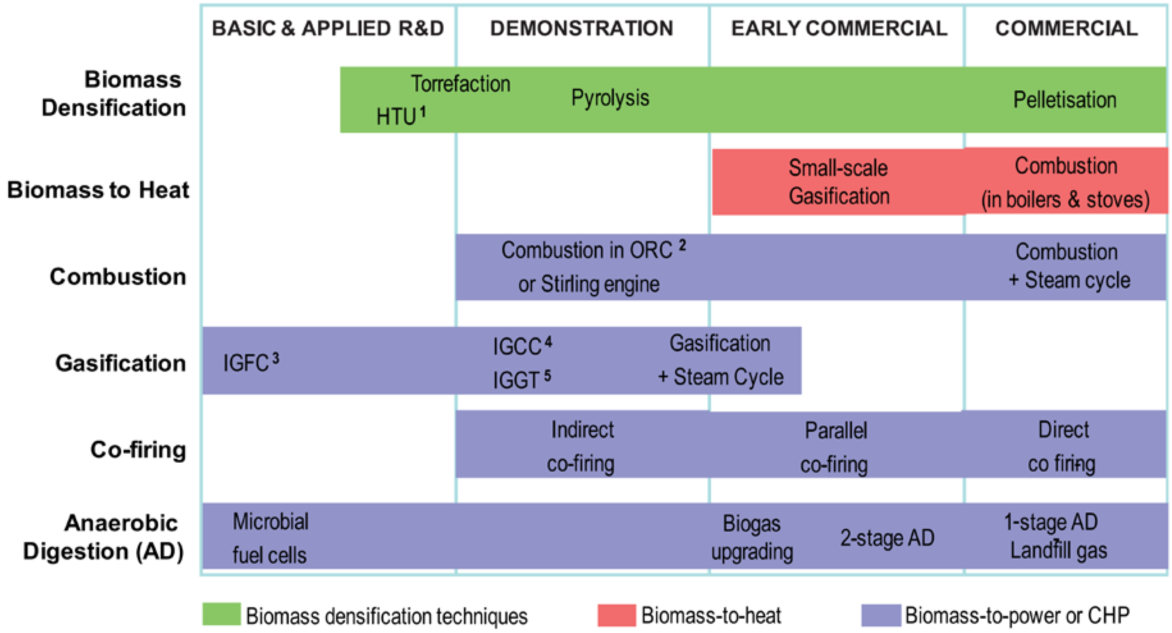

Figure F - 1 Development status of main biomass upgrade (densification) and conversion technologies. From: (Bauen, Berndes et al. 2009; E4tech 2009)

(1 = Hydrothermal upgrading, 2= Organic Rankine Cycle, 3 = Integrated gasification with fuel cell, 4 and 5 = Integrated Gasification with combined cycle/gas turbine)

According to Faaij, dedicated BIGCC plants are possible in the scale range of ~30 MWe on the shorter term increasing to ~100 MWe size range on the longer term. Associated generating efficiencies are estimated at around 30-40% (LHV) for the size range of MWe (Faaij 2006; IEA/OECD 2007). This requires however that several technical issues associated with dedicated gasification are resolved. Examples are fuel pre-treatment and tar removal[42]. Also their efficiency and reliability still need to be fully established. The dedicated BIGCC technology has seen rapid development and extensive R&D programmes in the 1990's, but seem to have stalled in the last decade. Current development seems to be slow, although several BIGCC projects are in the pipeline in northern Europe, USA, Japan, and India. Further R&D required to commercialize dedicated biomass gasification relates to reliability of fuel feed systems, increase acceptability of wide variance in feedstock quality, gas cleaning and further scale-up (Faaij 2006; Bauen, Berndes et al. 2009).

F 2 CO_2 capture

Pre-combustion capture is currently the most promising option to capture CO_2 from either dedicated biomass BIGCCs or IGCCs with co-firing of biomass. The technology to capture CO_2 from the syngas generated in a gasifier can be considered proven

[42] Due to the lower operating temperature in fluidised bed gasifiers, tar is formed which should be removed. In entrained flow gasifiers operating temperature are higher such that tar formation is hindered.

technology and is commercially available in other applications than for electricity production. To make CO_2 capture with high efficiencies in the range of 85-95% possible, the syngas that is formed after gasification has to be shifted after it is cleaned. The 'water gas shift' (WGS) reaction, yields heat and a gas stream with high CO_2 and H_2 concentrations. The CO_2 can then be removed with chemical and physical solvents, adsorbents and membranes. For the near-term it is expected that chemical or physical solvents (or a combination) are used for the CO_2 removal. Syngas dilution with atmospheric nitrogen largely eliminates the benefits in air-blown gasification systems (Rhodes and Keith 2005; IEA/OECD 2006; Koornneef 2010).

Physical absorption consumes energy for compression and pumping of the solvent. This together with energy loss due to shift reaction results in an energy penalty of about 8% pts, see also Table F - 13. Due to the higher CO_2 partial pressure in the syngas, the energy penalty for pre-combustion capture is theoretically lower compared to other capture concepts.

When applying pre-combustion CO_2 capture on IGCC facilities, or gasifiers in general, the main processes involved in CO_2 capture are considered to be the same independently of the fuel input (oil, coal, biomass and waste) (ZEP 2006). The composition of the fuel feed has an impact on the composition of the syngas exiting the gasifier. This may in turn affect for instance the shift process and CO_2 capture energy requirement. Such operating issues when firing biomass (or waste fuels) should be taken into consideration for IGCC applications with pre-combustion CO_2 capture.

Although several IGCC power plants (including co-gasification of biomass) with CO_2 capture are planned worldwide, the pre-combustion concept has not yet been proven in an IGCC power plant. Proving its reliability and effectiveness in power plant concepts is therefore one of the main RD&D targets. In addition, improving the efficiency of the WGS step and integration of this process with CO_2 capture is also an area of research. This is expected to result in low energy penalties in the future (see Table F - 13).

F 3 Costs

The cost of electricity generation with IGCC largely depends on capital and fuel cost. Here we focus on the capital cost. Coal fired IGCC power plants have typically higher capital requirement compared to PC power plants. In the last decade the capital cost of both power plants have risen do to increase in cost of steel, equipment and other materials. An overview of estimated IGCC capital cost for future years is presented in Table F - 11. The cost of IGCC power plants varies widely in literature, as can be seen in the table.

Co-gasification of biomass in relative small co-gasification rates is assumed to have minor impact on capital requirement. Additional capital cost can be expected due to additional fuel pre-treatment and fuel feeding trains compared to coal fired IGCCs. Accurate estimates of additional capital cost due to co-firing have not been found in literature.

Future cost of IGCC power plants are expected to decrease due to technological learning. Experience and wide scale deployment will contribute to lower capital cost. This historical trend has been observed for several power generation technologies (see also (Riahi, Rubin et al. 2004; Junginger, de Visser et al. 2006)).

Table F - 12 Overview of cost of coal/biomass fired IGCC power plants in literature

Technology	Fuel	View year	Capital cost €/kWe	Literature source
IGCC no ccs	Coal	2010	1288- 1851	(IEA/OECD 2008)
IGCC no ccs	Coal	2030	1047-1610	(IEA/OECD 2008)
IGCC ccs	Coal	2010	1852-2254	(IEA/OECD 2008)
IGCC ccs	Coal	2030	1449-1932	(IEA/OECD 2008)
IGCC ccs	Coal	2010	1690	(IEA/OECD 2006)
IGCC ccs	Coal	2020	1316	(IEA/OECD 2006)
IGCC no ccs	Coal with possible biomass co-firing up to 10–20% (energy)	2020	2184	(IEA ETSAP 2010)
IGCC no ccs		2030	1716	(IEA ETSAP 2010)
IGCC no ccs	Coal/biomass co-gasification	2030	1315	This study
IGCC no ccs	Coal/biomass co-gasification	2050	1133	This study
IGCC ccs	Coal/biomass co-gasification	2030	1930	This study
IGCC ccs	Coal/biomass co-gasification	2050	1518	This study

All cost data from literature references are converted to 2010 euros.

Table F - 13 Overview of cost of dedicated biomass fired BIGCC power plants in literature

Technology	Fuel	View year	Capital cost €/kWe	Literature source
IGCC no ccs	Biomass	2025	1530-1932	(IEA/OECD 2008)
IGCC ccs	Biomass	2025	2093-2415	(IEA/OECD 2008)
IGCC no ccs	Biomass	-	1173	(Rhodes and Keith 2005)
IGCC ccs	Biomass	-	1623	(Rhodes and Keith 2005)
IGCC no ccs	Biomass	2030	1616	This study
IGCC no ccs	Biomass	2050	1272	This study
IGCC ccs	Biomass	2030	2231	This study
IGCC ccs	Biomass	2050	1656	This study

All cost data from literature references are converted to 2010 euros.

As can be seen in Table F - 11, Table F - 12 and Table F - 13, the capital cost of dedicated BIGCC power plants is significantly higher compared to IGCCs based on coal and co-gasification. First generations of BIGCC show investment cost of 5,000–3,500 euro/kWe depending on the scale. Economies of scale and technological learning are, however, expected to result in significant cost decrease and a more narrow difference in capital cost requirement compared to coal/biomass fired IGCCs.

CO_2 capture results in higher cost of electricity due to increased capital cost, maintenances cost and cost of fuel. The latter is the consequence of the efficiency penalty. Annual operating and maintenance cost (excluding fuel) are estimated to be approximately 5% of specific capital cost. Capital cost increase due to capture are in the range of 400-600 euro/kWe which means an increase in capital cost ranging between 20% and 50%; strongly depending on the capital cost without capture.

Capture cost of pre-combustion capture systems are in general lower compared to other capture concepts due to lower energy requirement and lower specific capital cost.

Table F - 14 Assumptions on cost of IGCC and BIGCC power plants used in this study

Technology		**IGCC**		**BIGCC**	
Fuel(s)		**coal/biomass**		**biomass**	
View year		**2030**	**2050**	**2030**	**2050**
Biomass share (prim. input)	%	Up to 30%	Up to 50%	100%	100%
Net electric efficiency	%	52%	56%	50%	54%
Total Investment costs	€/kW	1315	1133	1616	1272
Total O&M costs	€/kW	63	52	70	51
Capture efficiency	%	90%	95%	90%	95%
Electric efficiency loss CO_2 capture	%	6.6%	4.1%	6.6%	4.1%
Net electric efficiency with CO_2 capture	%	45.0%	52.2%	43.2%	50.3%
Investment costs capture	€/kW	615	385	615	385
Investment costs (with capture)	€/kW	1930	1518	2231	1656
O&M costs capture	€/kW	37	23	46	29

F 4 Potential: Drivers & Obstacles

In IEA (IEA/OECD 2008, table 2.3), the potential for power generation from IGCC and BIGCC in the years 2030 and 2050 haven been estimated. The potential of BIGCC with CO_2 capture is in that study assumed to be zero due to high cost of power generation. The potential of coal fired IGCC with CCS is there estimated at 165-676 TWh/yr in the year 2030 depending on the future scenarios for global climate policy. For the year 2050 this potential is estimated at about 426-2083 TWh/yr. The highest estimate equates to about 5% of global electricity production. Assuming that 30% biomass can be co-gasified in these IGCCs with CO_2 capture, global production of electricity from biomass with CCS in IGCCs can be as high as 1.5%.

In general, the largest potential is foreseen for co-gasification with or without CO_2 capture, as economies of scale result in high conversion efficiencies and relative lower capital cost of large coal fired IGCCs compared to dedicated BIGCCs. The potential for IGCC power plants with and without CO_2 capture is highly dependent on technical and economic drivers and obstacles.

Technical drivers

- IGCC has favourable prospects for technological advances regarding flue gas cleaning and conversion efficiency with and without CO_2 capture.
- Fuel flexibility for IGCC power plants that can use biomass, coal and natural gas as feedstock is an advantage over, for instance, PC power plants.

- Technical improvements for (B)IGCC may build on the experience and further development of gasification technology in (petro)chemical sector which produce base chemicals and transport fuels (e.g. FT-diesel).
- IGCC allows CO_2 capture with relative lower energy penalty and makes use of a capture technology that is proven and available on the required scale for commercial sized power plants.
- Environmental performance of IGCC power plants is in general favourable over PC power plants. Biomass co-gasification may further improve this performance.

Technical obstacles

- IGCC technology is not yet widely commercially proven at large scale; BIGCC not at all. Risk aversive utilities may therefore not easily adapt the technology, independent on feedstock flexibility and CO_2 capture advantages.
- IGCC operation requires skilled labour compared to combustion plants. The potential of (B)IGCC lies therefore predominantly in developed countries, at least in the near to mid term.
- Several technical considerations such as those regarding fuel delivery, storage and preparation need to be addressed (Fernando 2009).
- Feedstock restrictions are dominated by the ability to gasify the feedstock. Typically, to reach large scale and high efficiency of conversion, pre-treatment of biomass feedstock is required. Depending on the type of gasifier, a wider range of feedstock can be used.
- CO_2 capture integrated in IGCCs is not yet proven.

Economic drivers

- Feedstock flexibility for IGCC power plants will make utilities less dependent on volatile coal/biomass/natural gas prices.
- The economical feasibility of (B)IGCC with or without CO_2 capture largely depends on the price of CO_2 certificates. CCS will be commercially viable only if emission reduction policies are stable and CO_2 price are high.
- Lower energy requirement and capital cost of pre-combustion capture is expected to result in lower CO_2 capture cost compared to other capture technologies.

Economic obstacles

- Security of low cost biomass supply within fuel speciation ranges for large scale power plants is a possible barrier. Transport cost of biomass may be high and dominant when availability of local biomass that meets the fuel specifications is low.
- There are drawbacks of using biomass for power generation relating to its production, transportation and composition (Fernando 2009).
- Scale-up of BIGCC plants is considered necessary to reach economies of scale and decrease cost of electricity.

Appendix G Factsheet Bio-Ethanol Production

Technology: bio-ethanol production with CO_2 capture

Output: bio-ethanol

Feedstock(s):

Starch and sugars: e.g. cereal crops, maize, sugarcane, sugar beet, potato, sorghum, cassava, wheat

Ligno-cellulosic: e.g. straw, wood pellets, bagasse

G 1 Process and Technology Status with and without carbon capture

Conventional production of bio-ethanol

Bio-ethanol can be produced through several production routes. They differ on the conversion technology (and sometimes the feedstock) used. A currently mature technology converts sugar and starch into ethanol (alcohol). In practice, bio-ethanol production gradually develops from using sugar and starch mainly (but not solely) stemming from traditional food crops towards sugars derived from cellulose and hemicellulose, see also Figure F-1. Bio-ethanol from sugar and starch is the most common biofuel, accounting for more than 80% of total biofuel usage (IEA/OECD 2007; REN21 2010). Using well known and mature technologies the biofuel is produced based on the conversion of biomass into sugars, fermentation of 6-carbon sugars to ethanol and finally distillation to fuel grade ethanol (IEA/OECD 2007). This technology is widely used and commercially available. Technical and economical improvements can still be made by using improved enzymes and bacteria, process & plant optimization, improved water separation methods and by producing value-added co-products (Bauen, Berndes et al. 2009).

Bio-ethanol can be produced with commercially available technologies from all sugar and starch containing feedstock such as cereal crops, maize, sugarcane, sugarbeet, potato, sorghum and cassava. Depending on the feedstock the conversion process may yield different by-products. Typical value-added by-products are animal feed and fertilizers. By-products from the conversion processes can be produced on-site by combustion in a boiler. Depending on the technology and feedstock, fossil fuels are used to produce heat and power. The heat and power are typically used on-site in the production process. In the case of excess production this power and heat can be sold. Overall, these by products help to reduce the production cost (IEA/OECD 2007; Bauen, Berndes et al. 2009).

As can be seen in Table G - 14, the largest producers of conventional bio-ethanol are Brazil (dominantly sugarcane ethanol) and the United States (dominantly maize ethanol). Currently, this ethanol is used in 5%-10% blends with gasoline (E5, E10) and as 85% blend (E-85) in flex-fuel vehicles (IEA/OECD 2007). In Brazil E25 is most used (REN21 2010).

Bio-ethanol production produces CO_2, depending on the process configuration, at several production steps. This CO_2 may have a biogenic or fossil origin. A large source of biogenic CO_2 is the fermentation step where sugars are converted into ethanol. The fermentation step produces a high purity CO_2 stream. For every litre of ethanol produced, 765 g of CO_2 is generated. Table G - 14 shows the CO_2 emissions coming from the fermentation step from bio-ethanol produced in 2008. In 2008, worldwide 50 Mt of CO_2 (with biological origin) is produced by this fermentation process.

Table G - 15 Ethanol production and CO_2 emissions from ethanol fermentation in 2008 (after Xu et al. (Xu, Isom et al. 2010))

Region	Ethanol production (million litres)	CO_2 emission from ethanol fermentation ($Mt\ CO_2$)
World	65 641	49.8
United states	34 065	25.9
Brazil	24 497	18.6 (23 Mt in 2009)
European Union	2777	2.1
China	1900	1.5

In the United States, more than 90% of fuel ethanol is derived from maize feedstock, while sugarcane and molasses are the primary sources for ethanol production in Brazil (GEF 2009; Xu, Isom et al. 2010).

The other main source of CO_2 is the power production process where fossil fuels or by-products are converted into power and heat. This flue gases from the boiler contains a low concentration of CO_2. The CO_2 from both the off-gases from the fermentation as the power and heat production process can be captured, compressed, transported and stored.

Advanced production of bio-ethanol

It is also possible to produce ethanol from other types of biomass like ligno-cellulosic. Ligno-cellulosic is any organic matter that contains a combination of lignin, cellulose and hemicelluloses. It is however difficult to break the ligno cellulosic biomass down into sugars and therefore the production of ethanol requires more advanced pre-treatment and conversion processes than those used in conventional ethanol production (Bauen, Berndes et al. 2009). The production of ethanol based on ligno-cellulose feedstock contains three main steps, namely pre-treatment, hydrolysis and fermentation. In the pre-treatment step, the biomass is cleaned and reduced in size by mechanical or physical processes (milling, crushing, ammonia fibre explosion, steam explosion etc). In the hydrolysis step the cell structures in the biomass are broken down and the hemicellulose is converted into sugars. This hydrolysis can be done in several ways, for example by the use of enzymes or acids. The use of acids is costly and produces large amounts of waste. The current estimate is that the enzymatic hydrolysis will be the main route followed in 2020 (reductions in costs for this route are expected to be higher compared to using acids). In the final process step, fermentation, the sugars from the cellulose and hemicellulose parts of the biomass are converted into ethanol. The fermentation and distillation step is quite similar to the current ethanol production where fermentation is used to convert the cellulose parts of the biomass to ethanol (Ecofys 2007). It is in principle possible to construct ligno-cellulose ethanol plants based on existing regular ethanol plants.

Currently, large scale production of advanced bio-ethanol conversion technologies on a commercial basis does not exists; see also Figure G-1. However, the increased interest for more efficient produced biofuels from a cost, environmental and security perspective has led to the initiation of many pilots[43], which are about an order of magnitude smaller than established production facilities. Also the discussion around competition to food production has contributed to this increased interest. Developments in the production of ligno-cellulose ethanol have accordingly accelerated in recent years in the field of suitability and production of enzymes. Experts believe that commercial scale plants will become available in the coming years (Bauen, Berndes et al. 2009).

Independent of the biomass type, the development of pre-treatment technologies for biomass is crucial for both established and advanced technologies whereas the process steps afterwards can mostly rely on already available technologies. Although the fermentation step of the advanced technology is rather similar to that of the conventional bio-ethanol production, efficiency improvements for this step are possible (Ecofys 2007).

Ligno-cellulosic based bio-ethanol can be produced from a wider range of feedstock. This means that the total available biomass for energy production increase both in variety and in quantity. Ligno-cellulosic feedstock includes cellulosic wastes (agricultural waste and the biological component of MSW[44]), maize stover, cereal straw, forestry products and wastes, food processing wastes, fast-growing woody plants such as poplar trees, switch-grass, willow and miscanthus. The main advantage is that cellulosic feedstock could be grown on land that is less suitable for

[43] There are demonstration initiatives, including a 25 tonne/day facility in Denmark, but these are still relatively small compared to the existing ethanol production facilities that produce in the range of 100-200 ktonne of ethanol per year.
[44] Municipal solid waste

common agriculture and at higher yields per hectare, which would decrease the environmental impact of biomass production (IEA/OECD 2007; Bauen, Berndes et al. 2009).

The production of ligno-cellulose ethanol production is estimated at about 2020 million litres[45] in 2009, or 43 PJ (Ecofys 2007). In IEA/OECD (IEA/OECD 2007), the potential for bio-ethanol for the year 2050 is estimated at 45 EJ.

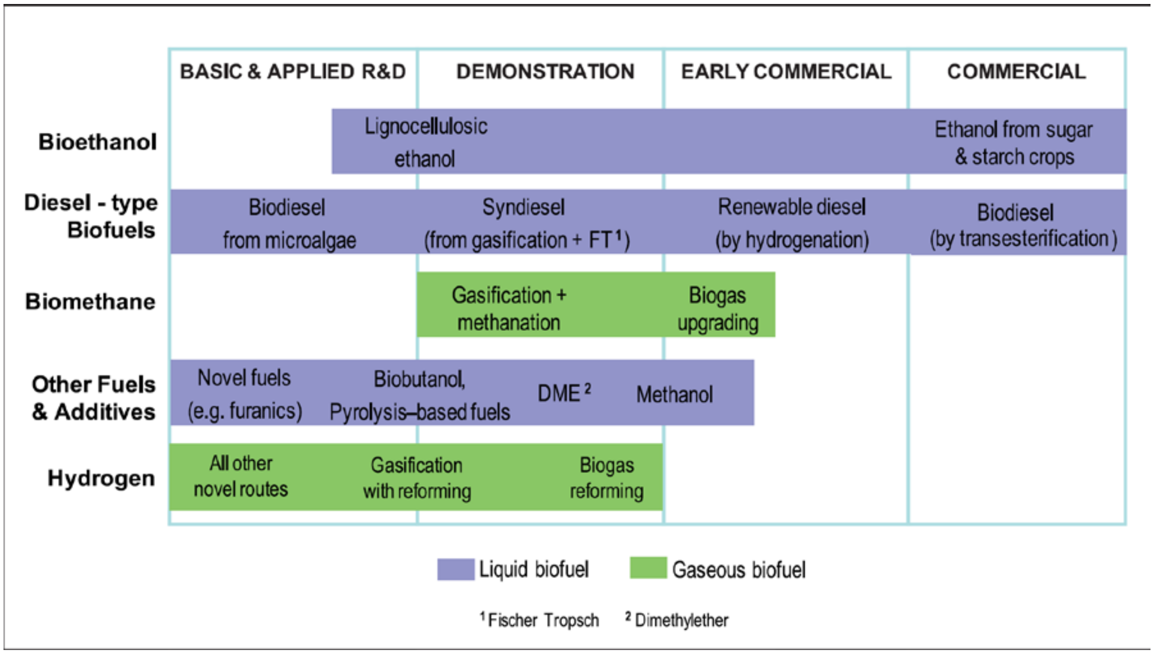

Figure G - 1 Development status of main technologies to produce biofuels, after Bauen et al. (Bauen, Berndes et al. 2009)

G 2 CO_2 capture from ethanol production

As mentioned earlier, the fermentation step of both conventional and advanced bio-ethanol production is similar and per litre of ethanol the same amount of biogenic CO_2 is co-produced. The CO_2 concentration in the off-gasses of an ethanol production plant (conventional or advanced) is about 98.8-99.6 % on a dry basis. This is after the removal of water from the product gas stream. The CO_2 leaves the fermentation process at atmospheric pressure and moderate temperatures of about 25-50 degrees Celsius. Further treatment is not deemed necessary and the CO_2 can be compressed in the multistage compressor to the required transport pressure of 100-150 bar, typically. The energy requirement for the compression step is about 0.11-0.12 MWh_e/tonne CO_2 (Möllersten, Yan et al. 2003; Ecofys 2007).

[45] Estimated based on 1604 kt and a density of ethanol of 794 kg/m^3 (Ecofys 2007).

In addition to the almost pure CO_2 from the fermentation process, it is also possible to capture the CO_2 from the flue gases of boiler for the production of power and heat. The CO_2 concentration in the flue gases is considerably lower than in the off-gases of the fermentation process and requires a separation step, i.e. a post-combustion capture technology. Separation of the CO_2 requires heat and electricity and extra investments for equipment and operational expenditures. The amounts of CO_2 produced in the boiler are comparable to the amount produced in the fermentation step. Depending on the fuel that is used, the emissions of the power and heat production process can be smaller or larger than the emissions from the fermentation step (Möllersten, Yan et al. 2003; Bonijoly, Fabbri et al. 2009; A. Fabbri, C. Castagniac et al. 2010).

G 3 Costs

The techno-economic performance of both the conventional and advanced bio-ethanol production chains is highly dependent on costs and availability of the biomass. Feedstock costs are highly location (regional) specific. For instance, yields of biofuels from purpose grown crops depend on the species, soil type and climate. Feedstock costs account for at least half of the production cost (Bauen, Berndes et al. 2009). Bio-ethanol from sugar cane has in general the lowest costs for conventional bio-ethanol due to low feedstock cost and due to revenues from the co-produced energy. Capital cost reductions due to economies of scale and lower feedstock cost makes the ligno-cellulosic option competitive in the longer run, according to several estimates in literature. Current and expected costs of producing ethanol are depicted in Table G - 15 and Table G - 16. Other studies expect a decrease in ethanol production cost without CO_2 capture, as shown in Table G - 15.

The costs of CO_2 capture from the fermentation step are in general low as investment costs; operational costs and the energy requirement for drying and compression are small. In earlier studies the cost of capture from fermentation step (excluding transport and storage) was estimated between 4.5–9 €/tonne CO_2, (Xu, Isom et al. 2010), 8 €/tonne (Bonijoly, Fabbri et al. 2009) and approximately 20 €/ tonne (A. Fabbri, C. Castagniac et al. 2010).

Table G - 16 Ethanol production cost (including fuel cost) reported in literature

Feedstock	**(IEA/OECD 2007) (US$/lge[3])**	**(Bauen, Berndes et al. 2009)**		**(Bauen, Berndes et al. 2009)[3]**		**Updated from (Ecofys 2007) (euro/ l)**					
		2008[2]	2022	2030	2050	2005		2020		2050	
CO_2 capture (y/n)	n	n	n	n	n	n	y[4]	n	y	n	y
Wheat		0.66				0.51	0.52	0.45	0.46	0.43	0.44
sugar beets	0.31					0.62	0.64	0.60	0.62	0.59	0.60
cereals, maize	0.31-0.42	0.57[1]				0.46	0.47	0.43	0.45	0.42	0.43
sugar cane	0.16-0.26	0.23				0.23	0.24	0.16	0.17	0.09	0.11
ligno-cellulosic	0.53	0.45	0.38	~0.29	~0.28	0.57	0.59	0.36	0.37	0.30	0.32

All values in $euro_{2010}$

[1]maize produced in USA

[2]for Lignocellulosic ethanol the reference year is 2015

[3]original values are in lge (litre gasoline equivalent). Conversion factor of 1.5 is used, i.e. 1.5 l ethanol = 1 l gasoline

[4]capture cost of 12 €/ tonne based on assumptions: 125 kWh/tonne for CO_2 capture, 40 euro/MWh electricity price, capital cost of capture of 7.5 Meuro for 0.2 Mtonne scale, scale factor of 1, annual capital charge of 13.15 %, 100% capture from fermentation, no capture from power and heat generation, ethanol production scale 100 MW (2005), 200 MW (2020), 400 MW (2050). Note that the results shown in the table above are not directly comparable with results from our study shown elsewhere due to differences in feedstock cost assumptions.

Table G - 17 Assumptions for the calculation of ligno cellulosic ethanol production with CO_2 capture in the view years

View year	2030	2050
Conversion efficiency ηf (kg fuel/kg feedstock)	20.4%	24.8%
Capital and O&M cost		
present scale (MW output)	200	400
Scale factor	0.83	0.82
Capex present scale (€/kW)	1580	1064
Load factor	8000	8000
Annual production (Million litres)	244	11.52
O&M	5.0%	489
		3.6%
Capital cost CO_2 capture		
Mtonne from fermentation	0.18	0.37
known scale for compressor (Mtonne output)	0.20	0.20
Capex (€/kW)	36.5	
O&M CO_2 capture		
compression kWh/tonne CO_2	125	125
energy cost(euro/MWh)	40	40
% O&M of capital (non energy)	6%	6%

G 4 Potential & Obstacles

Conventional bio-ethanol production from sugar and starch is a mature technology and for a long time in commercial operation. Technical obstacles are therefore not expected.

For the advanced production of bio-ethanol from ligno-cellulosic this lies differently. The ligno-cellulosic biomass needs to be decomposed into sugars before the fermentation. Research and development is needed to improve this conversion process. Production at larger scale has to be proven reliable before this technology can break through. We believe that this may happen in the near to medium term considering that many pilots are being initiated.

There are no technical obstacles expected for capturing CO_2 from the fermentation process of bio ethanol plants. The quality of CO_2 (the level of impurities) that comes from the fermentation process does not require further treatment before the compression step, although water has to be removed to avoid corrosion. The technologies that are required for the (drying and) compression of CO_2 are readily available (Ecofys 2007).

To reduce energy consumption for the compression of captured CO_2, the operating pressure of the fermentation installation can be increased. However, higher operating pressure has negative influence on the fermentation process (Ecofys 2007).

More in general, the obstacles for this technological route are, after IEA (IEA/OECD 2007):

- Amount and type of land used for feedstock production
- Producing large amounts of biofuels from conventional feedstock results in additional use of water, pesticides and fertilizers
- Increased use of N-based fertilizers results in N_2O emissions which negatively affects the GHG performance.
- The availability of enzymes to enable the utilization of lignocellulose may be a bottleneck for the shorter term. This is not assumed to be a major bottleneck in 2030 and beyond.

Appendix H Factsheet Synthetic Biodiesel Production

Technology: Gasification with Fischer Tropsch synthesis

Output: Electricity and diesel

Feedstock(s):

Woody biomass: including wood chips, wood pellets, sawdust, bark from forestry operations and processing. Agricultural residues: straw, sugar bagasse, palm kernel shells. Energy crops: including short rotation coppice or forestry (willow, poplar, eucalyptus), miscanthus, switchgrass. Waste related streams: Including RDF[46], municipal waste, and demolition wood.

H 1 Process and Technology Status with and without carbon capture

Biodiesel production through (trans)esterification of vegetable oils (e.g. from rapeseed, canola and sunflower) is currently a commercial and the most widely applied conversion technology to produce diesel from biomass. Another route to produce biodiesel is through synthesis. This synthetic biodiesel production is based on gasification[47] of the bio-feedstock into mainly hydrogen (H_2), carbon monoxide (CO) and carbon dioxide (CO_2) and recombine them into liquid fuel through the so-called Fisher-Tropsch reaction. In this factsheet, the conversion process for biomass feedstock into synthetic biodiesel is described, together with the possibilities to capture CO_2 from this process.

Gasification combined with Fischer-Tropsch synthesis is an advanced technology for the conversion of biomass into liquid biofuels. Several gasification technologies are available to convert biomass into syngas. Typical technologies are fluidised bed, entrained flow and two stage gasifier (van Vliet, Faaij et al. 2009). The entrained flow gasification process has generally the highest conversion efficiency but requires small biomass fuel particles (1 mm), i.e. enhanced pre-treatment (van Vliet, Faaij et al. 2009).

In principal, through gasification a wide variety (also lower grade) of feedstock, including municipal solid waste (MSW)[48], can be converted into syngas.

[46] Refuse derived fuel

[47] Gasification is a form of thermochemical conversion process. With the use of thermochemical conversion process a wide range of feedstock can be converted in a wide range of transport fuels, including synthetic diesel and gasoline, methanol, ethanol, dimethylether (DME), methane, and hydrogen

[48] Municipal solid waste typically consist of both biobased as fossil based components.

The biomass gasification process typically utilizes air or nearly pure oxygen to generate syngas. Compared to air-blown gasifiers, oxygen blown gasifiers show superior performance in terms of efficiency. The thermal efficiency and calorific value of the syngas from biomass is lower than that from coal because of the typical high moisture content of the biomass (Demirbas 2005). Commercial coal gasification systems are available up to several GWth and currently about 15 GW_{th} of coal-to-liquid capacity is installed worldwide (IEA ETSAP 2010). For biomass, energy output is generally limited to about 80 MWth. Beside limitations in the economic supply of large quantities of biomass, large scale gasification of biomass is predominantly hindered by technical limitations (IEA ETSAP 2010). Examples are feeding systems design, corrosion issues and product gas cleaning. A wide range of feedstock can be gasified, including wood, charcoal, coconut shells and rice husks. However, depending on the specific design of a gasification system not all feedstock may be acceptable. An individual gasification system is typically designed to operate for a more narrow range of feedstock (Demirbas 2005; Bauen, Berndes et al. 2009; van Vliet, Faaij et al. 2009).

After pre-treatment, gasification and cleaning of the syngas, the CO and H^2 in the syngas can be catalytically converted in a Fischer Tropsch (FT) reactor to hydrocarbons of various chain lengths, i.e. lighter and heavier hydrocarbons. The FT process has become more efficient and more economic since its invention in the 1920s. Also the selectivity of the process has significantly increased (van Vliet, Faaij et al. 2009). Technological analysis show that this selectivity still can be further increased[49] (Ecofys 2010). Several FT processes are commercially available; examples are technologies by Sasol and Shell. They convert coal derived feedstock into hydrocarbons on a large scale.

The products[50] that are generated by the FT process have to be upgraded using conventional upgrading processes as used in petrochemical refineries, for instance hydrocracking.

Besides fuels also other products can be produced with the FT process, including: naphtha, ethene, propene, olefins, alcohols, ketones, solvents and specialty waxes. Also, the synthesis gas that is not converted[51] in the FT-reactor can be used to generate electricity in a gas turbine combined cycle (Laan 1999; Larson, Fiorese et al. 2009).

[49] Van Vliet et al. (2009) assumes a selectivity of 85 wt% in their study

[50] For instance, waxes produced by the FT process can be converted into additional fuels. (van Vliet, Faaij et al. 2009).

[51] Syngas that is not converted in one pass can either be recycled or used for power generation. Economics are typically favourable for the last option. (Larson, Fiorese et al. 2009; van Vliet, Faaij et al. 2009)

Van Vliet et al. mention that about 10% of LHV input is converted into electricity which is partly used on-site and partly delivered to the grid. Larson (Larson, Fiorese et al. 2009) calculates 5.2-5.4 % of HHV input to be converted into electricity. In the case when CO_2 capture is applied this rate declines to 3.7% (HHV). Overall conversion of feedstock to product is expected to be in the range between 43.3-45.3 % (HHV) by Larson et al (2009) and between 44 and 52% (LHV) by van Vliet et al. (2009).

Current experience with biomass gasification in combination with FT is limited. The technology is clearly in the demonstration phase. The Choren plant (15 000 ton of biodiesel per year) in Germany is an example of such a demonstration plant. In comparison, several coal-to-liquids (CTL) plants are operating in South Africa, one with a capacity of 175,000 barrels per day. Successful demonstration could lead to commercial scale bio fed plants coming into operation over coming decades (Bauen, Berndes et al. 2009).In UNCTAD (UNCTAD 2008), some authors estimate that a thermochemical biofuel industry (including FTL) could be in place by 2020. Here we assume that the technology is available on a commercial scale in 2030.

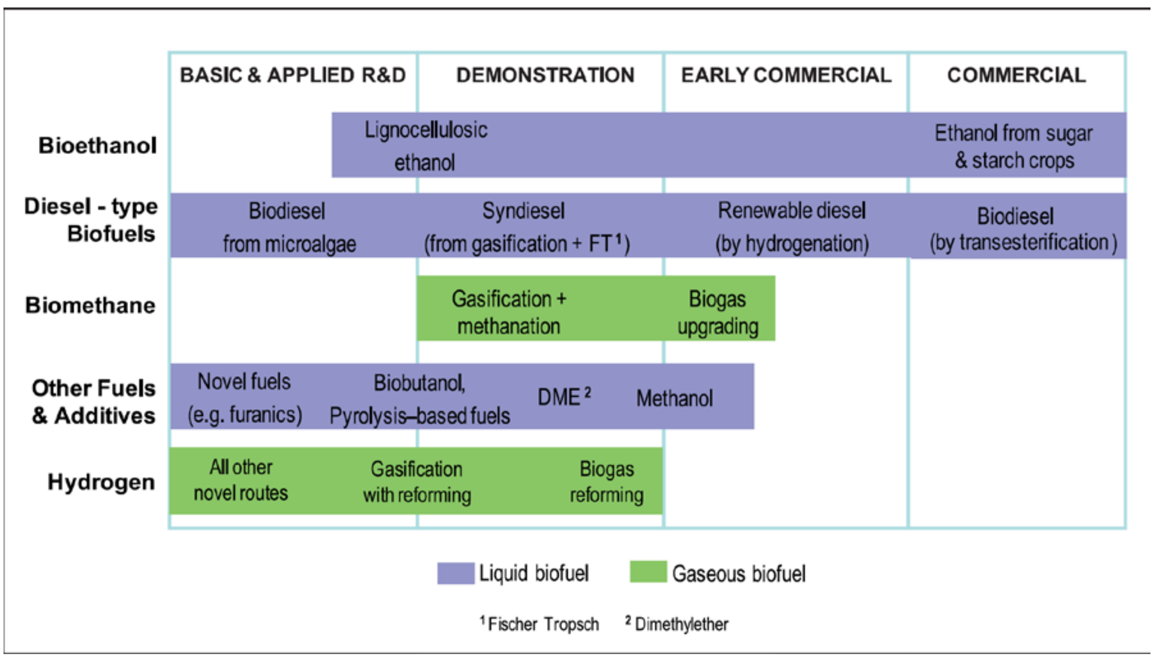

Figure H - 1 Development status of main technologies to produce biofuels, after (Bauen, Berndes et al. 2009)

Biodiesel is currently most often used in 5%-20% blends (B5, B20) together with conventional diesel. It is also used in the pure form (B100) (IEA/OECD 2007). Fuels produced with the FT synthesis are of a high quality due to a very low aromaticity and zero sulphur content (Laan 1999).

H 2 CO_2 capture

CO_2 removal is already an important part of the gas cleaning process that is required before the syngas can be fed into the FT process. Before removal the H_2/CO ratio is adjusted to an optimal ratio for the FT process with the use of the water gas shift process. The CO_2 must be removed to increase the partial pressure of CO and H_2 to assure a high efficiency of the FT process. The capture technology applied is in fact a pre-combustion capture technology, for instance with the use of Selexol as sorbent. The capture technology applied is thus equal to the capture process in an IGCC with CO_2 capture. About 90% of the CO_2 content in the shifted syngas can typically be removed with this technology. According to literature, approximately 54% of the carbon originally present in the feedstock is captured. In Larson et al (2009) 51-54% of the CO_2 is captured and stored (Dooley and Dahowski 2009; Larson, Fiorese et al. 2009). The largest part (23-32%) of the remaining carbon content is embodied in the FT product, i.e. in the synthetic diesel. The rest of the carbon is released as CO_2 in the tail gas. This CO_2 can be removed using a post-combustion technology (Dooley and Dahowski 2009; Larson, Fiorese et al. 2009).

To make the separated CO_2 suitable for transport and storage, the CO_2 typically has to be dried and compressed. This consumes approximately 100 kWh per tonne of CO_2, depending on the required transport pressure. Electricity generated on-site can be used for compression and drying.

The technology required to remove the CO_2 and to subsequently compress and dry it, is commercially available and proven. Technological bottlenecks are not expected for the additional processes that are required to make CO_2 available for transport and storage.

H 3 Costs

The production cost of biomass-to-liquid (BTL) depends mainly on the costs for biomass, the conversion efficiency and the size of the plant. Unit costs for larger plants are lower due to economy of scale effects. Numerous cost estimates can be found in literature showing a wide range of outcomes, see table below. Van Vliet et al. argue therefore that cost estimates should be interpreted as best-guess values and attention should be paid to uncertainties in those estimates. Uncertainties stem mainly from assumptions on feedstock price, the chosen technology, its configuration and performance, the equipment costs, and on the basic economic assumptions such as economic lifetime and interest rate. In the table below recent cost estimates are shown for studies that take into account CO_2 capture from BTL installations.

The cost of CO_2 removal largely depends on the assumptions on the energy use and equipment cost of CO_2 compression and drying. According to van Vliet (2009) the capital requirements for this process is about 38 Meuro[52] for a 400 tonne/hr unit (~3 Mtonne/yr). Larson et al. (2009) assume a 9.4 Meuro capital requirement (2 % of total capital requirement) for a compression unit that accommodates a flow of 112 t/hr (0.88 Mt CO_2/yr). The results of Larson et al. show CO_2 avoidance cost of 16.5 euro/tonne (Larson, Fiorese et al. 2009) for FT biodiesel production including CO_2 removal. Van Vliet et al. report a lower 7 euro per tonne break-even price[53] at the factory gate. Costs are expected to decrease over time due to scale up in the BTL plant. Economies of scale are expected to reduce the cost towards 6 euro/ tonne in 2050.

CO_2 capture according to our estimates and that of van Vliet (van Vliet, Faaij et al. 2009) has little influence on the production cost of biodiesel. Larson et al. (Larson, Fiorese et al. 2009) reports a higher increase due to the capture of CO_2, this can however be explained by the assumption that disposal cost of CO_2 are taken into account.

[52] A scaling factor of 0.67 is used by Van Vliet (2009) to calculated the capital requirement of compression and drying

[53] This does not include transport and storage or CO_2.

Table H - 18 Overview of synthetic biodiesel production cost with and without CO_2 capture

Source	**(IEA/OECD 2007) (Ide[2])**		**(Bauen, Berndes et al. 2009)**		**(van Vliet, Faaij et al. 2009)[1]**		**(Larson, Fiorese et al. 2009)[2]**		**(Bauen, Berndes et al. 2009) [3]**		**Updated from (Hamelinck and Hoogwijk 2007) (euro/ l)[5]**					
View year	Current	Future potential	2015	2022	2020	2020	2007-2020	2007-2020	2030	2050	2005		2020		2050	
CO_2 capture	n	n	n	n	n	y	n	y[4]	n	n	n	y	n	y	n	y
Feedstock																
Pellets (Salix)[1]					0.2-0.6	0.2										
Torrefaction (eucalyptus) [1]						0.2										
Lignocellulosic	>0.7	0.5-0.6	0.76	0.52	0.3				0.39 – 0.48	0.35-0.44	0.70	0.70	0.62	0.63	0.55	0.56
mixed prairie grasses							0.54	0.71								
corn stover							0.52	0.57								

All values are in $euro_{2010}$

[1]Van Vliet et al assume in two BTL cases that the biomass is treated before it is converted in the biorefinery. Pelletization and torrefaction is used to increase the density and create more 'coal like' fuels. Cost ranges can be explained by the difference in assumption on size of biorefineries and consequently by economies of scale. Original data is converted assuming a heating value for diesel of 36.4 MJ/litre.

[2] Larson et al. (Larson, Fiorese et al. 2009) note: "Although the approach involves radically different energy system configurations from systems currently in use, the systems described involve components that are either already commercial or could become commercially available during the next decade."

[3]converted from gasoline equivalents using heating value ratio of diesel and gasoline of respectively 36.4 and 32 MJ (LHV)/litre.

[4]Includes cost of CO_2 disposal.

[5]Note that the results shown in the table above are not directly comparable with results from our study due to differences in feedstock cost assumptions.

H 4 Potential & Obstacles

For the long term, i.e. 2050, the potential market for biodiesel is estimated to be in the order of 20 EJ. This is however based on the assumption that technological development results in advances of conversion technologies, in specific that large scale biomass gasifiers become available (IEA/OECD 2007; Larson, Fiorese et al. 2009). A critical uncertainty for BTL plants is that it requires a large amount of feedstock per installation to reach economic viability. The availability of sustainable biomass to feed this plant is thus also critical. A challenge is to reach economies of scale or to make the technology economically viable at a smaller scale. This would enable distributed production of biodiesel and reduces transport cost of both biomass (dominant) and end-product, and would reduce difficulties in feedstock procurement (Bauen, Berndes et al. 2009).

Depending on the type of gasifier, a wider range of feedstock can be used. Typically, to reach large scale and high efficiency of conversion, pre-treatment of biomass feedstock is required. Pelletization and torrefaction seem interesting pre-treatment options for biomass. In the longer term torrefaction may be an interesting option to increase the density of biomass and a create coal like intermediate product which has favourable characteristics over untreated biomass when gasifying. However, in these pre-treatment options about 9 to 18% of the energy contained in the biomass is lost (van Vliet, Faaij et al. 2009).

Commercial scale demonstration plants for synthetic fuel production that also co-process coal and biomass in combination with CO_2 capture is opted by Larson et al. (Larson, Fiorese et al. 2009) as a requirement for commercial scale deployment.

Biodiesel production could benefit from advances in technologies that are not exclusive for BTL facilities, such as: further improvements in FT selectivity, large scale (pressurised) gasification, large scale biomass logistics, reduced energy requirement for oxygen production (needed for gasification process) and advances in syngas cleaning.

Table H - 19 Assumptions for the calculation of FT-biodiesel from wood with CO_2 capture in the view years

Fuel	2030	2050
Conversion efficiency ηf (kg fuel/kg feedstock)	14.2%	14.2%
Capital cost BTL facility		
present scale (MW output)	200	400
Scale factor	0.85	0.85
Capex (€/kW)	1615	1296
Load factor	8000	8000
Annual production (10^6 GJ)	5.76	11.52
Annual production (Million litres)	244	489
O&M	4.4%	4.4%
Capital cost CO_2 capture		
fraction available for capture	60%	60%
fraction captured	90%	90%
Mtonne captured	0.74	1.47
Capex (€/kW)	78	62
O&M CO_2 capture		
compression kWh/tonne CO_2	98	98
energy cost(euro/MWh)	40	40
%O&M of capital (non energy)	6%	6%