BIOMASS AND CCS – GUIDANCE FOR ACCOUNTING FOR NEGATIVE EMISSIONS

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BIOMASS AND CCS – GUIDANCE FOR ACCOUNTING FOR NEGATIVE EMISSIONS

Key Messages

- Certain greenhouse gas (GHG) accounting rules do not adequately recognise, attribute and reward negative emission technologies, in particular biomass with carbon dioxide capture and storage (bio-CCS).

- Most schemes at least recognise negative emissions from bio-CCS by either allowing for net-back accounting on a portfolio level ("pooling") or the generation of credits ("offsetting").

- Regional cap-and-trade schemes generally do not recognise negative emissions from bio-CCS. However, the architecture of most schemes would allow for either pooling or offsetting if the regulating bodies implement these methods in the schemes.

- Consultation among the regulating bodies is essential to clarify the status of bio-CCS and the recognition and reward of negative emissions.

- Incentivising bio-CCS remains a challenge, due to the baseline of many schemes. Currently, there is a debate about whether bio-CCS delivers a double dividend for emissions abatement and thus should receive double credits.

- Land use change (LUC) is a big concern. Especially in developing countries, implementation of monitoring systems for land use and forestry activities is poor or patchy, so "carbon leakage" is likely to occur. Some schemes might accelerate forest clearing in these countries. The opposite can happen as well, i.e. generation of more forest plantation due to increased demand.

- Low carbon fuel standards (LCFSs) include detailed GHG accounting rules for calculating upstream emissions and also consider LUC effects to some extent.

- Parity of treatment between fossil and biogenic CO_2 is necessary with respect to accounting and sustainability issues.

- Two options for the future design of policies exist:
    1. Centrally planned view (i.e. incentivising and prioritising bio-CCS while phasing out fossil fuels)
    2. Economic purist view (i.e. letting carbon markets drive the deployment of bio-CCS)

- Regulating bodies in the EU and US are currently discussing how to address the sustainability concerns around bio-CCS. This broader discussion will likely initiate a complex political process.

Background to the Study

Biomass use for energy production in processes such as combustion and gasification, and its use to produce biofuels such as bioethanol, results in CO_2 emissions. If CCS is applied to these emissions, because the CO_2 is recently taken-up by the biomass from the atmosphere, then actual CO_2 removal from the atmosphere can take place. This is referred to as 'negative emissions' (compare Figure 1). At present there is only one technology which may be able to be deployed at the required scale –bio-CCS.

Low-carbon energy technologies are usually incentivized by recognition of their GHG emissions performance, for example within emissions trading schemes (ETS). However, for this to occur, the emissions must be able to be accounted. With the negative emissions potential of bio-CCS, there are several difficulties.

The first is that conventional cap-and-trade schemes reward the maximum for zero emissions, not below zero.

Secondly, for all suggested incentive or support schemes for bio-CCS, a most important factor in the accounting of net GHG balance is the accounting of the emissions from the supply-side of the biomass. In this regard, especially GHG emissions and environmental impacts arising from direct or indirect land use change (dLUC/iLUC) are an issue.

Consequently, there is a need for analysis of the options for correctly accounting, reporting and rewarding all emissions relating to bio-CCS, and of ways of including it in ETS schemes to appropriately recognising its GHG performance. IEAGHG commissioned this analysis to Carbon Counts Company (UK) Ltd.

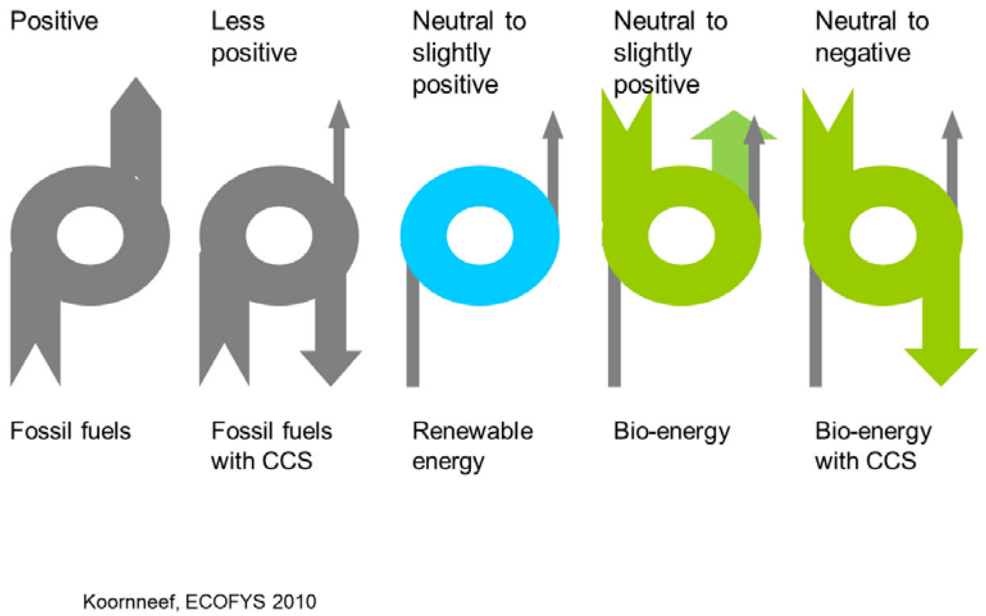

Figure 1 Carbon balance for different energy systems

Scope of Work

The main objectives of this study are as follows:

- *GHG accounting rules applicable to bio-CCS:*
  Understand how they apply, assess their ability to appropriately recognise, attribute and reward negative emissions and suggest potential scope, options and pathways for improvement where necessary. This should include consideration of how other incentive schemes outside ETSs account for GHG emissions associated with bioenergy use, in particular in relation to life-cycle GHG emissions and dLUC/iLUC.
- *Sustainability and potential negative environmental impacts of bio-CCS:*
  Provide an assessment of measures to regulate sustainability impacts and other potential negative environmental effects that could arise through promoting bio-CCS (e.g. leakage, transboundary issues, dLUC/iLUC effects).
- *Options to appropriately reward bio-CCS:*
  Taking into account the GHG accounting rules and issues for sustainability, consider options for modifying policies to appropriately reward operators undertaking bio-CCS.

Therefore the full value chain for different bio-CCS pathways has to be considered, covering: growing, harvesting, distribution, processing, retail and consumption of final products. Within this, the GHG accounting rules for each stage of the value chain are reviewed in order to address how life-cycle GHG emissions are accounted for.

This study reviews the following GHG schemes and accounting rules in detail (the main report provides a detailed description of the schemes in Table 2.1 on p. 12ff):

- 2006 IPCC Guidelines for National GHG Inventories under the framework of UNFCCC and Kyoto Protocol (2006 IPCC GLs)
- EU GHG Emissions Trading Scheme (EU ETS)
- EU Renewable Energy Directive (EU RED)
- EU Fuel Quality Directive (EU FQD)
- US EPA GHG Reporting Program (US GHGRP)
- California Emissions Trading Scheme (California ETS)
- California Low Carbon Fuel Standard (California LCFS)
- Australia Carbon Pricing Mechanism (Australia CPM)[1]
- Kyoto Protocol Clean Development Mechanism (CDM)
- Kyoto Protocol Joint Implementation (JI)

In terms of the *sectoral* scope, the study covers GHG accounting rules applicable to bio-CCS in:

- Electricity generation,
- Industry, and
- Liquid fuel production.

The *geographical* scope of the review covers mainly the developed countries, as presently only these are obliged to GHG emission limitations and reduction targets. The following accounting rules are considered within the scope of the study:

- International rules
- Regional and domestic rules
- Project-based schemes
- Product-based schemes

[1] The Australian Government has introduced repeal bills in November 2013, aiming to abolish the carbon tax scheme from 1st July 2014.

Findings of the Study

Introduction to bioenergy

Biomass consists of any organic matter of vegetable or animal origin. It is available in many forms and from many different sources, including:

- Agricultural crops and residues (e.g. energy crops, food processing waste, animal waste)
- Forestry products and residues (e.g. harvested wood and processing/logging residues)
- Municipal and other waste (e.g. sewage, sludge, waste wood, industrial waste)
- Microalgae and bacteria

Biomass is the most widely used renewable energy source worldwide, currently accounting for around 77% of renewable energy and around 10% of global primary energy use. Although the use of woody biomass in domestic heating and cooking continues to account for most bioenergy worldwide (often termed 'traditional' biomass), there is an ever increasing diversification of biomass sources and their end uses ('modern' biomass) – with the development of new conversion technologies offering multiple routes for value creation.

Most biomass activities worldwide are focused on energy products and services; however there is growing interest and research into other products such as chemicals and pharmaceuticals, which could be combined with bioenergy production. As a result, the bioenergy sector has witnessed significant growth in recent years, particularly the use of biofuels within the transport sector, which has grown faster than for heat and electricity uses. Figure 2 presents a schematic overview of the various pathways by which biomass sources can be converted into final energy products or services, and the principal removals and sources of CO_2 emissions arising from the source through to end energy products.

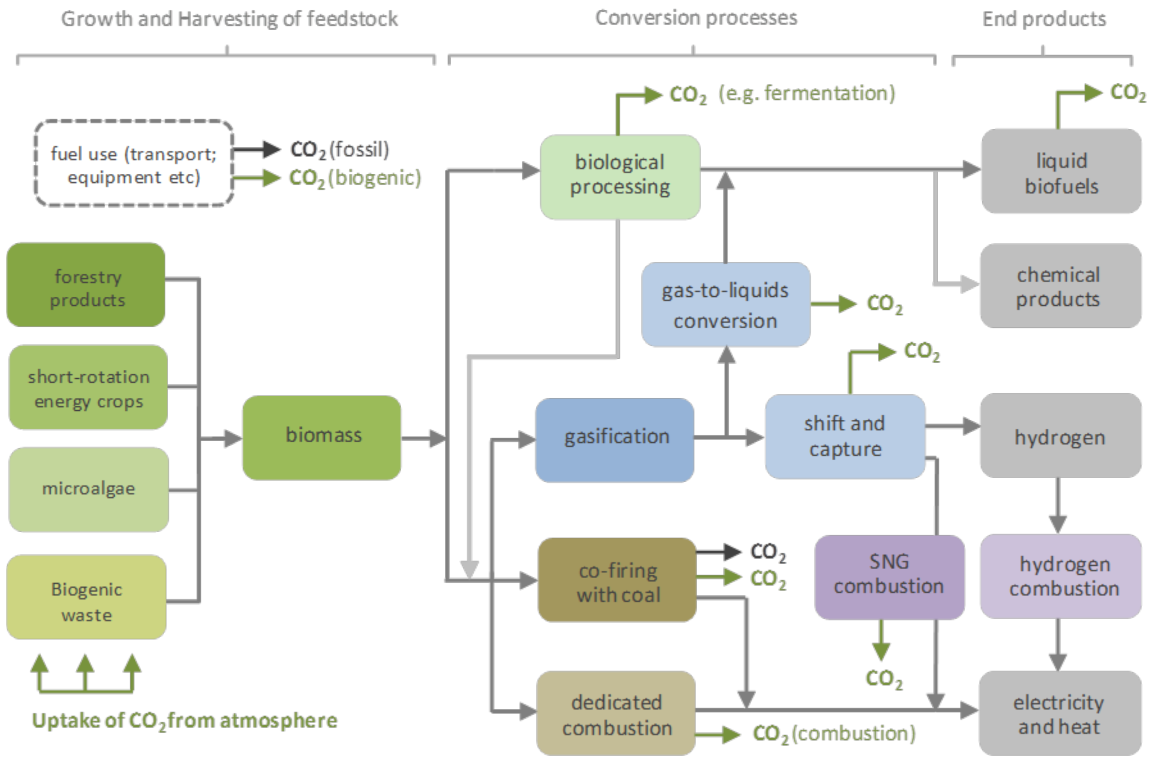

Figure 2 Bioenergy pathways and sources of CO_2 (adapted from Rhodes and Keith, 2005) (Note: Figure is only exemplary and does not include all chemical conversion routes, such as esterification, hydrotreatment.)

Based on the various bioenergy pathways outlined above, bioenergy combined with CCS technology can potentially be applied to a wide range of sectors covering multiple commercial processes. These can be grouped as follows:

- Power generation
    - Dedicated biomass combustion
    - Co-firing
    - Anaerobic digestion
    - Gasification
- Industry
    - Biomass combined heat and power (CHP) boilers (esp. pulp & paper industry)
    - Black liquor gasification
    - Cement kilns
    - Iron & steel furnaces
- Biofuels production
    - Bioethanol
    - Biodiesel
    - Biomass synthetic natural gas (SNG) and H_2 production

Recognising and attributing negative emissions

The general principle underpinning climate policy design for CCS support is recognition of captured and stored CO_2 as "not emitted" to atmosphere, and/or recognition of the technology as a "non-emissive end-use". This typically requires the monitoring of CO_2 flows through the whole chain to quantify the mass of CO_2 captured and therefore not emitted, monitoring of the capture and transport system to quantify any fugitive emissions (i.e. leaks), and comprehensive geological storage site monitoring to provide assurances that the injected CO_2 remains in the intended geological formation and isolated from the atmosphere over the long-term and to quantify any leaks that occur. Impermanence can negate at least part of the environmental benefits achieved by CCS, compromising the effectiveness of policies and measures designed to support the technology, and serving to undermine the environmental integrity of any emission reduction units awarded to a CCS project under an emission trading scheme. For this reason, a key focus of GHG accounting rules for CCS is on managing permanence risk.

In general, all of the schemes reviewed allow for the captured CO_2 to be recognised and accounted for as "not emitted". In nearly all cases, this is dependent on monitoring of CO_2 storage sites to provide assurances over the permanence of emission reductions achieved through CCS.

In all the schemes reviewed, there is a general assumption that growth and harvesting of biomass leads to CO_2 removal and CO_2 emissions respectively, as shown in Figure 3. This is either explicit, through the direct inclusion of CO_2 removals and emissions within the GHG accounting rules, or implicit through the way in which CO_2 emissions from biomass combustion and processing are accounted for. The scientific or technical basis for this zero emissions assumption is correct as capturing and storing CO_2 from biogenic sources should lead to net removals of CO_2 from the atmosphere. The theory is subject to the proviso that biomass carbon stocks (C-stocks) are effectively replenished, and that biomass production is not causing land use changes that give rise to net increases in CO_2 emissions due to reductions in biological C-stocks (compare Figure 3 and 5). However, the asymmetry of GHG accounting rules can create "carbon leakage" because C-stock changes can go unaccounted for. In this case the zero-emissions assumption is undermined.

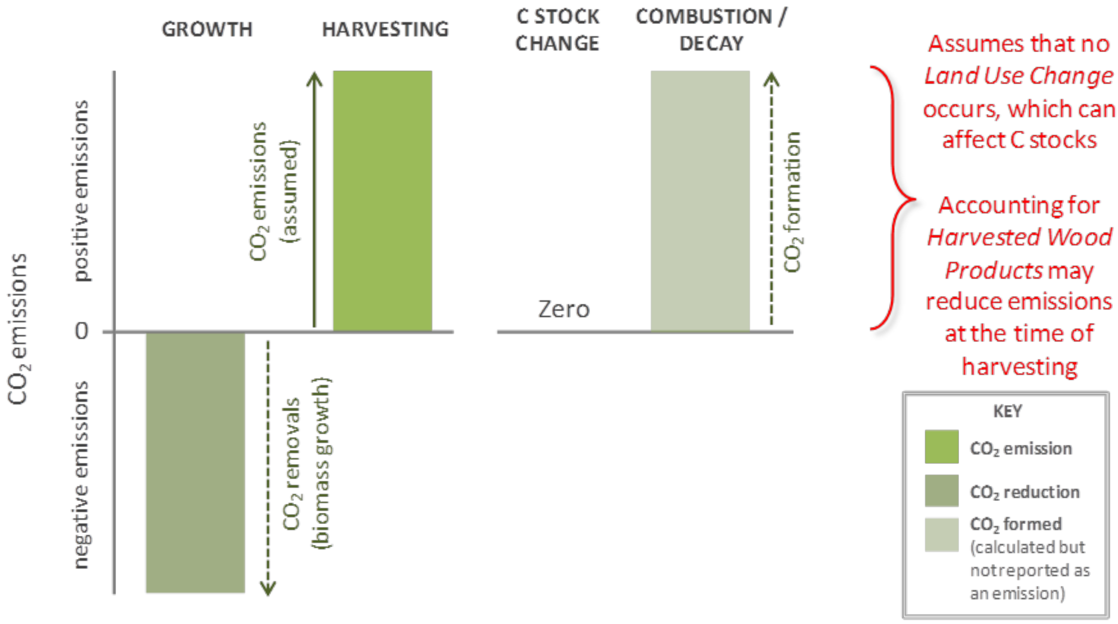

Figure 3 GHG accounting for biomass growth, harvesting and combustion/decay

The aggregate effect of recognising captured and stored CO_2 as "not emitted" and the accounting of CO_2 generated from biomass combustion or decay (fermentation) as zero should result in bio-CCS being recognised as delivering negative emissions under a given scheme. This is on the basis that a covered installation/facility generating CO_2 from biomass produces zero "regulated" emissions, whilst any mass of captured CO_2 that is transferred offsite for geological storage in appropriate sites can then be subtracted from its GHG inventory (zero minus X = minus X; see Figure 4).

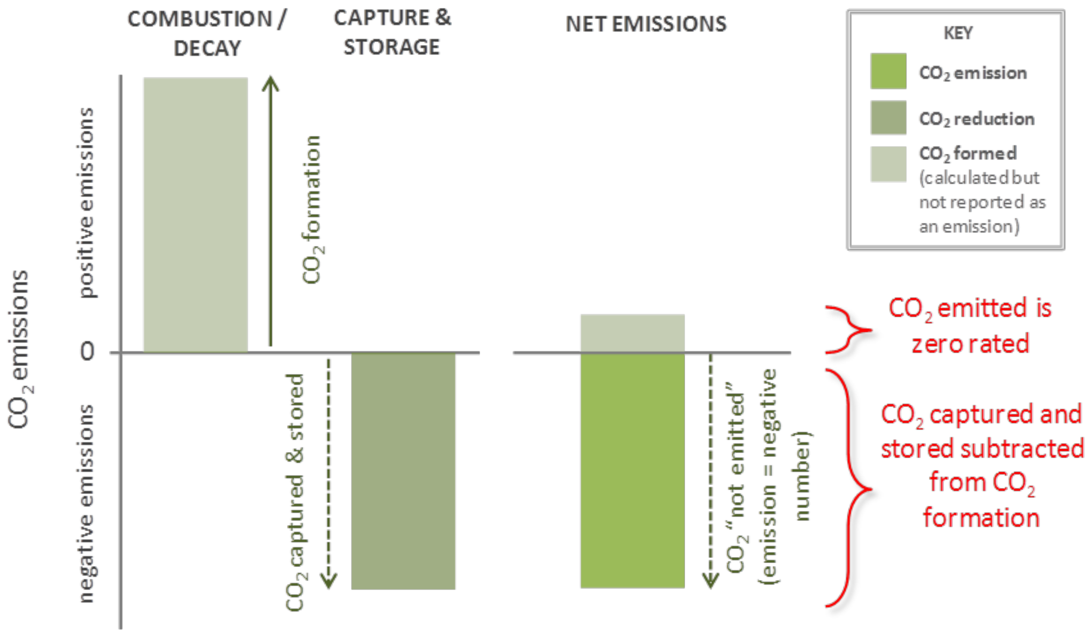

Figure 4 GHG accounting for bio-CCS with negative emissions

The concepts and principles outlined above are the cornerstone of good environmental policy making in the field of carbon pricing and market-based mechanisms, and form an important backdrop to the discussion presented in the following sections regarding how bio-CCS is currently included within various GHG accounting rules for inventory compilation.

To achieve a deeper understanding of the appropriateness of different GHG accounting rules to recognise and attribute negative emissions, the assessment focuses on the treatment of GHG emissions across the bio-CCS value chain in the following five contexts:

1. How CCS is included within a scheme's GHG accounting rules;
2. The way in which biomass growth, harvesting and combustion and processing emission sources from the conversion of biomass to energy are accounted for;
3. Whether and how dLUC and/or iLUC arising through biomass cultivation are effectively taken into account;
4. Whether other emissions occurring in the supply chain are included in the scheme (e.g. emissions arising from the transport of biomass); and,
5. Whether the rules can appropriately allow for negative emissions to be recognised and attributed to the entities included in the scheme.

Points 1 and 2 determine the capacity of the scheme to recognise CCS as an emission reduction technology and biomass combustion or processing as a zero-rated emitting activity (i.e. a renewable energy); points 3 and 4 relate to whether the full GHG emissions associated with biomass production are taken into account; point 5 is essentially the culmination of points 1-4 in terms of whether the scheme can potentially recognise negative emissions, i.e. where the zero-emission of biomass combustion is subsequently deducted when capture and stored, leading to negative emissions.

The review presented attempts to outline the treatment of these aspects under various GHG accounting scheme rules in order to illustrate how the issues link together and highlight where the main challenges for negative emission technologies such as bio-CCS may lie.

International GHG accounting rules in the 2006 IPCC GLs generally allow for negative emissions from bio-CCS to be recorded and recognised in national GHG inventories for Parties to the UNFCCC and Kyoto Protocol. The review did not identify any potential barriers within the GHG accounting rules. Similarly, project-based schemes such as the CDM and JI, the US GHGRP and the LCFSs reviewed – namely the California LCFS and the EU RED/FQD – all potentially allow for negative emissions achieved using bio-CCS to be recognised within the ambit of their respective GHG accounting rules.

However, under the EU ETS, only the mass of "fossil carbon" transferred for geological storage may be deducted from an installations GHG inventory, which prevents negative emissions from bio-CCS being recognised under the scheme. Further, installations exclusively using biomass are exempted from the scheme, implicitly excluding recognition of such activities. Options to address these shortfalls include:

- Amending the EU ETS Monitoring Mechanism Regulations (EU MMR) to include biogenic CO_2 within the ambit of Article 49, where this is for the purpose of geological storage, and modifying the exclusion of installations using biomass so as to include installations using bio-CCS. This could be achieved either through a Commission Decision or possibly via the comitology process under Article 23 of the EU ETS Directive.

- Proposing specific new monitoring and reporting guidelines for bio-CCS installations – which would need to be made by a Member State – for approval through the comitology process. These would need to address the barriers highlighted above, as well as outline any specific methodological issues that must be addressed for bio-CCS projects (e.g. specific rules on life-cycle GHG emissions accounting and dLUC/iLUC issues). It is important to note that the EU MMR allows for such future innovations in relation to the revised CO_2 transfer provisions of the Regulation (see recital 13 of the preamble).

Under the Australia CPM, emissions from the combustion of biomass are not treated as "covered emissions", potentially posing a barrier to recognition of the capture and storage of such source streams. Therefore, further clarification is necessary as to how bio-CCS might fit within the scheme. Applicable domestic offsets – such as the Carbon Farming Initiative – are not relevant to the potential types of bio-CCS applications, although international offsets generated under JI could be a means to recognise and reward bio-CCS within the scope of the CPM.

The California ETS does not allow for negative emissions to be recognised under the scheme for the reason that an appropriate quantification methodology for CCS does not yet exist within the scheme.

The discrepancy between international and some sector specific GHG accounting rules such as LCFSs (which do recognise negative emissions), and regional cap-and-trade schemes (which appear not to allow for recognition of negative emission technologies) suggests that whilst national governments may accrue the benefits of negative emission technologies, e.g. under the UNFCCC, there is only limited means to incentivise the private sector to undertake such activities (e.g. the application of CCS at biofuels refineries could qualify, whilst CCS at biomass fired power plant would not have any benefits). Consultation with the European Commission – DG Climate Action, the Australian Clean Energy Regulator, and the California Air Resources Board (CARB) is recommended in order to clarify the status of bio-CCS and to discuss potential options to recognise and reward negative emissions.

Table 1 contains a summary of the above GHG accounting rules with regards to bio-CCS.

Table 1 Summary of GHG accounting rules for bio-CCS[2]

Scheme	CCS	Biomass growth/ harvesting/ combustion/ processing	dLUC/iLUC	Life cycle emissions	Negative emissions
2006 IPCC Guidelines	✓	✓	✓	✓	✓
EU ETS	(✓)	✓	✗	✗	✗
EU RED/FQD	✓	✓	✓	✓	✓
US GHGRP	✓	✓	✗	✗	(✓)
California ETS	✗	✓	✗	✗	(✓)
California LCFS	✓	✓	✓	✓	✓
Australia CPM	✓	✗	✗	✗	✗
CDM/JI	✓	(✓)	✓	✓	(✓)

[2] Red cross mark = not included in scheme. Green check mark = included. Light green check mark = included under certain constraints. Please refer to the original table in the report for more information and constraints (Table 2.2, p. 41).

(Appropriately) Rewarding negative emissions

One of the key objectives of this study was to consider options to appropriately account for negative emissions in GHG scheme rules. For bio-CCS, other factors may be pertinent to the consideration of how appropriate different policies may or may not be for supporting bio-CCS, and what level of reward these should offer. Considerations in these contexts therefore include:

- The level of reward that should be given to negative emission technologies, recognising the benefits they offer compared to other emission abatement technologies.
- Consideration of potential dLUC, iLUC and sustainability impacts of bioenergy projects, and accounting for this element in the level of reward provided to bio-CCS projects given the potential for leakage to occur.

The term "negative emission" elicits the idea that technologies such as bio-CCS deliver a "double dividend" for emissions abatement. To an extent, this is correct based on the following two components:

1. The first benefit is the zero emission from the biomass part of the technology.
2. The second benefit is the negative emission from applying CCS to these source streams.

A wide range of literature, including integrated modelling assessments, has highlighted the benefits associated with the use of bio-CCS and other negative emission technologies (such as direct air capture). Benefits highlighted include:

- *Offsetting the emissions sources that are more difficult to abate*
  Because emissions are negative, they can be used to deliver deeper reductions in global GHG emissions whilst allowing more challenging emissions sources, such as those from aviation, to continue.
- *Reducing the overall cost of mitigation*
  As negative emission technologies can be used to offset emissions from sources that are more costly to abate.
- *Offsetting legacy or historical emissions*
  CO_2 can essentially be harvested from the atmosphere and transferred to long-term geological storage. This could allow for more rapid emission reductions to be made in future, thereby offsetting previous inaction or the effects of "over-shooting" previous emission reduction targets.
- *Putting a price ceiling on CO_2 emission reductions*
  As essentially negative emission technologies could be deployed to offset higher cost emission sources.
- *Involving more countries*
  In cases where countries have only limited domestic CO_2 abatement potential.

These benefits are additional to more conventional emission reduction technologies that can typically only reduce the rate by which CO_2 is added to the atmosphere towards zero, eliminate it completely, or add carbon to the less permanent biological pool through afforestation, reforestation, avoided deforestation and other land management practices.

On this basis, it is conceivable that negative emission technologies such as bio-CCS deliver a "double dividend", and therefore could warrant additional subsidies or "double crediting" for each tonne of CO_2 captured and stored. Problematically, the benefit from substitution of fossil fuel for biomass is typically forgone under schemes, such as regional cap-and-trade programmes, as it is inherently included within the schemes' baselines. Consequently, only the negative quotient of emission reductions is recognised, which means that bio-CCS effectively competes on a per tCO_2 reduction basis with other mitigation options including substituting coal for biomass or applying CCS to fossil CO_2 sources. Project-based schemes can overcome this problem if the fuel substitution benefits are included within the baseline, although this is predicated on demonstrating that the counterfactual outcome would be a fossil fuel-fired plant. These issues create challenges for incentivising bio-CCS relative to other emission reduction technologies under GHG trading schemes.

In any case, such amendment would need to be accompanied by an appropriate approach for rewarding negative emissions. This could involve either:

- Allowing pooling so that net-back accounting could be applied at the portfolio level;
- Establishing some form of crediting system for negative emissions, either from the New Entrant Reserve (NER) of the EU ETS or a dedicated "negative emission" reserve or credit scheme; or
- Establishing rules and methodologies for bio-CCS to be treated as domestic or community offset projects (DOP or COP) under the EU ETS, or clarifying the scope for the use of JI under the EU Effort Sharing Decision.

Managing LUC effects

Concerns over dLUC and iLUC have been a major issue in the design of policies promoting the use of biomass derived fuels, principally liquid biofuels. Specific concerns relate to potential C-stock changes that can occur as a result of dLUC/iLUC, such as:

- Clear-felling of forests,
- Conversion of natural forests to plantation forests to provide woody biomass for energy generation,
- The conversion of forest land to agricultural plantations for the growth of energy crops, and
- The conversion of other land to grow food in response to conversion of cropland for biomass production.

Paradoxically, these concerns are being augmented by the expansion of policies to promote the use of biomass and biofuels such as the EU ETS, the California LCFS and the EU RED/FQD. These policies are believed to be accelerating the rates at which potential suppliers – primarily in developing countries – are acting to clear natural forests to make way for high value energy crop cultivation, such as sugar cane, soya and palm oil for biofuels production. On the other hand, it is also possible that increased demand of wood leads to increased production, i.e. more generation of forest plantations building up a larger carbon inventory.

A major concern is the asymmetry between approaches to account for biofuel or biomass use, which typically apply comprehensive MRV requirements for GHG emissions accounting and employ a zero emission factor in order to avoid double-counting, versus accounting approaches applied to the agriculture, forestry and land use (AFOLU) sector, which tend to be far more patchy and mask emissions/C-stock changes arising from both dLUC and iLUC as a result of cultivating and harvesting energy crops and biomass. This is summarised graphically below in Figure 5.

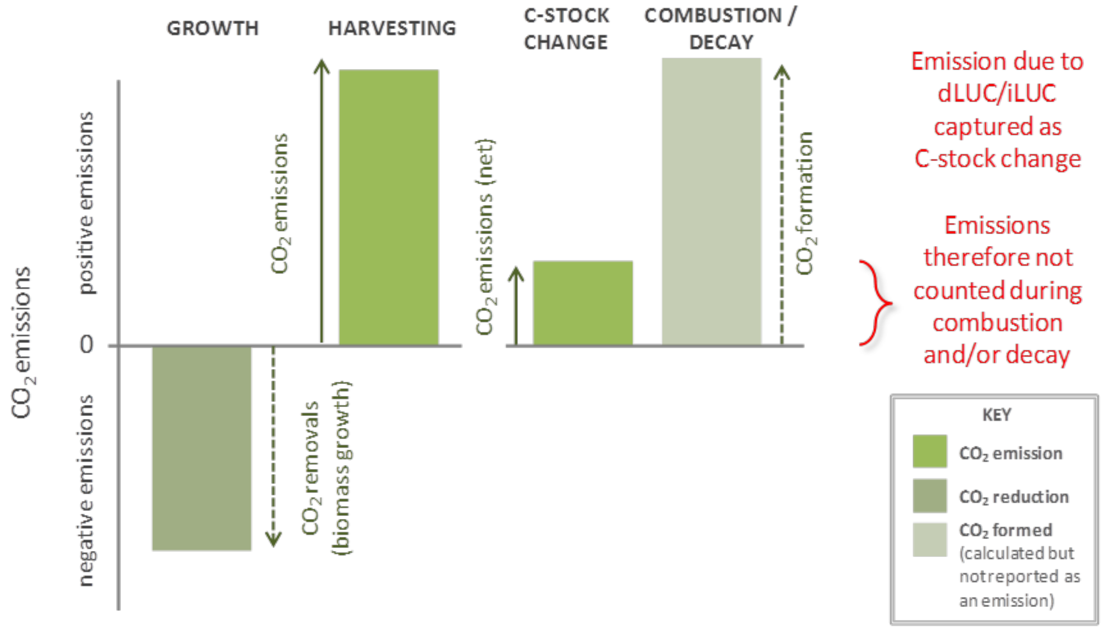

Figure 5 GHG accounting and land use change effects

Two core challenges affect the robustness of measuring dLUC and iLUC effects in national GHG inventories with regards to land conversion:

1. *Lack of data*
   This hampers effective tracking of land conversion over time. An example is that where Tier 1 methods are employed to estimate C-stock changes due to land conversion, a default assumption is made that biomass C-stocks stay the same, even though a land conversion is recorded. This generally applies because the previous use of the land is unknown/unrecorded.
2. *Reporting requirements*
   In this case land management activities affecting large tracts of land go unreported. This is particularly acute for forest management activities, which could potentially lead to conversion of natural forest to plantation forest with less carbon without triggering a land use change. Other situations would include more intensive forest plantations with more carbon in soil and growing stock, also without triggering land use change and thus leaving this carbon accumulation unaccounted for. This would be exacerbated by reporting at lower Tiers.

These effects can apply in combination, where both poor data and a lack of reporting results in land conversions going completely unrecorded. The impacts of such challenges for dLUC and iLUC in biomass and biofuels policy design can be summarised as two types:

- *Cross-sector impacts*
  Within a single country, where accounting for use of biomass and biofuels in e.g. energy or transport sectors of a country's GHG inventory leads to CO_2 emissions totals of zero, whilst the LULUCF (Land Use, Land Use Change and Forestry) or AFOLU sector of the GHG inventory does not appropriately record C-stock changes caused by dLUC/iLUC, especially where these changes can be linked to the benefits achievable in the energy or transport sectors.
- *Cross-border impacts*
  This is similar to cross-sector impacts, although in this case a national GHG inventory may effectively capture the LUC changes occurring within the national jurisdiction, but

not where biomass/biofuels are imported from other countries, especially if the supplier countries have less stringent approaches to LULUCF/AFOLU accounting and reporting.

In either case, the asymmetry of approaches to reporting in the different parts of the inventory can lead to leakage, where support measures are applied to biomass and biofuels as zero emission technologies, especially as these potentially drive further land use changes. Two approaches have been adopted in bioenergy policies and GHG accounting rules at national and regional levels to address these issues, involving either:

- *Quantitative approaches*
  Quantitative approaches involve setting requirements to include all upstream GHG emissions arising from growth, harvesting, LUC, processing and transport in the emission factor or GHG intensity calculated for a particular bioenergy product. This allows full life-cycle GHG accounting to be included in the emission factor applied to biomass combustion, so as to avoid perverse outcomes and leakage.
- *Qualitative approaches*
  As an alternative to requiring full life-cycle GHG emissions accounting, restrictions on certain types of biomass products may be imposed by scheme operators based on the prior assessment of suitable products, or the use of national or international standards for biomass production.

In practice, both types of approaches may be selectively applied under a particular scheme, with restrictions being imposed on certain bioenergy products that fail to meet a certain life-cycle GHG threshold. It is also useful to note that qualitative approaches are often applied in conjunction with efforts to manage sustainability aspects of bioenergy production outside of the GHG emission effects.

The assumption that the combustion or decay of biomass leads to zero emissions provides the basis for calculating negative emissions for bio-CCS, when such sources are captured and stored. However, the zero emission assumption is predicated on the growth and harvesting of biomass being in equilibrium, which is not necessarily always the case. Significant controversy has arisen regarding the promotion of biofuels in jurisdictions such as the US and EU, and the effects of energy crop cultivation on land degradation and the loss of C-stocks as a result of dLUC and iLUC. Assessing the extent to which this is occurring and being accounted for is dependent on establishing a robust monitoring system for LULUCF and REDD (Reducing Emissions from Deforestation and Forest Degradation) activities, although at present these are generally patchy and poorly implemented across many parts of the world, especially in developing countries. Consequently, bioenergy can be imported into regulated jurisdictions, and GHG benefits accrued upon its use (e.g. under the EU ETS), absent of consideration of the dLUC and iLUC effects and associated GHG emissions occurring upstream in the fuel supply chain.

In order to tackle this issue, policies such as LCFSs include detailed GHG accounting rules for calculating the upstream emissions from biomass growth, harvesting, transport, processing and, to some extent, dLUC/iLUC effects, which are then taken into account in the emissions at the point of use. Such quantitative approaches – although not without controversy – do set out to address the issues presented by inadequate LULUCF and REDD monitoring and reporting around the world.

On the other hand, regional cap-and-trade programmes aimed at regulating emissions in electricity and heat production do not include such considerations. The clear exception is the California ETS, which applies qualitative approaches to limit the application of a zero emission factor to only a few specific biomass types. Further, the EU has clarified the sustainability requirements for biomass use in the EU ETS by aligning it with the EU RED, including requirements to show compliance with voluntary sustainability schemes to demonstrate good practice. The US has considered the scope for introducing measures to take account of the upstream effects of biomass use, although it has not yet implemented such measures. Little information is available regarding measures to restrict biomass under the Australia CPM.

Expert Review Comments

Five reviewers from engineering, research and policy organisations took part in the expert review of the draft report and submitted useful comments. In general, the reviewers stated that the report provided a good description of how various policies take bio-CCS into account and they acknowledged the complexity of the area the study covers. The main suggestions included improvement of the figures showing CO_2 emissions accounting, addition of references, restructuring of some chapters, and removal of the overview on biomass energy to the appendix. Carbon Counts addressed these issues in the final report.
Interestingly, some comments asked for additional background information, whereas others suggested removal of this information. The contractor tried to find the right balance in the final version of the report. Some reviewers requested the report should draw stronger conclusions and provide recommendations for policy makers, i.e. answering what the best incentive mechanism for bio-CCS is. As this was beyond the scope of this study and because IEAGHG wants to remain unbiased and "non-prescriptive" in terms of policies, Carbon Counts did not consider those requests.

Conclusions

Discussions regarding support measures for bio-CCS should include consideration of potential approaches to address GHG emissions from dLUC and iLUC and other sustainability concerns, in addition to the assurance of CO_2 storage integrity. On the other hand, in making such considerations of the emissions from the biomass supply chain, it is important to be mindful of the parity of treatment of biomass fuels compared to fossil fuels, which do not need to account for upstream emissions in their supply chain. The scope for opening up this broader discussion is likely to initiate a complex political process. Experiences in Europe in implementing Article 7(a)(5) of the EU FQD (relating to the calculation of life cycle GHG emissions from fossil fuels), which continues to be debated in Brussels four years after adoption of the Directive, suggests the challenges of such a discussion could be considerable. Potential issues under World Trade Organisation rules may also need to be taken into account.

In terms of the design of policies to support bio-CCS, the study presents two potential schools of thought:

1. The centrally planned view, which would take the view that the benefits of bio-CCS need to be prioritised, whilst also phasing out fossil fuels. On this basis, bio-CCS should be given additional incentives compared to biomass or CCS on fossil CO_2 sources;
2. The economic purist view that carbon markets can drive innovation, and that ultimately bio-CCS would become deployed as and when only the most costly emission sources remain to be tackled. Moreover, the latter school of thought suggests the existence of negative emission technologies allows policy makers to be more ambitious in establishing GHG emission reduction targets.

Both viewpoints will need to be considered in discussions regarding the design of policy measures to support bio-CCS and other negative emission technologies.

Recommendations

As IEAGHG is not policy-prescriptive, we encourage related policy-orientated organisations to make use of the relevant information in this report and develop it into recommendations for policy makers. This should particularly include the formulation of suitable incentives mechanism for bio-CCS. This study also does not cover certain issues, such as the timeframe on which negative emissions realise and the question whether all forms of bio-CCS should be promoted equally and over other GHG mitigation measures. In addition, further work needs to investigate if and when biogenic CO_2 should be accounted for and define sustainability criteria for bio-CCS.

IEAGHG should track the developments in this area by continuing its activities and participation, such as in the EU Bio-CCS Joint Task Force. This includes following up with the on-going work around the California ETS and LCFS, as the regulators are currently developing a quantification methodology for CCS.

IEA Greenhouse Gas R&D Programme

Biomass and CCS – guidance for accounting for negative emissions

(IEA/CON/12/206)

FINAL REPORT

Carbon Counts Company (UK) Ltd

8 January 2014

Prepared by:
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Our Ref: 053

PREFACE

This report was prepared by *Carbon Counts Company (UK) Ltd* ("Carbon Counts") under contract to the IEA Greenhouse Gas R&D Programme ("IEAGHG"). The lead authors were Paul Zakkour, Greg Cook and Justin French-Brooks.

The project team would like to thank Tim Dixon and Jasmin Kemper of the IEAGHG for their oversight and inputs during the development of the report.

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The comments and inputs from the peer reviewers were also greatly appreciated, and helped to add depth and quality to many areas of the report.

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Figures, Tables and Boxes

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ACRONYMS AND ABBREVIATIONS

1996 GLs	Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories
2000 GPG	IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories
2006 GLs	2006 IPCC Guidelines for National Greenhouse Gas Inventories
A/R	Afforestation/Reforestation (under the Kyoto Protocol)
AAU	Assigned Amount Unit (the trading and compliance unit of the Kyoto Protocol, equal to 1 tCO_2e)
AB32	California Global Warming Solutions Act, 2006
ACR	American Carbon Registry
ACU	Australian Carbon Unit (trading unit of the CPM, equal to 1 tCO_2e)
ACU	Australian Carbon Credit Unit (trading unit of the CFI, equal to 1 tCO_2e)
AFOLU	Agriculture, forestry and land use
AM	Approved methodology (for the CDM)
APCR	Allowance Price Containment Reserve (under California ETS)
ARD	Afforestation, reforestation and deforestation
BAF	Biogenic adjustment factor
Bio-CCS	Biomass energy with carbon capture and storage
CAR	Climate Action Reserve
CARB	California Air Resources Board
CCS	Carbon dioxide capture and storage
CCS M&Ps	Modalities and procedures for CCS in the CDM
CDM	Clean Development Mechanism
CDM M&Ps	Modalities and procedures for the CDM
CER	Certified Emission Reduction (units issued under CDM, equal to 1 tCO_2-equivalent)
CFI	Carbon Farming Initiative (Australian offset programme)
CH_4	Methane
CM	Cropland management
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent (based on global warming potentials of non-CO_2 GHGs)
COP	Conference of the Parties
COPs	Community Offset Projects (under the EU ETS)
CP	Commitment Period (under the Kyoto Protocol)
CPM	Carbon Pricing Mechanism (Australian policy)
C-pool	Carbon pool
CRF	Common reporting format (for national GHG inventories)
C-stock	Carbon stock
DECC	Department of Energy and Climate Change (UK)
dLUC	Direct land use change (emissions driven by changes on the land used to produce the biomass)
DOPs	Domestic Offset Projects (under the EU ETS)
EF	Emissions factors
EPA	US Environmental Protection Agency
EPA	Environmental Protection Agency (US)
ERU	Emission reduction unit (under JI)

ERU	Emission Reduction Unit (trading unit under JI, equal to 1 tCO_2e)
ESD	EU Effort Sharing Decision
ETS	Emission trading scheme
EU	European Union
EU ETS	European Union GHG Emissions Trading Scheme
EU MRR	EU ETS Monitoring and Reporting Regulation (No. 601/2012)
EUA	European Union Allowance (the trading unit of the EU ETS, equal to 1 tCO_2e)
FM	Forest management
FQD	EU Fuel Quality Directive (2009/30/EC)
GHG	Greenhouse Gas
GHGRP	Mandatory Greenhouse Gas Reporting Program (US Regulation 40 CFR 98)
GM	Grassland management
GTAP Model	Global Trade Analysis Project land model
IEA	International Energy Agency
IEA GHG	IEA Greenhouse Gas R&D Programme Implementing Agreement
iLUC	Indirect land use change (changes in use of other land as a consequence of bioenergy production, principally displacement effects)
IPCC	Intergovernmental Panel on Climate Change
JI	Joint implementation (under the Kyoto Protocol)
lCER	Long-term CER, issued to A/R CDM projects
LCFS	Low Carbon Fuel Standard
LUC	Land use change
LULUCF	Land use, land use change, and forestry
MRV	Monitoring, reporting and verification
MRV	Monitoring, reporting and verification
NER	New Entrant Reserve (under the EU ETS)
NER300	300 million EUAs set aside from the NER for sale (to raise revenue to support renewable energy and CCS projects)
PDD	Project design document (under the CDM)
QELRO	Quantified emission limitation and reduction obligation
R&D	Research and development
RED	EU Renewable Energy Directive (2009/28/EC)
REDD+	Reducing Emissions from Deforestation and forest Degradation in developing countries, including forest management
RFS	Renewable Fuel Standard (US biofuels policy)
RMU	Removal unit (under Kyoto Protocol)
RV	Revegetation
SNG	Synthetic natural gas
t	Metric tonne
tCER	Temporary CER, issued to A/R CDM projects
UN	United Nations
UNFCCC	UN Framework Convention on Climate Change
US	United States of America

EXECUTIVE SUMMARY

Introduction

The objective of the report is to consider the way in which greenhouse gas (GHG) accounting rules, as applied under various polices and measures designed to promote GHG emission reductions, appropriately recognise, attribute and reward negative emissions.

Unlike conventional GHG abatement technologies, which generally only eliminate or reduce emissions towards zero or add carbon to the less permanent biological pool,[1] negative emission technologies are able to achieve long-term removal of CO_2 from the atmosphere. One such technology is the application of carbon capture and storage (CCS) to biogenic CO_2 sources (bio-CCS), such as those arising from biomass combustion (e.g. in generating heat and electricity) or biomass decay (e.g. during fermentation processes in the production of bioethanol). As plants grow, they absorb (or "remove") CO_2 from the atmosphere, which is typically re-released back to the atmosphere upon combustion or biological degradation of the harvested biomass. Using CCS to capture and store the CO_2 from such sources can remove carbon from the short-term biological cycle and locks it up for long periods of time in the geological carbon pool, leading to a net reduction in atmospheric CO_2.

Interest in negative emission technologies, in particular bio-CCS, has grown over recent years because of their potential benefits when compared to conventional abatement measures. These include: (i) the capacity to remove or compensate for historical emissions by removing their legacy from the atmosphere – this aspect is important if action to mitigate GHG emissions is delayed in the first part of this century; and, (ii) the ability to reduce the overall costs of climate change mitigation by offsetting more difficult to abate – or "recalcitrant" – emission sources (e.g. emissions from aviation).

Notwithstanding these benefits, recent literature has highlighted that certain low carbon policies and measures – and associated GHG accounting rules – do not adequately recognise, attribute and reward negative emissions in an appropriate way. This report reviews a range of GHG accounting rules in this context.

Recognising and rewarding negative emissions

International GHG accounting rules in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* generally allow for negative emissions from bio-CCS to be recorded and recognised in national GHG inventories for Parties to the UNFCCC. Similarly, project-based schemes such as the *Clean Development Mechanism* (CDM) and *Joint Implementation* (JI), the US *GHG Reporting Program* and the low carbon fuel standards reviewed – namely the California *Low Carbon Fuel Standard* (LCFS) and the EU *Renewable Energy Directive* (RED) and *Fuel Quality Directive* (FQD) – all potentially allow for negative emissions achieved using bio-CCS to be recognised within the ambit of their respective GHG accounting rules. This is because scheme either compliance operates at a *portfolio level*, allowing negative emissions to be "netted back" against positive emissions elsewhere in the portfolio (e.g. against other emissions in a county; or other emissions in a fuel suppliers portfolio), or it allows "credits" to be generated. For the latter, credits can be

[1] Through afforestation, reforestation, avoided deforestation and other land management practices.

generated based on the emissions for an alternative scenario (the baseline), minus the emissions for the actual activity (which in the case of bio-CCS could be negative), giving rise to net positive credits. However, regional cap-and-trade schemes GHG accounting rules do not generally recognise and attribute negative emissions should they arise.

Under the EU *Emission Trading Scheme* (EU ETS), only the mass of "fossil carbon" transferred for geological storage may be deducted from an installation's GHG inventory, which prevents negative emissions from bio-CCS being recognised. Further, installations exclusively using biomass are exempted from the scheme, implicitly excluding recognition of such activities. Several options to address these shortfalls are outlined in the report. Notwithstanding these barriers and options to address them, any amendment to the EU ETS rules would need to be accompanied by an approach to *reward* negative emissions. Presently, whilst the scheme's architecture potentially allows for *pooling* (i.e. "netting-back" at a portfolio level) and *domestic offsets* (i.e. crediting), these elements of the legislation are largely defunct. Also, mechanisms to allocate EUAs to an installation that accounts for and reports negative emissions do not exist. Options to address these aspects are also discussed in the report.

Under the Australia *Carbon Pricing Mechanism* (CPM), emissions from the combustion of biomass are not treated as "covered emissions", potentially posing a barrier to recognising the capture and storage of such source streams. Therefore, further clarification is necessary as to how bio-CCS might fit within the scheme. Applicable domestic offsets credits – such as the *Carbon Farming Initiative* (CFI) – are not relevant to the potential types of bio-CCS applications reviewed, although international offset credits generated under JI could be a means to recognise and reward bio-CCS within the scope of the CPM.

The California ETS does not allow for negative emissions to be recognised because an appropriate *"quantification methodology"* for CCS does not yet exist under the scheme.

The discrepancy between international and some sector-specific GHG accounting rules such as low carbon fuel standards (which do recognise negative emissions), and regional cap-and-trade schemes (which do not to recognise negative emission technologies), suggests that whilst national governments may accrue the benefits of negative emission technologies under e.g. the UNFCCC, there is only limited means to incentivise the private sector to undertake such activities (e.g. the application of CCS at a biofuels refinery could qualify, whilst CCS at biomass fired power plant would not have any rewards). Further, the differential treatment of transfers of fossil CO_2 *and biogenic* CO_2 *under regional cap-and-trade scheme GHG accounting rules means that an incentive is provided for fossil-CCS but not bio-CCS. This distortion should be removed to encourage biomass users to consider applying CCS. In most cases this will require a new type of mechanism to reward such activities e.g. net-back accounting or crediting approaches.*

Consultation with the European Commission – DG Climate Action*, the* Australian Clean Energy Regulator*, and the* California Air Resources Board *(CARB) is recommended in order to clarify the status of bio-CCS and to discuss potential options to recognise and reward negative emissions.*

Allocating an appropriate level of reward

A wide range of literature, including integrated modelling assessments, has highlighted the benefits associated with the use of bio-CCS and other negative emission technologies compared to conventional emission reduction technologies. On this basis, it is conceivable that negative emission technologies such as bio-CCS deliver a "double dividend" for emissions abatement, and therefore could warrant additional subsidies or "double crediting" for each tonne of biogenic CO_2 captured and stored.

Problematically, the benefits from substitution of fossil fuel for biomass is typically forgone under schemes such as regional cap-and-trade programmes as it is inherently included within a scheme's "baseline". Consequently, only the negative quotient of emission reductions could be recognised, which means that bio-CCS effectively competes on a per tCO_2 reduction basis with other mitigation options including substituting coal for biomass, or applying CCS to fossil CO_2 sources. These issues create challenges for incentivising bio-CCS relative to other emissions reduction technologies under GHG trading schemes, as the net effect of applying CCS to a fossil or biogenic CO_2 stream would be recognised on the same per tCO_2 basis. Project-based schemes can overcome this problem if the fuel substitution abatement effect is included within the baseline (i.e. if the baseline is for an equivalent fossil fuel source).

In terms of the design of policies to support bio-CCS, two potential schools of thoughts are discussed in the report: (1) the *centrally-planned* view, taking the position that the benefits of bio-CCS need to be prioritised whilst also phasing out fossil fuels. On this basis, bio-CCS should be given additional incentives compared to only biomass substitution or CCS on fossil CO_2 sources. This could be take a variety of forms, including through emissions trading type approaches (e.g. tradable "credits"), or other measures such as feed-in tariffs or "green certificates"; and, (2) the *economic purist* view that carbon markets can drive innovation, and that, aside from certain niche circumstances where it is advantageous to do so, ultimately bio-CCS might only be deployed as and when only more recalcitrant emission sources/more costly abatement options remain to be tackled. Moreover, the latter school of thought suggests the existence of negative emission technologies allows policy-makers to be more ambitious in establishing GHG emission reduction targets.

Both viewpoints will need to be considered in discussions regarding the design of policy measures to support bio-CCS and other negative emission technologies.

Managing land use change effects

The assumption that the combustion or decay of biomass leads to zero emissions provides the basis for calculating negative emissions from bio-CCS where such sources are captured and stored. However, the zero emissions assumption is predicated on the growth and harvesting of biomass being in equilibrium, which is not necessarily always the case. Significant controversy has arisen regarding the promotion of biofuels in jurisdictions such as the US and EU, and the effects of energy crop cultivation on land degradation and loss of biological carbon stocks (C-stocks) as a result of land use changes (LUC). Assessing the extent to which this is occurring and being accounted for is dependent on establishing a robust monitoring system for *Land Use, Land Use Change, and Forestry* (LULUCF) and *Reducing Emissions from Deforestation and Forest Degradation* (REDD) activities, although at present these are generally patchy and poorly implemented across many parts of the world, especially in developing countries. Consequently, bioenergy can be imported into regulated jurisdictions, and GHG benefits accrued upon its use (e.g. under the EU ETS), absent of consideration of the LUC effects and associated GHG emissions – as well as more general sustainability impacts – occurring upstream in the fuel supply chain.

In order to tackle this issue, policies such as low carbon fuel standards include detailed GHG accounting rules for calculating the upstream emissions from biomass growth, harvesting, transport, processing and, to some extent, LUC effects, which are then taken into account in the emissions at the point of use. Such *quantitative* approaches – although not without controversy – do set out to address the issues presented by inadequate LULUCF and REDD monitoring and reporting around the world.

On the other hand, regional cap and trade programmes aimed at regulating emissions in electricity and heat production do not generally include such considerations. Exceptions are the California ETS, which restricts the application of a zero-emissions factor to only a few specific biomass types. Further, the EU has clarified the sustainability requirements for zero-rating biomass used in the EU ETS, including for it to be compliant with national and voluntary sustainability schemes that demonstrate good practice in land use. The US has considered the scope for introducing measures to take account of the upstream effects of biomass use in the mandatory *Greenhouse Gas Reporting Programme* (GHGRP) by using "biogenic adjustment factors", although it has not yet implemented such measures. Little information is available regarding measures to restrict biomass under the Australia CPM.

Discussions regarding support measures for bio-CCS should include consideration of potential approaches to address GHG emissions from LUC and other sustainability concerns. Without addressing such concerns, the creditability of negative emission claims could be placed under scrutiny. On the other hand, in making such considerations, it is important to be mindful of the parity of treatment of biomass fuels compared to fossil fuels, which do not need to account for upstream emissions in their supply chain under the GHG accounting rules reviewed. The scope for opening up this broader discussion is likely to make for a complex political process; experiences in Europe in implementing Article 7(a)(5) *of the EU FQD (relating to the calculation of life cycle GHG emissions from fossil fuels), which continues to be debated in Brussels four years after adoption of the Directive, suggests the challenges of such an approach could be considerable. Potential issues under World Trade Organisation rules might also need to be taken into account (see BTG, 2008).*

1 INTRODUCTION

1.1 Bio-CCS and negative emissions

The prospect of developing technologies which can deliver negative emissions – removing greenhouse gases (GHGs) from the atmosphere – is significant to combating climate change as it offers the possibility of making deeper and faster cuts in atmospheric concentrations of carbon dioxide (CO_2). Biomass energy with carbon capture and storage (bio-CCS) – the capture and storage of CO_2 generated from biological energy sources – is one such technology. As plants grow, they absorb (or "remove") CO_2 from the atmosphere, which is typically re-released back to the atmosphere upon combustion or biological degradation (CH_4 and CO_2) of the harvested biomass. Using CCS to capture and store the CO_2 from such sources can remove carbon from the short-term biological cycle and locks it up for long periods of time in the geological carbon pool. This transfer of carbon from the biological to geological pool results in GHG emissions accounting recording a negative emission at the point of capture (Box 1.1).

Box 1.1 Biomass and negative emissions

Emissions and removals from biomass energy: zero-emissions rating biomass
Biomass can be considered as a renewable source of energy because the harvested material is constantly replenished by the growth of new biomass. A range of biogenic matter and a number of different conversion processes can be used to produce bio-energy (see Annex A). When biomass is converted to produce energy, the carbon absorbed during its growth is released back to the atmosphere, where it can be removed by absorption into new biomass growth. In general, this cycle gives rise to a zero net change in atmospheric CO_2 concentrations, and therefore combustion of biomass is considered to have zero CO_2 emissions i.e. zero-emission rated. For slow growing woody biomass (i.e. trees), the carbon released during its combustion generally takes longer to absorb than is achieved in an annual growth cycle, leading to short-term increases in carbon in the atmospheric pool and reductions in the biological pool (or "stock"); renewable biomass is one where harvesting is sustained by replanting and re-growth of new biomass. For short-term annual crops (e.g. energy crops such as willow, miscanthus or sugar cane), the net change on an annual basis can be assumed to be zero. If changes occur in the underlying biological stock – as can arise through land use changes – then the emitted carbon may not be fully absorbed from the atmosphere over time, leading to longer-term shifts in the carbon stocks (C-stocks) in the atmosphere relative to the biosphere. Biological processes such as fermentation also produce CO_2, and these are also considered to be of biogenic origin with zero net emissions.

Negative emissions
When applying CCS to biomass emissions sources (combustion or decay), the carbon released is not emitted to the atmosphere (and potentially from there reabsorbed for shorter-term storage in biomass) but is instead transferred into the geological carbon pool for long-term, or permanent, isolation from the atmosphere. Therefore, rather than leading to a zero net change in atmospheric CO_2 concentrations, bio-CCS actually leads to a net removal of CO_2 from the atmosphere, and hence, all other things being equal, the net change in the atmospheric C-stock becomes negative (see Figure 2.7). As well as biomass energy with CCS, a range of other negative emission technologies are under consideration, including direct air capture and storage of CO_2 using "artificial trees" (see McGlashin *et. al*, 2012).

This makes negative emissions technologies quite distinct from other technologies and measures that can reduce emissions – for example, energy efficiency measures or substitution of coal by biomass – as these typically only reduce the rate at which CO_2 is added to the atmosphere, eliminate it completely. Alternatively, land management activities only add carbon to the less permanent biological pool through e.g. afforestation, reforestation, avoided deforestation and other land management practices. This difference is an important aspect when considering the design of policy schemes to support bio-CCS.

1.2 The role of bio-CCS

The potential for bio-CCS based negative emissions technologies to contribute to tackling climate change has recently been highlighted by several influential international institutions, including: the *United Nations Environment Programme* (UNEP, 2013; UNEP, 2010), the *Intergovernmental Panel on Climate Change* (IPCC, 2011), the *International Energy Agency* (IEA, 2013; IEA, 2012; IEA, 2011a), and the *United Nations Industrial Development Organisation* (UNIDO; IEA/UNIDO, 2011). The topic has also recently been reviewed in several research papers (e.g. Groenenberg and Dixon, 2010; Gough and Upham, 2011; ZEP, 2011; IMechE, 2011; McLaren, 2011; Socolow, 2011; McGlashin *et. al*, 2012). Benefits highlighted for bio-CCS include:

- The capacity to remove or compensate for historical emissions by removing their legacy from the atmosphere. This aspect is important if action to mitigate GHG emissions is delayed in the first part of this century; and,
- The ability to reduce the overall costs of climate change mitigation by offsetting more difficult to abate – or recalcitrant – emission sources (e.g. emissions from aviation).

Increasing interest in the role of bio-CCS and negative emission technologies, especially given the risk of limited action to tackle global GHG emissions in the next decade or so, is driving a political debate on the subject. For example, in the European Union, high-level stakeholders have discussed the role of bio-CCS with the potential view to forging ahead with EU-level policy to support the technology in coming years.[1] Therefore, with increasing political interest, it seems timely to carry out a comprehensive assessment of the policy issues for negative emission technologies and in particular the GHG accounting frameworks. Such GHG accounting frameworks provide the basis upon which bio-CCS and negative emission technologies may be suitably recognised and rewarded under existing low carbon polices and measures.

1.3 Purpose of this report

The *IEA Greenhouse Gas R&D Programme* (IEAGHG) has previously commissioned research in the field of bio-CCS. However, this report focussed on technical aspects related to the use of bio-CCS and did not specifically attempt to address policy-related matters such as GHG accounting rules (IEAGHG, 2011).

This report aims to fill that gap by providing a comprehensive review of how the current rules for compiling and reporting inventories of GHG emissions and removals, and for *monitoring, reporting and verification* (MRV) of GHG emissions and removals (hereafter collectively termed "GHG accounting rules"), apply to the various elements involved in the bio-energy and CCS chain. This includes international, regional and national approaches employed under policies and measures such as mandatory GHG emissions reporting, carbon taxes and emission trading schemes (ETSs). Some of the literature outlined above, for example Groenenberg and Dixon, McGlashin *et. al* (2012) and IMechE (2011), has suggested that in some cases GHG policies and their associated GHG accounting rules do not *recognise*, *attribute* and *reward* negative emission benefits to the entities that may use the technology. Further, several authors have proposed that specific incentives need to be provided to support bio-CCS given that negative emissions

[1] Biomass with CCS – removing CO_2 from the atmosphere. Workshop. EU Sustainable Energy week, 18-22 June 2012.

can be achieved with the technology with attendant benefits ahead of other abatement measures (e.g. IEA, 2013). These issues, gaps and potential barriers need to be clearly elucidated to help inform policy-makers of where the challenges lie and to assist in identifying potential measures that could be taken to support bio-CCS deployment in an *appropriate* way.

In addition, recent considerations on the potential for bio-CCS have also recognised the need for transparency as to the sustainability of any biomass used for this purpose, principally in relation to changes in land use driven by increasing demands for biomass energy. In a recent paper for the IEA, Pipatti argued that biomass can be produced unsustainably, and "*its damaging effects* [not only GHG emissions, but e.g. water depletion, loss of biodiversity] *may outweigh the benefits of negative CO_2 emissions offered by the technology"* (IEA, 2011a). Therefore any policies or measures used to support bio-CCS should ensure that adverse environmental impacts, including in terms of GHG emissions, land use change and sustainability effects potentially resulting from an increased uptake of the technology, are appropriately taken into account.

1.3.1 Study objectives

Based on the discussion above, the main objectives of this study are as follows:

1. *GHG accounting rules relevant to bio-CCS*: to understand:
   a) How they apply;
   b) Assess their ability to *recognise*, *attribute* and *reward* negative emissions; [1] and,
   c) Suggest potential scope, options and pathways for improvement where necessary.

   This includes consideration of how other incentive schemes outside ETSs account for GHG emissions associated with bioenergy use, in particular in relation to life-cycle GHG emissions and direct and indirect land use change. In this context, the study considers how incentives for biofuels use account for these aspects.
2. *Sustainability and potential negative environmental impacts of bio-CCS through land use change*: provide an assessment of measures to regulate sustainability impacts and other potential negative environmental effects that could arise through promoting bio-CCS (e.g. changes in biological C-stocks and the creation of emissions in the supply chain for biomass products outside of the immediate boundaries/jurisdiction in which it is being utilised).
3. *Options to appropriately reward bio-CCS*: taking into account the GHG accounting rules and issues for sustainability, consider options for modifying polices to *appropriately reward* operators undertaking bio-CCS.[2]

In making such an assessment, the full value chain for different bio-CCS pathways are considered, covering, *inter alia*, growing, harvesting, distribution, processing, retail and consumption of final products (e.g. fuels, electricity). Within this, the GHG accounting rules for each stage of the value chain are reviewed in order to assess how life-cycle GHG emissions are accounted for, as well as

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[1] In this report: *recognise* means reveal negative emissions through the accounting methodologies and reports; *attribute* means to allocate the negative emission reduction to the entity employing the technology; *reward* means to assign benefits to the entity employing the technology, including the negative quotient of reductions.

[2] *Appropriately reward* in this context means to assign a level of benefit commensurate with the true level of emission reductions achieved.

to consider the scope for *leakage*[1] to occur and potential negative environmental effects driven by e.g. land use change (LUC – both *direct* and *indirect*, or "dLUC" and "iLUC"; see Section 2.5). Based on this assessment, it is essential to understand how policies and measures create incentives at different parts of the chain, and what potential effects could arise as a result of potential leakage and/or transboundary issues.

1.4 Scope of the study

In terms of the ***sectoral scope***, the study is relevant to GHG accounting rules applicable to bio-CCS in electricity generation, bio-CCS in industry, and bio-CCS in liquid fuel production (see Annex A). The different value chains or pathways for bio-CCS highlighted above are also subject to different sets of policy and regulation, and as such can provide opportunities for cross-learning between different sectors. For example, the challenges of implementing the EU Renewable Energy Directive (EU RED)[2] for biofuels and the related revisions to the EU Fuel Quality Directive (EU FQD)[3] – which is essentially a 'portfolio standard' type approach for fuel suppliers across the whole value chain – highlights some of the pros and cons of taking such an approach in the electricity sector. Similar experiences can be seen for the California Low Carbon Fuel Standard under AB32.[4]

A second issue to consider is the ***geographical scope*** of the review. Presently it is mainly developed countries that have agreed significant GHG emission limitation and reduction targets and/or are implementing regional or national GHG emissions trading schemes that involve detailed MRV/GHG accounting provisions. Therefore, experience in these regions provides the core literature for the GHG accounting rule review. In general terms, however, issues associated with leakage, sustainability and dLUC/iLUC effects relate, in part, to developing countries that are supplying biomass or biofuels for use in developed countries. On this basis, an underlying theme in the study is the geographical distinction between developed and developing countries and the transboundary and leakage effects that can arise through asymmetric climate change mitigation policies. That said, developing countries also apply international GHG accounting rules to estimate their national GHG emissions and removals, and can also host project-based GHG crediting activities such as under the clean development mechanism (CDM).

On the basis of discussion above, the following GHG accounting rules as applied to bio-CCS related energy pathways are considered within the scope of the study:

- *International GHG accounting rules* – namely those available for national governments to use in preparing their country's GHG inventory reports under the *United Nations*

[1] *Leakage* in this context refers to the potential net changes in emissions occuring outside the boundaries and operational control of a particular policy and/or activity, but arising as a consequence of the policy and/or activity. In the case of bioenergy, this can arise from changes in land use in a one area or country which is supplying biomass to another area or country.

[2] Directive 2009/28/EC of the 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

[3] Directive 2009/30/EC of the European Parliament and of The Council of 23 April 2009 amending Directive 98/70/EC as regards the specification of petrol, diesel and gas-oil and introducing a mechanism to monitor and reduce greenhouse gas emissions and amending Council Directive 1999/32/EC as regards the specification of fuel used by inland waterway vessels and repealing Directive 93/12/EEC.

[4] California Global Warming Solutions Act, 2006 ("AB32"). Implemented in CCR: Title 17, Subchapter 10, Subarticle 7. §95480-95490.

Framework Convention on Climate Change (UNFCCC). For this assessment, the focus is on the most recent edition, the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006 GLs; IPCC, 2006) as these are likely to be in force from 2015 (see Table 2.1). The approach taken is economy-wide and includes accounting rules for both CO_2 emissions and removals by GHG sinks such as forests and other types of land use;

- *Regional, national and sub-national GHG accounting rules* – these cover policy measures in place to control GHG emissions in various jurisdictions, such as cap-and-trade based ETSs, and the attendant GHG accounting rules in force thereunder (see Table 2.1). Key amongst these are the *EU ETS Monitoring and Reporting Regulation* (EU MRR),[1] *AB32 Mandatory Greenhouse Gas Reporting Rule* (applied in California's emissions trading scheme),[2] the US EPA *Greenhouse Gas Reporting Program* (GHGRP),[3] and the Australia *Carbon Pricing Mechanism* (CPM) and *National Greenhouse and Energy Reporting Act, 2008* (NGER).[4] These schemes are focussed on sectors of the economy with the highest point source emissions, such as power and industry, and mainly employ cap-and-trade principles. The schemes' general architecture and boundaries can create issues for recognising negative emissions;
- *Project-based schemes GHG accounting rules* – project-based GHG offset schemes can provide useful guidance on GHG accounting rules. The main scheme in this context is the CDM. Whilst specific issues relating to bio-CCS activities have not been addressed, analogues within the schemes can be drawn upon to highlight potential approaches to GHG accounting with this scope of the study. One example is the way in which the CDM has developed accounting rules for leakage in biomass-based projects (see Section 2.5).
- *Product-based schemes* – such as low carbon fuel standard schemes that set portfolio standards on the GHG intensity of fuels sold and used in certain market. These include California's Low Carbon Fuel Standard (LCFS) and the EU RED/FQD, and primarily the rules for calculating biofuel GHG intensity and managing sustainability. These policy instruments adopt a portfolio standards/mandates approach on operators to limit the GHG emissions associated with the supply of energy products – namely liquid transport fuels – into markets.

In undertaking the study, it was not possible to review GHG accounting rules for every GHG policy and measure in operation around the world. Such a review would involve a considerable amount of research effort and would be unlikely to garner any enhancement of the understanding of the issues. Rather, a selection of schemes was made in order to obtain representative insights from a broad range of regional and sectoral settings, covering:

- Different parts of the world (International, Europe, USA, Australia, developing countries);
- A range of mechanisms (e.g. cap-and-trade, project- and product-based); and;
- Different bio-energy pathways (biomass use in power, industry and liquid biofuels).

A summary of policies and measures reviewed is outlined in Table 2.1.

[1] Commission Regulation (EU) No 601/2012 of 21 June 2012 on the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and Council.
[2] California Govt, Mandatory Reporting of Greenhouse Gas Emissions (title 17, CCR §95100-95157).
[3] US EPA, Final Rule on Mandatory Reporting of Greenhouse Gases (Title 40, CFR Part 98).
[4] The Regional Greenhouse Gas Initiative (RGGI) in the North Easter States of the USA was not included in the review.

The policy instruments described and the underlying GHG accounting rules all provide a basis for estimating the relative climate mitigation benefits achieved through application of emission reduction measures. As such, it is important that they appropriately recognise and reward the negative emissions that can be achieved through technologies such as bio-CCS so that benefits are applied accordingly.[1] It is important to note that since biomass combustion is considered to have zero emissions, it generally already avoids any penalties under GHG regulatory frameworks. This means that additional measures or incentives for negative emissions may be necessary to make such technologies an attractive option for investors, and to promote it ahead of simply combusting biomass and emitting the CO_2 generated to the atmosphere. This aspect is a key consideration for the research presented in this report.

1.5 Approach

The issues described above set the backdrop for the research described in this report. The focus of the study is on bio-CCS, although many of the considerations described may equally apply to other negative emission technologies such as direct air capture. The report is structured as follows:

- **Chapter 2** describes the current GHG accounting rules applicable to bio-CCS based on the various schemes outlined above, and whether they can appropriately *recognise* and *attribute* negative emissions within their scope;
- **Chapter 3** considers whether the various schemes reviewed allocate *rewards* for negative emissions so as to incentivise uptake of such technologies;
- **Chapter 4** considers the *appropriateness* of rewards, taking account the net environmental benefits of negative emission technologies and also the potential sustainability and land use change effects of biomass cultivation;
- **Chapter 5** sets out the main conclusions from the study and recommendations for further work.

Annex A also provides an overview of the various pathways for employing bio-CCS and the expected future trends in bio-CCS uptake as part of a broad portfolio of measures to limit mean global temperature increases to less than 2°C in 2100.

[1] For conventional fossil fuel based technologies using CCS, the net benefit can only tend towards zero.

2 RECOGNISING AND ATTRIBUTING NEGATIVE EMISSIONS

2.1 Introduction

In the introductory chapter of this report (Chapter 1), the scientific basis for bio-CCS and negative emissions was outlined. This suggested that, in general terms, bio-CCS can lead to a net removal of CO_2 from the atmosphere and therefore lead to "negative emissions" (Box 1.1).

The purpose of this Chapter is to assess whether the GHG accounting rules in place at various levels, as applied to various biogenic CO_2 source streams (see Figure 2.2 for examples of the source streams), *recognise* and *attribute* the scientific basis for "negative emissions".

In making this assessment, the main issue with recognising the benefit is whether the GHG accounting rules appropriately reveal that a negative emission is occurring; under some schemes such as the European Union Emissions Trading Scheme (EU ETS),[1] its design incentivises regulated entities to reduce emissions towards zero, the level at which costs/penalties under the scheme are avoided. No additional reward is available for going below zero, and because of this, its GHG accounting rules do not make a provision for negative emission reductions to be recorded, at least at the installation level (Groenenberg and Dixon, 2011).

The existence of different GHG accounting rules, applied at different levels, also mean that the benefits of negative emissions can also be recognised and attributed to different entities: it could be a *country* where a bio-CCS activity takes place with the reductions counting towards any regulatory GHG emission reduction targets imposed under international law (i.e. under the UNFCCC and Kyoto Protocol); or it could be an *operator* undertaking the activity, where the benefits may also need to be recognised and attributed under regional, national or sub-national GHG policy instruments in place in those jurisdictions, or through project-based emissions trading schemes such as the CDM.

This *geographical* distinction is an important consideration for assessing the appropriateness of the various GHG accounting rules in place under different schemes, as often the schemes are designed for different purposes, with specific approaches taken for certain sectors of the economy, and therefore use different reporting boundaries and so on, as discussed further below. To capture these geographical variations in approaches, a non-exhaustive range of GHG accounting rules applicable at different scales have been reviewed, as outlined in Section 1.4.

Prior to presenting the assessment of the different scheme rules, some of the key concepts and principles for GHG accounting are outlined. These provide an important basis for understanding the subsequent analysis of the different GHG accounting rules.

2.2 Key concepts in GHG accounting

As with any accounting framework, GHG accounting is underpinned by several important principles which ensure that GHG inventories compiled use methods that provide a true reflection of the actual GHG emissions and GHG removals taking place within the time period

[1] Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community (consolidated version).

applied for the inventory – usually a calendar year. This requires that the inventory is compiled in a transparent, complete, consistent, comparable and accurate way.

When considering different levels of GHG accounting – be it country, organisation, installation or product – an extremely important aspect to consider is the inventory *boundary*. This is critical to capturing – or not – the effects of geographical variations and the risks posed by carbon leakage as a result of asymmetric carbon polices in place across jurisdictions.

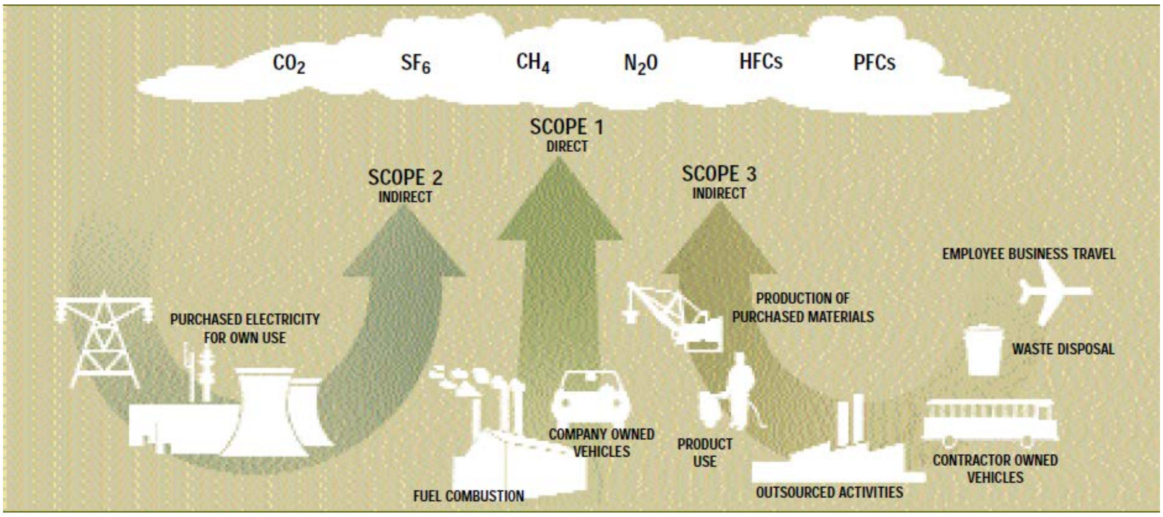
2.2.1 Understanding accounting boundaries

The GHG inventory *boundary* determines the scope of gases and emission sources and/or removals by sinks to be included within the inventory, which will vary according to the purpose, scope and rules under which the GHG inventory is going to be used. Typically, in scoping the boundaries a distinction can be made between:

- *Direct emissions* ("scope 1"), which are those arising from within the boundaries of a specific activity; and,
- *Indirect emissions* ("scope 2" and "scope 3" emissions), which are those occurring outside of the boundary but potentially attributable to the activity (e.g. emissions from power generation related to bought-in electricity).

These differences are summarised graphically below (*Figure 2.1*).

Figure 2.1 Overview of scopes and emissions



Source: WBCSD/WRI (2004)

Different boundaries will apply for different scales and different purposes of GHG accounting. For example, a country's national GHG inventory should include all emissions sources within its national territory i.e. be economy-wide covering all relevant sectors. In this case, distinctions between *direct* and *indirect* emission sources do not generally apply as all sources will be *direct emissions* as they will fall within the country's territory, and emissions associated with imported products are excluded. In the case of imported electricity, the emissions will be attributed to the country where the power was generated.

In cap-and-trade based emissions trading schemes such as the EU ETS, generally only sub-sectors of the economy are covered, and the regulatory regime applies only to *direct emissions* from qualifying activities included in the scheme; *indirect emissions* are not considered.[1] Conversely, for project-based accounting such as the CDM, careful consideration of the boundaries is often necessary in order to accurately determine the net effects of implementing a specific project in one place and potential effects on emissions elsewhere, in particular so as to avoid perverse outcomes e.g. leakage.[2] This aspect is pertinent for projects in developing countries as in general there are limited economy-wide controls on GHG emissions in place, meaning leakage can occur without any measures being available to restrict emissions and/or penalise emitters. Similarly, product-based accounting, such as for low carbon fuel standards, should take account of the full life-cycle emissions arising from the production, transport and use.

2.2.2 Consistency and comparability

A further consideration is that, in principle, a consistent approach should be taken to GHG accounting and inventory compilation across installation, project, product, corporate and national levels. This ensures that a compatible and comparable approach is taken that allows data collected through monitoring to be used to fulfil various different objectives (e.g. installation GHG emissions inventory; national GHG inventory; corporate GHG emissions inventory). This becomes important when assessing the GHG accounting rules applicable to different inventories, as in theory they should all dovetail together to create a universal approach to inventory compilation (Box 2.1).

Box 2.1 Linking national inventories and national climate policies

National GHG inventories are generally compiled by countries as part of their obligations under the UNFCCC. It is a record of all emissions of GHGs from various source sectors in the country, removals by carbon sinks, and changes in C-stocks arising as a result of land use changes taking place in its territory. It is applied for a given calendar year. It is typically presented on a sectoral basis, compiled in accordance with guidelines established by the Intergovernmental Panel on Climate Change (IPCC; see Table 2.1).

For countries bound by emission limitation targets under the Kyoto Protocol, the annual national GHG inventory provides the basis for compliance with these targets. As such, where the burden of meeting these targets is passed on to various parts of the economy – for example through the application of policies such as the EU ETS (where private sector participants are expected to make the reductions) – the GHG accounting rules (or "monitoring and reporting rules") for that scheme should be consistent with the international rules to ensure that the efforts made by participants can be recognised in the national GHG inventory. For this reason, GHG accounting rules at a national and international level are closely linked; if the rules are not compatible, actions taken by private entities under national polices and measures cannot be recognised in the national GHG inventory, and conversely, if actions are recognised at the country level but not passed on to the private entities, the incentive to take action is not passed on. Consequently, governments need to be mindful of this requirement when designing incentive policies for low carbon technology deployment.

[1] Under the EU ETS, boundaries are defined by the operator, but must include all relevant GHG emissions from all sources belonging to qualifying activities carried out at the installation.

[2] Boundaries for a CDM project must encompass all anthropogenic emissions by sources of greenhouse gases under the control of the project participants that are significant and reasonably attributable to the CDM project activity. Under CDM, leakage is defined as any anthropogenic emissions by sources of greenhouse gases which occurs outside the project boundary, and which is measurable and attributable to the CDM project activity.

In general, the principle means that the most stringent rules applied should apply, *de facto*, to all GHG accounting and inventory methods used to estimate GHG emissions. As will be seen in subsequent sections of this report, this is an important aspect for the different GHG accounting rules applicable to CCS.

2.2.3 Linking schemes

Building on the linkage between national inventories and GHG accounting rules for national policies, then by extension, GHG accounting rules for different ETSs – both cap-and-trade and project-based approaches – need to be established on the same basis. It is a fundamental requirement for any market-based approach that the incentive provided is commensurate with the level of emission reductions achieved, and that the calculation of emission reductions be carried out using a comparable methodology. Or in other words: a ton of CO_2 emissions reduced at one installation or through one project activity should be equal and therefore *fungible* (i.e. interchangeable) with a ton of CO_2 emissions reduced in another. This requirement is equally applicable in the case of a carbon tax, where a tCO_2 of emissions reductions achieved – and therefore a quantum of tax avoided – by one regulated entity is equivalent to that of another regulated entity. This requirement is critical to ensuring that the policy objectives of such schemes are achieved in a consistent way and their environmental integrity is not compromised. A key element of emissions trading scheme or carbon tax design – and in particular ETS scheme linkage – is therefore enforcement of similar GHG accounting rules. Where schemes differ substantially, or employ different rules, the scheme operator will typically impose restrictions on scheme linkages.

2.2.4 Assessing GHG accounting rules in relation to negative emissions

The concepts and principles outlined above are the cornerstone of good environmental policy making in the field of low carbon technology development, carbon pricing and market-based mechanisms. They therefore form an important backdrop to the discussion presented in the following sections regarding how bio-CCS is currently included within various GHG accounting rules for inventory compilation.

To achieve a deeper understanding of the appropriateness of different GHG accounting rules to recognise and attribute negative emissions, the assessment focuses on the treatment of GHG emissions across the bio-CCS value chain in the following five contexts:

1. How CCS is included within a scheme's GHG accounting rules;
2. The way in which biomass growth, harvesting and combustion and processing emission sources from the conversion of biomass to energy, including final use, are accounted for;
3. Whether and how direct and/or indirect land use changes arising from biomass cultivation are effectively taken into account;
4. Whether other emissions occurring in the supply chain are included in the scheme (e.g. emissions arising from the transport of biomass); and,
5. Whether the combination of the rules assessed in the context of 1-4 above can appropriately allow for negative emissions to be recognised and attributed to the entities included in the scheme.

Points 1 and 2 determine the capacity of the scheme to recognise CCS as an emission reduction technology and biomass combustion or processing as a zero-emissions activity (see Box 1.1);

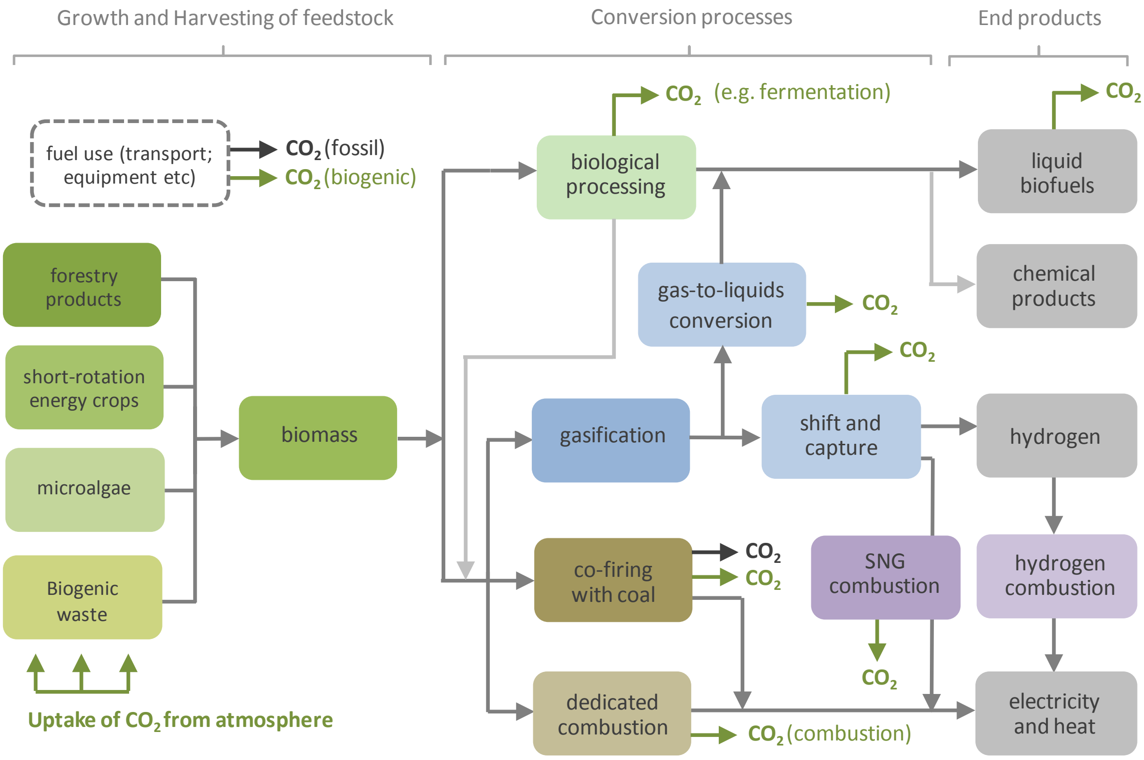
points 3 and 4 relate to the whether the full GHG emissions associated with biomass production are taken into account; point 5 is essentially the culmination of points 1-4 in terms of whether the scheme can potentially recognise negative emissions i.e. whether a zero-emission from biomass conversion is subsequently deducted when capturing and storing such sources, leading to negative emissions.

The review presented attempts to outline the treatment of these aspects under various GHG accounting rules in order to illustrate how the issues link together and highlight where the main challenges for negative emission technologies such as bio-CCS may lie.

A summary description of the schemes reviewed is provided in Table 2.1 below.

The potential biogenic CO_2 emissions sources to which CCS could be applied is illustrated in the schematic below (Figure 2.2). It is useful to note that it is not just at the point of final end use of bio-energy products, but also at intermediate conversion steps such as in biofuels refining or the gasification of biomass to produce synthetic natural gas (SNG).

Figure 2.2 Bioenergy pathways and sources of CO_2



Source: adapted from Rhodes and Keith, 2005

Table 2.1 Summary of GHG schemes and accounting rules reviewed

<table>
<tr><th>Scheme</th><th>Description</th><th>GHG Accounting / MRV Rules</th></tr>
<tr><td>UNFCCC reporting of national GHG inventories</td><td>Under the UNFCCC, all Parties must develop, periodically update, publish and make available to the Conference of Parties (COP), national inventories on GHG emissions and removals by sinks using comparable methodologies as agreed by the COP (Articles 4 & 12). Reporting requirements vary between Parties: Annex I Parties are obliged to annually report national GHG inventories of anthropogenic emissions and removals by sinks in a common reporting format (CRF): non-Annex I Parties are only required to report periodically. Since COP17, both Annex I, and all but the Least Developed and small island states non-Annex I Parties are obliged to report biennial updates of National Communications, including national GHG inventories.</td><td rowspan="2">The Intergovernmental Panel on Climate Change (IPCC) is mandated by the COP to develop appropriate national GHG inventory compilation guidelines. Currently three guidelines are applicable in the first commitment period of the Kyoto Protocol (CP1), namely the:
• Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (1996 GLs)
• IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000 GPG)
• IPCC Good Practice Guidance for Land Use, Land Use Change and Forestry (2003 GPG LULUCF)
In the future (likely applicable from 2015 onwards during Kyoto Protocol CP2, 2013-20), Annex I Parties will need to use the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 GLs) and also publish Biennial Reports using a CRF. In addition, Biennial Update Reports containing national inventories following the 1996 GLs, the 2000 GPGs and the 2003 GPG LULUCF is encouraged for non-Annex I developing countries Parties from December 2014, excluding the least developed country Parties. Scope for future reporting by non-Annex I Parties using 2006 GLs is also foreseen.
The 2006 GLs outline a modified approach to inventory compilation compared to the 1996 GLs, which followed the Kyoto Protocol CRF (see left). The 2006 GLs are organised as follows:
Vol 2: Energy (CRF 1)
Vol 3: Industrial Processes and Product Use (CRF 2 & 3)
Vol 4: Agriculture, forestry and land use (AFOLU; CRF 4 &5)
Vol 5: Waste</td></tr>
<tr><td>Kyoto Protocol compliance with assigned amounts and IET</td><td>The Kyoto Protocol sets quantified emission limitation or reduction obligations (QELROs) for Annex B Parties, which are measured in assigned amount units (AAUs) equal to 1 tCO_2-e; AAUs are determined by the countries national GHG inventory. It is essentially a GHG cap-and-trade scheme, with AAUs being tradable between Annex B Parties. “Offset” units from the project-based CDM and JI may also be used to meet compliance requirements (see below). Annex I Parties may also issue Removal Units (RMUs; equal to $1tCO_2$-e) where there is a net increase in the carbon stock of the relevant sink from Land Use, Land Use Change or Forestry (LULUCF) activities under Article 3.3 and 3.4 of the Protocol. RMUs can be used towards compliance with QELROs. National GHG inventories under the KP must be reported in accordance with the CRF by sector covering:
Sector 1 – Energy (fuel combustion; fugitive emissions)
Sector 2 – Industrial Processes
Sector 3 – Solvents and other product use
Sector 4 – Agriculture
Sector 5 – LULUCF
Sector 6 – Waste
Sector 7 – Other
A range of supplementary information must also be provided, e.g. for LULUCF.</td></tr>
<tr><td>Kyoto Protocol clean development mechanism (CDM)</td><td>The CDM is a project based mechanism. Under the Kyoto Protocol, Parties with a QELRO may acquire Certified Emission Reductions (CERs) from CDM projects in developing countries. CERs, which equal $1tCO_2$-e, can be used towards a Party’s reduction target, and as such act as an “offset” mechanism by reducing the Party’s obligation to reduce emissions domestically.
In the EU, the approach has been privatised to an extent by allowing regulated entities in the EU ETS to surrender CERs towards their obligations.</td><td>The CDM modalities and procedures (CDM M&Ps) is the rulebook for CDM (UNFCCC, 2005). It sets out, inter alia, governance, participation, verification requirements for CDM projects. To date, four CDM M&Ps have been established for different project types, including specific M&Ps for Afforestation/Reforestation and CCS (CCS M&Ps). At a project level, specific Approved Methodologies (AMs) must be developed according to the M&Ps that set out the project-type specific GHG accounting rules, the basis for calculating the CERs generated by a project. The approach to implementing the AM for a project must be set out in a Project Design Document (PDD), which must be submitted to the CDM Executive Board for Registration.</td></tr>
</table>

Scheme	Description	GHG Accounting / MRV Rules
Kyoto Protocol joint implementation (JI)	JI is a *project-based mechanism*. Under the Kyoto Protocol, Parties with a QELRO may acquire Emission Reduction Units (ERUs) from JI projects in other Annex B Parties, as applied in the same way as the CDM.	The JI sets *eligibility requirements* for the Party's inventory quality/system for tracking AAUs, which if met, allows the Party to issue ERUs as additional without the need to apply a project specific approach. This is termed JI "Track 1". If the eligibility criteria are not met, the activity must be approved by the JI Supervisory Committee by submitting a PDD following a procedure similar to CDM – termed JI "Track 2".
EU GHG emissions trading scheme (EU ETS)	The EU ETS implements a *GHG cap-and-trade scheme* across the EU-27 plus 4 non-EU countries, covering more than 11,000 large GHG emitting installations such as power stations, cement plants, steel works etc. Allowances (EUAs) are auctioned by the EC, with certain trade exposed sectors receiving a free allocation against a benchmark. It is currently in Phase III, running 2013-2020. ERUs from JI and CERs from the CDM may be used for compliance purposes, subject to EU enforced *quantitative* and *qualitative* restrictions on certain types of CERs e.g. large hydro; afforestation/reforestation; industrial gas projects are all banned, whilst CERs from projects registered *after* December 2012 are only eligible when located in a Least Developed Country or country with a bilateral agreement with the EU (none of the latter yet exist).	Regulation No. 601/2012 on monitoring and reporting (the "MRR") sets down rules for MRV for qualifying installations in Phase III of the scheme. The EU CCS Directive establishes a legal framework for the environmentally safe geological storage of CO_2 in the EU-27, which includes MRV requirements for CO_2 storage sites in the EU, and underpins inclusion of CCS in the EU ETS.
EU Renewable Energy Directive (EU RED) and the EU Fuel Quality Directive (EU FQD)	The EU RED and FQD implements a *portfolio standard* for fuel suppliers, based on reaching a target of 10% renewable transport fuel use in the EU by 2020. Under the FQD, fuel suppliers in the EU are required to annually report the GHG intensity of fuel and energy supplied and used within each Member State according to: • the total volume of each type of fuel or energy supplied, indicating where purchased and its origin; and • life cycle GHG emissions per unit of energy. The 10% reduction target is made up of various components: • a 6% reduction of the GHG intensity of fuels by 2020 compared to 2010* • an additional 2% from technologies capable of reducing life cycle GHGs (including CCS), and • a further 2% through the purchase of CERs from the fuel supply sector. *Eligible fuels must have a GHG intensity at least 35% lower than the fossil fuel comparator, increasing to 50% in 2017, and 60% in 2018 (for new installations).	The GHG intensity of biofuels should be calculated in accordance with Article 19 of the RED/Article 7(d) of the FQD (2009/30/EC). This sets out two approaches involving either: • a default emissions intensity relative to fossil fuels, as set out in parts A and B of Annex V of the RED (FQD Annex IV); or • following a prescribed method as set out in Sections C, D and E of Annex V of the RED (FQD Annex IV). Calculation of the GHG intensity of fossil fuels, as well as means to incorporate reductions achieved through technologies capable of reducing life-cycle emissions and the use of CERs, should be undertaken according to a methodology developed under FQD Article 7a(5). Proposed approaches and methods were consulted on during 2009/2010, although a final agreement has yet to be reached.
US EPA GHG Reporting Program (GHGRP) – 40 CFR Part 98	The US EPA GHGRP is designed to help the EPA better understand sources of GHGs to help make informed policy, business, and regulatory decisions. Any facility in the US which emits > 25 ktCO_2-e/year is required to annually report its emissions of relevant gases. Presently nearly 8,000 facilities in the US are reporting GHG emission under the rule. *NOTE: the GHGRP covers only reporting requirements, and does not impose caps or reduction targets on facilities.*	The GHGRP has a wide number of subparts which set out the accounting rules applicable to different GHG emitting facilities. No subparts specifically relate to biomass reporting, although this is covered for the different sectors in each subpart where relevant. Two subparts pertain directly to CO_2 storage activities: subpart RR and subpart UU. Only subpart RR allows amounts of CO_2 injected to be reported as sequestered, and applies to wells regulated under the US EPA UIC Class VI, which also includes extensive provisions relating to MRV for CO_2 storage sites.

Scheme	Description	GHG Accounting / MRV Rules
California Emission Trading Scheme	Assembly Bill (AB) 32 – the Global Warming Solutions Act – sets down the basis for a *GHG cap-and-trade scheme* in the US State of California. It applies to a range of activities including power plants, refineries, cement kilns and various other industrial plants that emit >25 ktCO_2-e/year in the State, covering around 350 installations. The scheme involves the use of auction and free allocation to distribute the trading units (California GHG Allowances) in the cap. It includes provisions for linkages (none yet established) and allows the use of offsets from various domestic schemes, such as Forest and Livestock Projects, as well as projects developed by Air Resources Board (ARB)-approved Offset Project Registries: currently the American Carbon Registry (ACR) and the Climate Action Reserve (CAR). Credits from these registries must be converted to ARB-approved units for use in the ETS	MRV rules are set out in California Code or Regulation, Title 17, Division 3, Chapter 1, Subchapter 2, Article 2: Mandatory Greenhouse Gas Emission Reporting. This includes a range of provisions including MRV rules for 'Carbon Dioxide Suppliers' and guidance on 'Biomass derived fuels'. The ACR and CAR have so far established around 30 offset methodologies covering a range of activities. The ACR recently consulted on a new offset methodology for CCS in Oil and Gas Reservoirs, although this will not be able to directly link to the California ETS until approved by the ARB.
California Low Carbon Fuel Standard (LCFS)	AB32 also included the LCFS. It is a *portfolio standard* designed to reduce GHG emissions by reducing the "carbon intensity" of transportation fuels used in California by an average of 10% by the year 2020. This covers GHG emissions associated with the combination of all of the steps in the "life-cycle" of a transportation fuel, including direct GHG emissions associated with the production, transportation, and use of each fuel. For some biofuels, it also includes GHG emissions resulting from land use changes associated with the fuel. It includes a sliding scale of targets to be met. Suppliers may trade "credits" and "debits" to meet their obligation.	Enforcement of the LCFS is dependent on reporting by fuel suppliers in the State using various methods: *Method 1* – ARB carbon intensity lookup table for various fuels. This is incorporated into a model called "CA-GREET" which includes a wide range of default factors that should be used to calculate GHG intensity of the fuel; *Method 2A* – Customised ARB lookup values. This involves suppliers adopting alternative values in the CA-GREET model, subject to approval; *Method 2B* – New Pathway under CA-GREET. This involves the development of a new set of values for a specific fuel pathway currently not included in CA-GREET ; These methods also include consideration of the land use change emissions, where relevant.
Australia Carbon Pricing Mechanism (CPM)	The CPM is a carbon tax that will transition to *GHG cap-and-trade* scheme for large emission sources in Australia, covering approximately 60% of the country's emissions including electricity generation, stationary energy, landfills, wastewater, industrial processes and fugitive emissions. It involves two stages: • *Fixed price*—The carbon price is fixed for the first three years. In 2012–13 it is \$23/tCO_2-e, in 2013–14 it is \$24.15/t and in 2014–15 it is \$25.40/t. Liable entities can purchase units up to their emissions levels. Purchased units cannot be traded or banked. • *Flexible price*—From 1 July 2015 the price will be set by the carbon market, with allocation based on auctioning of units up to a cap set by regulation. The CPM will link with the EU ETS and allow the use of CERs, as well as domestic ACCUs generated under the Carbon Farming Initiative (CFI). Offset use is restricted to 50% of an entities total liability.	CPM liable entities must monitoring and report emissions to the Clean Energy Regulator under the *National Greenhouse and Energy Reporting Act* (2007) and related implementing provision (e.g. the *National Greenhouse and Energy Reporting Regulations*, 2008; and the *National Greenhouse and Energy Reporting (Measurement) Determination*, 2008. Projects developed under the CFI are required to develop specific GHG accounting methodologies, which are subject to approval by an appointed Board, in a similar ways as for CDM.

2.3 Carbon capture and storage

2.3.1 General principle

CCS involves the separation of CO_2 from industrial and energy related emission sources, its transport to a storage location and its injection and storage in suitable geological formations to achieve long-term isolation of the CO_2 from the atmosphere. On this basis, the general principle underpinning climate policy design for CCS support is recognition of captured and stored CO_2 as "not emitted" to atmosphere, and/or recognition of the technology as a "non-emissive end-use" (US EPA term). This typically requires the monitoring of CO_2 flows through the capture, transport and injection system to quantify the mass of CO_2 captured and therefore not emitted, monitoring of the capture and transport system to quantify any fugitive emissions (i.e. leaks), and comprehensive geological storage site monitoring to provide assurances that the injected CO_2 remains in the intended geological formation and isolated from the atmosphere over the long-term and to quantify any leaks that occur. Storage site monitoring is essential to manage the risk of *permanence*. Impermanence can negate at least part of the environmental benefits achieved by CCS, compromising the effectiveness of policies and measures designed to support the technology, and serving to undermine the environmental integrity of any emission reduction units awarded to a CCS project under an emission trading scheme or CO_2 tax. For this reason, a key focus of GHG accounting rules for CCS is on managing permanence risk (Box 2.2).

Box 2.2 Permanence in GHG accounting

The use of CCS as a climate mitigation technology introduces concerns over permanence because CO_2 formation is not eliminated, but rather its emission is avoided by injection into geological reservoirs rather than to the atmosphere. Concerns over permanence arises *vis-à-vis* the possibility that the injected CO_2 could leak from the subsurface back to the atmosphere at some future point in time. To address this matter, three essential elements are generally employed in regulatory approaches as part of a risk management framework to manage impermanence risk:

1. To assure project integrity and to reduce the likelihood of impermanence arising, a range of upfront conditions on, *inter alia*, site selection and characterisation must be applied; this is because a key part of achieving permanent storage is the selection of a high quality geologically storage site in the first place;
2. Rules and regulatory oversight of storage site operation and closure is needed to ensure that it is effectively managed so as to reduce the risk of leakage occurring due to poor practice. A key part of this oversight is the imposition of robust MRV requirements;
3. Short-, medium- and long-term responsibility for the stored CO_2 must be allocated, with the responsible party accepting liability to remediate any damage caused by leakage, including the replacement of an equivalent amount of units to any quantities of CO_2 leaks determined to have occurred.

This combination of requirements can provide assurances that permanence may be achieved for many 100's if not 1000's of years. Such assurances serve to maintain the environmental integrity of polices and measures designed to support CCS and also for emissions trading schemes into which CCS-derived units are sold. A consequence is that inclusion of CCS in emissions trading is typically underpinned by regulatory approaches to control site development, operation and closure and to allocate liability across the project life-cycle.

Carbon is also stored in biological form in biomass and soils, such as in forests and grasslands, and can be enhanced through land use measures such as afforestation and/or reforestation. Concerns over permanence arise because of the reversibility of such activities either through human activity, natural disturbances and/or climatic events and climate change. In order to address concerns over impermanence, approaches such as temporary crediting have been applied to afforestation/reforestation (A/R) under the CDM, and the evolution of complex GHG reporting rules for the LULUCF sector in national inventories (see Box 2.4). Approaches using risk management frameworks (as applied for CCS) have generally not been favoured by policy-makers. Options include the use of forest management standards.

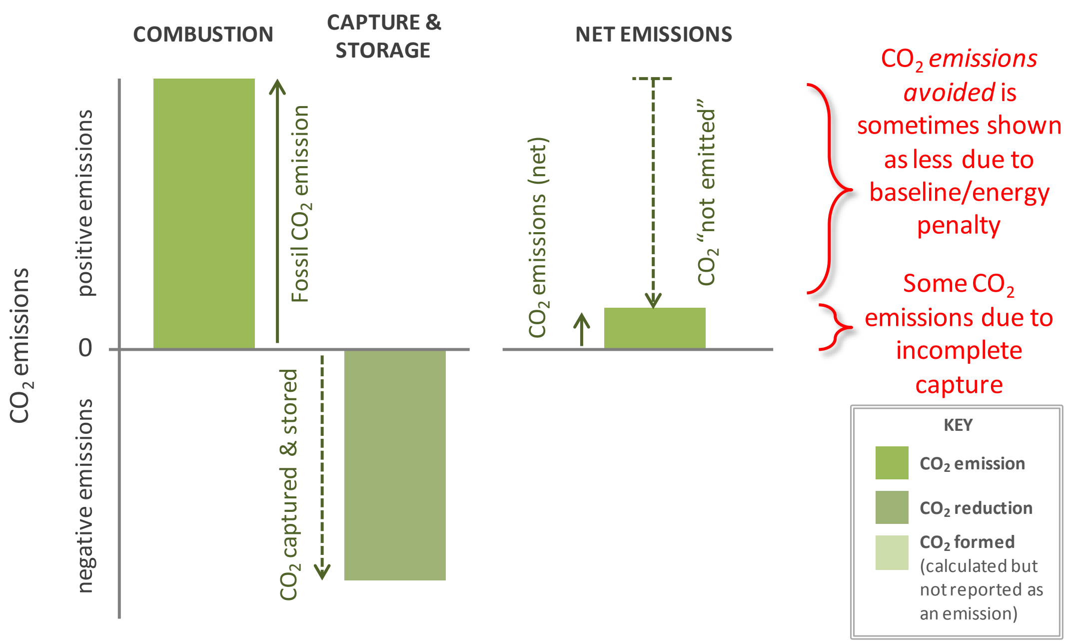
Key issues for GHG accounting:

- Whether captured and stored CO_2 is recognised as not emitted, and on what basis?
- What monitoring requirements are needed to support the assumption of being "not emitted (i.e. for the management of permanence); and,
- How emissions and emission reductions are attributed across the chain of capture, transport, injection and storage.

The general principle is summarised graphically below (Figure 2.3); this shows the formation of CO_2 from conversion processes as a positive emission (e.g. during conversion to fuels – in this example, assumed from fossil fuels), and the capture and storage of CO_2 as a negative emission that is subtracted from the amount formed. The result is typically a small net emission attributable to the installation where the CO_2 was generated, a result of incomplete capture of the CO_2. Sometimes the net emission reductions achieved by CCS are shown relative to an equivalent unabated plant (i.e. the unabated plant is the baseline against which the effectiveness of the CO_2 capture activity is measured against). In these cases, the *emissions reduction* is less than the *emissions avoided* because of the additional energy and emissions arising from the power used for the capture process – this effect is known as the "energy penalty".

Approaches to recognising these principles in various GHG accounting frameworks are described in the next sections.

Figure 2.3 GHG accounting for CO_2 capture and storage



Source: Carbon Counts

2.3.2 Recognising captured and stored CO_2 as not emitted

In general, all of the schemes reviewed allow for captured and geologically stored CO_2 to be recognised and accounted for as "not emitted". In nearly all cases, this is dependent on monitoring of CO_2 storage sites to provide assurances over the permanence of emission reductions achieved through CCS (see Box 2.2).

Under **international GHG accounting rules**, which for the first time included guidance on GHG accounting for CCS in national GHG inventories in the 2006 GLs, the following principle applies:

> *"Where CO_2 emissions are captured from industrial processes or large combustion sources, emissions should be* ***allocated to the sector generating the CO_2 unless it can be shown that the CO_2 is stored in properly monitored geological storage sites*** *as set out in Chapter 5 of Volume 2."* (Volume 1, Chapter 1, pg. 1.6)

This means that a country's national GHG inventory may only report captured and stored CO_2 as "not emitted" in the relevant source category (e.g. the energy sector) where IPCC guidance for monitoring CO_2 storage sites is followed. For example, even if a national GHG inventory report showed that a power plant captured its CO_2, it would have to assign the CO_2 generated by the power plant as emitted to the atmosphere in the *Energy Sector* total unless it is also shown that the storage site is being "properly monitored" in accordance with *Volume 2, Chapter 5*. Guidance provided in Volume 2, Chapter 5 sets detailed, site-specific (i.e. Tier 3; see Box 2.3), monitoring requirements for injection and storage, including aspects such as site characterisation, leakage risk assessment, and quantification of any leaks. As such, the 2006 GLs take a risk-based approach to managing permanence (Box 2.2), relying on detailed monitoring of the sites to allow countries to continue reporting the stored CO_2 as not emitted in their inventory.

The approach in the 2006 GLs is broadly mirrored in **regional cap-and-trade and GHG reporting schemes** and associated GHG accounting rules (see also Box 2.1). In the **EU ETS**, under *Article 49* of the EU MRR, captured "fossil carbon" may be deducted from an installations GHG inventory, and therefore be accounted for as "not emitted" by the source installation, only where it is *transferred* to a storage site regulated under the EU CCS Directive. The EU CCS Directive sets down detailed requirements for, *inter alia*, site characterisation and selection, risk assessment and monitoring, allowing permanence to be managed following similar approaches to the 2006 GLs. As CO_2 pipelines and CO_2 storage sites are included as qualifying installations under the EU ETS, they must monitor, quantify and report any leaks of CO_2 and surrender EUAs equal to the amount determined to have leaked. This maintains the environmental integrity of the EU ETS. Similarly, under the **US GHGRP**, regulated entities may deduct amounts of CO_2 transferred offsite in accordance with *subpart PP* ("Carbon Dioxide Suppliers"), which requires such entities to report the amount of CO_2 transferred offsite and the end use application for which the CO_2 was transferred, including for long-term storage, where known. However, "geological sequestration" can only be reported by the injection facility where *subpart RR* rules are applied ("Geological Sequestration of Carbon Dioxide"), which must be accompanied by UIC Class VI regulatory oversight. These provide comprehensive approaches for site selection and management. Injection of CO_2 at sites regulated under Class II UIC rules must apply *subpart UU* of the GHGRP ("Injection of Carbon Dioxide"), which does not allow "geological sequestration" to be reported. In **Australia**, the CPM applies to a "covered emission" defined as emissions that are *"...released to the atmosphere*". On this basis, capture and storage of the CO_2 avoids CPM liabilities. Leaks from transport and storage still attract liabilities under the CPM, as they must be monitored under the *National Energy and Greenhouse Gas Reporting Act, 2008*. In **California**, CCS has yet to be included in the state-wide ETS on the basis that no California Air Resources

Board (CARB)-approved CCS "*quantification methodology that ensures that the emissions reductions are real, permanent, quantifiable, verifiable, and enforceable*" is in existence.[1]

Box 2.3 Tiers of approaches

The IPCC and EU ETS GHG accounting rules adopt Tiers of approaches, mainly with a view to either supporting inventory compilation using limited resources, or to reduce the cost of inventory compilation, especially where *materiality* of the source stream is low. The latter is the case for tiers as used in the EU ETS, with higher tiers imposing less rigorous uncertainty requirements on the data used.

Tiers in IPCC Guidelines

Under IPCC Guidelines, the lowest tier (Tier 1) is the most simple approach to calculating emissions and removals in certain sectors or sub-sectors, typically employing international default factors to make estimates of emissions or removals through changes in carbon stocks ("C-stock"). Tier 2 generally involves using country or region specific factors that are representative of the country, resulting in slightly better data resolution. Tier 3 methods usually involve using data and information specific to a particular project or activity, resulting in high inventory quality.

In the Guidelines, countries are advised to focus efforts on *Key Categories*, namely those that are most material to the country's national inventory, and use as high tiers as possible for these sectors in order to improve overall inventory quality.

A consequence of using different tiers is that the accuracy/spatial resolution of inventory data can be compromised when using lower tiers. This can result in the GHG inventory for a country – or sectors or sub-sectors in the country – not being a true reflection of the actual emissions or removals through C-stock changes taking place. This complicates matters for bio-CCS given the potentially long and complex value chains that cross international borders. For sources employing CO_2 capture, Tier 3 methods must be applied, meaning that the national GHG inventory should provide a true reflection of the emission reduction achieved. However, this is not the case for other parts of the inventory in particular for Forest Land and other land use categories, as discussed further below.

Project-based schemes such as the CDM and JI also allow for the recognition of CCS as an emission reduction technology. In the CDM, detailed rules and guidance for CCS project activities are set out in the recently-agreed *Modalities and procedures for carbon dioxide capture and storage in geological formations as clean development mechanism project activities* (CCS M&Ps).[2] The CCS M&Ps set out a risk-based approach to managing permanence, following similar lines to that under the 2006 GLs and as employed in the EU, US and Australia. In principle, this allows for fungibility of CERs generated by CCS with regional trading schemes as commensurate approaches to managing permanence apply (see Section 2.2.3). Under JI, Track 1 approaches would rely on the provisions of the 2006 GLs and any national implementing legislation to regulate CCS, whilst Track 2 procedures would likely mirror CDM requirements.

In the **low carbon fuel standards** reviewed, namely the California LCFS and EU RED/FQD, CCS could in principle be applied to biogenic CO_2 emissions arising during feedstock processing (e.g. emissions of CO_2 during fermentation of sugar cane juices at a bio-refinery) and potentially in other stages of the fuel production cycle (Figure 2.2). The **EU RED/FQD** rules for calculating the GHG intensity of different biofuels includes specific provisions for including CCS within the estimate (*Section C* of *Annex IV* of RED and *Annex V* of the FQD; see Table 2.1). The approach set

[1] California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. CCR Title 17, Subchapter 10, Article 5. §95852(g)
[2] UNFCCC, Decision 10/CMP.7

out in *Section C* of *Annex IV/V* does not provide guidance on how permanence should be taken into account for such activities. Further, the FQD also supports "*the use of any technology (including CCS) capable of reducing life cycle greenhouse gas emissions per unit of energy from fuel or energy supplied"* as a means for fuel suppliers in the EU to meet up to 2% of the 10% target for improvement of the GHG intensity of fuels sold in the EU market (see Table 2.1). In this way, the EU RED/FQD supports the application of CCS in both bio- and fossil-fuel production. Similarly, the **California LCFS** allows for CCS to be incorporated into the GHG intensity calculation for various fuels, including CARBOB[1], diesel or gasoline (by applying a credit for innovative methods such as CCS) and also, potentially, in the biofuels supply chain through so-called Method 2A and Method 2B options (see Table 2.1).

2.3.3 Attributing emissions and reductions across the CCS chain

Under **national GHG inventory guidelines** and in the **regional reporting and GHG cap-and-trade schemes** reviewed, the emission reductions achieved through CCS are recognised and attributed at the point of CO_2 generation. In the case of national GHG inventories, the amount captured and stored is deducted from the relevant source category in the inventory. For reporting under the GHGRP the amounts transferred from the installation is deducted from its inventory in accordance with *subpart PP*. Under the EU ETS and Australian CPM, the facility/installation where the CO_2 was generated is absolved of its liability for the CO_2 generated where the CO_2 is transferred offsite. In all cases, emissions occurring during transport, injection and storage would be attributed to the transport or storage installation.

In **project based schemes**, the entire chain of capture transport and storage would need to be included within the boundary of the project activity, resulting in the net emission reductions across the entire chain being recognised. Recognition and attribution of the emission reduction to different installations or entities across the chain is not relevant as all parts of the CCS chain would need to be included within the boundary of the CDM activity.

In the **low carbon fuel standards**, the emission reductions achieved through CCS in the production of a fuel are recognised at the point of product use (i.e. fuel combustion), rather than the point where the CO_2 was generated. This is because the GHG intensity calculated for the various fuel products in the scheme is based on the GHG emissions occurring across the supply chain, which could potentially include the use of CCS during upstream production (i.e. the GHG accounting methodology employs a boundary covering the entire supply chain). This approach can potentially lead to double-counting: for example, if a bio-refinery in Brazil applies CCS, the reductions could potentially be counted twice towards compliance under the EU FQD: once, in the GHG intensity calculation applied for fuel delivered from that refinery, and again a second time, if the activity generates CERs under the CDM that are subsequently used for compliance with the EU FQD in Europe (see Table 2.1). This may be one of the challenges delaying full implementation of the EU FQD in Europe at the current time.

[1] California Reformulated Gasoline Blendstock for Oxygenate Blending. It is the blendstock to which ethanol is added to produce finished California gasoline.

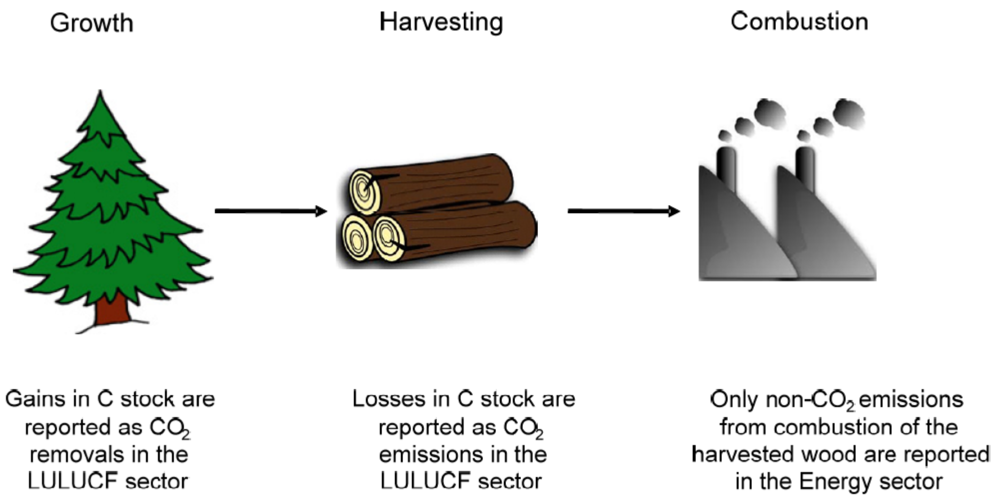
2.4 Biomass growth, harvesting, combustion and decay

2.4.1 General principle

The growth of biomass leads to the removal of CO_2 from the atmosphere through its absorption into the biological carbon pool, including in above ground biomass, dead organic matter, and soils (see Box 1.1). As such, land use activities can serve to remove CO_2 from the atmosphere and store it as organic carbon within the various pools, avoiding its release to atmosphere, albeit subject to issues of permanence (Box 2.2). The C-stocks in the various pools provides the basis for accounting for CO_2 removals from the atmosphere by GHG sinks i.e. the movement of carbon from the atmospheric C-stock to the biogenic C-stock. When standing *woody* biomass is harvested the carbon is removed from the biological C-stock, and for the purposes of GHG accounting is typically assumed to be immediately oxidised and emitted to the atmosphere, either through combustion or decay; consequently, this is recorded as an emission from the biogenic carbon pool. On this basis, when the *woody* biomass is subsequently combusted (e.g. for energetic purposes) or decays (e.g. through processing), CO_2 emissions arising from these processes do not need to be accounted for in a GHG inventory on the basis that this would lead to double counting[1] i.e. a debit on the *Land Use, Land Use Change and Forestry* (LULUCF) sector in the inventory from harvesting would also be debited again as CO_2 emissions on e.g. the *Energy Sector* side of the inventory when combusted. An exception to this is the case for harvested wood products, whereby the carbon may remain "locked" into forest products (e.g. sawn wood) for a long period of time (see IEA, 2011a for a detailed overview).

The principle underpinning biomass accounting is shown schematically below (Figure 2.4).

Figure 2.4 Reporting of CO_2 emissions in national GHG inventories



Source: IEA, 2011a.

For short-lived annual crops, for example sugar cane and other energy crops (i.e. *non-woody* biomass), the changes in C-stock through the annual cycle of growth and harvesting is generally assumed to balance over one year i.e. CO_2 emissions due to crop harvesting is balanced by CO_2

[1] Emissions of non-CO_2 GHGs must be accounted for at the point of combustion or decay, as these are not covered by C-stock change calculations.

removals during equivalent new crop growth. Therefore, the net change in C-stock can generally be assumed to be zero on annual basis (see Figure 2.5).

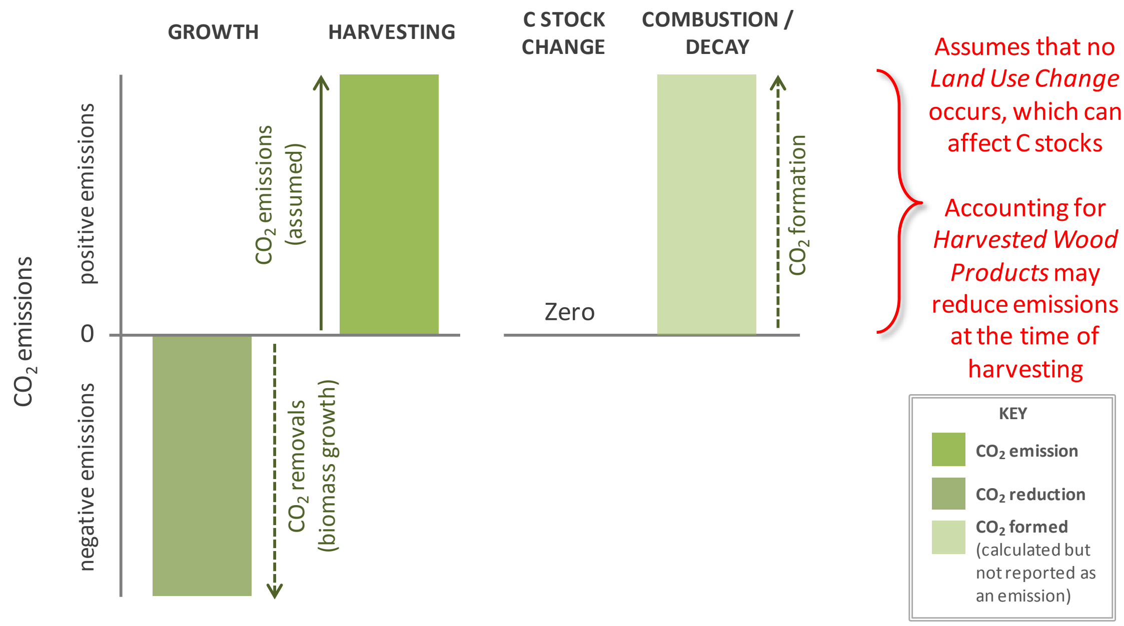
Key issues for GHG accounting:

- Whether and how removals of CO_2 from the atmosphere into biological sinks through the growth of biomass are incorporated into GHG accounting rules;
- Whether biomass is accounted for as an emission at the time of harvesting; and,
- How GHG emissions accounting from biomass combustion (for heat and power generation) and processing (e.g. fermentation to make biofuels) are recorded.

Note: emissions due to land use changes are not discussed in this section.

Approaches to these issues under different GHG accounting schemes are outlined in the following sections.

Figure 2.5 GHG accounting for biomass growth, harvesting and combustion



Source: Carbon Counts

2.4.2 Accounting for biomass growth and harvesting

In all the schemes reviewed, there is a general assumption that growth and harvesting of biomass leads to CO_2 removal and CO_2 emissions respectively. This is either explicit, through the direct inclusion of CO_2 removals and emissions within the GHG accounting rules, or implicit through the way in which CO_2 emissions from biomass combustion and processing are accounted for (see below). The latter case is generally applicable to regional schemes targeted at point source emissions that do not include CO_2 removals by sinks within their ambit.

Under **international GHG accounting rules** there is variable treatment of LULUCF and the *Agriculture, Forestry and Land Use* (AFOLU) sector within national GHG inventories.[1] This is

[1] LULUCF is the term generally applied to Kyoto Protocol 1st commitment period, following the CRF and 1996 GLs and 2003 GPG for LULUCF. AFOLU brings together agriculture and forestry into one reporting category in the 2006 GLs.

principally driven by the complex, essentially political, matters relating to voluntary and differential *reporting* requirements for Parties under the Kyoto Protocol, rather than the *GHG accounting* rules *per se*. In the case of the former, compliance obligations (i.e. the numerical targets inscribed in QELROs) are based on national GHG emission totals *without* the inclusion of LULUCF, although a subset of LULUCF covering *afforestation*, *reforestation* and *deforestation* (ARD) activities is partially included, albeit subject to certain complex rules. On the other hand, the reporting of removals and emissions in some other land use categories is not mandatory, but may be elected to be included by a Party (see Box 2.4).

Box 2.4 LULUCF reporting requirements under the Kyoto Protocol

Under the Kyoto Protocol, Annex I Parties with inscribed QELROs must report emissions by sources and removals by sinks of GHGs resulting from LULUCF activities, in accordance with Article 3, paragraphs 3 and 4.

Under Article 3.3, Parties must report net changes in GHG emissions by sources and removals by sinks through direct human-induced LULUCF activities that occurred since 1990. These can be used to meet Parties QELROs, limited to:

- Afforestation
- Reforestation
- Deforestation (collectively, "ARD")

Under Article 3.4, Parties may elect to voluntarily report other human-induced activities related to LULUCF in the first commitment period specifically:

- Forest Management (FM)
- Cropland Management (CM)
- Grazing Land Management (GM)
- Revegetation (RV)

Upon election, this decision by a Party is fixed for the first commitment period. Within this framework, significant complexity exists, with various accounting approaches applying to different types of LULUCF activities, covering:

- Gross-net accounting – considers only the C-stock changes in the commitment period (applies to ARD accounting)
- Net-net accounting – considers removals and emissions during the commitment period compared to the Parties LULUCF emissions in a 1990 base year (applies to CM, GM and RV accounting)
- Gross-net with a cap – applies a cap to FM accounting.

Derogations to this apply when calculating a Parties AAUs, depending on whether LULUCF accounted for a net *source* or net *sink* of emissions in the 1990 base year. In the case of the former, Parties are allowed to include the level of emissions from ARD (actually only deforestation) in the base year calculation to determine their QELRO and AAUs. Further, when LULUCF activities under Articles 3.3 and 3.4 result in a net removal of GHGs, an Annex I Party can issue removal units (RMUs) on the basis of these activities as part of meeting its QELRO.

There are a number of reasons behind the complexity, including concerns over *magnitude* (the potential volume of emission reductions achievable through LULUCF), *saturation* (where a forest reaches climax of C-stock, leaving only scope for declining C-stock) and *permanence* (the potential for reversals due to forest fire, pestilence, climatic effects such as El Niño). This makes accounting and reporting for LULUCF is an extremely complex and contentious topic.

Other issues include (i) the lack of transparency over the assumptions being made by Parties in calculating and reporting LULUCF; and (ii) voluntary reporting requirements for FM, the potentially most emissive activity: in the Second Commitment Period of the Kyoto Protocol, reporting on FM is mandatory for Parties. However, issues still remain for LULUCF reporting, especially in relation to human induced land use changes such as plantation forests, as well as range of complexities regarding reporting of items such as "natural disturbances" and "harvested wood products".

Source: www.unfccc.int; Global Witness, 2009. Decision 2/CMP.7

In terms of applicable GHG accounting rules, the various IPCC guidelines provide methods to estimate inventories of CO_2 removals by sinks and emissions due to harvesting to assess net C-stock changes across all land use categories. However, the differential reporting requirements leads to complications for the treatment of land use change, as discussed below (Section 2.5), although it does not directly impact GHG accounting rules for biomass growth and harvesting.

In the IPCC guidelines, harvesting of biomass is assumed to lead to immediate full oxidation of the stored carbon as a result of decay or combustion at the time that harvesting occurs. This approach is taken to allow changes in C-stocks within the various land use categories to be tracked over time. An exception is where an additional C-pool for harvested wood products is included, which can "offset" the default assumption regarding the complete oxidation of stored carbon at the time of harvesting.

Regarding short-rotation crops, the 2006 GLs apply the following principle:

> *"Carbon dioxide from the combustion or decay of short-lived biogenic material removed from where it was grown is reported as zero in the Energy, IPPU and Waste Sectors (for example CO_2 emissions from biofuels, and CO_2 emissions from biogenic material in Solid Waste Disposal Sites (SWDS)). For short-lived products in the AFOLU sector* [e.g. energy crops]*, when using Tier 1 methods it is assumed that emissions are balanced by carbon uptake prior to harvest, within the uncertainties of the estimates, so the net emission is zero. Where higher Tier estimation shows that this emission is not balanced by a carbon removal from the atmosphere, this net emission or removal should be included in the emission and removal estimates for AFOLU Sector through carbon stock change estimates"* (2006 GLs, Volume 1, Chapter 1)

This means that, in general terms (i.e. excluding situations where higher tiers are applied, which is not typically the case – see Box 2.3), growth and harvesting of energy crops does not lead to any C-stock changes, and therefore it is correct to account for emissions during their combustion or decay as zero. Higher tier reporting approaches may reveal some imbalances in C-stock changes due to energy crop production, which would be recorded as a *removal* or *emission* in the relevant inventory.

Regional cap-and-trade and GHG reporting schemes are limited in scope to only large point sources of emissions, and do not cover activities involving CO_2 removals by sinks. Therefore there are no applicable GHG accounting rules for CO_2 removals.[1] Similarly, **low carbon fuel standard regulations** do not directly address GHG accounting methods for CO_2 removals by sinks: typically methodologies employed specifically exclude uptake of CO_2 during growing from the calculation. However, emissions from other cultivation related activities are included (see Section 2.6 below), as well as emissions arising from land use change, a source of major contention within these schemes (see Section 2.5 below).

In **project based schemes**, specific rules apply to LULUCF project activities. In the CDM, eligible activities are limited to A/R activities, with specific GHG accounting rules for these projects set

[1] The Australian CPM specifically excludes emissions from land, including levels of carbon sequestered in living biomass, dead organic matter or soil, from the scope of "covered emissions" (Subdivision 5, Section 30(6) of the Clean Energy Act, 2012)

out in *Modalities and procedures for afforestation and reforestation project activities under the clean development mechanism in the first commitment period of the Kyoto Protocol*.[1] Within these rules, the actual *net GHG removals by sinks* is determined based on verifiable changes in C-stocks in the various C-pools within the boundary of the project activity.

2.4.3 Biomass combustion and processing emissions

The principle established in **national GHG inventory accounting** – namely that CO_2 emissions from combustion or decay (e.g. processing/fermentation) of biomass is captured through net C-stock changes between the growth (removal) and harvesting (emissions) of biomass in the LULUCF/AFOLU sector – means that in order to avoid double-counting, CO_2 emissions from these activities do not need to be reported in a country's national GHG *emissions* inventory total. This is confirmed in Volume 1, Chapter 1 of 2006 GLs, which state that:

> *"Emissions of CO_2 from biomass fuels are estimated and reported in the AFOLU sector as part of the AFOLU methodology. In reporting tables, emissions from combustion of biofuels are reported as information items but **not** included in the sectoral or national totals to avoid double counting;"*
>
> *"For biomass, only that part of the biomass that is combusted for energy purposes should be estimated for inclusion as an **information item** in the Energy sector."*
>
> *"In some instances, biofuels will be combusted jointly with fossil fuels. In this case, the split between the fossil and non-fossil fraction of the fuel should be established and the emission factors applied to the appropriate fractions."*

This general principle pervades into **other GHG accounting rules for regional, national, project and product** (i.e. biofuels) approaches, where typically biomass combustion or decay is given a zero-emissions factor (see Box 2.5 and Box 1.1).

Problematically, the use of a zero-emissions factor for biomass combustion assumes that any emissions arising as a result of C-stock changes in the LULUCF/AFOLU sector are being appropriately accounted for somewhere within a regulated system (e.g. as reported in national GHG inventories to the UNFCCC), and that including the CO_2 emissions would lead to double counting. However, the differential approaches to reporting in the LULUCF/AFOLU sector, and differential requirements with respect to countries obligations to enhance carbon sinks (i.e. between Annex I and non-Annex I Parties to the UNFCCC) mean that this is assumption does not necessarily hold true. This asymmetry in GHG emissions reporting brings into doubt the validity of assuming a zero-emissions factor in some schemes because, in reality, the net result is that emissions from C-stock changes potentially go unaccounted for, meaning that bio-energy support policies can actually create carbon *leakage*.[2]

[1] UNFCCC Decision 5/CMP.1

[2] See footnote 1 on page 3 for definition of leakage in this context.

Box 2.5 Emissions factors in GHG accounting

Emissions factors (EF) are a key component of GHG accounting methods. An EF is the average emission rate of a given GHG for a given source relative to units of activity. EFs can therefore be used to calculate the total emissions for a certain activity based on multiplying the level of activity by the EF (GHG emissions = EF (tCO_2/unit) x Activity (units)). An activity may be defined using a fairly narrow boundary, such as the combustion of natural gas. In this case, the EF can be derived by the carbon content of the natural gas per unit, and the total emissions determined by the multiplying the EF by the total volume or mass of natural gas combusted (the activity level).

Emissions factors can also be applied in a composite way to a widely defined scope of activities with wider boundaries. In this case, the EF is determined by dividing the total level of GHG emissions by the level of activity (EF = GHG emissions / units). An example could be the calculation of the emissions intensity a particular fuel product, derived by summing the emissions from fuel production, processing and transport and dividing it by the mass of fuel produced or delivered. This type of EF is applied under the EU RED/FQD and the California LCFS. These are sometimes referred to as Implied Emission Factors.

Implied EFs have significant latitude for uncertainty because they are reliant on the quality of the underlying emissions data used, which may be patchy, especially where the emissions have been estimated using low Tiers (see Box 2.3). Such composite approaches then act to mask subtle variations in the production of similar products, and as such can be a fairly crude means to assign values and design policy, particularly where penalties and rewards may be assigned drawing on EFs. As such, EFs can be a potentially challenging aspect in climate policy design.

For **project-based schemes**, whilst CO_2 emissions arising from combustion of biomass are not included on the assumption that it there are no changes in C-stocks in the LULUCF sector, this is based on a number of components designed to ensure that this is the case, including the requirement to take account of *leakage*. For the **regional cap-and-trade and GHG reporting schemes** reviewed, this is generally not the case, however. This is understandable since their primary focus is on regulating emitting activities at the point of fuel use (i.e. large point source emitters within their jurisdiction).[1] That said, some of the schemes reviewed include components within the GHG accounting rules that are designed to support the robustness of a zero-emissions factor assumption, as taken under the CDM. In the case of **low carbon fuel standards**, the schemes cover GHG emissions from both production and use of fuels and therefore a core component of their GHG accounting rules is the calculation of GHG emissions occurring during harvesting, processing, transport and use,[2] although land use change effects are to some extent only partially included, as discussed below.

In some of the GHG accounting rules reviewed, it can be seen that an approach, or a combination of approaches, is sometimes used to provide assurances regarding the assumption of using a zero-emissions factor for biomass combustion. These cover:

1. *Qualitative approaches* – setting restrictions on the types of fuels that can be considered as biomass, or zero-emissions rated biomass; and/or,
2. *Quantitative approaches* – covering requirements to estimate the full emissions from biomass production, including land use change, and potentially setting restrictions

[1] In the case of the US GHGRP, no emission limits are set on covered facilities. For reporting, CO_2 emissions from the combustion of biogenic material must be calculated using the emission factors set out in the relevant subpart, but reported separately to emissions arising from combustion of fossil fuels.
[2] On this basis, such schemes adopt a zero-emissions assumption for combustion of biofuels, whilst emissions from fossil fuel combustion adopt appropriate emission factors. This is correct since the recommended practice for recording biofuels combustion in national GHG inventories under the 2006 GLs is to apply a zero-emission factor.

thereunder i.e. by including all upstream emissions in the estimate of a bioenergy products' GHG intensity and/or emission factor (see Box 2.5). (after Fritsche, 2010)

These aspects are discussed further in the context of land use change in the next section.

2.5 Land use change

2.5.1 General principle

Concerns over direct land use change (dLUC),[1] and indirect land use change (iLUC),[2] has been a major issue in the design of policies promoting the use of biomass derived fuels, principally liquid biofuels. Specific concerns relate to potential C-stocks changes that can occur as a result of dLUC/iLUC, such as, *inter alia:* clear-felling of forests, conversion of natural forests to plantation forests to provide woody biomass for energy generation, the conversion of forest land to agricultural plantations for the growth of energy crops, and the conversion of other land (e.g. natural unmanaged land) to grow food in response to conversion of cropland to e.g. energy crop production (iLUC), essentially a displacement effect (see Box 2.6). Such activities can lead to long-term shifts in biogenic C-stocks, with a reduction in biogenic C-stock resulting in a transfer of carbon from the biosphere to the atmosphere in the form of CO_2.

Paradoxically, these concerns are being augmented by the expansion of polices to promote the use of biomass and biofuels such as the **EU ETS**, the **California LCFS** and the **EU RED/FQD**. These policies are believed to be accelerating the rates at which potential bioenergy suppliers – primarily in developing countries – are acting to clear natural forests to make way for high value energy crop cultivation, such as sugar cane, soya and palm oil for biofuels production. Furthermore, residues arising from the processing of these products can also potentially be used as biomass fuel in combustion plants (e.g. palm oil kernels; see also Box A-1 in Annex A), and treated as biomass – as described previously.

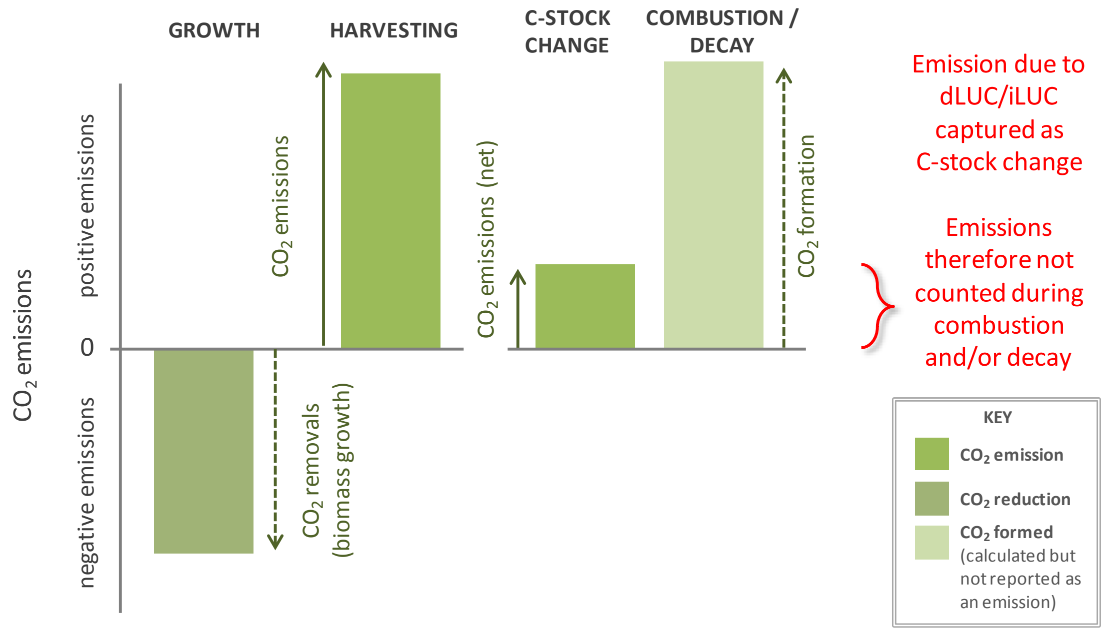
A major concern is the asymmetry between approaches to account for biofuel or biomass use, which typically apply comprehensive MRV requirements for GHG emissions accounting and employ a *zero-emissions factor* in order to avoid double-counting (as outlined in Section 2.4), versus accounting approaches applied to the AFOLU sector, which tend to be far more patchy and mask emissions/C-stock changes arising from both dLUC and iLUC as a result of cultivating and harvesting energy crops and biomass. In order to take account of this issue, some regional and national GHG policies and measures impose requirements to calculate potential dLUC/iLUC effects for bioenergy promoted under the scheme, and/or impose restrictions on the types of bioenergy sources that may be zero-emissions rated within the scheme, as described further below.

The GHG effect of dLUC/iLUC is summarised graphically below (Figure 2.6). In the diagram, a decrease in the biogenic C-stock due to dLUC/iLUC is represented by a decrease in the amount of CO_2 removed from the atmosphere during biomass growth and an increase in emissions to atmosphere due to biomass harvesting (e.g. forest clearance). In theory, such a change in C-stock should be recorded in a GHG inventory as an emission in the AFOLU sector, allowing

[1] dLUC relates to emissions driven by changes on the land used to produce the biomass.
[2] iLUC relates to changes in use of other land as a consequence of bioenergy production, principally displacement effects.

emissions from combustion or decay of the harvested biomass to still be reported as zero so as to avoid double-counting. In practice, however, often the underlying changes are not effectively recorded, which places the assumption regarding a zero-emissions factor for bioenergy combustion or decay sources in doubt. It is also worth noting that positive dLUC/iLUC effects can occur where e.g. degraded lands are improved through reforestation.

Figure 2.6 GHG accounting and land use change effects



Source: Carbon Counts

Key issues for GHG accounting:

- Whether and how emissions from both direct and indirect land use change (dLUC/iLUC) are incorporated into a schemes GHG accounting rules;
- Whether additional measures are imposed under national schemes to take account of dLUC/iLUC effects.

2.5.2 Treatment of emissions from direct and indirect land use change

The treatment of biomass growth, harvesting, combustion and processing in various GHG accounting rules was described in the previous section. This outlined that assumptions regarding growth and harvesting, principally in relation to woody biomass in forests, provides a basis for estimating C-stock changes in standing biomass. The approach is a fundamental pillar of AFOLU/LULUCF GHG accounting. A second fundamental pillar is that of *Land Conversion*, where land use changes from one type to another within a country, e.g. forest land to cropland, should be reported in the national GHG inventory and C-stock changes calculated and reported accordingly. The discussion outlined here focuses on this latter aspect and its treatment in GHG accounting rules.

Under **international GHG accounting rules**, the 1996 GLs introduced three types of key land use change and management practices affecting CO_2 removals and emissions, covering (i) changes in forest and other woody biomass stocks, (ii) forest and grassland conversion, and (iii) abandonment of managed lands. The 2003 GPG LULUCF introduced further guidance in relation to accounting for land conversion into other types of land use, based on expanded list of categories of land. The most recent guidance in the 2006 GLs built on these approaches to ensure systematic reporting for all potential land use conversions from one category of land use to another, as well as conversion of unmanaged land to managed land.[1] Conversion of land results in C-stock changes in biomass, dead organic matter and soils, which can be either recorded as increases in C-stocks (e.g. *Cropland* converted to *Forest Land*), or decreases (e.g. *Forest Land* converted to *Cropland*); the 2006 GLs provide guidance for calculating C-stock changes under the various scenarios. The guidance is provided at various Tier levels (Box 2.3), and also incorporates three different approaches to recording land use conversions, depending on data availability. Where a land use conversion takes place, it must be reported in a conversion category for 20 years or longer before it can be reported as land *remaining* in that land use category.

Box 2.6 Concerns over biofuels policy in the US and Europe

Concerns regarding land use change effects of biofuels policy have been at the forefront of international debate since a publication by Searchinger *et al.* in 2008. Drawing on analysis of the effects of the 2007 US federal Renewable Fuel Standard (RFS1), their study used a worldwide agricultural model to estimate GHG emissions due to land use change, concluding that the iLUC impacts more than offset the positive direct effects of biofuels promoted under RFS1, as follows:

> *"corn-based ethanol, instead of producing a 20% savings, nearly doubles greenhouse emissions over 30 years and increases greenhouse gasses for 167 years. Biofuels from switchgrass, if grown on U.S. corn lands, increase emissions by 50%. This result raises concerns about large biofuel mandates and highlights the value of using waste products."*

Their findings started a contentious debate regarding "food versus fuel", referring to the assertion that the use of land to grow biomass for energy reduces the availability of land for food and feed crops, leading to displacement and land use change. The launch of biofuels policies in the US and Europe also coincided with record global food prices in 2008, further augmenting concerns regarding "food vs fuel". Another paper published in the same edition of *Science* also drew attention to the potentially negative dLUC effects of growing biofuels (Fargione *et al.*, 2008), suggesting that:

> *"Converting rainforests, peatlands, savannas, or grasslands to produce food crop-based biofuels in Brazil, Southeast Asia, and the United States creates a 'biofuel carbon debt' by releasing 17 to 420 times more CO_2 than the annual GHG reductions that these biofuels would provide by displacing fossil fuels"*

On the other hand, a wide range of industry groups have countered these claims, suggesting Searchinger's analysis is flawed and wildly over-exaggerated.[2] As such, the design of policies to promote bioenergy remains a challenging area. Since iLUC concerns were aired regarding RFS1, the US EPA has worked on a revised system that incorporates iLUC in the life-cycle GHG fuel pathway assessments, as launched in 2012 (RFS2). Similarly, the California LCFS also includes an iLUC modifier in the CA-GREET model to address such concerns.

In 2009 the EU introduced the RED, which it considered to contain sufficient safeguards to appropriately capture and account for dLUC effects from biofuels; means to control iLUC effects remained less clear, however, and in general, approaches taken have been widely derided by a range of observers. The problems with the RED were further augmented when it became apparent that it was promoting imports of cheaper biofuels and feedstocks from developing countries, rather than enhancing domestic production of vegetable oils for biodiesel as originally intended. In the face of pressure from a wide range of stakeholders, further analysis on potential iLUC effects was carried out (Laborde, 2011; Marelli et. al, 2011). Both papers concluded that iLUC effects of the EU's biofuels policy are significant and should be addressed.

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[1] The six land use management categories covered by the IPCC Guidelines are: Forest Land; Cropland; Grassland; Wetlands; Settlements; Other Land. Note: C-stock changes in unmanaged land do not need to be monitored and reported unless it is converted to another land use category.

[2] See for example: http://theenergycollective.com/gcooperrfa/233586/busting-big-oil-myths-rfs-and-ethanol-part-iii-iluc-and-greenhouse-gases

Notwithstanding the sincere efforts of the IPCC to provide guidance on GHG accounting and reporting for *Land Conversion*, two core challenges affect the robustness for measuring dLUC and iLUC effects in national GHG inventories:

1. *Lack of data*, which hampers effective tracking of land conversion over time. An example is where Tier 1 methods are employed to estimate C-stock changes due to *Land Conversion*, which allows a default assumption to be made that biomass C-stocks stay the same, even though a *Land Conversion* is recorded. This generally applies because the previous use of the land is unknown/unrecorded;
2. *Reporting requirements* (Box 2.4), which means land management activities affecting large tracts of land go unreported. This is particularly acute for *Forest Management* activities,[1] which could potentially lead to conversion of natural forest to plantation forest without triggering a land use change. This is exacerbated by reporting at lower Tiers.

These affects can apply in combination, where both poor data and a lack of reporting results in land conversions going completely unrecorded. The impacts of such challenges for dLUC and iLUC in biomass and biofuels policy design can be summarised as two types:

- **Cross-sectoral impacts** – within a single country, where accounting for use of biomass and biofuels in e.g. *Energy* or *Transport* sectors of a country's GHG inventory leads to CO_2 emissions totals of zero, while the *LULUCF/AFOLU* sector of the GHG inventory does not appropriately record C-stock changes caused by dLUC/iLUC, especially where these changes are driven by the GHG benefits achievable in the *Energy* or *Transport* sectors (Kuikman *et al*, 2011);
- **Cross-border impacts** – this is similar to cross-sectoral impacts, although in this case a national GHG inventory may effectively capture the LUC changes occurring within the national jurisdiction, but not where biomass/biofuels are imported from other countries, especially if the supplier countries have less stringent approaches to LULUCF/AFOLU accounting and reporting.

In either case, the asymmetry of approaches to reporting in the different parts of the inventory can lead to leakage where support measures are applied to biomass and biofuels as zero-emissions technologies, especially as these potentially drive further land use changes. To address these problems, bioenergy polices and measures and the associated GHG accounting rules at national and regional levels have typically taken steps to impose certain restrictions on bioenergy sources, as described in the next section.

2.5.3 Measures employed in national polices and measures to account of dLUC/iLUC effect

As highlighted previously, two approaches have been generally been adopted, involving either *quantitative approaches* and/or, *qualitative approaches* (Section 2.4; after Fritsche, 2010). In practice, both types of approaches may be selectively applied under a particular scheme, with restrictions being imposed on certain bioenergy products which fail to meet a certain life-cycle GHG threshold. It is also useful to note that qualitative approaches are often applied in

[1] Under the UNFCCC, *"Forest management" is* [defined as] *a system of practices for stewardship and use of forest land aimed at fulfilling relevant ecological (including biological diversity), economic and social functions of the forest in a sustainable manner* (UNFCCC, Annex to Decision 16.CMP.1 – part of the Marrakesh Accords)

conjunction with efforts to manage sustainability aspects of bioenergy production outside of the GHG emission effects (Box 2.7). Approaches in these contexts as applied in GHG accounting rules are reviewed and discussed below.

Box 2.7 Bioenergy and non-GHG related sustainability concerns

In addition to concerns regarding the GHG emissions arising from dLUC and iLUC, other important issues can be critically affected by land use change including:

- biodiversity and natural habitats;
- water quality;
- soil quality;
- food supply and prices; and
- local communities and cultural stability.

Such variables cannot be directly included in GHG accounting frameworks and are generally poorly represented in life-cycle assessments of bioenergy (Bringezu, *et. al*., 2009). For this reason, additional policy and regulatory measures are often employed in bioenergy legislation to control their effects. In the EU, the EU RED allows only biofuels produced with raw material not obtained from "land with high biodiversity value", whilst the US RFS and California LCFS have noted various efforts aimed at addressing sustainability biofuels, although as yet neither includes specific measures to restrict certain fuels on sustainability grounds.

Problematically, in practice, sustainability issues outlined above appear to be often conflated with dLUC and iLUC aspects, resulting in rather mixed responses, such as the approach taken in the EU (see below).

Quantitative approaches

Quantitative approaches involve setting requirements to include all upstream GHG emissions arising from growing, harvesting, land use change, processing and transport in the emission factor or GHG intensity calculated for a particular bioenergy product. This allows full life-cycle GHG accounting to be included in e.g. the emission factor applied to biomass combustion, so as to avoid perverse outcomes and leakage.

In the review of GHG accounting rules, none of the **regional GHG reporting and cap-and-trade schemes** incorporate upstream emissions arising from dLUC/iLUC within their GHG accounting rules: all apply a zero-emissions factor to biomass, meaning that upstream emissions are not included. Some **regional GHG cap-and-trade schemes** do include *qualitative* approaches to restrict the materials to which the zero-emission factor can be applied (see next Section).

Under **project-based schemes** such as the CDM, project boundaries are set to incorporate all sources of emissions under the control of the project developer that are reasonably attributable to the project activity. It also requires *leakage* to be taken into account.[1] On this basis, emissions from dLUC/iLUC should be included. For example, under ACM0006[2], *CO_2 emissions resulting from soil carbon stock changes following land use change or change in land management practices* must be estimated and included as project emissions (i.e. dLUC). Leakage (i.e. iLUC) effects are considered to be minimised by restrictions on the types of lands from which biomass may be sources (see next section).

[1] See footnote 2 on page 17.

[2] Approved Consolidated Methodology 0006: Consolidated methodology for electricity and heat generation from biomass

For **low carbon fuel standards**, rule design is based on setting a *portfolio standard* for all fuel sold and used in a market. The standard sets a target for reductions in the overall GHG intensity of the fuel portfolio over time, covering both production and use. In this way, cleaner fuels with lower GHG emissions during production and use are promoted; the zero-emissions factor applied to biofuels gives them advantage compared to fossil fuels, so long as the upstream emissions from their production do not outweigh the benefits at the point of use. Both the EU RED/FQD and the California LCFS (and the US RFS) include methods to incorporate C-stock changes and emissions from dLUC and iLUC, whilst the latter is also generally managed through the imposition of additional *qualitative* restrictions (see next section).

Under the **EU RED/FQD**, the methodology set out in *Section C* of *Annex V/IV*, which must be employed for calculating actual GHG emissions of biofuels production and use (see Table 2.1), includes the following parameter:

e_l = annualised emissions from carbon stock changes caused by land use change.

This parameter must also be calculated when using default factors set out in *Section A* and *B* of *Annex V/IV*, and must be equal to or less than zero in order to apply default factors to calculate GHG intensity; otherwise the method in *Section C* must be used. In *Section C*, parameter e_l is to be calculated based on the C-stocks for the previous land use relative to current land use,[1] plus a bonus factor where it can be shown that the biomass is obtained from restored previously degraded lands. What this means is that dLUC/iLUC effects must be shown to be zero (when using a default factor) or included in the calculation of the GHG intensity of the biofuels (using the *Section C* method). Further, only biofuels that deliver GHG savings of at least 35% compared to a fossil fuel comparator are allowed,[2] increasing to 50% by 2017, and 60% by 2018 for new installations. These requirements act as a quantitative restriction on the types of biofuels eligible under the RED/FQD, meaning that biofuels with significant dLUC/iLUC effects – as well as other significant GHG emissions in their supply chain – are both implicitly and explicitly constrained under the scheme. However, although the effects of dLUC and iLUC are therefore included in biofuels GHG intensity calculation method, and should therefore penalise biofuels where dLUC/iLUC is a major source of emissions, a contentious debate continues over the validity of the approach (see Box 2.6 and Section 4.3).

Under **the California LCFS**, emissions resulting from dLUC and iLUC are incorporated in Method 1 life-cycle GHG emissions intensity values applied to various fuels, as derived from the CA-GREET Model (see Table 2.1), and the so-called "iLUC modifier". The modifier value for dLUC and iLUC in the CA-GREET Model are derived from the Global Trade Analysis Project (GTAP) model developed at Purdue University.[3] Any operators proposing alternative GHG emission intensity estimates under either *Method 2A* or *Method 2B* must request the Executive Officer to conduct analysis or modelling of the impact of the approach, including dLUC/iLUC impacts, which would be calculated using the GTAP Model. The GTAP Model includes modules covering global Land Use and Land Cover (GTAP 8), based on data from the Food and Agriculture Organisation (FAO),

[1] Covering both soil and vegetation, and based on a reference year of 2008 or 20 years prior to when the raw material was obtained.
[2] The saving is calculated relative to a fossil fuel comparator, either the latest actual value for fossil petroleum products used in the EU, or a reference value of 83.8 gCO_2e/MJ.
[3] Further information in GTAP is available at: https://www.gtap.agecon.purdue.edu/default.asp

to provide insight into dLUC/iLUC effects of biofuels cultivation. Whilst this essentially serves to take account of such effects in the fuel's life-cycle carbon intensity calculation – and therefore implicitly penalise fuels with significant dLUC/iLUC impacts – the approach is restricted by the shortcomings of the GTAP model, which have been acknowledged by the CARB (CARB, 2009).

Based on this review, all schemes reviewed *with the exception of* **regional GHG reporting and cap-and-trade schemes** include some form of *quantitative* considerations of upstream emissions arising from dLUC/iLUC within their ambit. These efforts aim to include the dLUC/iLUC effects within the carbon/GHG intensity calculation, and/or implicitly or explicitly impose penalties or restrictions where theses are determined to be high.

Alternative approaches involving *qualitative* limitations to the types of biomass that may be used within a scheme are discussed next.

Qualitative approaches

As an alternative to requiring full life-cycle GHG emissions accounting, restrictions on certain types of biomass products may be imposed by scheme operators based on a prior assessment of suitable products, or the use of national or international standards for biomass production.

Within **regional GHG reporting and cap-and-trade schemes**, the **California ETS** provides an example in which restrictions are set on the types of biomass that qualify as zero-emissions rated. The scheme includes the category of *"Emissions without a Compliance Exemption"*[1] where emissions arising from combustion of the material listed must be calculated and reported, but do not count towards an entities compliance obligation under the scheme (i.e. are essentially zero-emissions rated). A wide number of fuel types are listed, which for biomass includes:

- *"A range of biogenic waste materials;*
- *All agricultural crops or waste;*
- *Wood and wood wastes identified to follow all of the following practices:*
    - o *Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 or other locally or nationally approved plan; and*
    - o *Harvested for the purpose of forest fire fuel reduction or forest stand improvement."*

All other biomass under the scheme is considered as "non-exempt" and therefore its use does not absolve the user of requirements to surrender California allowances for emissions arising from these sources of energy. The use of a California specific regulatory forest management reference standard provides the scheme with assurances regarding the sustainability of the biomass supply base, and by proxy, dLUC/iLUC effects.

Similar approaches may be taken with respect to how biomass is defined under a scheme, for example, by restricting the definition of materials that qualify as zero-emissions rated biomass. Within the **EU ETS**, the **US GHGRP** and **Australian CPM**, however, fairly wide definitions for biomass are included to which a zero-emissions factor can be applied when combusted (and

[1] §95852.2 of the ETS rule

therefore not incur any compliance requirements under the scheme; Box 2.8).[1] On this basis, none of these schemes effectively employ qualitative restrictions as a means to take account of dLUC/iLUC effects from biomass use.

Box 2.8 Defining biomass in GHG accounting rules

As shown in the case of the California ETS, defining eligible biomass provides a potential means to restrict the applicability of zero-emissions rating to only certain types of materials. However, of the rules reviewed, most adopt very similar broad definitions of biomass:

"'biomass' means the biodegradable fraction of products, waste and residues from biological origin from agriculture (including vegetal and animal substances), forestry and related industries including fisheries and aquaculture, as well as the biodegradable fraction of industrial and municipal waste; it includes bioliquids and biofuels" (EU Regulation 601/2012/EC; EU RED)

"Biomass means non-fossilized and biodegradable organic material originating from plants, animals or microorganisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material." (GHGRP, subpart A)

"biomass means non-fossilised and biodegradable organic material originating from plants, animals and micro-organisms, and includes: (a) products, by-products, residues and waste from industry, including the agriculture and forestry industries; and (b) non-fossilised and biodegradable organic components of commercial and industrial, construction and demolition, and municipal waste" (Australia National GHG and Energy Reporting Act, 2008)

However, notwithstanding the broad definition of biomass under the **EU ETS**, in October 2012 the European Commission, by way of *MRR Guidance Document No. 3* on *Biomass issues in the EU ETS* (EC, 2012b), provided additional clarification on how to interpret the definition of biomass and it's zero-emissions rating under the EU ETS. The guidance document explains that because the zero-emissions rating of biomass and bioliquids under EU ETS constitutes a 'support scheme' for bio-energy in accordance with the EU RED, biomass use in the EU ETS must be compliant with EU RED *Article 17(1)* sustainability requirements (as outlined above). The sustainability requirements are qualified further in the document, highlighting that the "application of sustainability criteria for biomass" *means* testing whether it complies with the definition of the biomass in the EU RED, and consequently, whether it can be zero-emissions rated (see Box 2.8). Where this can't be proven, the biomass emissions cannot be zero-emissions rated and must be treated in the same way as fossil CO_2 emissions.

Presently no specific sustainability criteria are applicable to solid or gaseous biomass under European law, other than biogas used for transport purposes. Therefore, drawing on the EU RED, *Guidance Document No. 3* notes that there are three ways to meet sustainability requirements:

- by means of compliance with a national system (see Box 2.9 below for examples of such schemes);
- by using a voluntary scheme that the Commission has recognised (of which there are presently 14, albeit subject to various restrictions)[1]; and/or

[1] In the EU, under Article 38 of Regulation 601/2012, biomass has a zero-emissions factor. In Australia, under Subdivision 5, Section 30(3) of the Clean Energy Act, 2012, , "covered emissions" do not include emissions attributable to biomass, biofuels or biogas.

- in accordance with the terms of bilateral or multi-lateral agreement concluded by the EU and which the Commission has recognised for this purpose (none yet are in existence).

The burden of proof is on operators to demonstrate that the biomass used is sustainable with respect to compliance with one of the standards listed above.

Box 2.9 EU Member State activities to regulate sustainable biomass

The UK

The UK DECC and Ofgem have introduced mandatory reporting requirements for solid biomass and biogas power generation under both the Renewables Obligation (RO) and the forthcoming Renewable Heat Incentive (RHI) scheme. Since 1 April 2011, biomass electricity generators over 50kW have been required to report against the following sustainability criteria:

- minimum 60% GHG emission saving for electricity generation using solid biomass or biogas relative to fossil fuel (not including dLUC or iLUC effects)
- general restrictions on using materials sourced from land with high biodiversity value or high carbon stock – including primary forest, peatland, and wetlands

Following a transition period, the Government intends that from October 2013 generating stations of 1 megawatt (MW) capacity and above will be required to meet these criteria in order to receive Renewables Obligation Certificates (ROCs) under the RO. Similar plans are intended for the RHI, and the Government is currently consulting on tightening its sustainable forest management criteria for wood fuel.

See: https://www.gov.uk/sustainability-standards-for-electricity-generation-from-biomass

The Netherlands

There are currently no mandatory regulations in place in the Netherlands to ensure that solid biomass used in electricity generation is from sustainable sources and does not contribute to adverse social and environmental impacts. In 2007, the Dutch Commission 'Sustainable Production of Biomass' formulated sustainability criteria around six themes - GHG emissions; competition with food and other local applications; biodiversity; environment; prosperity; and social well-being. These were subsequently formulated into a set of nine principles with criteria and indicators, with a view to developing an official certification system. These gave rise to a voluntary certification scheme (NTA 8080 - Sustainably Produced Biomass). However no mandatory certification system is yet in place; as an interim measure, the Government plans to introduce a reporting obligation and GHG balance calculation tool.

See: http://somo.nl/publications-en/Publication_3971

See: http://www.sustainable-biomass.org/

Germany

Germany's implementation of the EU RED regulation was split into two separate regulations, one for biomass used for electricity generation (*BioSt-NachV*) and one for biomass used for biofuel production (*Biokraft-NachV*). The former, adopted on 23 July 2009 and amended July 2010, outlines mandatory sustainability criteria for use of biomass in power generation receiving national financial support, covering nature conversation, sustainable agricultural management and GHG emissions. In alignment with the Commission's recommendations made to Member States on the development of their biomass sustainability schemes, Article 8 of the regulation requires that the greenhouse gas emission saving from the use of bioenergy must be at least 35%, increasing to at least 50% from 1 January 2017 and 60% from 1 January 2018.

See: http://www.erneuerbare-energien.de/fileadmin/ee-import/files/english/pdf/application/pdf/nachv_verordnung_en_bf.pdf

On this basis, the EU ETS imposes qualitative restrictions on the types of biomass that may be zero-emissions rated, based on national or voluntary standards. In principle, this should restrict

[1] Schemes which have so far been approved are available at: http://ec.europa.eu/energy/renewables/biofuels/sustainability_schemes_en.htm
A review of these schemes was not possible within the scope of this report.

the use of biomass which could have dLUC/iLUC effects associated with its production, albeit with strong reliance on the capacity of the national or voluntary scheme to recognise and control such effects.

In **project-based schemes**, and more specifically the CDM, the definition of biomass within *Approved Methodologies* (AMs) relating to bioenergy is very similar to those outlined above (Box 2.8).[1] However, notwithstanding the similarities, AMs tend to include specific limitations on the types of land from which biomass may be sourced. These are designed to provide checks to prevent emissions from dLUC arising due to land conversion at the project site.

The following restrictions are typical for AMs within the CDM:

- Biomass generally must be from renewable source and not lead to changes in land use and C-stocks;[2]
- Biomass is sourced from residues which were previously left to decay;
- Biomass is sourced from dedicated plantations, subject to, *inter alia*, the following:
    - The cultivated land being clearly identified and used only for dedicated energy biomass plantations;
    - The CDM project activity does not lead to a shift of pre-project activities outside the project boundary, i.e. the land under the proposed project activity can continue to provide at least the same amount of goods and services as in the absence of the project (i.e. iLUC);
    - The plantations are established:
        - On land which was, at the start of the project implementation, classified as degraded or degrading; or
        - On a land area that is included in the project boundary of one or several registered A/R CDM project activities;
    - The land area of the dedicated plantations will be planted by direct planting and/or seeding;
    - After harvest, regeneration will occur either by direct planting, seeding or natural sprouting;
    - The land area where the dedicated plantation will be established is, prior to project implementation, severely degraded and in absence of the CDM project activity would have not been used for any other agricultural or forestry activity;
    - Only perennial plantations are eligible.[3]

Under JI Track 2, projects are generally required to show that biomass used is sourced from residues that were previously dumped. These conditions, alongside the requirements to account for dLUC effects as project emissions as highlighted previously, are considered to provide a robust basis for accounting for dLUC and iLUC issues within the CDM and JI.

[1] This includes: ACM0003, ACM0006, ACM0017, ACM0020, AM0007, AM0036, AM0042, and AM0057, covering activities such as substitution of fossil fuels with biomass, heat and power generation using biomass, production of biodiesel, and use of biomass waste in pulp and paper making. See www.cdm.unfccc.int.

[2] Annex 18 of the Report of the 23rd Meeting of the CDM Executive Board sets out a lengthy definition for renewable biomass, covering five conditions under which biomass may be considered as "renewable".

[3] Project proponents can apply for revision of the methodology to include annual plantations, providing evidence that annual plantations would not result in depletion of the soil carbon.

As highlighted previously, **low carbon fuel standards** include GHG accounting methods to estimate emissions resulting from dLUC (previous section) and also include efforts to address both dLUC and iLUC through prohibitions on certain types of biofuels sources. Under the **EU RED/FQD** – and by extension the EU ETS through *Guidance Document No. 3* (EC, 2012b) – a range of *sustainability criteria* are established,[1] which includes a detailed set of prohibitions covering biofuels made from raw materials sourced from the following:

- *Land with high biodiversity value* – covering land that that was one of the following in 2008: primary forest and other wooded land; nature protection areas or areas for the protection of rare, threatened or endangered ecosystems or species; and highly diverse grassland;
- *Land with high carbon stock* – covering land that that was one of the following in 2008: wetlands; and/or continuously forested areas; and
- *Peatland* – material obtained from land that was peatland in January 2008

Specific derogations apply, for example, if it can be shown that cultivation did not interfere with nature protection or that land use changes due to biomass cultivation did not lead to net CO_2 emissions. A range of work to further elaborate approaches to manage the sustainability of bioenergy in the EU is ongoing, such as the certification of voluntary schemes for sustainability assessment of bioenergy sources, as highlighted above (page 34).

Neither the **US RFS** nor the **California LCFS** impose any restrictions on the types of land from which biofuels are sourced, relying instead on a quantitative approach and the requirement for new fuel "pathways" proposed under the relevant process (e.g. *Method 2B* of the California LCFS) to be subject to approval.

2.6 Biomass supply

2.6.1 General principle

As well as net emissions potentially occurring as a result of dLUC and iLUC, biomass and biofuels will generally lead to GHG emissions as a result of cultivation, harvesting, processing and transportation of the products. Emission sources include N_2O emissions from fertiliser use, combustion emissions from mechanised equipment used for biomass harvesting, and emissions from road and ship transport. Although likely to be a relatively small, these emissions can go unaccounted for where a zero-emissions factor is applied to biomass sources under a particular scheme.

Key issues for GHG accounting:
- Whether and how emissions from biomass cultivation and harvesting are included in a scheme's GHG accounting rules;
- Whether and how emissions from biomass transport are included in a scheme's GHG accounting rules.

[1] Article 17 of Directive 2009/28/EC.

2.6.2 Treatment of emissions from biomass cultivation and transport

Under **international GHG accounting rules**, emissions from cultivation, mechanical harvesting, processing and transport of biomass are, in principle, to be recorded in the relevant source sectors of the national GHG inventory of the country where these activities take place. Source sectors where emissions would be captured include *AFOLU/Agriculture* (relating to e.g. N_2O emissions arising from fertiliser application) and *Mobile combustion/Transport* – relating to CO_2 emissions from mechanised equipment used for harvesting, and transport emissions. Emissions arising from marine transport should be reported by Parties, although they are not included in national GHG emission totals as they occur in international waters. Emissions from this source are therefore not included in international emissions accounting frameworks.

The **regional cap-and-trade and GHG reporting schemes** reviewed are limited in their application to large point sources of emissions only, and do not cover activities occurring outside of a regulated installation's boundary. Therefore, life-cycle emissions are excluded, as demonstrated through the application of a zero-emissions factor for biomass combustion.

Under **project based schemes**, emissions arising from these activities should be included as project emissions within the project boundary. For example, in the CDM, ACM0006 includes within the project emission calculation methodology requirements to calculate CO_2 emissions from on-site fossil fuel consumption and offsite transportation. Similar requirements apply under JI Track 2.

As highlighted previously, GHG accounting rules under **low carbon fuel standards** cover the full range of upstream emissions, and therefore include other life-cycle emissions arising from biomass cultivation and transport. For example, the EU RED/FQD includes emissions from these sources in default values (*Section A* and *B* of *Annex V/IV*) as well as in calculation methods (*Section C* of *Annex V/IV*). The latter includes *"emissions from the...cultivation process itself; from the collection of raw materials; from waste and leakages; and from the production of chemicals or products used in extraction or cultivation"*. The California LCFS includes emission from these sources in the CA-GREET Model (see Table 2.1).

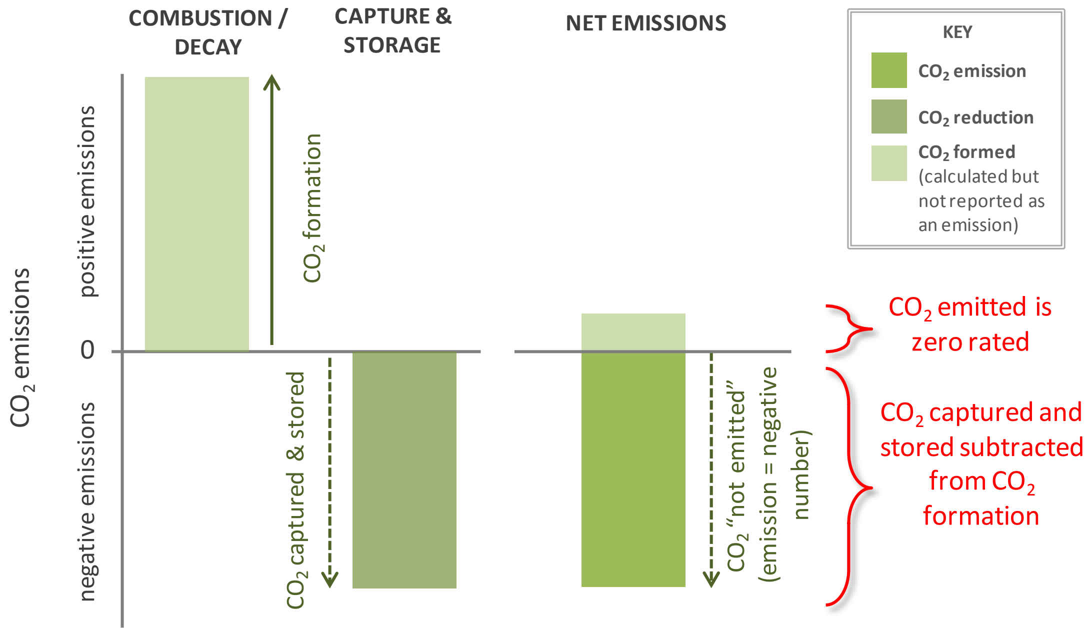
2.7 Recognising and attributing negative emissions

2.7.1 General principle

The aggregate effect of recognising captured and stored CO_2 as "not emitted" (Section 2.3) and the accounting of CO_2 formed during biomass combustion or decay (fermentation) as zero (Section 2.4), should result in bio-CCS being recognised as delivering negative emissions under a given scheme. This is on the basis that a covered installation/facility generating CO_2 from biomass produces zero "regulated" emissions, whilst any mass of captured CO_2 and transferred offsite for geological storage in appropriate sites can then be subtracted from its GHG inventory (zero *minus* X = minus X; Figure 2.7).

The scientific or technical basis for this assumption is correct as capturing and storing CO_2 from biogenic sources should lead to net removals of CO_2 from the atmosphere (Box 1.1). The theory is subject to the proviso that biomass C-stocks are effectively replenished, and that biomass production is not causing land use changes that give rise to net increases in CO_2 emissions due to reductions in biological C-stocks (as discussed in Section 2.5).

Figure 2.7 GHG accounting for bio-CCS with negative emissions



Source: Carbon Counts

Note: Assumes 90% of formed CO_2 is captured; storage is permanent. C-stock changes and emission from dLUC/iLUC and from biomass supply not shown. Where these create a GHG emission which is accounted for as described in the previous sections, these would be added to net emissions column (i.e. reduce the level of negative emissions, and potentially lead to net positive emissions depending on their scale).

Key issues for GHG accounting:

- Whether the GHG accounting rules implicitly or explicitly acknowledge negative emissions.
- Where the negative emission is attributed under the GHG accounting rules.

Note: this section does not consider whether negative emissions can be "rewarded".

2.7.2 Acknowledging and attributing negative emissions

The **international GHG accounting rules** as set out in the 2006 GLs clearly acknowledge the potential role of bio-CCS in generating negative emissions. This is described in Volume 2, Chapter 2 on *Stationary Combustion*, which states that:

> *"If the plant is supplied with biofuels, the corresponding CO_2 emissions will be zero (these are already included in national totals due to their treatment in the AFOLU sector), so the subtraction of the amount of gas transferred to long-term storage may give <u>negative emissions</u>. This is correct since if the biomass carbon is permanently stored, it is being removed from the atmosphere."*

This means the negative emission is attributed to the source sector where the capture and transfer offsite occurs, in this case a stationary combustion source (the same principle would apply to industrial CO_2 sources). It is also important to note that any emissions of biogenic CO_2 occurring during transport and storage (e.g. due to leaks) are not ascribed a zero-emissions factor, on the following basis (following on from above):

> *"The corollary of this is that any subsequent emissions from CO_2 transport, CO_2 injection and the storage reservoir itself should be counted in national total emissions, irrespective of whether the carbon originates from fossil sources or recent biomass production. This is why in sections 5.3 (CO_2 transport), 5.4 (Injection) and 5.5 (Geological Storage) no reference is made to the origin of the CO_2 stored in underground reservoirs"*

In other words, the negative emission is already applied to the source sector to avoid double-counting in both *LULUCF/AFOLU* and *Energy* sector totals in the inventory, and therefore cannot apply elsewhere in the inventory as there are not provisions within the 2006 GLs to "net-back" the emission to the source category.

These same principles should broadly apply in **regional GHG reporting and cap-and-trade schemes** (see Box 2.1). Under the **US GHGRP**, the current transfer provisions for "Carbon Dioxide Suppliers", and the differential reporting of biogenic and fossil CO_2 emissions, suggests that negative emissions are implicitly accepted. The scheme does not actually differentiate on whether the deduction can be made on the basis of permanence, as amounts may be deducted by "Carbon Dioxide Suppliers" irrespective of the end-use of the CO_2. Only operators of "Geological Storage Sites" may report the amount sequestered. Research in the US relating to "biogenic adjustment factors" (BAFs) is considering the scope to employ negative BAFs where CO_2 sequestration is greater than the CO_2 emissions resulting from combustion of a particular biomass fuel (US EPA, 2011; see Section 4.3.1). On the other hand, emissions from biogenic sources are to be excluded for the purposes of calculating obligations to report under the GHGRP; where this results of emissions of <25 ktCO_2-e/yr, the facility is excluded from GHGRP requirements, meaning that facilities burning significant amounts of biomass are likely to be excluded from the program. In the **EU ETS** and **Australian CPM**, negative emissions could, in principle, be recorded in a qualifying installations inventory based on deducting the mass of CO_2 captured and transferred, although there are issues preventing this outcome. Furthermore, the benefits of doing so are less clear (see the next section). Problematically, in the **EU ETS**, the CO_2 transfer provisions set out in *Article 49* of the EU MRR, which provides the basis for deducting amounts of captured CO_2 transferred for geological storage from an installation's GHG inventory, applies only to "fossil carbon"[1] meaning that any biogenic CO_2 transferred offsite may not be deducted (Section 2.3). This implicitly means that negative emissions are not possible. Further, installations "exclusively using biomass" are entirely exempted from the scope of the scheme (under *Annex 1.1* of Directive 2003/87/EC). Similarly, under the **Australia CPM**, emissions from biomass are not considered as "covered emissions" and on that basis, installations primarily burning biomass are excluded. This suggests that there would be no reporting of negative emissions under these schemes, thereby posing an issue for their use as a means to reward bio-CCS. On the other hand, under the EU ETS, CO_2 capture installations are included as qualifying activities in the scheme,[2] as are "Carbon Dioxide Suppliers" under the GHGRP, meaning that actually implementing CCS at a site exclusively using biomass could automatically qualify the

[1] Defined as *"inorganic or organic carbon that is not biomass"*.

[2] Defined as "*Capture of greenhouse gases from installations covered by this Directive for the purpose of transport and geological storage in a storage site permitted under Directive 2009/31/EC*". This leaves some ambiguity whether the requirement would be triggered or not, but could potentially bring a 'exclusively biomass' plant into the ambit of the scheme based on the definition of an installation as "*a stationary technical unit where one or more* [qualifying activities] *are carried out and any other directly associated activities which have a technical connection with the activities carried out on that site and which could have an effect on emissions and pollution*"

operator/installation/facility into the scheme; issues relating to deduction of transferred biogenic CO_2 under *Article 49* of the EU MRR would still pervade, however. Under the **California ETS**, CO_2 emissions from biomass must be included in the calculated level of emissions for any facility, meaning any facility burning biomass would be included, although CCS is not yet included so negative emissions cannot be reported on this basis at the time of writing (see Section 2.3). The anomaly present between the treatment of fossil CO_2 and biogenic CO_2 in some GHG accounting rules results in an incentive being provided to fossil-CCS but not bio-CCS. Given the negative emissions benefits of bio-CCS, this differential treatment should be removed from these schemes, although this will – in most cases – require a new type of mechanism to *reward* such activities (as discussed in the next Chapter).

Project based schemes offer the scope to include negative emissions based on the principle described above, namely: that biogenic CO_2 emissions are zero-emissions rated, and that capturing and storing can be subtracted from zero, leading to negative emissions. The CCS M&Ps under the CDM do not include any prohibitions against the use of bio-CCS, and the prospect of the technology was one of the factors in garnering support for CCS inclusion in the CDM amongst certain Parties' and NGOs.

Under **low carbon fuel standards**, the possibility exists, in principle, for negative emissions to be reported for covered fuels, based on the inclusion of CCS within the GHG accounting methodologies employed to estimate a fuel's GHG intensity. If this were to arise it could result in a road transport fuel that actually removed CO_2 from the atmosphere even after combustion. The concept provided the basis for recommending inclusion of CCS within the **California LCFS,** albeit in relation to CO_2 use in enhanced oil recovery (Farrell and Sperling, 2007). However, it does seem something of an unlikely prospect in relation to biofuels.[1]

A summary of the review set out in the proceeding section is presented in Table 2.2.

Options to address gaps in the current GHG accounting rules are in terms of the capacity of various schemes to *recognise* and *reward* negative emissions are discussed in the next Chapter, and some thoughts on options to address barriers are outlined in the *Conclusions* in Chapter 5.

[1] The biogenic CO_2 emissions arising from biomass fermentation during the production of e.g. sugarcane ethanol is only a small fraction of the total GHG emissions of sugarcane ethanol production. The possibility of capturing biogenic CO_2 emitted during mobile combustion seems unlikely to be economically feasible (although not technically infeasible: Saudi Aramco showcased a Hummer fitted with CCS at the Qatar Climate Conference in 2012).

Table 2.2 Summary of GHG accounting rules for bio-CCS

Scheme	CCS	Biomass growth/ harvesting/ combustion/ processing	dLUC/iLUC	Life cycle emissions	Negative emissions
2006 IPCC Guidelines	Included. Involves deducting captured CO_2 from source sector total where stored in geological reservoir monitored following IPCC guidance	Included (in principle). Based on C-stock change accounting. When biomass is harvested, it is assumed to be 100% oxidised to CO_2 and emitted. Reporting emission from biomass combustion would result in double-counting.	Included (in principle). Land Conversion is supposed to be reported under IPCC Guidelines. Implementation is patchy, leading to cross-sector and cross-border effects.	Included. Country's to report all emissions by sources and removals by sinks within their national territory.	Included. Negative emission may be recorded in national GHG inventory.
EU ETS	Included. Subtract captured and transferred fossil CO_2 from installation inventory where transferred to site regulated by EU CCS Directive.	Zero-emissions factor assumed for biomass combustion to avoid double-counting (based on IPCC).	Not included	Not included	Not possible. Only transferred fossil CO_2 can be deducted from an installation's GHG inventory.
EU RED/FQD	Included. Subtract captured CO_2 from GHG intensity calculation	Included. Emissions from biofuels production included in GHG intensity calculation.	Included. Emissions from dLUC/iLUC (partially) included in GHG intensity calculation.	Included.	Possible.
GHGRP	Included. Only subpart RR allows reporting of amounts of CO_2 geologically sequestered.	Zero-emissions factor assumed for biomass combustion to avoid double-counting (based on IPCC).	Not included	Not included	Possible. Subject to biomass plant exclusions.
California ETS	Excluded. Subject to ARB-approved CCS methodology (none yet)	Zero-emissions factor assumed for biomass combustion to avoid double-counting (based on IPCC).	Not included	Not included	Possible. Subject to inclusion of CCS within the scheme.
California LCFS	Included. Methods 2A and 2B plus included for fossil fuels	Zero-emissions factor assumed for biomass combustion to avoid double-counting (based on IPCC).	Included. CA-GREET model includes "iLUC modifier" derived from GTAP Model.	Included	Possible.
Australia CPM	Included. "Covered emissions" relate only to emissions to atmosphere	Specifically excluded.	Not included	Not included	Not possible. Subject to biomass plant exclusions.
CDM/JI	Included (CCS M&Ps)	Zero-emissions factor, subject to precedents from other bio-energy Approved Methodologies.	Included. Subject to precedents from other bio-energy Approved Methodologies.	Included. Subject to precedents from other bio-energy Approved Methodologies.	Possible. Subject to a new methodology being developed and approved.

3 REWARDING NEGATIVE EMISSIONS

3.1 Introduction

In Chapter 3, the review outlined that some GHG accounting rules allow negative emissions from bio-CCS to be *recognised* and *attributed* within different GHG policy frameworks (e.g. Kyoto Protocol cap-and-trade), whilst other schemes, such as the **EU ETS** and **Australia CPM** would potentially require amendment in places to accommodate the approach within the scheme's GHG accounting rules. The issue of *rewarding* these negative emissions with respect to providing an incentive to undertake bio-CCS is a key policy issue that is addressed in this chapter.

Based on the general assumption in policy design that most viable abatement technologies only reduce CO_2 emissions towards zero rather than actually reduce them negatively, challenges can arise in relying on different GHG policy instruments to reward negative emissions; in most cases the instruments have simply not been designed to take account of such technologies. As such, new types of accounting approaches or mechanisms may be needed to accommodate negative emission technologies within their ambit. Critical factors in assessing the capacity of a scheme to reward negative emissions relate to the scheme architecture. This includes, *inter alia*, the nature of covered sources, the compliance entity, the target, the baseline and the use of credits, which are summarised for the various schemes reviewed in Table 3.1. Other scheme-specific factors can also have an effect such as exclusions (e.g. as under LULUCF reporting for countries; Box 2.4) and the scope to use "offsets" from project-based approaches.

Under the various schemes reviewed, the options for rewarding negative emissions can be simplified to two basic approaches:

1. Net-back accounting; and/or
2. Issuing "credits" for the negative emissions;

These are discussed in the following sections.

3.2 Net-back accounting

A relatively simple approach to accommodate and reward bio-CCS under cap-and-trade schemes is to account only for *net emissions*, thereby avoiding *de facto* the need to accommodate negative emissions within the scheme. In other words, any negative emissions can be used to offset (or "netted-back") against positive emissions occurring elsewhere in the scheme. A critical factor to enable "net-back" accounting to work is for compliance to apply at a *portfolio level*, that is, at a higher level than the *installation-* or *project-level* in order that a range of emissions sources are included against which to net-back negative emissions.

As shown in Table 3.1, this is the case for some schemes reviewed, such as **international GHG cap-and-trade under the Kyoto Protocol**, where the compliance entity – the country – is liable for emissions from a *portfolio* of emission sources. In this case, a country in which a bio-CCS project takes place would be able to offset or "net-back" the negative emissions achieved against a wider portfolio of emissions, thus avoiding a net negative total (as outlined by Ascui, 2010). This would serve to provide a reward and therefore incentivise the country, as the compliance entity, to employ negative emission technologies.

Table 3.1 Design features of different GHG regulatory schemes

Scheme	Compliance entity	Covered sources	Target	Baseline / Allocation	Units
Kyoto Protocol	Country (signatory Party)	Portfolio of emissions in national territory: – Emissions from most sectors (excl. bunker fuels) – Removals and emissions from LULUCF (see Box 2.4)	Aggregate target for sources based on reduction in Annex B *Period*: 2008-12 (CP1) 2013-20 (CP2)	1990 emissions	CER, ERU, tCERs, ICERs, RMU
EU ETS	Installations / operator	Large point sources (power plants, cement, iron & steel etc.) All emissions sources inside installation boundary.	Installation target implicit, based on CO_2 price (auction/tax) and cost of abatement. Free allocation for some installations. Annual compliance.	Total cap of EUAs determined by EU reduction target. Zero (implicit) or to level of free allocation	EUA, CER, ERU, Domestic offsets
Calif. ETS					ACR, CAR
Australia CPM					CER, ERU, ACUs
GHGRP			None	n/a	n/a
EU RED/ FQD	Fuel suppliers	Suppliers portfolio covering: – Upstream emissions – Emission from fuel combustion	Aggregate target, based on GHG intensity of fuel. Interim targets to 2020	2010 GHG intensity	n/a
Calif. LCFS					
CDM/JI	Project operator	Wide range of candidate activities. All emissions and removals within boundary + leakage	n/a	Counter-factual reference	CER, ERU

A potential shortfall in this scenario occurs where the country has a zero-carbon economy (or near-zero carbon economy) and therefore could, with bio-CCS deployment, potentially record negative emissions in its national GHG inventory. Although this seems unlikely to be an issue in the near-term, a single country's negative emissions could, in principle, again be "netted-back" against other countries where emissions are occurring, thus providing a global benefit for the atmosphere. However, it is important to note that under this scenario there would not be any direct incentive for the specific country to undertake bio-CCS unless its target was adjusted accordingly, or a form of benefit transfer between negative emitters and positive emitters could be established (e.g. a transferable "credit" such as an RMU; see the next section).

Similarly, under **low carbon fuel standards**, a *portfolio* approach is also taken for compliance, so that compliance entities – namely fuel suppliers – could accommodate a negative emission fuel in the portfolio. Although unlikely, this could be offset or "netted-back" against other fuels in the supplier's portfolio with net positive emissions. This would again reward the negative emission and provide an incentive for undertaking such activities. The key point is that under both these schemes, the *portfolio* based approach means that negative emissions can effectively be rewarded through netting-back against other positive emissions, thus providing a reward for the compliance entity to undertake bio-CCS. It is unlikely that a supplier's entire portfolio could become negative, although in principle this could be netted-back against other suppliers, although the incentive to do so would not be present without modifying the operators target, or incorporating some form of trading with benefit transfer capability.

Conversely, under **regional cap-and-trade schemes** the compliance entity – the installation operator – is liable only for a single or small collection of sources occurring at a single installation. Furthermore, under these schemes the implied baseline is zero, or rather they are based on the allocation and trading of "emissions rights", which are always positive (see Box 3.1). This means that any technologies that deliver emission reductions below zero for the compliance entity cannot be readily rewarded. There are also currently legal and regulatory barriers which prevent recognition of negative emissions in most of the schemes reviewed (Section 2.7).

Box 3.1 Incentives in regional cap-and-trade schemes

Although different cap-and-trade schemes can vary according to a range of design factors (Table 3.1) they all share a common central feature, namely that participants are required to acquire and surrender a number of permits or "emission rights" equivalent to their emissions. Emissions therefore represent an *operational* cost, and excepting for certain perverse incentives which can arise through certain scheme rules (e.g. over-allocation of free emission rights), participants are always incentivised to reduce their emissions. Depending upon the allocation approach adopted within the cap-and-trade scheme, a verified reduction in emissions will either reduce the need for the participant to buy permits or will allow the participant to hold a surplus amount of permits - which may then be sold or banked.

Where permits are *freely allocated* to participants, participants are 'rewarded' to the extent that they reduce their emissions and can then profitably sell surplus permits; the reward however only extends as far as their ability to reduce their emissions to zero. Alternatively, where permits are auctioned, participants who reduce emissions are 'rewarded' by needing to purchase fewer permits through auction; however again the reward only extends as far as their ability to reduce their emissions to zero. In both cases, the emissions cost is fully removed and there is therefore no additional incentive to continue abating below zero emissions i.e. with negative emissions (see Figure 3.3 below).

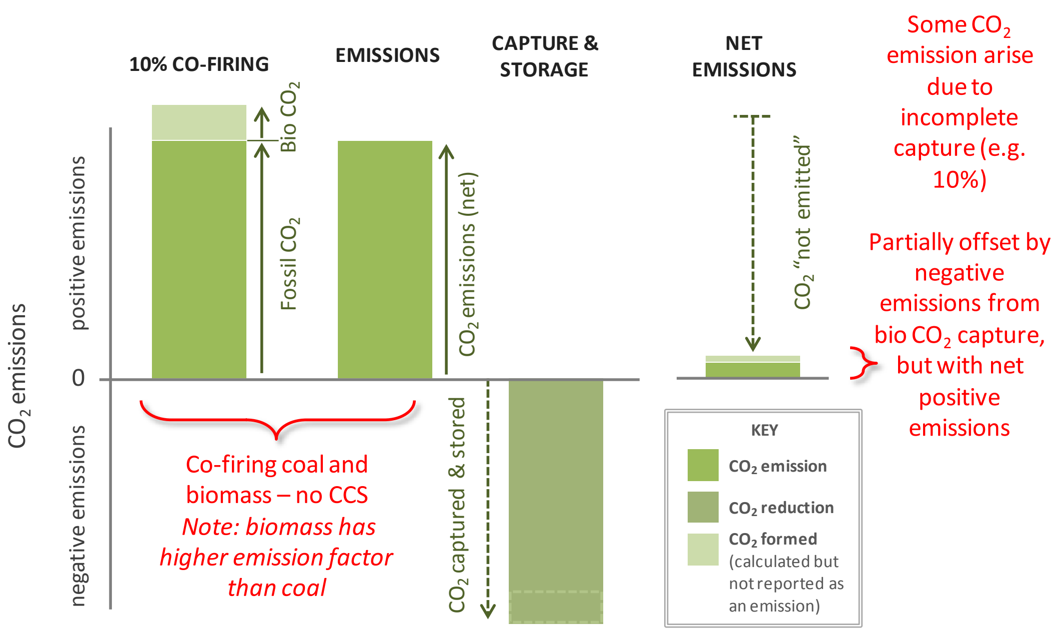
3.2.1 Netting-back multiple sources in a single installation

Notwithstanding the legal and regulatory barriers present in the **EU ETS** and **Australian CPM** (Section 2.7), a possible scenario where negative emissions from bio-CCS could potentially be rewarded at a single installation is where it is applied to a subset of emissions sources at the installation, and that the net emissions from the whole installation do not go below zero, meaning that "netting-back" is possible for the compliance entity. In principle, this approach could apply in the case of installations co-firing a mixture of fossil and biomass fuels, or in industrial plants where some biogenic emissions arise alongside fossil emission sources, such as cement kilns or pulp and paper mills. In combustion plants, technical factors typically limit biomass co-firing to a maximum of 20% of energy input, although levels around 5% are more typical. Assuming a typical capture rate of 90%[1] and an energy penalty[2] in the region of 10-20%, CCS applied to large-scale co-fired power plants would in most situations likely result in positive

[1] The capture rate is the share of CO_2 emissions by mass in the exhaust stream which can be physically captured.
[2] The energy penalty represents the additional energy requirement of the capture equipment.

emissions on a net basis i.e. the negative emissions associated with capture of the biogenic CO_2 stream would be offset by the additional emissions arising from operation of the capture plant. Similarly, it may be the case that bio-CCS is used in only part of an installation (e.g. one unit within a coal-fired power plant) or to a specific slip-stream, also leading to net positive emissions (Figure 3.1). Such an approach would require modifications to e.g. the EU ETS monitoring rules to allow subtraction of transferred biogenic CO_2, in order to be applicable to co-firing. Where co-firing rates exceed around 20% biomass or in cases of pure biomass firing (or where greater capture efficiency is achieved), net negative emissions would occur which would require other mechanisms through which to reward such activities, such as crediting (see below).

Figure 3.1 GHG accounting for co-firing (at 10%)



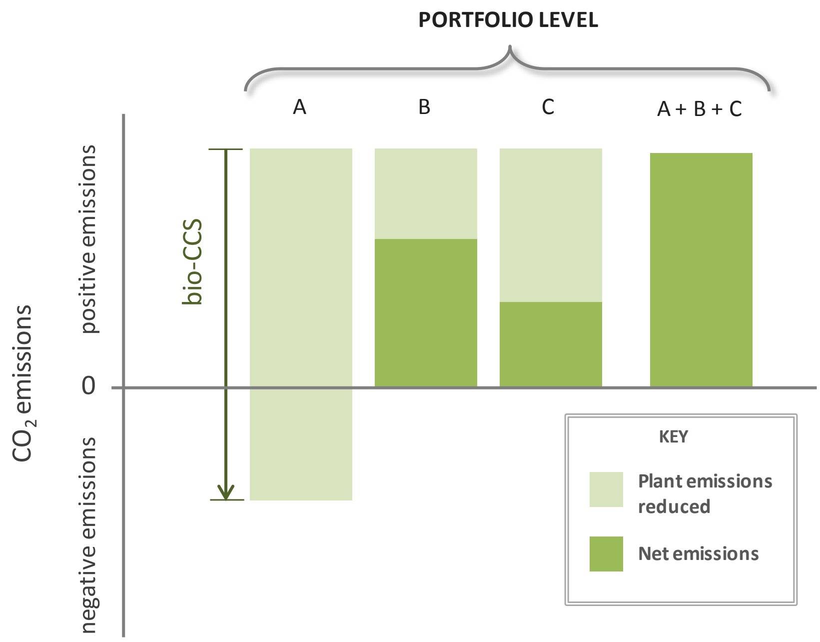
Source: Carbon Counts

Note: Figure is simplified for illustrative purposes; other factors could affect the overall GHG balance at an individual installation (e.g. energy penalty effects).

3.2.2 Netting-back through *pooled* compliance across multiple installations

Even though in practice a compliance entity may be responsible for a number of installations, compliance under regional cap-and-trade schemes is still managed at the installation level. In order to overcome this, the compliance obligation would need to be *pooled* to create a portfolio approach that could allow net-back accounting to apply across several qualifying installations. This option is outlined graphically in Figure 3.2 as a simple example covering a mixed portfolio of installations – plants A, B and C, each starting with the same emissions. Over a given reporting period, bio-CCS is undertaken at plant A resulting in negative emissions at that plant. Plants B and C also achieve emissions reductions, although these are marginal (e.g. through energy efficiency improvements), and emissions therefore remain positive at both plants. In this example, the negative emissions associated with plant A can be "netted off" against the positive mass of emissions from plants B and C. At the end of the compliance period, the operator surrenders permits arising from its net emissions at the *portfolio* level.

Figure 3.2 GHG accounting under a pooling arrangement



Source: Carbon Counts

Clearly, this approach is also imperfect in that it requires that positive emissions exceed negative emissions across the portfolio. In practice, it would be applicable to many power sector operators within the EU ETS, most of which have large portfolios and would be unlikely to implement bio-CCS at a large number of their plants – at least over the short- to medium-term. However, for smaller portfolios it may only be applicable in some cases and would not be applicable in cases of single installation operators implementing dedicated biomass plants with CCS (e.g. independent power producers).

The possibility of *pooling* was included within the EU ETS under *Article 28* of the ETS Directive (Box 3.2). Options for pooling do not currently exist in either the California ETS or Australia CPM.

Box 3.2 Pooling under the EU ETS

It has been proposed that pooling under Article 28 of Directive 2003/87/EC (the EU ETS Directive) may be a means to incentivise bio-CCS in the EU ETS, as it allows the negative emissions to be 'netted off' at the portfolio level (Ascui, 2010). The provisions for 'pooling' under Article 28 allow operators to form a pool of installations for the same EU ETS Annex I (qualifying) activity (be it combustion installations; pulp and paper installations; oil refineries etc.). Operators wishing to form a pool are required to apply to the competent authority in the relevant Member State, specifying the installations and the period for which they want the pool; a trustee is then nominated, having responsibility *inter alia* for surrendering allowances equal to the total emissions from installations in the pool. However, pooling has not been extensively used, in part due to the case-by-case requirement of Member State justification and subsequent approval from the Commission. Early experiences also suggested that there are complex administrative issues associated with pooling between several entities. More importantly, the wording of Article 28 provides for the use of pooling only until the end of December 2012, and not having been extended in the revised Directive, appears to be dormant.

In the absence of a *pooling* arrangement, other mechanisms will be needed to accommodate negative emissions in **regional cap-and-trade schemes**, including **project-based approaches** along the lines of the CDM or JI, as discussed in the next section,.

3.3 Issuing "credits"

Rather than relying on net-back accounting to accommodate negative emission technologies within any particular **regional cap-and-trade scheme**, it may be more practical and effective to consider issuing equivalent and fungible credits to installations employing bio-CCS with negative emissions. The practicalities of whether to apply a credit to all negative emissions, or just those where net-back accounting is not possible would need to be considered. Also, for situations where co-firing takes place, it will be necessary to consider the practicalities of how best to reward negative emissions: either through direct issuing of "credits" for any negative emissions that arise on an *ad hoc* basis, or by opting the plant out of the cap-and-trade scheme and including it as a separate offset under a project-based approach. These are all practical considerations which need further analysis to assess their relative pro's and con's.

Notwithstanding these practical considerations, it is clear in the context of the schemes covered in this review that a crediting mechanism – either through direct crediting or via project-based credits – could be essential to rewarding negative emissions under the **EU ETS** or **Australia CPM**.[1]

There are several options to consider, based on using mechanisms already present within the scheme, or via linking to external schemes, as discussed below.

3.3.1 Direct crediting from an allowance reserve

This approach would involve withholding and earmarking a portion of the total tradable permits/allowances within a scheme in a special reserve (Ascui, 2010). The reserved permits could then be used to directly credit the storage of eligible biogenic CO_2 on the basis of the recorded mass of negative emissions, established according to the schemes GHG accounting rules (as reviewed in Section 2.2.4; which would need amending in some cases).

There are precedents for using permit reserves within cap-and-trade schemes, albeit for different purposes. Within the **EU ETS**, a number of EUAs from the total allocation within each phase of the scheme is placed into a *New Entrant Reserve* (NER), which is made available to eligible new entrants into the scheme subject to auctioning or free allocation. Other cap-and-trade schemes often have similar reserves, for example the **California ETS** has an Allowance Price Containment Reserve (APCR) where around 1% of the annual allowances are withheld from auctioning. Reserves can also be used to develop specific incentive programmes for specific low-carbon technologies or projects, serving as a direct subsidy for eligible activities: for example, in Phase III of the EU ETS, a portion of the EUAs in the NER are earmarked for sale to fund selected CCS and other innovative renewable energy projects within the EU – the so-called 'NER300', established through the sale of 300 million EUAs from the NER.[2]

[1] Subject to the discussions presented in Section 2.7, which suggested that actually employing CO_2 capture at a biomass plant could serve to bring it within the scope of the EU ETS.
[2] Information on NER300 available at: http://ec.europa.eu/clima/policies/lowcarbon/ner300/

A reserve for crediting negative emissions arising from bio-CCS could potentially be created either from unallocated permits during a given phase of a cap-and-trade scheme (i.e. from a new entrants' reserve)[1] or from a set-aside reserve specifically created for the purpose during the allocation process – or a combination of both. Within the latter option, unused permits could potentially be transferred to the new entrants reserve in the event of bio-CCS not being developed within the scheme.

Key advantages of the approach include:

- Credits would be fully fungible with the scheme into which they are sold; and,
- Using a reserve from the overall allocation "cap" would maintain the environmental integrity of the scheme i.e. no additional "offsets" included.

Potential challenges include setting the level of the reserve (although surplus allowances could be simply auctioned alongside other units), or over-subscription to the reserve (Ascui, 2010). In the case of the latter, ensuring transparency upfront about the size of the reserve – as applied today in the **EUs NER** and the **California APCR** – would send a clear signal to participants regarding the likelihood of obtaining credits. The approach would require modifications to existing legislation e.g. in the EU ETS, Directive 2003/87/EC would need to be modified to allow for issuance of EUAs from the NER on the basis of negative emissions, and Regulation 601/2013 (monitoring guidelines) would need to extend the *transfer* provisions in *Article 49* to include biogenic CO_2.

It is useful to note that the same principles would apply under a carbon tax (e.g. as proposed in South Africa), where a rebate equal to the tax rate could be issued on the basis of the level of negative emissions achieved (as proposed by Azar *et. al.*, 2006).

3.3.2 Direct crediting using specific bio-CCS credits

Ascui (2010) has proposed the option of creating a new class of credit specific to bio-CCS projects. The author notes that – unlike the case of creating a special permit reserve – such an approach would not require up-front allocation, which would avoid the challenges associated with using an allowance reserve. However, Ascui notes that there could be significant political challenges in creating a new class of trading unit which could be unlimited in terms of its allocation (and also because there are likely to be other negative emission technologies seeking similar types of subsidy e.g. direct air capture; biochar; see McGlashin *et. al*, 2012 for examples of other negative emission technologies).

Notwithstanding the potential drawbacks of this approach, and although more akin to setting a mandate or portfolio standard, it is interesting to note that in a recent Communication, the European Commission proposed the concept of a *CCS Certificate* for incentivising CCS in Europe.[2] Under its draft outline, certain emitters would be required to purchase *CCS Certificates* equivalent to a certain share of their emissions, which would be linked to EUAs that would be retired in exchange for a *CCS Certificate*. The desired volume of carbon reductions achieved

[1] This also includes those permits returned to a reserve by closed, or partially closed, installations

[2] COM 2013/0180. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on the *Future of Carbon Capture and Storage in Europe*.

through the *CCS Certificates* would be known in advance, and an equivalent volume of EUAs within the EU ETS would be permanently withdrawn from the market. The potential benefits of such an approach includes the ability to define how much CCS should be developed. It is also conceivable that two classes of certificates could be created: fossil CCS and bio-CCS to help appropriately reward the relative benefits from each (the capacity to remove CO_2 from the atmosphere, as opposed to only reducing emissions towards zero; see Box 1.1) and as discussed in the next Chapter (Section 4.2). The proposal remains at the concept stage, however, and subject to further work based on responses to the proposals by stakeholders. At time of writing, the European Commission has produced a synthesis of views based on 171 responses received (EC, 2013).[1] According to the synthesis of responses, it is apparent that the concept of a *CCS Certificate* scheme was generally not well received, principally because of potential "distortive effects" such a measure could have on the functioning of the EU ETS (EC, 2013). At the current time, therefore, such an approach seems unlikely to gain traction in Europe, at least in the near-term.

3.3.3 Generating "credits" using project-based approaches

Both the **international** and **regional cap-and-trade schemes** reviewed include provisions for the use of "offset" credits using project-based mechanisms (see Table 3.1). **Project-based mechanisms** represent a type of baseline-and-credit scheme in which each verified unit of emission reduction (e.g. tonne CO_2) achieved through one or more abatement project earns a credit; these can then be traded within carbon markets based on cap-and-trade principles as equivalent compliance units, such as in the EU ETS or under international cap-and-trade implemented under the Kyoto Protocol. Options for project-based approaches come in two forms: domestic offset credits and international offset credits, as reviewed below.

Domestic offsets

Domestic offsets are project-based mechanisms similar to the CDM or JI Track 2, from which specific credits can be generated that are fungible for compliance in an ETS. The main difference is that they are sourced from within a schemes jurisdiction for activities falling outside the scope of the ETS. In the **regional GHG cap and trade schemes** reviewed, the following domestic mechanisms are available:

- California ETS – covering various approved protocols and project types, and provisions to link to offset registry suppliers (ACR, CAR – see Table 2.1);
- EU ETS – provision for domestic offsets under *Article 24a* of the ETS Directive (2003/87/EC); and,
- Australia CPM – *Carbon Farming Initiative (CFI)*, generating *Australian Carbon Credit Units* (ACCU) as eligible compliance units under the scheme.

Under the **California ETS**, there is no specific prohibition on developing bio-CCS offset projects. However, a key proviso is that an offset credit must *"represent a GHG emission reduction or GHG removal enhancement that is real, additional, quantifiable, permanent, verifiable, and enforceable"*. Presently the State of California has not set its own GHG accounting standards for

[1] Covering *CCS Certificates*, as well as other potential support mechanisms for CCS such as reserve auctions along similar lines to the NER300; emission performance standards for power plants to implement CCS; and any other potential support mechanisms. More information is available at: http://ec.europa.eu/energy/coal/ccs_en.htm

CCS that are commensurate with this requirement (see Section 2.3.2), which could prevent progress of CCS-based offset projects in at least the near-term. That said, the ACR recently consulted on a new offset methodology for *CCS in Oil and Gas Reservoirs*, which could potentially pave the way for the use of CCS-based offsets in California.[1]

In the **EU ETS**, *Article 24a* of the ETS Directive ("Harmonised rules for projects that reduce emissions") offers the possibility of establishing an internal offsetting mechanism within the EU for projects and sectors outside of the EU ETS.[2] As noted by Groenenburg and Dixon (2010) this approach can provide a means for linking installations using exclusively biomass to the EU ETS, thereby paving the way for incentivising bio-CCS in line with the EU ETS. In principle, a domestic offset in the EU ETS acts in a similar but unilateral/domestic way to that of JI (see below; after Groenenburg and Dixon, 2010). As yet, the use of domestic offsets in the EU remains untested, as described in more detail below (Box 3.3).

Although there are potential economic and environmental benefits in approaching bio-CCS as a *Domestic Offset Project* (DOPs) or *Community Offset Project* (COPs) in Europe, there are some potential challenges to doing so. Firstly, it has not been tried, so it would suffer from first-mover disadvantage. Second, it remains unclear whether it would be developed by the Member State(s) or the European Commission. Third, other options such as a credit reserve approach may be simpler solutions, or through the use of JI (subject to limits under the Efforts Sharing Decision) although further analysis is required to assess the relative benefits of different options.

In **Australia**, the CFI is limited in its scope to agricultural emissions avoidance projects, landfill legacy emissions avoidance projects, or introduced-animal emissions avoidance projects. Therefore, the only possible application potentially relevant to this study is the use of CCS on biogas combustion from landfill legacy emissions, although assessment of this type of activity hasn't been considered in detail within the scope of this report, and is likely to be small.

International offsets

International GHG cap-and-trade under the Kyoto Protocol introduced two project based schemes – the CDM and JI – that can generate "credits" that may be used for compliance towards a Party's QELROs (i.e. targets; see Table 2.1). In practice, governments in regulated countries have to n extent "outsourced" the process of acquiring such credits to private entities by allowing them to be used for compliance within their own **regional cap-and-trade scheme**, as is the case with the **EU ETS** and also proposed for the **Australian CPM**; the **California ETS** does not allow international offsets.[3] It is worth noting that innovative means of using international offset credits are also under consideration in the **EU RED/FQD** (see Table 2.1).

[1] Available at: http://americancarbonregistry.org/carbon-accounting

[2] Note that the EU ETS Directive, under Article 24, allows Member States to unilaterally include additional sectors and gases in the scheme ("opt-in"). This in practice means that a domestic offset needs to be set in the context of the opt-in provision. Since installations that exclusively combusting biomass are presently excluded, they could in theory be opted-in to provide a potential incentive for bio-CCS. However, since such installations would then only generate negative emissions, the approach would be subject to the same limitations as discussed in Section 3.2.

[3] Both *quantitative* and *qualitative* restrictions are in place regarding the number of CERs and type of projects from which they may be sourced in the EU. In terms of the latter, industrial gas projects, LULUCF and certain large hydro are prohibited, as are CERs from projects *Registered* after December 2012 not located in a Least Developed Country. Also, in Phase II of the EU ETS, CERs will need to be swapped into EUAs before being used for compliance.

Box 3.3 Domestic offsets under the EU ETS

Article 24a of the EU ETS creates provisions for "*implementing measures for issuing allowances or credits in respect of projects administered by Member States that reduce greenhouse gas emissions not covered by the Community scheme*", often referred to as Domestic Offset Projects (DOPs) and/or Community Offset Projects (COPs).

In terms of implementation, an EU Member State (DOPs) or the European Commission (COPs) would be required, for a specific DOP/COP, to propose *inter alia*:

- Monitoring and reporting and accounting rules;
- Methods for determining the baseline;
- Means to demonstrate how projects thereunder would be "additional" i.e. not covered by other legislation regulating GHG emissions; and,
- Means to ensure that double counting is avoided.

However, precise details on what would need to be included in a DOPs/COPs proposal are not set out anywhere in EU rules. Also, it is unclear as to what types of credits could be issued, by who, and under which regulatory structure (domestic or EU; DOPs or COPs). The latter aspect could be important if this provides the basis for determining the baseline and additionality under a DOP, which could vary between Member States. In this context, the European Commission concluded that COPs would be preferable, although the legislation remains ambiguous (EC, 2008).

In respect of the EUs Effort Sharing Decision (ESD; 406/2009/EC) – which sets targets for emission reductions in non-EU ETS sectors (set at 10% below 2005 levels by 2020, with variable levels imposed for different Member State) and also on the use of CERs and ERUs under the ESD – the Decision expressly excludes *any* limitation on the use of DOPs/COPs units. This suggests that DOP/COPs would need to be credits that are independent of the ERUs under the JI (see below).

Another complicating factor is the potential linkages between emission reductions subject to DOP/COP and Member State's targets under the EU ESD with respect to emission reductions in non-EU ETS sectors and use of CERs and ERUs under the ESD, should a DOP be linked to ERUs. Administratively, any proposal for a DOPs/COPs would go through a "comitology" process i.e. subject to approval by the *EU Climate Change Committee*, rather than the potentially lengthy Co-decision process (the standard rule making procedure for the EU legislature).

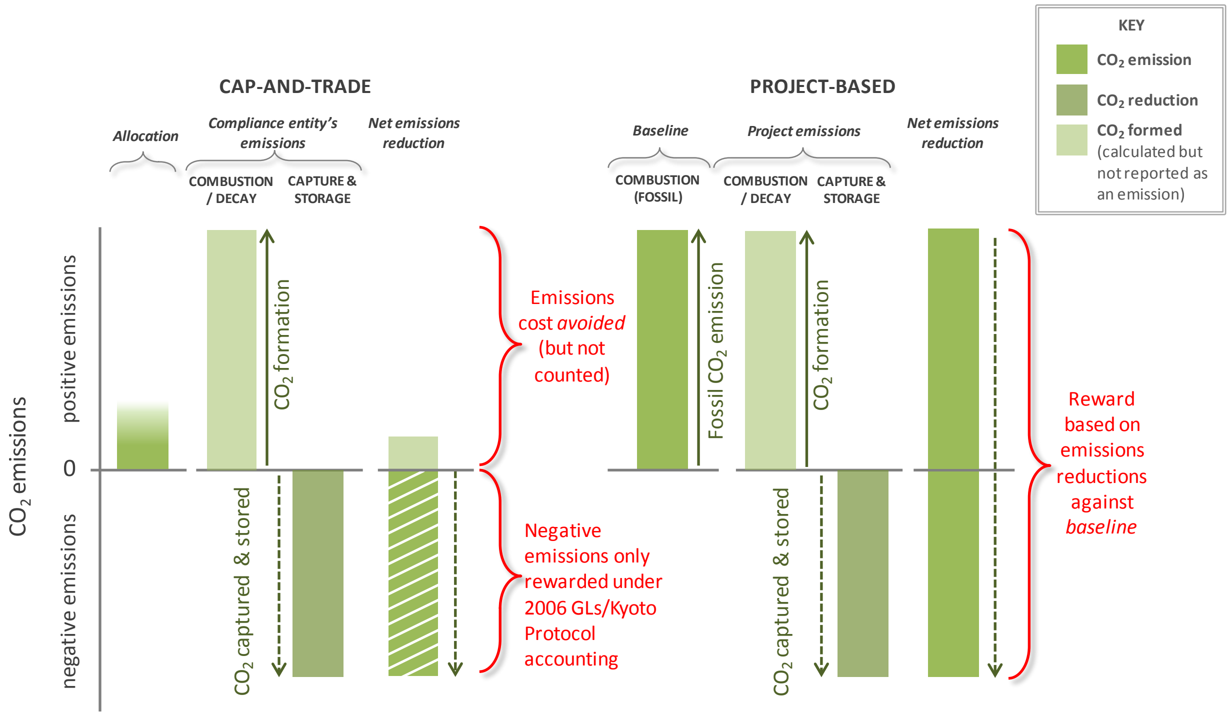
To date, no effort has been made by any Member State to propose a domestic offset programme, at least not publically. Several Member States including Germany, France, Hungary, Poland, Czech Republic and Estonia have developed domestic offset projects under the umbrella of Joint Implementation.

Sources: Directive 2003/87/EC; Decision 406/2009/EC; EC, 2008; von Unger and Hoozgaad, 2010.

As outlined in Chapter 2, in principle the scheme rules for both CDM and JI impose no challenges for recognising negative emissions compared to cap-and-trade schemes (see Section 2.7.2 and Figure 3.3), and therefore could be applied to bio-CCS projects taking place in developing and developed countries respectively. Figure 3.3 shows that under cap-and-trade schemes, the combustion of zero-emissions rated biomass leads to the avoidance of emission costs, but the negative emissions part is not generally rewarded, with the exception of the Kyoto Protocol. On the other hand, under a project-based approach both components of the emissions reduction e.g. the substitution of coal with biomass *and* the negative emissions associated with capture and storage of biogenic CO_2, could potentially be rewarded with in a project-based approach, subject to baseline requirements.

Considerations for international offsets are discussed below.

Figure 3.3 Negative emissions under cap-and-trade versus project-based mechanisms



Source: Carbon Counts

Joint Implementation

In respect of using JI at least in the **EU**, there are a number of challenges for implementation. Groenenburg and Dixon (2010) described three options under which JI which could be applied to bio-CCS within the EU, covering:

1. Member States [now the European Commission in Phase III of the EU ETS] converts EUAs from the NER to ERUs and transfers these to entities in the EU member state that developed reduction projects on their own territories. This would reduce the amount of EUAs available to participants in the EU ETS. *This is similar to the "Credit Reserve" approach described in Section 3.3.1*.

2. Member States convert Assigned Amount Units (AAUs) from their national emission registries to ERUs and transfer these to entities in their own country or within the EU that develop reduction projects on their own territories. *This is in essence similar to a domestic offset scheme described above*.

3. Member States convert AAUs from their national emission registries to ERUs and transfer or sell these to entities in other EU Member States that invest in emission reduction projects on their own territories, and make the revenues available to the project. *This is broadly consistent with the existing international regime for JI*.

However, there are challenges to realising these options, including:

- Under the EU Effort Sharing Decision (ESD; 406/2009/EC) Member States are limited in their use of CERs and ERUs (note that DOPs use is potentially unlimited; see Box 3.3);

- The separate treatment of ERUs and DOPs credits in the ESD implies that the different units must be used.

The implications of these rules are that swapping AAUs or EUAs to ERUs might be more effectively achieved through a DOP or a *Credit Reserve* approach. Within the EU ETS, further evaluation and consultation of the interactions between JI, DOP and a *Credit Reserve* are needed to assess the most suitable approach. Any approach taken needs to be considered in the following contexts:

- *The overall level of level of "reward" that should or could be allocated to a bio-CCS project or other negative emission technology* – the various options could have implications in these contexts. This matter is discussed further in Section 4.2;
- *The overall effect of "offset" supply on the environmental integrity of the scheme's cap and emission reductions thereunder* – any approach involving an EUA to ERU swap should in principle mean the level of offset is zero (depending on the level or reward allocated), although this suggests that an alternative method using EUAs directly may be equally appropriate; and,
- *The effect of any "offset" on Member States in terms of their Kyoto Protocol QELROs*, which could be affected by the level of reward allocated to bio-CCS;

It is worth noting that, in the past, EU Member States have adopted different approaches to the use of domestic JI projects. The UK Government has decided to cancel any surplus AAUs rather than trade them on the grounds of environmental integrity, having taken the view that converting unused AAUs into ERUs to be sold on by private companies would not be environmentally robust. The Dutch government has also decided not to host JI projects, having ruled that converting its AAUs into ERUs would be counter-productive as it would not help them reach their Kyoto targets. The UK has also expressed a similar view, namely: that all carbon saved in the UK should contribute to the UK's carbon reductions and not those of another Annex I country. While the UK and Netherlands have ruled out the use of domestic JI, several other Member States have been more supportive. For example, most French ERUs generated to date have been surrendered by French entities under the EU ETS.

Clean Development Mechanism

The CDM is restricted to deployment in non-Annex I countries, which does not include any countries under **international GHG trading in the Kyoto Protocol** or any **regional GHG cap-and trade programmes**. The CDM cannot therefore reward bio-CCS projects located within Annex I countries. At the current time no CCS *Approved Methodology* has been approved by the CDM Executive Board, meaning that rewarding of bio-CCS under the CDM would first require a new methodology applicable to bio-CCS projects to be developed and approved. This would need to be consistent with the CDM GHG accounting rules as reviewed in Chapter 2.

The use of CERs from a bio-CCS project for compliance in **regional cap-and-trade schemes** would be subject to any restrictions imposed on the use of such credits. Under the **EU ETS**, both quantitative and qualitative restrictions have been imposed for CERs in Phase III of the scheme (Table 2.1 and footnote 3 on page 50), although so far no such restrictions have been proposed for use of CERs under the **Australian CPM**.

Whilst the options outlined above suggest ways in which bio-CCS could be accommodated and rewarded in existing GHG market-based mechanisms, a broader question persists regarding the *appropriateness* of the level of reward given the unique nature of negative emission technologies such as bio-CCS. This is reviewed in the next chapter.

4 APPROPRIATELY REWARDING NEGATIVE EMISSIONS

4.1 Introduction

One of the key objectives of this study was to consider options to *appropriately* account for negative emissions in GHG scheme rules. The scope for recognising, attributing and rewarding negative emissions has been discussed in Chapters 2 and 3, although the discussion there made only limited consideration of what an appropriate level of reward for such activities would or could be. For bio-CCS, other factors may be pertinent to the consideration of how *appropriate* different policies may or may not be for supporting bio-CCS, and what level of reward these should offer. Considerations in these contexts include:

- The level of reward that should be given to negative emission technologies, recognising the benefits they offer compared to other emission abatement technologies; and,
- Consideration of potential dLUC, iLUC and sustainability impacts of bioenergy projects, and accounting for this element in the level of reward provided to bio-CCS projects given the potential for leakage to occur in these contexts (see Section 2.5).

These are discussed in turn in the remainder of this chapter.

4.2 Determining the level of reward

The term “negative emission” elicits the idea that technologies such as bio-CCS deliver a “double dividend” for emissions abatement. To an extent, this is correct based on the following two components:

1. the first benefit is the *zero emissions* from the biomass part of the technology, and
2. the second benefit is the *negative emission* from applying CCS to these source streams.

The “negative emissions” part means bio-CCS “harvests” CO_2 from the air by transferring it from the shorter-term carbon cycle between atmosphere and biosphere to the long-term geological “pool” (Box 1.1). As such, bio-CCS can be used to accelerate reductions in atmospheric CO_2 concentrations (providing that biomass remains as a sustainable renewable resource), and compensate for – or “offset” – historical emissions. This potentially allows for the “over-shooting” of global emission reduction targets because any legacy emissions could be cleaned up later using negative emission technologies. Other potential benefits outlined include (after Azar, 2006; IMechE, 2011; IEA, 2012; IEA; 2013a; IEA, 2013b):

- *Tackling difficult or “recalcitrant” emission sources (e.g. aviation emissions)* – on the basis that negative emission technologies can provide a means to “offset” such sources, rather than providing direct abatement. Also, the use of biomass-to-liquids technologies with CCS offers a means to produce hydrogen which can substitute fossil based transport fuels.
- *Putting a ceiling price on CO_2 emissions* – in the context of direct air capture technologies on the basis that they could be used to “offset” any emission sources that are more costly to abate;

- *Involving more countries* – in cases where countries have only limited domestic CO_2 abatement potential.

These benefits, which are often reflected in integrated assessment model analysis (see Box 4.1), have led to suggestions that urgent actions are needed to support bio-CCS and, potentially, that *additional* rewards should be given to such technologies because of the extra benefits they can deliver whilst also continuing to provide important energy services required by society (e.g. IEA, 2013a). In essence, this means that the "double dividend" offered by bio-CCS implies that the rewarding of a "double-credit" could be appropriate for each tonne of biogenic CO_2 stored.

Box 4.1 Future role of bio-CCS in climate mitigation

Several integrated modelling efforts have highlighted the benefits of bio-CCS under climate constrained scenarios (e.g. Azar *et. al.*, 2006; Calvin et. al, 2009; Azar *et. al.*, 2010; Edenhofer, *et. al.*, 2010). A review of their outputs is included in IEA, 2012.

The modelling studies all tend to show that bio-CCS can play an important role in future actions to tackle climate change. In essence, the models provide a quantitative reflection of the benefits described in the text. For example, modelling shows that actions to tackle climate change can be taken later as bio-CCS can offer a means to reduce atmospheric CO_2 concentrations more rapidly in the future, and the studies also concur that bio-CCS can reduce the overall costs of mitigation; a result of bio-CCS offering a means to offset more recalcitrant emission sources that exist "higher up the global marginal abatement cost (or "MAC") curve".

Whilst these benefits are manifest in modelling results, all of the models are built on assumptions regarding constraints on future emissions. This inherently provides perfect foresight for technology deployment according to on an increasing carbon price and model optimisation that achieves the most efficient and appropriate suite of future energy technologies including bio-CCS. Problematically, today these future benefits are not reflected in current polices and carbon prices, and it is difficult to consider ways in which the future "option" value of bio-CCS may be translated into present day value or benefit. In reality, this means that these benefits will only be realised when the majority of easier, lower cost, emission sources have been tackled, rather than deploying bio-CCS today on the assumption that these benefits will accrue in the future.

On this point it is also important to note that the existence of bio-CCS technologies poses two potential moral hazards, as noted in the literature: (1) that negative emission technologies only act as an offset, and therefore shouldn't be included under carbon markets as they would simply allow continued use of fossil fuels elsewhere in the scheme (McLaren, 2011), and; (2) negative emission technologies such as bio-CCS shouldn't be seen as an excuse not to take action on climate change today and to overshoot targets on the basis that such emission could be corrected in the longer-term (e.g. The Guardian, 2013).

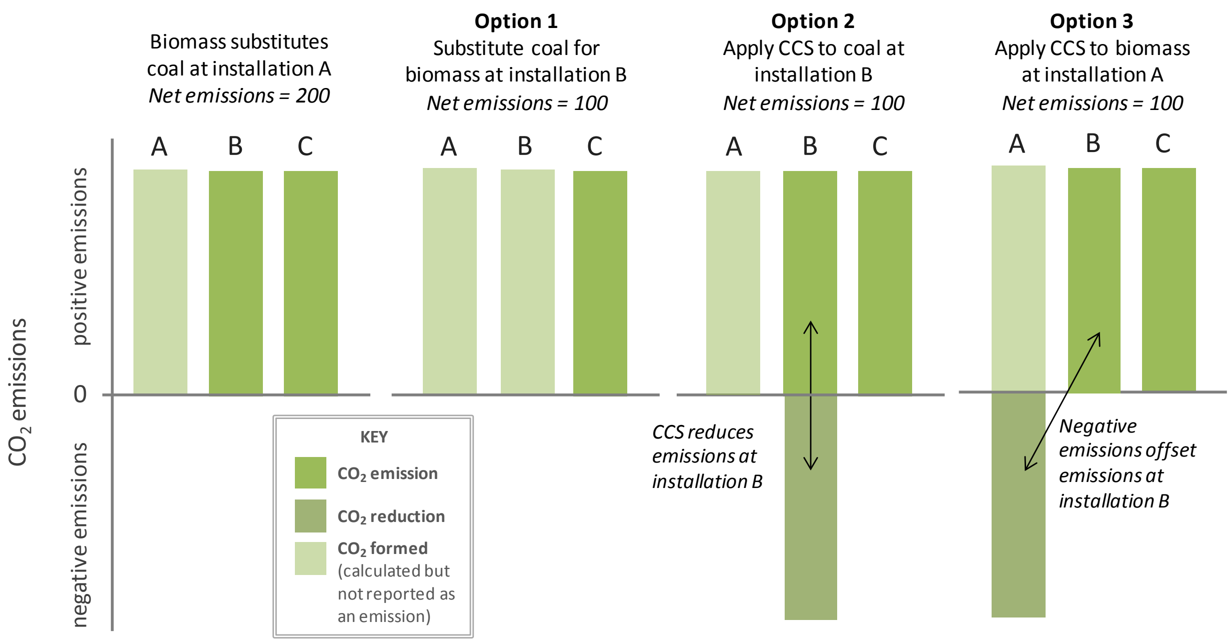
On the other hand, and notwithstanding the potential benefits of bio-CCS, it is possible to argue that its use only substitutes one form of carbon storage for another by transferring carbon stored in biomass to storage in geological reservoirs. On this basis, the negative emissions don't represent a genuine emission reduction, but rather just a C-stock transfer. This summation is only partly correct: although the approach does, in principle, involve a simple C-stock transfer, this can have benefits for permanence (see Box 2.2), whilst a more important corollary is that in making the transfer, an important energetic service/output is delivered (e.g. power generation). More importantly still, this can lead to substitution effects in service delivery i.e. by substituting fossil fuel based alternatives.

Problematically from the perspective of rewarding bio-CCS, whilst the benefits of C-stock transfer between the two pools can potentially be seen in GHG accounting rules as "negative emissions", the substitution effect is not always accounted for. This is because often the substitution effect is already accounted for in the scheme's "baseline". This means that only the single abatement benefit of reducing emissions below zero (i.e. below the biomass "baseline") is recognised, which will result in the biomass component of a bio-CCS installation only being compared to an unabated biomass plant rather than e.g. unabated coal, essentially losing the "double dividend". For example, a biomass plant in a **regional cap-and-trade scheme** avoids any liabilities under the scheme,[1] meaning that capturing and storing the CO_2 would only provide "carbon benefits" equal to the negative emission component rather than both the biomass benefit and the CCS benefit (see Figure 3.3). To illustrate this point by way of example: a power plant operator with a portfolio of three coal-fired installations, each emitting 100 units of GHGs per year, faces several abatement choices. If a cap is applied to the installations, the operator may opt to reduce GHG emissions by 100, and does so by substituting coal for biomass at one plant (installation A in Figure 4.1); following this, if a further reduction of 100 is then mandated, the operator faces three options to achieve additional reductions:

1. To substitute coal for biomass at installation B;
2. To apply CCS to the coal-fired emissions at installation B;
3. To apply CCS to the biomass-fired installation A (as shown in Figure 4.1)

All three options can achieve the same outcome i.e. net emissions of 100, although only *option 3* delivers negative emissions.

Figure 4.1 Example of GHG abatement choices on a portfolio of sources



Source: Carbon Counts

Note: factors such as incomplete capture and higher rate of CO_2 formation of biomass relative to coal per unit of energy generated are not shown to simplify presentation of the concept.

On this basis, the option of adding CCS to a biomass plant to generate negative emissions competes on a tCO_2 for tCO_2 basis with a range of other potential abatement options available across a portfolio of installations in a particular scheme. Consequently, the deployment of CCS at

[1] Because the baseline in the scheme is implicitly zero as this is the level where no liabilities are accrued.

a biomass plant is only likely if site-specific or economic circumstances make it more attractive compared to other abatement options.[1] The same applies in **international GHG cap-and-trade under the Kyoto Protocol** and also when considering bio-CCS in the supply chain under a **low carbon fuel standard**, as again any emissions arising from biomass fermentation are already avoiding any liability under the scheme (i.e. zero-emissions rated), resulting in the quantum of CO_2 reduction "rewarded" being only equal to the negative emission component. Therefore, negative emission technologies such as bio-CCS must compete for investment against other abatement technologies that can deliver the same tCO_2 reduction. In fact, this drawback is highlighted by the "net-back" accounting options discussed in Section 3.2, as what is actually outlined there shows that the negative quantum of the reduction can only ever be used to offset against another source of GHG emissions, rather than reflecting any "double dividend".

On the other hand, **project-based schemes** (or analogous crediting schemes or tax rebates) can provide a basis for recognising and rewarding both the *zero-emissions biomass* and *negative emissions* from storage, as the baseline can be selected for a higher emitting technology where relevant, e.g. an unabated coal-fired plant (see Figure 3.3). This approach in practice typically relies on demonstrating that the counterfactual – as used to determine the baseline – is equivalent to an unabated fossil fired plant and not a biomass plant, otherwise the same issue arises.

However, even when adopting project-based approaches, the biomass part of the benefit will always be considered independently from the negative emission part of the reduction, if also eligible under the scheme. As such, the two abatement technologies – biomass and CCS – even when considered together are likely always to be considered as two separate abatement options, with different costs and different potential for implementation: biomass will have one abatement cost, which will be considered according to one set of economic factors, and CCS another, assessed against the option of implementing CCS on other emission sources. As such, negative emission technologies might only become truly competitive when other less challenging emission sources have become widely abated. This problem is alluded to by Socolow in the context of direct air capture negative emission technologies, where he concludes that they will only be deployed when other, more recalcitrant, emission sources are left to be abated (Socolow, 2011). This appears sensible given that economic efficiency suggests that abatement actions should be undertaken in a cost ordered way from lowest to highest; such an approach underpins the concept of emission trading as a means to effectively and efficiently allocate resources to emissions abatement across a wide portfolio of options.

Notwithstanding economic efficiency arguments, this issue creates challenges for incentivising bio-CCS relative to other emissions reduction technologies under GHG trading schemes (and potentially through CO_2 taxes) using either net-back accounting or crediting (or rebates). As such policy-makers will need to make careful considerations regarding the type and level of reward that should or could be allocated to bio-CCS technologies; in terms of e.g. whether to develop policies targeted specifically at bio-CCS which can offer a combined reward, and whether an

[1] e.g. site specific circumstances such as proximity to storage that makes a bio-CCS project more viable than a fossil CCS project, or the marginal cost of increasing biomass use makes applying CCS to the existing biomass plant more attractive.

additional reward would be needed to incentivise deployment ahead of just biomass or just CCS on fossil sources.

Such an approach poses further considerations. One is the nature of offset credits: such credits act to offset emissions taking place elsewhere and don't actually reduce absolute emissions. Therefore offering a "double credit" in the form of an offset will need to consider the effects on the environmental integrity of any scheme into which the offset is supplied: such an offset would actually potentially provide a "double offset" for fossil sources within the scheme it is sold into. Another is that incentivising bio-CCS ahead of fossil-CCS may not result in optimised deployment of CCS. This is because a biogenic CO_2 emission source may not always be located in proximity to a suitable CO_2 storage site relative to a fossil CO_2 source, posing the question as to whether it is economically and environmentally efficient to deploy CCS at the biogenic CO_2 source ahead of the fossil CO_2 source. Another argument is that, depending on the availability geological CO_2 storage resources, valuable geological storage space shouldn't be taken up by fossil CO_2 when biogenic CO_2 offers a means of developing negative emissions, along with the inherent benefits that go with that option compared to CCS on fossil CO_2. Conversely, it may be more prudent to focus on applying CCS to fossil CO_2 sources to reduce the rate at which CO_2 is added to the atmosphere, rather than focussing on negative emission technologies. These are difficult policy choices to make.

In considering the policy options, two schools of thought could be adopted that will influence decisions. From a *centrally planned* perspective, and taking account of the results of integrated assessment modelling (Box 4.1), negative emission technologies should be prioritised in order to bring down atmospheric CO_2 concentrations as fast as can be achieved; this relies on the phasing out of fossil fuels as quickly as possible in parallel to avoid lock-in of fossil fuel infrastructure for the next 50 years or so. On this basis, bio-CCS should be given additional incentives today ahead of just biomass *or* CCS on fossil CO_2. Options could include the use of portfolio standards for biomass users (e.g. a *CCS Certificate* as discussed previously), the use of feed-in tariffs, or green certificates i.e. similar support measures as afforded to renewable energy today outside of GHG policy. Furthermore, if geological storage capacity is constrained, then it makes sense to prioritise its use for biogenic CO_2 rather than fossil CO_2, assuming fossil CO_2 will be phased out. However, whilst feasible, the problem would remain that biomass to energy, and existing economic support measures available for that technology, would still be considered as an option independent of applying CCS to biomass plants. It is therefore questionable whether any additional incentive to deploy bio-CCS would be achieved. Moreover, if the international climate regime is still reliant on national GHG "caps" as the means to drive innovation (i.e. as applied under the Kyoto Protocol) rather than technology-driven approaches, negative emission technologies such bio-CCS will only ever act as an "offset" against other sources of emissions at the level of a country's emissions portfolio. In fact, this issue has led some observers to advocate that negative emissions technologies should be taken out of the scope of carbon markets to avoid perverse outcomes (McLaren, 2011).

The potential shortfalls associated with prioritising bio-CCS potentially lend credence to a more *economic purist* view. This would be that – assuming all other impediments to bio-CCS in, e.g. those present in GHG accounting frameworks, have been removed – carbon markets can potentially drive innovation, and ultimately, with a significantly stringent cap, the requirement for negative emission technologies. At some point in time the "cap" should become so low that such technologies will be necessary to offset other recalcitrant emission sources that are more challenging and/or costly to abate. Moreover, it is arguable that the addition of bio-CCS to the toolbox of potential measures available to tackle climate change should allow policy-makers to increase their level of ambition in terms of emission reduction commitments in the near-term.

Both of the viewpoints will need to be considered in any policy discussions regarding the design of support mechanisms for CCS and bio-CCS.

4.3 Accounting for land use change and sustainability

As outlined in Section 2.4, the negative emission aspects of bio-CCS are predicated on the assumption that growth and harvesting of biomass are in a state of equilibrium such that CO_2 emissions from biomass combustion or decay is offset by uptake of CO_2 during biomass growth. This allows the application of a zero-emissions factor to CO_2 emissions originating from biogenic sources in GHG accounting frameworks. As outlined in Section 2.5, where land use changes occur, the equilibrium is disturbed and the zero-emissions factor assumption is no longer valid, however.

An idealised approach to managing the problem would be to have a much-improved global system for monitoring, reporting and accounting of LULUCF and REDD[1] activities. This would allow for land use changes to be accounted for where they occur, and measures introduced to limit their effects or restrict biomass supply from locations where problems are identified. However, whilst slow progress is being made in both areas (see, for example, Box 2.4), there is a significant way to go before human induced land use changes – especially those driven by increasing demand for bioenergy – can be effectively identified, quantified in terms of GHG effects, and supply restrictions imposed. As such, the promotion of bioenergy resources is hamstrung by concerns over the potential leakage effects posed by dLUC and iLUC.

In order to address the problem in the near-term, various piecemeal approaches have been employed to fill the gap posed by the lack of comprehensive LULUCF accounting, as discussed below.

4.3.1 Quantitative approaches – accounting for upstream emissions

Quantitative approaches to managing the sustainability and life-cycle GHG emissions of biomass and biofuels were described previously (Section 2.5). The analysis showed that **low carbon fuel standards** generally adopt quantitative approaches to account for full life-cycle GHG emissions, and in some cases include methods to account for dLUC and iLUC effects. Examples include the iLUC modifier in the CA-GREET Model in the **California LCFS** (see Section 2.5), and the GHG intensity calculation methods set out in *Annex V/VI* of the **EU RED/FQD**.

Although these approaches are not without controversy (Box 2.6), they are significantly more advanced relative to efforts to quantify the life-cycle GHG emissions associated with biomass used for electricity and heat production in most jurisdictions reviewed. Problematically, this aspect is of fundamental importance to bio-CCS and negative emissions in the power and

[1] REDD is "reducing emissions from deforestation and forest degradation"

industry sectors, and therefore an important part of the policy debate regarding options to promote bio-CCS. Ongoing discussions and actions in this context are briefly reviewed below.

In Europe, the European Commission considered the issue in 2010 in an assessment of sustainability requirements for solid and gaseous biomass used in electricity, heat and cooling in the EU (EC, 2010). The report highlighted that:

- The current legal framework for agriculture in Europe – the Common Agricultural Policy as well as other measures – provides for a sound basis for the sustainability and life-cycle GHG emissions, including dLUC and iLUC, of biomass sourced from within the EU; and,
- The expansion in trade of biomass and increasing imports from third countries may lead to the unsustainable production of biomass.

It also noted that a number of Member States are taking unilateral action to address these concerns, drawing on the sustainability requirements of *Article 17* of the **EU RED** (see Box 2.9). It concluded that the wide variety of biomass feedstocks available make it difficult to propose a harmonised scheme across the EU. Rather, it proposed that Member States that have, or plan, to introduce biomass sustainability schemes should adopt similar approaches for calculating the full life-cycle GHG emissions of biomass growth, harvesting, production and transport as applied to liquid biofuels in *Annex V* of the EU RED. The report set out a proposed method in *Annex I* (EC, 2011; see also Table 2.1 for a description of the method proposed under the EU RED). To date, there have been some limited actions by Member States to implement this proposal, although most domestic schemes do not include consideration of emissions from dLUC and iLUC, which tend to be managed through qualitative approaches (Box 2.9). Since the publication of its 2010 report, the European Commission has subsequently taken further steps to clarify and restrict the treatment of biomass and bioliquids under the EU ETS, as described previously (Section 2.5.2; EC, 2012b). However, since there is presently no sustainability criteria applicable to solid and liquid biomass in the EU, the approach is reliant on the effectiveness of national and voluntary standards to manage dLUC/iLUC and sustainability impacts in its supply chain.

In the **US**, the EPA is presently considering scientific and technical issues associated with accounting for emissions of biogenic CO_2, focussing on the potential for “adjusting” total onsite biogenic CO_2 emissions according to growth of the feedstock and/or avoidance of biogenic emissions more generally in the carbon cycle. The EPA’s approach considers the use of “biogenic adjustment factors” (BAFs) to take account of the emissions occurring in the production and supply of biomass, where a BAF of 0 would mean that removals match emissions i.e. C-stock changes equal zero, with higher factors reflecting shortfalls in removals compared to emissions during combustion, and *vice versa* (US EPA, 2011). This approach has yet to be implemented under the GHGRP and is still under consultation by the EPA.

A general concern affecting the introduction of full life-cycle GHG accounting for biomass is that of *parity* of treatment compared to fossil fuels. In essence, accounting for “upstream” emissions of biomass production reduces the potential subsidy available for its use without taking into account the full life-cycle GHG emissions of the comparable fossil fuel. On the one hand, it may be possible to argue that there is no need to take account of the full life-cycle emissions of the comparable fossil fuels as these are not gaining any benefits or rewards under a **regional cap-**

and-trade scheme such as the EU ETS. However, this is not the case. A high-quality anthracite coal from a non-gassy mine will have significantly lower life-cycle GHG emissions than a sub-bituminous coal from a gassy mine, which may even have higher life-cycle GHG emissions than lignite. Similarly, natural gas has a comparative advantage over coal under an emissions trading scheme because of its lower emissions per unit output, but this typically does not include GHG emissions associated with e.g. transportation of LNG by ship and potentially GHG emission from treatment of contaminated gas (e.g. venting and flaring). Therefore, introducing requirements to calculate the full life-cycle GHG emissions of biomass would pose challenges in emissions trading schemes as it could be argued it does not provide a level playing field in comparison to the treatment of fossil fuels. Experiences in Europe in implementing *Article 7(a)(5)* of the EU FQD (relating to the calculation of life cycle GHG emissions from fossil fuels), which continues to be debated in Brussels almost five years after its adoption, suggests the challenges of taking such an approach could be considerable.

4.3.2 Qualitative approaches – restricting certain types of biomass/biofuels

Rather than relying on quantitative approaches, an alternative method is to restrict the types of biofuels that may apply a zero-emissions rating. For example, the **California ETS** imposes such a restriction (see Section 2.5). In practice, such approaches can be combined with quantitative approaches, by e.g. setting default factors for certain types of biofuels, and then imposing thresholds on allowable fuels. An example of this approach is the 60% GHG emission saving required by Ofgem for biomass fuels under the UK Renewables Obligation (see Box 2.9), and methods used to restrict certain types of biofuels under **low carbon fuel standards**.

Some efforts have been made to implement such restrictions under **regional cap-and-trade schemes**, for example, under the **EU ETS** where additional guidance was recently issued on zero-emissions rating biomass (see Section 2.5.2; EC, 2012b). Presently there are no such restrictions imposed under the **Australia CPM** or the **US GHGRP**, with a wide variety of biomass products qualifying for a zero-emissions factor under the scheme (see Box 2.8). As such, the basis for accounting for negative emissions from bio-CCS under the schemes could be potentially compromised by the fact that potential “upstream” effects of biomass supply – including dLUC and iLUC – and are not being taken into account. Consequently, the consideration of any option for incentivising bio-CCS under these schemes should also consider how to address this issue. On the other hand, such approaches will also likely open up a discussion regarding the parity of treatment of biomass fuels compared to fossil fuels, as outlined previously.

5 CONCLUSIONS & RECOMMENDATIONS

This report has reviewed the potential for GHG accounting frameworks and associated GHG reduction policies to *appropriately recognise, attribute and reward* negative emissions arising from CO_2 abatement technologies such as bio-CCS. The review has covered:

- Potential applications of bio-CCS (set out in Annex A);
- GHG accounting frameworks and their potential to recognise and attribute negative emissions;
- The scope for GHG reduction policies to reward negative emissions; and,
- A discussion regarding the appropriate level and type of reward for negative emission technologies such as bio-CCS.

The main conclusions and findings are discussed below.

Applications of biomass with carbon capture and storage
A brief review of the use of biomass in energy, as set out in Annex A, highlights that there are a wide variety of potential bioenergy products, covering agricultural products and residues, forest products and residues, waste matter and algae and bacteria. The potential to apply CCS to biogenic CO_2 emissions sources arising from various conversion processes is wide, covering heat and power generation for industry and public electricity supply, and also in biofuels production through application to various offgas streams. On this basis, bio-CCS and negative emission technologies can play a key role in decarbonising energy use from such activities.

The review did not identify any sector- or activity-specific issues or barriers to account for negative emission from bio-CCS. Certain sector-specific barriers may exist, based on e.g. the specific details of sector-specific monitoring rules, although an exhaustive review of all sector specific GHG accounting rules was beyond the scope of this report. The range of general issues identified as discussed throughout the report will pervade into any sector- and activity-specific GHG accounting rules under the schemes reviewed. Resolution of these issues should be the focus of any near-term efforts to support bio-CCS and negative emissions.

Recognising and rewarding negative emissions
International GHG accounting rules in the 2006 GLs generally allow for negative emissions from bio-CCS to be recorded and recognised in national GHG inventories for Parties to the UNFCCC and Kyoto Protocol. This is based on applying a zero-emissions factor to biomass combustion, and where CCS is applied, the subtraction of captured and stored CO_2 from the relevant sector totals. On this basis, the review did not identify any barriers for accommodating bio-CCS with negative emissions in the international GHG accounting rules.

Similarly, project-based schemes such as the **CDM** and **JI**, the **US GHGRP** and the low carbon fuel standards reviewed – namely the **California LCFS** and the **EU RED/FQD** – all potentially allow for negative emissions achieved using bio-CCS to be recognised within the ambit of their respective GHG accounting rules.

However, **regional cap-and-trade schemes** do not generally recognise and attribute negative emissions, should they arise. Under the **EU ETS**, only the mass of "fossil carbon" transferred for geological storage may be deducted from an installation's GHG inventory, which prevents negative emissions from bio-CCS being recognised under the scheme. Further, installations exclusively using biomass are exempted from the scheme, implicitly excluding recognition of such activities. Options to address these shortfalls include:

- Clarifying whether the addition of a CO_2 capture plant, as an activity falling within the scope of the EU ETS, to an installation exclusively combusting biomass would bring the entire installation within the scope of the scheme;
- Amending the EU MRR to include biogenic CO_2 within the ambit of *Article 49* where this is for the purpose of geological storage, and modifying the exclusion of installations using biomass so as to include installations using bio-CCS. This could be achieved either through a Commission Decision or possibly via the comitology process under *Article 23* of the EU ETS Directive; and/or,
- Proposing specific new monitoring and reporting guidelines for bio-CCS installations – which would need to be made by a Member State – for approval through the comitology process. These would need to address the barriers highlighted above, as well as outline any specific methodological issues that must be addressed for bio-CCS projects (e.g. specific rules on life-cycle GHG emissions accounting and dLUC and iLUC issues). It is important to note that the EU MRR allows for such "future innovations" in relation to the revised *CO_2 Transfer* provisions of the Regulation (see recital 13 of the preamble).

In any case, such an amendment would need to be accompanied by an appropriate approach to reward negative emissions as presently there is no means within the scheme to allocate EUAs (or other "credits") to an installation that accounts for and reports negative emissions. This could involve either:

- Allowing *pooling* so that "net-back" accounting could be applied at the level of a portfolio of installations included within the scheme;
- Establishing some form of crediting system for negative emissions, either from the new entrant reserve (NER) or a dedicated "bio-CCS" or "negative emission" reserve or credit scheme; or,
- Establishing rules and methodologies for bio-CCS as *Domestic-* or *Community- Offset Projects* (DOP or COP) under the EU ETS (Article 24a), or clarifying the scope for the use of JI under the EU *Effort Sharing Decision*.

Under the **Australia CPM**, emissions from the combustion of biomass are not treated as "covered emissions", potentially posing a barrier to recognising the capture and storage of such source streams. Therefore, further clarification is necessary as to how bio-CCS might fit within the scheme. Applicable domestic offsets – such as the *Carbon Farming Initiative* – are not relevant to the potential types of bio-CCS applications, although international offsets generated under JI could be a means to recognise and reward bio-CCS within the scope of the CPM.

The **California ETS** does not allow for negative emissions to be recognised because an appropriate "*quantification methodology*" for CCS does not yet exist under the scheme.

The discrepancy between international and some sector-specific GHG accounting rules such as low carbon fuel standards (which do recognise negative emissions), and regional cap-and-trade *schemes (which appear not to recognise negative emission technologies), suggests that whilst national governments may accrue the benefits of negative emission technologies under e.g. the UNFCCC, there is only limited means to incentivise the private sector to undertake such activities (e.g. the application of CCS at a biofuels refinery could qualify, whilst CCS at biomass fired power plant would not have any benefits). Further, the differential treatment of transfers of fossil CO_2 and biogenic CO_2 under regional cap-and-trade scheme GHG accounting rules means that an incentive is provided for fossil-CCS but not bio-CCS. This distortion should be removed to encourage biomass users to consider applying CCS. In most cases this will require a new type of mechanism to reward such activities (as summarised above).*

Consultation with the European Commission – DG Climate Action*, the* Australian Clean Energy Regulator*, and the* California Air Resources Board *(CARB) is recommended in order to clarify the status of bio-CCS and to discuss potential options to recognise and reward negative emissions.*

Allocating an appropriate level of reward

A wide range of literature, including integrated modelling assessments, has highlighted the benefits associated with the use of bio-CCS and other negative emission technologies (such as direct air capture). Benefits highlighted include:

- *Offsetting more recalcitrant emissions sources* – because emissions are negative, they can be used to deliver deeper reductions in global GHG emissions whilst allowing more challenging emissions sources such as those from aviation to continue.
- *Reducing the overall cost of mitigation* – as negative emission technologies can be used to offset emissions from recalcitrant sources which are more costly to abate (e.g. aviation emissions).
- *Putting a price ceiling on CO_2 emission reductions* – as essentially negative emission technologies could be deployed to offset higher cost emission sources.
- *Offsetting legacy or historical emissions* – because CO_2 can essentially be harvested from the atmosphere and transferred to long-term geological storage. This could allow for more rapid emission reductions to be made in future, thereby offsetting previous inaction or effects of "over-shooting" requisite emission reduction targets.
- *Involving more countries* – in cases where countries have only limited domestic CO_2 abatement potential.

These benefits are additional to more conventional emission reduction technologies that can typically only reduce the rate by which CO_2 is added to the atmosphere towards zero, eliminate it completely, or add carbon to the less permanent biological pool through afforestation, reforestation, avoided deforestation and other land management practices.

On this basis, it is conceivable that negative emission technologies such as bio-CCS deliver a "double dividend", and therefore could warrant additional subsidies or "double crediting" for each tonne of CO_2 captured and stored. Problematically, the benefits from substitution of fossil fuel for biomass is typically forgone under schemes such as **regional cap-and-trade programmes** as it is inherently included within a scheme's "baselines". Consequently, only the negative quotient of emission reductions are likely to be recognised, which means that bio-CCS effectively competes on a per tCO_2 reduction basis with other mitigation options including substituting coal for biomass, or applying CCS to fossil CO_2 sources. Project-based schemes can overcome this problem if the fuel substitution benefits are included within the baseline, although this is predicated on demonstrating that the counterfactual outcome would be a fossil fuel-fired plant. These issues create challenges for incentivising bio-CCS relative to other emissions reduction technologies under GHG trading schemes.

In terms of the design of policies to support bio-CCS, two potential schools of thoughts are discussed in the report: (1) the *centrally-planned* view, taking the position that the benefits of bio-CCS need to be prioritised whilst also phasing out fossil fuels. On this basis, bio-CCS should be given additional incentives compared to biomass or CCS on fossil CO_2 sources. This could be take a variety of forms, including through emissions trading type approaches (e.g. tradable "credits"), or other measures such as feed-in tariffs or "green certificates"; and, (2) the *economic purist* view that carbon markets can drive innovation, and that, aside from certain niche circumstances where it is advantageous to do so, ultimately bio-CCS might only deployed as and when only more recalcitrant emissions/more costly abatement options remain to be tackled. Moreover, the latter school of thought suggests the existence of negative emission technologies allows policy-makers to be more ambitious in establishing GHG emission reduction targets.

Both viewpoints will need to be considered in discussions regarding the design of policy measures to support bio-CCS and other negative emission technologies.

Managing land use change effects

The assumption that the combustion or decay of biomass leads to zero emissions provides the basis for calculating negative emissions from bio-CCS where such sources are captured and stored. However, the zero emissions assumption is predicated on the growth and harvesting of biomass being in equilibrium, which is not necessarily always the case. Significant controversy has arisen regarding the promotion of biofuels in jurisdictions such as the US and EU, and the effects of energy crop cultivation on land degradation and the loss of biological C-stocks as a result of land use changes (dLUC and iLUC), as well as other sustainability impacts. Assessing the extent to which this is occurring and being accounted for is dependent on establishing a robust monitoring system for LULUCF and REDD activities, although at present these are generally patchy and poorly implemented across many parts of the world, especially developing countries. Consequently, bioenergy can be imported into regulated jurisdictions, and GHG benefits accrued upon its use (e.g. under the EU ETS), absent of consideration of the dLUC and iLUC effects and associated GHG emissions occurring upstream in the fuel supply chain.

In order to tackle this issue, policies such as **low carbon fuel standards** include detailed GHG accounting rules for calculating the upstream emissions from biomass growth, harvesting, transport, processing and, to some extent, dLUC/iLUC effects, which are then taken into account in the emissions at the point of use. Such *quantitative* approaches – although not without controversy – do set out to address the issues presented by inadequate LULUCF and REDD monitoring and reporting around the world.

On the other hand, **regional cap and trade programmes** aimed at regulating emissions in electricity and heat production do not include such considerations. A clear exception is the **California ETS**, which applies *qualitative* approaches to limit the application of a zero-emissions factor to only a few specific biomass types. Further, the EU has clarified the sustainability requirements for zero-rating biomass used in the **EU ETS** by aligning it with the EU RED, including requirements to show compliance with national and voluntary sustainability schemes to demonstrate good practice. The **US** has considered the scope for introducing measures to take account of the upstream effects of biomass use under the GHGRP by using "biogenic adjustment factors", although it has not yet implemented such measures. Little information is available regarding measures to restrict zero-emissions rated biomass under the **Australia CPM**.

Discussions regarding support measures for bio-CCS should include consideration of potential approaches to address GHG emissions from dLUC and iLUC and other sustainability concerns. Without addressing such concerns, the creditability of negative emission claims could be placed under scrutiny. On the other hand, in making such considerations, it is important to be mindful of the parity of treatment of biomass fuels compared to fossil fuels, which do not need to account for upstream emissions in their supply chain under the GHG accounting rules reviewed. The scope for opening up this broader discussion is likely to make for a complex political process; experiences in Europe in implementing Article 7(a)(5) *of the EU FQD (relating to the calculation of life cycle GHG emissions from fossil fuels), which continues to be debated in Brussels four years after adoption of the Directive, suggests the challenges of such an approach could be considerable. Potential issues under World Trade Organisation rules might also need to be taken into account (see BTG, 2008).*

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Annex A – Overview of biomass energy and capture of CO_2 emissions

A-1 Bioenergy and carbon capture and storage

The following chapter provides a brief overview of the use of bio-CCS. This includes a description of current biomass use within global energy supply, and the options available to apply CCS technology within various biomass energy pathways.

A-1.1 Bioenergy pathways

Biomass consists of any organic matter of vegetable or animal origin (IEA, 2009). It is available in many forms and from many different sources, including:

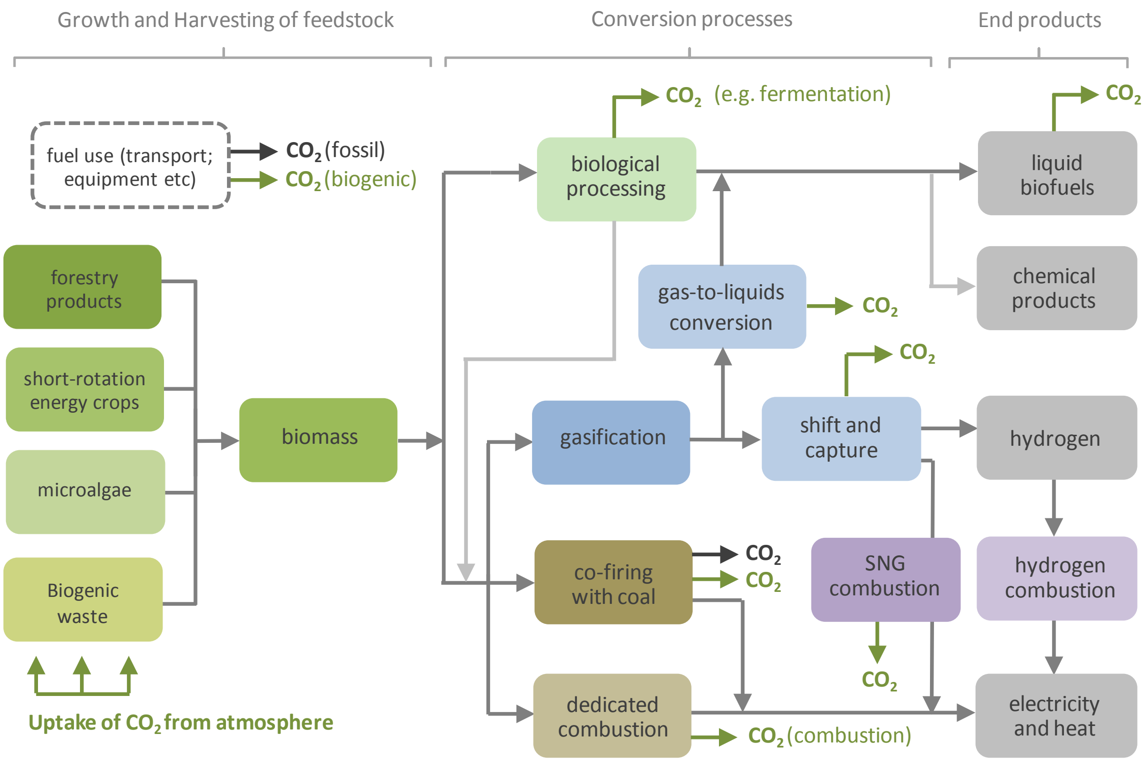
- Agricultural crops and residues (e.g. energy crops, food processing waste, animal waste)
- Forestry products and residues (e.g. harvested wood and processing/logging residues)
- Municipal and other waste (e.g. sewage, sludge, waste wood, industrial waste)
- Microalgae and bacteria

Biomass is the most widely used renewable energy source worldwide, currently accounting for around 77% of renewable energy and around 10% of global primary energy use. Although the use of woody biomass in domestic heating and cooking continues to account for most bioenergy worldwide (often termed ‘traditional’ biomass), there is an ever increasing diversification of biomass sources and their end uses (‘modern’ biomass) – with the development of new conversion technologies offering multiple routes for value creation.

Most biomass activities worldwide are focused on energy products and services; however there is growing interest and research into other products such as chemicals and pharmaceuticals, which could be combined with bioenergy production. As a result, the bioenergy sector has witnessed significant growth in recent years, particularly the use of biofuels within the transport sector, which has grown faster than for heat and electricity uses (IEA, 2008a).

Figure A-1 presents a schematic overview of the various pathways by which biomass sources can be converted into final energy products or services, and the principal removals and sources of CO_2 emissions arising from the source (biomass feedstock) through to end energy products (e.g. electricity and heat, and liquid biofuels).

Figure A-1 Bioenergy pathways and sources of CO_2



Source: adapted from Rhodes and Keith (2005)

The various pathways by which biomass feedstock can be converted to useful energy may be grouped into two broad categories:

- **Biomass to electricity and heat**. The production of heat by the direct combustion of biomass is the leading bioenergy application worldwide. The biomass fuels used are typically raw feedstocks such as wood chips upgraded into pellets and other products which can be more easily transported, stored and combusted. Heat can be produced in combination with electricity generation in combined heat and power (CHP) installations, representing a major source of biogenic CO_2 emissions worldwide. Other technologies producing electricity from biomass include dedicated combustion plants using municipal solid waste (MSW) and, for sewage and other wet organic wastes such as manure and slurry, the use of biogas produced from anaerobic digestion. There has also been significant growth over the past decade in the co-combustion, or 'co-firing', of biomass with coal in coal-fired power plants. These installations all represent large sources of CO_2 potentially available for capture, although in the case of the latter, plant emissions comprise both biogenic (biomass combustion) and fossil (coal combustion) CO_2. Other technologies are typically at pre-commercial stages of development, including biomass-based gasification plants which can offer high purity streams of biogenic CO_2 potentially available for capture (Figure A-1).

- **Biomass to liquid fuels**. Demand for alternatives to liquid fossil fuels within the transport sector represents a significant and growing share of the bioenergy in many regions worldwide, and the use of bioethanol derived from sugar and starch crops and biodiesel from oil crops is commercially established in several countries - most noticeably the US and Brazil. The large-scale production of these so-called 'first generation' or conventional biofuels, gives rise to significant amounts of biogenic CO_2. The production of 'second generation' biofuels based on non-food, mainly lignocellulosic, biomass feedstocks opens up a wider set of conversion pathways and processes; such technologies could potentially produce a wide range of liquid fuels, as well as chemicals and gaseous fuels. As with conventional production, advanced cellulosic bioethanol production produces fermentation CO_2, whereas advanced biodiesel covers several technologies including the hydrogenation of oils or fats to form hydrogenated vegetable oil (HVO) and the Fischer-Trospch diesel process involving the gasification of feedstock to syngas followed by shift conversion to produce a range of liquid fuels (and/or hydrogen for use in electricity generation, industrial applications or as an energy carrier). Growth in this type of process potentially offers a major source of CO_2 emissions available for capture in the future. Further, the future generations of biofuels – sometimes referred to as 'third generation' biofuels – such as oils produced from algae, may also represent significant sources of biogenic process and combustion CO_2.

A-1.2 Application of bioenergy with CCS

Based on the various bioenergy pathways outlined above, bioenergy combined with CCS technology can potentially be applied to a wide range of sectors covering multiple commercial processes. These can be grouped as follows:

- Power generation
- Industry
- Biofuels production

The potential to apply bio-CCS within each is summarised below.

A-1.2.1 Power generation

The worldwide installed capacity for biomass-based power generation was about 53 GW in 2009 with an estimated electricity production of around 288 terawatt-hours (TWh), equivalent to just over 1% of total global generation (IEA, 2011b). OECD countries currently account for around 75% of worldwide generating capacity from biomass, around half of which is located in the EU, using predominantly wood waste and MSW. However, many developing countries including China, Brazil, Latin America, Thailand, and India are turning increasingly to biomass power plants alongside other renewable resources (IEA, 2007). Energy security and renewable support policies will act as drivers for increased use of biomass in power generation. Over the next decade or so, the strong growth in biomass co-firing seen over the past decade is likely to continue, driven by economic, flexibility and scale benefits as well as policy support in many countries. Where the opportunities exist for an economically viable supply of feedstock, combustion from dedicated biomass plants is also likely to play an increasing role in power generation, although this will be highly dependent upon local policy and regulatory circumstances.

A range of technologies exist or are being developed to produce electricity from biomass, offering sources of biogenic CO_2 potentially available for capture. The main options available include:

- Dedicated (stand-alone) biomass combustion
- Co-firing in coal-fired power plants
- Anaerobic digestion
- Gasification

Dedicated biomass combustion
The direct combustion of biomass in a boiler produces heat which is then used to produce electricity via a steam turbine or [heat] engine. Economies of scale for dedicated biomass power plants, including the need to ensure economic bulk supply of biomass, suggest that plants are typically only commercially viable at a larger scale (30-100 MWe) when using low cost feedstocks available in large volumes such as agricultural or wood residues and black liquor from the pulp and paper industry (*ibid*). At this scale, large demonstration- or commercial scale CO_2 capture may be possible at costs comparable with other CCS power projects (e.g. capture from coal and gas-fired plants).

CHP, or cogeneration, plants can have typical overall efficiencies in the range of 80-90%; where there is sufficient demand and a readily available source of low-cost biomass feedstock, such as in the pulp and paper and sugar-cane industries CHP can therefore significantly reduce the costs of power production. Biomass CHP can also be used in domestic and commercial heating systems. Large-scale modern biomass-fired CHP units represent a significant existing source of biogenic CO_2 suitable for post-combustion capture.

Waste-to-energy plants burn MSW to generate electricity or heat. Despite its large technical potential in many urban locations worldwide, MSW is typically uneconomic without strict waste regulations incentivising its use in power generation. Emissions from most MSW plants will necessarily comprise both biogenic and fossil CO_2, according to the particular waste streams.

Co-firing
The co-combustion or 'co-firing', of liquid or solid biomass with fossil fuels in power plant boilers or CHP units provides a highly cost-effective means of biomass power generation. Although co-firing can be applied to a range of feedstocks and plant scales, most activities have increasingly focused on the use of solid biomass co-fired in large-scale coal-fired power plants, particularly in Europe where biomass co-firing is incentivised through various renewable policies and support schemes as well as the EU ETS. Because they are major emitters of CO_2, coal-fired power stations are important candidates for large-scale CCS deployment; the co-firing of biomass at these facilities offers the opportunity to further reduce emissions and if combined with CCS, the potential to achieve net negative emissions. This potential depends upon *inter alia* the share of biogenic versus fossil CO_2 in the captured stream and also the fossil CO_2 emitted as part of the capture process energy requirements (e.g. for CO_2 separation and compression), also known as the 'capture penalty'.

Anaerobic digestion
Anaerobic digestion is a natural process in which microorganisms break down organic matter in the absence of free oxygen into biogas (mainly a mixture of CO_2 and methane). The biogas can then be combusted directly in engines to produce power or heat.[1] Anaerobic digestion can

[1] It can also be cleaned and used as synthetic natural gas or as a vehicle fuel.

biodegrade virtually all biomass that animals can digest (essentially any biomass excluding woody materials) and is particularly suited to animal manure, sewage sludge from waste water treatment plants, wet agricultural residues and the organic fraction of MSW (IEA, 2009a). Anaerobic digestion units are typically small-scale offering only relatively small sources of CO_2 emissions for capture.[1] However, the biogas can also be cleaned to produce biomethane; as part of this process the CO_2 in the biogas must be removed thereby offering a potential high-purity low cost source of CO_2 for capture.

Gasification

In a gasification plant, biomass feedstock can be converted into fuel gas, a mixture of several combustible gases, which can then be combusted directly to produce power or heat. The fuel gas can also be upgraded to syngas for the production of liquid biofuels.[2] If hydrogen is produced for use in power production or other applications, the syngas undergoes a shift reaction and gas clean up step where the CO_2 content is separated. This CO_2 stream therefore offers a pure CO_2 source available for low cost capture, and subsequent transport and storage. Technical complexity and high costs have limited the uptake of biomass gasification in most regions, and there are currently few commercial-scale plants worldwide.

A-1.3 Industry

The main application of modern biomass today is within industry, where it is mainly combusted in the production of process heat (IEA, 2010c). Roughly three-quarters of industrial energy demand arises from the production of energy-intensive commodities, such as metals, chemicals and petrochemicals, non-metallic mineral materials, and pulp and paper (*ibid*). Although the use of biomass for energy in industry is expected to grow over the coming decades, increasing competition from the power sector for reliable supplies of low-cost biomass sources is likely to constrain its uptake potential. The evolution of regional regulatory frameworks relating to climate and waste policy will also be key drivers determining the rate and scale of biomass uptake in industry. Much of the expected increase is projected to come from the pulp and paper sector which is currently by far the largest industrial consumer of biomass for heat. Increasing demand is also expected from the non-metallic minerals (predominantly cement[3]), iron and steel and chemicals sectors.

The use of biomass combustion to produce heat is a mature technology, and where there is a reliable supply of cost-effective feedstock available, it can be competitive with fossil fuels. An increasing number of **biomass CHP boilers** are therefore found in industries such as pulp and paper that consume large amounts of heat and have large volumes of biomass residues at their disposal (IEA, 2009a). Post-combustion CO_2 capture from large-scale CHP boilers in integrated pulp and paper mills is possible where wood and bark waste is sufficiently available as fuel. IEA

[1] China is currently the largest producer of biogas in the world, with around 18 million farm households using biogas and about 3,500 medium to large-scale digester units (Defra, 2007). In Europe, specific support mechanisms have resulted in Germany being the leader in this technology, with farm-based units totalling a combined 550 MWe installed capacity in 2006 i.e. similar to that of a coal power plant (IEA, 2009).

[2] The ability for gasification to co-produce a range of end-products including heat and electricity, together with liquid fuels and possibly other products in bio-refineries is currently being investigated.

[3] The *Cement Technology Roadmap* 2009 (IEA/WBCSD, 2009) envisages an increase in the use of alternative fuels and biomass from current levels of less than 10% to 23-24% by 2030 and 37% by 2050.

(2011c) describe a hypothetical 180 MW CHP plant using waste at a pulp and paper mill having a capture potential of around 200,000 tCO_2 per year.[1] Black liquor processing also represents a potential source of biogenic CO_2 capture within pulp and paper manufacture. Approximately 60% of the CO_2 emissions from the pulp and paper industry worldwide are biogenic, and flue gases from pulp and paper mills contain around 13-14% CO_2 by volume. **Black liquor gasification** can however be applied for production of liquid fuels, producing a pure CO_2 stream in the process which can then be captured at relatively low cost (IEA/UNIDO, 2011).

Several studies have assessed the potential for post-combustion capture from boilers (including black liquor and CHP) at pulp and paper mills. The installation of CCS is however not generally considered economically viable for most facilities worldwide due to their limited production size and emissions volume. For example, a recent study assessing CCS potential in the UK considered CCS not to be viable for UK paper and pulp mills, as these all have emissions of less than 0.2 $MtCO_2$ per annum, with the majority of sites having emissions of less than 0.05 $MtCO_2$ (Vallack *et. al.*, 2011). Feasibility studies have therefore typically focused on very large-scale facilities such as those in located in Sweden and Finland. For example Hektor and Berntsson (2007) assessed post-combustion capture from flue gases in the recovery boiler at a large integrated Kraft pulp and paper mill. Five configurations are compared, with the use of natural gas combined cycle (NGCC) providing the large quantities of low-pressure (LP) steam needed for the solvent regeneration proving most viable.

As noted above, biomass fuels are also used in **cement kilns** and **iron and steel furnaces**. As with co-firing, these are typically combined with fossil fuels such that captured flue gas streams will comprise both biogenic and fossil CO_2. Numerous studies assessing the use of CCS at cement kilns and blast furnaces exist, with post-combustion generally considered to be a more viable option in the short-to medium term; applying post-combustion capture at cement kilns would as source of steam (e.g. a boiler or CHP plant), representing a further potential source of biogenic CO_2 for capture (where fuelled by biomass).

A-1.3.1 Biofuels production

As a result of climate change and other policies (e.g. energy security; agricultural development policy), global biofuels production has risen significantly over the past decade, from around 16 billion litres in 2000 to more than 100 billion litres in 2010 (IEA, 2011c). On an energy basis, biofuels now provide around 3% of total road transport fuel globally and considerably higher shares are achieved in certain countries (IEA, 2011c). In absolute volumes, US ethanol production currently accounts for the largest share of global biofuels production with over 60 billion litres per year (in 2012; EIA, 2012), followed by Brazil and the EU (IEA, 2011c).

According to the IEA *Biofuels Roadmap* (IEA, 2011c)[2], biofuels demand over the next decade is expected to be highest in OECD countries, although non-OECD countries will account for 60% of

[1] The non-CO_2 GHG emissions from the energy production at the pulp and paper plant are not considered. Non-CO_2 emissions would be approximately 1%-2% of the emissions of wood combustion using fluidised bed combustion (FBC), and less for the other technologies. The capture process would not affect these emissions if the CO_2 were separated from the flue gases during the capture process (IEA/UNIDO, 2011).

[2] The IEA Biofuels Roadmap is based on the IEA's BLUE Map Scenario which sets a target of 50% reduction in energy-related CO_2 emissions by 2050 from 2005 levels. To achieve the projected emission savings in the transport sector, the BLUE Map Scenario described in the IEA's *Energy Technology Perspectives* (IEA, 2010b) projects that sustainably produced biofuels will eventually provide 27% of total transport fuel.

global biofuel demand by 2030 and roughly 70% by 2050, with the strongest demand projected in China, India and Latin America. Conventional biofuels are expected to play a role in ramping up production in many developing countries because the technology is less costly and less complex than for advanced biofuels. Once technologies are proven and feedstock supply concepts have been established, advanced "second generation" biofuels are then expected to be deployed in other emerging and developing countries. In regions with limited land and feedstock resources, such as the Middle East and certain Asian countries, feedstock and biofuel trade will play an increasing role (*ibid;* Box A-1).

Several processes involved in the production of fuels from biomass feedstocks give rise to opportunities for large-scale capture of biogenic CO_2:

- **Bioethanol production**. Conventional bioethanol accounts for most existing biofuels production worldwide and can be based on sugar crops (sugar cane, sugar beet) or starch crops (wheat, maize) fermented to ethanol.[1] Advanced bioethanol is produced from ligno-cellulosic feedstocks, which are also fermented to ethanol following their biochemical conversion into fermentable sugars. In both conventional and advanced ethanol production, the fermentation step provides a source of biogenic CO_2 for potential capture. CO_2 is also produced in the power and heat production process, which could be captured using proven post-combustion technology. Worldwide, there are now at least three known bioethanol CCS plants at different stages of project development.[2]
- **Biodiesel production**. *Advanced biodiesel* covers several products and conversion routes. Increasing attention has been given to capture of CO_2 from the Fischer-Tropsch (FT) process, which is also a key stage in the production of coal-to-liquids (CTL), because CO_2 removal is already part of the FT production process: following gasification of the biomass feedstock, the CO_2 is removed as part of the gas clean-up stage before the resulting syngas is converted to biodiesel.
- **Biomass SNG and hydrogen**. This involves producing a synthetic natural gas (SNG) from biomass for use natural gas distribution systems. As part of the gas processing stage of biomass SNG production, CO_2 is removed using commercial absorption technology; a high purity CO_2 stream is produced upon regeneration of the absorption liquid, available for capture and compression (essentially a "pre-combustion" capture route). BioSNG production is currently at a demonstration stage, with some small-scale plants in operation around the world.[3] The applicability of CCS to biomass hydrogen production, involving capture of the high purity CO_2 stream produced as part of the process, has been briefly considered in the literature (for example IEA/UNIDO, 2011). However, no commercial demonstration plants for the production of hydrogen based on biomass feedstocks are either in operation or planned at present.

[1] Starch feedstocks must first undergo hydrolysis to convert the starch to simple sugars.
[2] Arkalon bioethanol plant, Kansas, USA (160-180 ktCO_2/yr); Decataur Carbon Sequestration Project, Illinois, USA (2.1-3.0 MtCO_2 over 3 years); São Paolo state, Brazil (20 ktCO_2/yr, as announced by the Global Environment Facility).
[3] In the USA, Germany and Sweden. More information available at: http://www.biofuelstp.eu/bio-sng.html

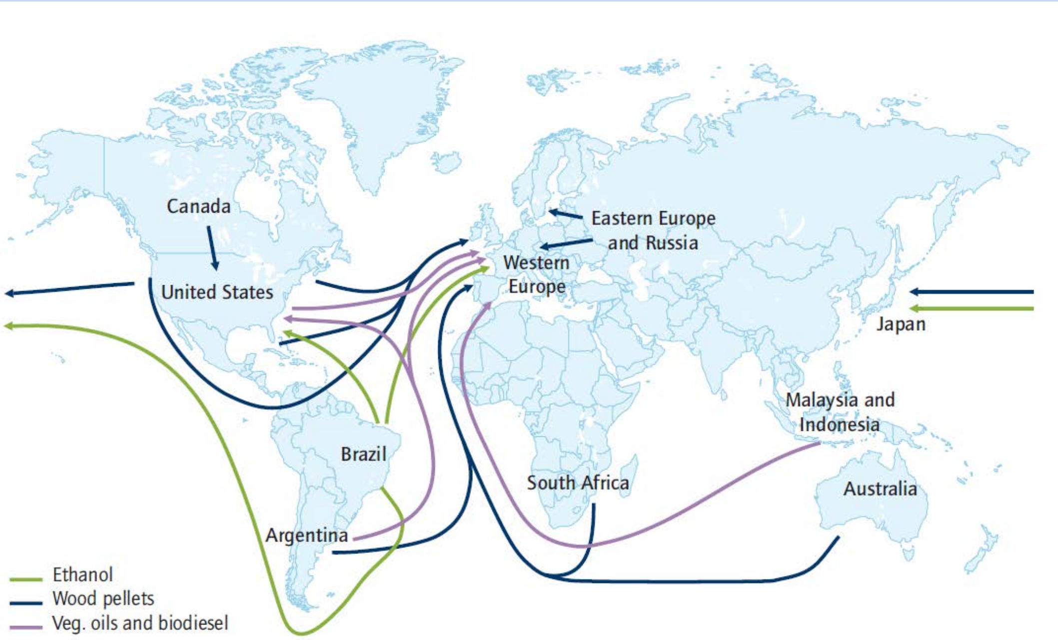
Box A-1 International trade in biomass and biofuels

International trade in biomass and biofuels has grown significantly over the past decade, mainly in response to oil price rises and renewable energy and climate policies. The main trade flows are shown below and can be summarised as follows (after Bradley *et al*, 2009):

- **Wood pellets** are shipped primarily from Canada, the US and the Baltic countries to the EU to meet biomass energy demand; of 1.8 million tonnes exported in 2006-7, Canada was the largest exporter at 740,000 tonnes, much of it to Belgium and the Netherlands. Exports from the Baltic States have fallen sharply due to lack of wood, while the southern states of the US are projected to become a major exporter.
- **Raw wood chips**. In 2006, 20% of the 231 million m^3 of wood chips produced worldwide were exported; the largest exporters were Australia, South Africa and Chile; the largest importers were Japan, China and Finland. Most of these imports were for pulp and paper, but increasingly they are being exported for energy.
- **Bioethanol** is the most transported biofuel globally; of the 2.8 billion litres exported in 2008, Brazil shipped 97%, primarily to the EU, Japan, India and the US.
- **Palm oil** is shipped in large volumes: 12.7 million tonnes in 2007-08. Major exporters were Malaysia and Indonesia, the major importers EU, China and India. While most palm oil is shipped as a food product, like wood chips it is increasingly shipped for energy production.
- **Biodiesel** net exports were 1.1 billion litres in 2007, the largest shippers being the US, Indonesia and Argentina, primarily to the EU and Japan to meet growing demand for transport biofuels.

Biomass and biofuel markets have globalised over the last decades but are still immature and face barriers such as tariffs that need to be reduced to create stable market conditions (IEA, 2011c). According to the IEA *Biofuels Roadmap*, trade will become increasingly important to promote biofuel production and meet blending mandates, as well as to balance demand and supply fluctuations among different regions (*ibid*). In 2010, 83% of the biofuels consumed in the EU were produced in the EU, part of which was produced from imported feedstock (EC, 2012a). The EU is also increasing its net imports of wood pellets[1] and, according to several recent studies there will be an increasing shortfall between EU demand and available bioenergy feedstocks in the future involving an ever increasing reliance on imports (Pöyry Energy Consulting, 2011; Eurelectric, 2011),. It is expected that whereas in the short term, trade will include conventional biofuels and feedstocks, after 2020 lignocellulosic feedstock trade will likely to grow rapidly and supply large advanced biofuel plants in coastal locations (IEA, 2011c). Although trade is currently driven largely by demand in the US, Europe and Japan, it is generally expected that non-OECD demand will become increasingly important over the coming decades, leading to increased trade volumes and the development of new trade routes.

World biomass shipping today



Source: IEA, 2011c, based on Bradley *et al*., 2009

[1] According to Eurostat data, 2.5 million tons of wood pellets were imported into the EU in 2010 (1.8 million tons in 2009).

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