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CARBON CAPTURE AND STORAGE IN THE CDM

Cédric Philibert (IEA), Jane Ellis (OECD), and Jacek Podkanski (IEA)
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FOREWORD

This document was prepared by the OECD and IEA Secretariats in Autumn 2007 in response to the Annex I Expert Group on the United Nations Framework Convention on Climate Change (UNFCCC). The Annex I Expert Group oversees development of analytical papers for the purpose of providing useful and timely input to the climate change negotiations. These papers may also be useful to national policy-makers and other decision-makers. In a collaborative effort, authors work with the Annex I Expert Group to develop these papers. However, the papers do not necessarily represent the views of the OECD or the IEA, nor are they intended to prejudge the views of countries participating in the Annex I Expert Group. Rather, they are Secretariat information papers intended to inform Member countries, as well as the UNFCCC audience.

The Annex I Parties or countries referred to in this document are those listed in Annex I of the UNFCCC (as amended at the 3rd Conference of the Parties in December 1997): Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, the European Community, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, United Kingdom of Great Britain and Northern Ireland, and United States of America. Korea and Mexico, as OECD member countries, also participate in the Annex I Expert Group. Where this document refers to “countries” or “governments”, it is also intended to include “regional economic organisations”, if appropriate.

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Executive Summary

Carbon dioxide capture and storage (CCS) in geological formations is a potentially important climate change mitigation measure in the coming decades, as geological formations can store large amounts of CO₂ (as well as other gases or liquids) for thousands of years. However, CCS has not been widely used to date. The largest CO₂ storage project to date (at the Sleipner field in the North Sea) has been injecting approximately 1 million tonnes of CO₂ per year since 1996 into a saline formation.

The possible inclusion of CCS projects under the Clean Development Mechanism (CDM) raises a number of issues, including how to deal with potential leaks of CO₂ and associated permanence and liability issues, what an appropriate project boundary is, how to deal with CDM-“leakage” (i.e. emissions resulting from the project activity beyond its boundaries) and what the possible impact of including CCS would be on the broad CDM portfolio. This paper assesses these issues.

While the bulk of long-term potential CO₂ emission reductions from CCS is associated with the capture and storage of CO₂ from combustion of fossil fuels, the short-term CCS potential is in different areas. These include enhanced oil recovery (EOR) projects and capture-ready streams of CO₂ from natural gas processing and industrial processes such as refineries, ammonia and hydrogen plants. The maximum short-term (i.e. in 2012) theoretical potential of CCS CDM projects is estimated at 584 Mt CO₂/year - larger than under the current CDM portfolio. However, this potential is unlikely to be reached given the long lead-time of projects. Hence, the risk that CCS technology could “crowd out” other technologies in the CDM portfolio seems unfounded.

With respect to enhanced hydrocarbon recovery CCS projects, some analysts have suggested that the increased availability of these fossil fuels and related CO₂ emissions should be accounted for as leakage. However, for enhanced oil recovery projects, it is unclear if the increase in oil availability augments or reduces CO₂ emissions – as this depends on what it substitutes for. Thus, it is suggested here that the use of this increasingly-available oil should not be accounted for as “leakage”. Nevertheless, impacts on local fuel markets should be considered closely for enhanced natural gas or coal bed methane recovery projects.

If the geological formation is properly chosen, underground formations can retain CO₂ for very long periods. The risk of CO₂ leaks is higher during and shortly after the injection phase, when the gas pressure is high. If they occur, leaks are thus more likely to do so during, or shortly after, the crediting period. Any emissions that occur during the crediting period (which includes emissions related to the capture, separation, transport, and storage process – as well as of potential leaks of the stored CO₂) could be accounted as project emissions. Project boundaries should include the entire reservoir and adjacent zones that the CO₂ plume may reach. This would ensure that possible leaks – which should be accounted for as “leakage” if beyond the project boundaries – do not simply go unnoticed. If any observed faults in the integrity of the storage reservoir are properly addressed, the risk of leaks decreases over time as more CO₂ dissolves in water, gets trapped in pores and reacts with rocks, thereby reducing the pressure. There is, however, a need to provide strong incentives for guaranteeing long-term site monitoring and proper storage remediation, in case any leaks occur.

It will be important to determine up-front who is liable for any release of CO₂ from CCS CDM projects in the long term. During the crediting period, as well as for the first few decades after – a period of time that could be made dependent on the history of the storage operations – liability may rest on the shoulders of the project participants; given the possibility they these companies do not last long enough, project participants could be asked to prove that their liability is covered by an “accredited” insurance company. Designated operational entities may also be involved. For the longer term, liability would need to be borne by the host country government, which would be best placed to prevent the risk of an anthropogenic action inadvertently damaging the storage site.

An alternative option is to make host countries liable when the crediting period is over, leaving them with the option to further transfer the liability to project participants for some time beyond the crediting period.

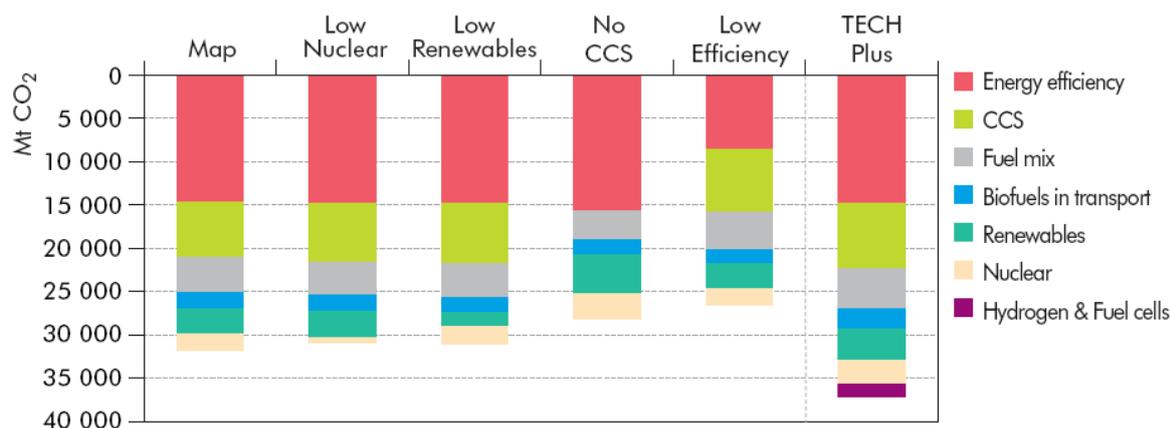
Because of the wide variance in liability issues between different potential CCS CDM projects, CDM rules for CCS projects could be established in a “staged” manner. Thus, in the first instance, projects where liability is easy to assign (e.g. projects where the reservoir is contained in one jurisdiction) could be made eligible under the CDM. More complex liability cases should be assessed on a case-by-case basis when they arise.

1. Introduction

Carbon dioxide capture and storage (CCS) technologies are increasingly recognised for their capacity to provide a large contribution to the mitigation of greenhouse gas emissions in the coming decades. For example, the IEA (2006) suggests that by 2050 the importance of CCS as an emission reduction technology could be second only to energy efficiency improvements, as shown in Figure 1 below (the second “slice” in the Map scenario). By contrast, the absence of CCS as a mitigation measure could entail 21% greater global emissions (Figure 1, “no CCS” scenario) than in the Baseline scenario, with CCS¹.

The Intergovernmental Panel on Climate Change (IPCC), in its Special Report on CCS, considered that the global economic potential of CCS would amount to 220 to 2 200 Gt CO₂ cumulatively (IPCC 2005, p.12). This corresponds to between 15 to 55% of the cumulative mitigation effort worldwide to 2100 for achieving stabilisation of atmospheric concentrations of greenhouse gases (GHG) of between 450 and 750 parts per million (ppm), averaged over a range of scenarios.

Figure 1: Global CO₂ emission reductions by contributing factor in the ACT and TECH Plus scenarios (below Baseline by 2050)



Source: IEA, 2006

The potential of CCS is extensive in both Annex I and non Annex I countries. IEA (2006) modelling exercises suggest that the bulk of emission reductions from CCS by 2050 would take place in developing countries; the differences between the “Map” scenario, which includes all technology options, and the “No CCS” scenario, amount to 1171 Mt CO₂ per year for OECD countries, 451 Mt CO₂ for economies in transition, and to 2108 Mt CO₂ for developing countries.

With respect to Annex I Parties, the Kyoto Protocol Article 2 states that they shall “(a) Implement and/or further elaborate policies and measures in accordance with [their] national circumstances, such as (...) (iv) Research on, and promotion, development and increased use of, (...) carbon dioxide sequestration technologies (...)”. The 2006 IPCC Guidelines for National Greenhouse Gas Inventories include guidance on how to treat CO₂ capture and geological storage; stored CO₂ does not show up in countries’ emissions. However, neither the Kyoto Protocol nor the Marrakech Accords provide explicit guidance if

¹ The five Accelerated Technology (ACT) Scenarios and the TECH Plus Scenario are all based on the same macro-economic assumptions as in the Baseline Scenario. The ACT scenarios focus on technologies which exist today or are likely to become commercially available in the next one to two decades. The increased uptake of cleaner and more efficient energy technologies are driven by the various policies, from R&D support to demonstration and deployment programmes to policy instruments to overcome barriers. Moreover, the ACT scenarios are based on CO₂ reduction incentives at USD 25/t CO₂ being in place from 2030 in all countries (IEA, 2006; Philibert, 2006).

and how the deployment of CCS technologies could be encouraged through the Clean Development Mechanism (CDM). Given the potential for CCS in developing countries, there is a strong interest in the deployment of CCS in these countries, in particular through the CDM.

Forecasts suggest that developing countries with large coal or oil and gas resources will increase their energy-related CO₂ emissions from fossil fuel use in the next decades, despite improvements in energy efficiency and development of non-carbon energy sources. While CCS can be economically attractive in some cases, e.g. for some enhanced oil recovery (EOR) projects, most cases of CCS from fossil fuel use will entail both significant energy losses and other costs that are not compensated by benefits others than climate change mitigation. Hence, the extent of deployment of CCS in developing countries will depend largely on incentives provided to undertake it. Such incentives could be either provided in the short-term, presumably under the CDM, or the longer term, e.g. under the CDM and/or any new incentive-providing mechanism (including, of course, any form of emission objectives) in the post-2012 climate mitigation architecture.

The question of the possible inclusion of CCS project activities under the Clean Development Mechanism (CDM) was raised at the first session of the Conference of the Parties to the UNFCCC acting as the Meeting of the Parties (COP/MOP 1) to the Kyoto Protocol, held at Montreal (Canada) in December 2005. COP/MOP1 decided 1) to organise a workshop on this issue in May 2006; 2) to solicit submissions by parties on CCS as CDM project activities, taking into account issues related to project boundary, leakage and permanence; 3) to request the Executive Board (EB) of the Clean Development Mechanism to consider proposals for new methodologies for CCS project activities, and 4) to consider all this material at its next meeting in view of achieving a decision.

Meanwhile, the CDM Executive Board (EB), which considered methodologies for three such projects, identified a number of political and methodological issues related to CCS project activities for consideration by the Conference of the Parties (CDM EB 2006). In Nairobi, December 2006, COP/MOP2 decided that more time was needed to carefully consider these issues. It requested the EB to continue considering proposals for new methodologies, and solicited submissions (by 21 September 2007 for Parties) on several issues, which are the following:

- a) Long-term physical leakage (seepage) levels of risks and uncertainty;
- b) Project boundary issues (such as reservoirs in international waters, several projects using one reservoir) and projects involving more than one country (projects that cross national boundaries);
- c) Long-term responsibility for monitoring the reservoir and any remediation measures that may be necessary after the end of the crediting period;
- d) Long-term liability for storage sites;
- e) Accounting options for any long-term seepage from reservoirs;
- f) Criteria and steps for the selection of suitable storage sites with respect to the potential for release of greenhouse gases;
- g) Potential leakage paths and site characteristics and monitoring methodologies for physical leakage (seepage) from the storage site and related infrastructure for example, transportation;
- h) Operation of reservoirs (for example, well-sealing and abandonment procedures), dynamics of carbon dioxide distribution within the reservoir and remediation issues;
- i) Any other relevant matters, including environmental impacts.

COP/MOP 2 also indicated that recommendations on CCS in geological formations as clean CDM project activities should be prepared for consideration by COP/MOP 3 in December 2007, with a view to taking a decision by COP/MOP 4.

This paper assesses the policy questions as highlighted in the relevant COP/MOP 2 decision, particularly leaks (or seepage) and permanence for geological storage, project boundaries and liability issues, and leakage, as well as a few others raised by some Parties. Since any emissions or leaks during the separation, capture and transport phases would occur during the crediting period of the project (and would therefore be accounted for as project emissions), the paper focuses its analyses for leaks and liability on storage, as it is in this part of the CCS process that long-term leaks could occur.

Terminology

This report uses the term “leaks” to refer to unintended re-emission of CO₂. “Leakage”, however, is used as for other CDM project types, i.e. to refer to changes in emissions resulting from a CDM project that occur outside the project boundary.

The next section of this paper briefly reviews the sources of CO₂ of possible interest for CCS technologies; the various capture technologies, and the various options for geological storage. It also assesses the possible impact of including CCS project activities on the global CDM portfolio and the possible “competition” between different project types that may result. Sections 3, 4 and 5 respectively address the issues of leaks and permanence; project boundaries and liability; and leakage. A concluding section summarises the analysis and identifies possible ways forward.

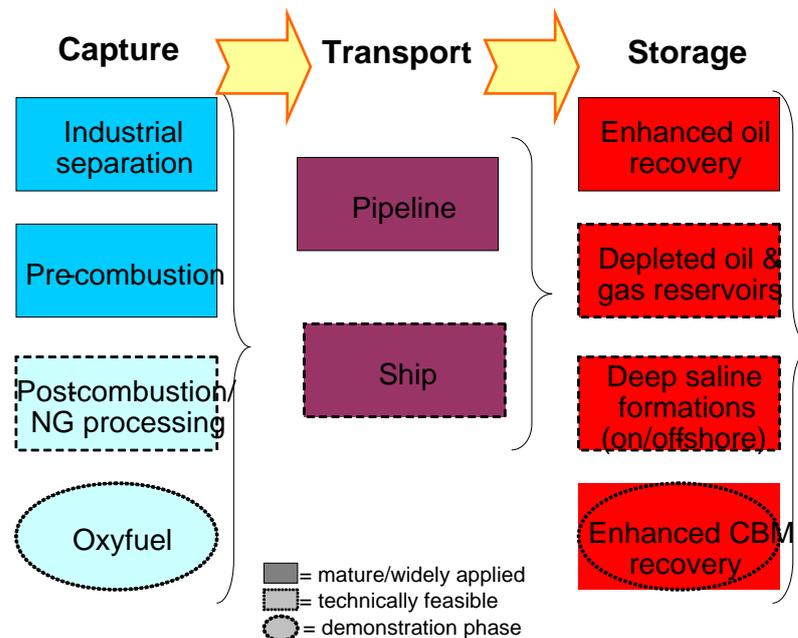
2. Context

CO₂ emissions are produced from a wide variety of combustion-related and industrial processes sources. CO₂ emissions from large point sources, such as power plants, refineries or cement plants, could be captured, transported and stored in several different ways (Figure 2). The technologies used within each step of the carbon dioxide capture and storage chain are at different stages of development. Some are mature/widely applied; some are economically feasible in some conditions, while other technologies are at the demonstration phase. Geological CCS projects (developed as CDM projects, or not) could involve different combinations of capture, transportation and storage technologies. In turn, this could lead to a wide range of potential CDM project types.

2.1 Carbon dioxide capture, transport and storage technologies

CO₂ capture already occurs in some energy and industrial activities. For example, CO₂ separation routinely occurs in industries where CO₂ is required as an input to a manufacturing process (e.g. production of urea). CO₂ must be stripped from natural gas during exploitation of fields with significant CO₂ content. CO₂ is also extracted in refineries, ammonia plants and hydrogen plants.

“Pre-combustion” separation of CO₂ can occur during the partial combustion of fossil fuels, used for example in the production of hydrogen or hydrogen-rich fuels. Electricity generation from Integrated Gasification Combined Cycle (IGCC) plants also requires pre-combustion separation of CO₂. “Post-combustion” CO₂ capture from flue gases is also possible, e.g. via absorption or flue gas treatment (IPCC 2005). This can be used to capture CO₂ from electricity generation plants (and indeed is the only option for CO₂ capture from existing power plants), although it is energy-intensive and so entails an energy penalty. Oxyfuel combustion refers to a technology under development whereby fuel is combusted in oxygen and re-circulated flue gas, rather than air (which is mainly made up of nitrogen). The exhaust gases from oxyfuel combustion contains thus mainly CO₂ and H₂O (water vapour), rather than nitrogen. As the vapour can be easily condensed, the waste gas is largely CO₂.

Figure 2: Different options for capture, transport and storage of CO₂, and their maturity

Source: Adapted from information in IPCC 2005

Transport of CO₂ can be done by pipeline or ship. Commercial-scale transport of CO₂ via pipeline and ship/tankers already occurs (IPCC 2005). Pipeline transport is normally of compressed (gaseous) CO₂, whereas transport on ships is often of liquefied CO₂, as this takes less volume. Liquefaction of gases is routinely used, e.g. for the transport of liquefied petroleum gas (LPG) or liquefied natural gas (LNG).

There are also different ways in which CO₂ can be stored. These include various underground geological formations such as oil and gas fields (in use or abandoned), saline formations or coal seams (mineable or unmineable). Experience with storing CO₂ in these types of formations varies. For example, the largest CO₂ storage project to date (at the Sleipner field in the North Sea) has been injecting approximately 1 million tons of CO₂ per year since 1996 into a saline formation. Other demonstrations, pilot or commercial projects, exist to inject CO₂ into depleted gas fields and coal mines.

CO₂ is being re-injected into various oil fields to increase the rate and amount of oil produced. Such enhanced oil recovery (EOR) can also use other fluids for the same purpose, notably water and steam. Globally, CO₂-based EOR projects inject around 40 million tonnes of CO₂ per year – of which 30 million come from natural underground sources of CO₂ and about 10 million tonnes is captured from industrial plants. The use of CO₂ for EOR can provide a valuable near-term opportunity for gaining storage experience, but this needs to be done at the right time in the life of a particular field. Enhanced gas recovery and enhanced coal bed methane recovery are in development phase.

2.2 Leaks and liability implications

The risk of leaks of carbon dioxide stored from underground formations will vary depending on the geological formation. For CO₂ injected as part of EOR operations, some of the CO₂ injected is resurfacing with the oil it helps to recover. Usually this CO₂ is routinely separated and re-injected, but a small fraction may remain in the fuel. However, current EOR activities have been designed to maximise oil production – not to store CO₂. Future “EOR CCS” projects could be managed differently to maximise storage. For other types of storage, seepage and leaks are more likely if CO₂ is stored in formations that extend across fault lines and/or that contain other potential “escape routes” for CO₂, such as abandoned wells. However, the risk of leaks can be minimised with careful planning. The IPCC estimates that, for appropriately selected and managed geological reservoirs, more than 99% of CO₂ injected is “very

likely”² to remain in place over the first 100 years of storage, and is “likely” to remain in place over 1000 years. Nevertheless, the variation in potential seepage rates or risks from different storage options may mean that different rules may be needed for different types of CDM projects.

Given that some stored CO₂ could escape, it will also be important to determine who is liable for any releases and would have to replace any associated emissions credits – thus being given an incentive to prevent the leaks. Although seepage rates and/or risks of sudden massive release of CO₂ are small, liability issues are important both in the short-term (i.e. over the crediting period of a CDM project activity) and in the longer-term (potentially for hundreds or even thousands of years). Further, if CO₂ is stored in a reservoir that crosses international boundaries, or that extends below international waters, or if various capture projects share one single reservoir, liability issues can affect more than one country.

2.3 CCS cost and potential

Unless there is a value to store CO₂ there is virtually no driver for the deployment of these technologies – except perhaps in the case of a few EOR projects. However, these costs vary widely between sites. Costs also vary depending on which type of capture technology, transportation and geographical storage are used, the depth at which CO₂ is stored, as well as whether CO₂ separation is routinely carried out or not, the required CO₂ purity, and whether CCS is designed to apply to an existing, or new, system (IPCC 2005). How far the point of CO₂ capture is from the storage site also matters, though the cost of transport is only a fraction of total costs. CCS activities may also have some economic benefits beyond climate change mitigation, from e.g. EOR activities or decreased local air pollution. Nevertheless, the relative costs or benefits of different types of CCS activities will affect their likelihood of being undertaken in a business-as-usual scenario, and thus their additionality under the CDM.

Cost estimates for large-scale, new installations range from 5 to 55 US \$ per net tonne of CO₂ captured from hydrogen and ammonia production or gas processing, from 15 to 75 US \$/tCO₂ captured from a coal or a gas-fired power plant, from 1 to 8 US \$/tCO₂ transported (depending on the distance and volumes) and 0.5 to 8 US \$/tCO₂ net injected (IPCC, 2005). Monitoring costs are generally less than 1 \$/tonne. The costs per tonne of CO₂ avoided in CCS projects are higher than the cost per tonne of CO₂ stored as the calculation must take into account the energy use associated with separating, capturing, transporting and storing the CO₂, and associated leakage.

There is a large technical potential for CCS from several activities in non-Annex I countries (Table 1). Some of these activities could be carried out under business-as-usual activities (e.g. for enhanced oil recovery), whereas others would not (e.g. retrofitting power stations to capture and store CO₂). In the short term, the potential is likely made of EOR activities and capture from point sources where the CO₂ is separated from other materials: refineries, ammonia plants, hydrogen plants, and exploited gas fields.

² In the IPCC WGI report, “very likely” corresponds to a probability of between 90-99% and “likely” corresponds to a probability of between 66-90%.

Table 1: Short and long-term technical potential for CO₂ capture in non-Annex I countries, selected industries (million tonnes CO₂/y)

	To 2012	2020
Hydrogen production	7.1	7.1
Refineries	322.3	322.3
Ammonia production	77.7	77.7
New coal-fired electricity*	--	2193
Retrofit of fossil-fired power stations	--	5077
Retrofit of cement factories*	--	1270
Natural gas processing *	167	334 ³
Enhanced oil recovery*	10	20 ⁴
Total	584.1	9301.1

Sources: IEA GHG R&D 2006, apart from * which also use data in IEA 2006, Cui 2006, authors' calculations

The technical potential for the volume of CO₂ capture from these activities in non-Annex I countries is huge: 9.3 billion tons of CO₂ around 2020, according to the authors' estimate. The short-term technical potential for industries that generate capture-ready CO₂ is much smaller, at 584 million tons CO₂ per year by 2012. Table 1 outlines the technical potential for CO₂ capture in different industries in non-Annex I countries. However, given the investment required for CCS projects, as well as the long-lead time for implementing such projects and having them approved as CDM projects, the actual take-up of CCS projects will be much lower than the technical potential, particularly pre-2012. The figures assume CO₂ capture for all large point sources, and that pre- and post-combustion CO₂ capture technologies are mature by 2020. Figure 6 (on page 30) shows the localisation of the world's largest emitting facilities (above 100 000 tCO₂ per year).

2.4 Potential impact of CCS on the CDM portfolio

CCS potential could, in theory, be very significant in terms of the CDM. The current CDM portfolio is expected to generate almost 380 million tons of credits per year between 2008 and 2012 (UNEP/Risoe 2007). Widespread uptake of just the short-term CCS opportunities could more than double the current CDM portfolio. If pre and post-combustion CCS facilities become widely used, this could in theory dominate the CDM portfolio in the long-term. This has led to concerns that CCS could crowd out other project types from the CDM (see, e.g., Miguez, 2006), particularly as it would be relatively easy to determine the additionality of many types of CCS projects; CCS projects would often generate large volumes of emission credits; and would have relatively low transaction costs per tonne of avoided emissions, as the result of their sheer size.

³ The figures for natural gas processing are the authors' estimates. The world proved natural gas reserve were estimated 1 January 2007 by the *Oil and Gas Journal* at 175 trillion cubic meters, of which about 98.5 trillion cubic meters are located in non-Annex I countries, mostly in the Middle East and Africa. Most of these reserves have a CO₂ content of between 1 to 10%, but some large fields have higher CO₂ content. Hence we took a conservative assumption of 7% CO₂ content on average, and considered that the CO₂ content of marketed natural gas will be down to 2%. The gas available for storage would thus amount to 4.9 trillion cubic meters, or about 10 billion t CO₂. If this natural gas supports 60 years of consumption, the extracted CO₂ would be 167 Mt per year. A few NG reservoirs, however, have a much higher CO₂ content. For example, the Natuna field, off the Indonesian coasts, contains 70% CO₂. The yearly extraction would be 20 billion cubic meters (bcm) of natural gas, meaning that about 90 Mt CO₂ – 90 “Sleipner” – would be stripped out each year and, hopefully, stored in the subsurface below sea ground. Hence we doubled the 2012 figure as our estimate for 2020 – while the economics of natural gas at that time may, or may not, warrant the exploitation of NG fields with high CO₂ content.

⁴ The figures for EHR are the authors' estimates, on the basis of a (hypothetical) 50% increase of current injection of CO₂ for EOR activities by 2012, and a doubling by 2020, for one half in non-Annex I countries. Enhanced gas recovery (EGR) and enhanced coal bed methane recovery (ECBM) are not expected to add much to the resulting numbers.

However, in practice, the importance of CCS CDM projects is likely to be significantly lower than the technical potential. Indeed, few types of CCS projects are likely to become popular under the CDM pipeline if international carbon prices are low. Only projects with low incremental costs (i.e. where the incremental costs are lower than the expected CDM benefits) would show up in this case, such as some EOR projects or ready-to-capture CO₂ stream projects.

Other projects, such as most types of CO₂ capture from power plants, will only be possible if carbon prices are high enough – and international or domestic emission reduction commitments stringent enough. In this case, many other options will compete with CCS, which is a relatively costly option. For example, the IEA (2006) suggests that, at a marginal cost of 25 \$/tCO₂ by 2050, CCS offers an important chunk of emission reductions worldwide, but not all technical potential for CCS would be tapped, and many other options would be important as well, as shown on Figure 1 above.

Furthermore, CCS projects will have considerable lead times for implementation. A thorough selection of appropriate sites and setting up the necessary infrastructure, such as pipelines, requires considerable time for planning and implementation. Institutional issues – both at national and international levels – may also reduce and/or delay the take-up of CCS in the CDM. Thus, even if COP/MOP 4 endorses CCS in the CDM by the end of 2008, only a few projects – if any – could be commissioned by 2012.

Thus, any concerns about CCS crowding out other useful technologies in the CDM should not be overstated, given the difference between the theoretical and market potential of CCS CDM projects. Further, such concerns could be alleviated by making the implementation of other project types easier, rather than making CDM projects more difficult. Small-scale projects, in particular for renewable energy and energy efficiency, already benefit from streamlined procedures. Further CDM developments, including those on “programmatic CDM” and project bundling that were initiated at COP/MOP 1, can help in this respect. Elaborating an incentive-providing mechanism that may succeed the CDM – or complement it in the post 2012 climate mitigation architecture – could also be useful.

3. Leaks and Permanence

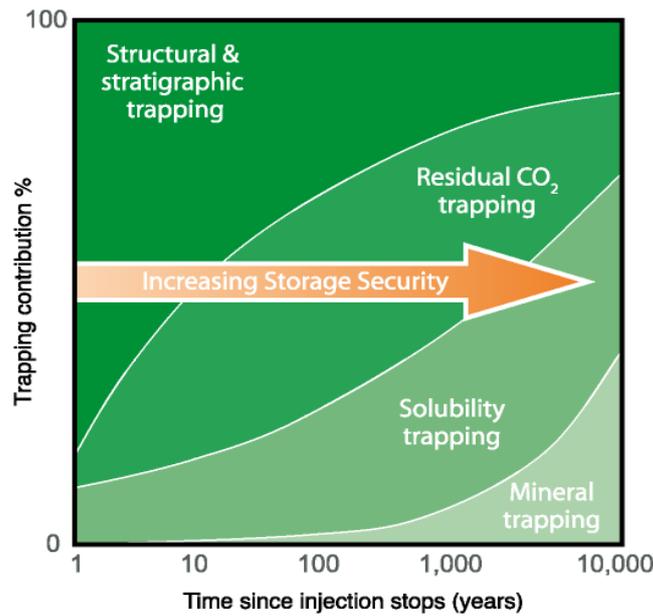
According to the Kyoto Protocol, CDM project activities need to result in emission reductions that are “real, measurable and long-term”. In the context of potential CCS CDM projects, this is only possible if the CO₂ injected as part of the CDM project is not re-emitted. This section outlines the various storage mechanisms, leaks rates or risks, and monitoring requirements and techniques.

3.1 Storage

The potential geological storage reservoirs for CO₂ are porous rock formations containing trapped fluids such as brine (water with high content of various salts), oil or gas. The potential reservoir should be capped by low-permeability layer of rock. The minimum storage depth is about 800 meters to ensure that the injected CO₂ remains in a dense, supercritical state.

CO₂ can be stored underground in deep saline aquifers, depleted oil and gas reservoirs or unmineable coal seams, onshore and under the sea bed. It can be used in oil fields for CO₂ enhanced oil recovery (EOR), in gas fields for enhanced gas recovery (EGR), and in coal fields for enhanced coal bed methane recovery (ECBM). Together, EOR, EGR and ECBM are referred to as enhanced hydrocarbon recovery (EHR).

Five basic trapping mechanisms keep CO₂ in a storage reservoir. Primary mechanisms include (1) stratigraphic trapping beneath a cap rock that overlays a formation holding the CO₂, and (2) structural trapping in fractures, folds and cavities (IPCC, 2005]. Secondary mechanisms include (3) CO₂ dissolution in water that is present in pores, (4) trapping in pores by capillary forces, and (5) chemical reaction with rock. Over time, secondary trapping mechanisms play an increasing role and decrease seepage risks and monitoring requirements (Figure 3).

Figure 3: Trapping mechanisms and their contribution to retention of CO₂ vs. time

Source: [IPCC, 2005]

In order to assess the quantity of CO₂ injected in a CCS project, the injection phase requires permanent measurement and monitoring – as well as verification of modelling results. However, because the importance of secondary trapping mechanisms that permanently immobilise CO₂ increases over time, the post injection period requires monitoring reservoirs and verification operations with possibly decreased frequency for long periods after abandonment. This has potentially significant impacts for the costs of monitoring CCS projects.

3.2 Leaks

For the reasons outlined in the introduction, this section focuses on potential leaks from only the storage component of the separation, capture, transport and storage chain. The highest risk of CO₂ leaks from the storage occurs during the injection phase and over the next several decades (Benson, 2006). This is because of three main factors. Pressure in the reservoir is highest during the injection phase, which allow for detection of leakage routes through a seal, fault or well. Ongoing monitoring during the injection phase provides information about the fate of a CO₂ plume (i.e. whether it is moving towards a potential source of leaks such as fault or well) while post injection monitoring further improves the knowledge of the CO₂ behaviour and allows for model verification.

The causes of leaks are likely to vary depending on the type of geological storage formation. In the case of a saline formation, seepage may result from insufficient geological data on the cap rock. Leaks from storage in an oil or gas field could mostly result from a well failure, due to chemical dissolution of the well bore isolation material (cement) or corrosion/failures of completion components.

In general terms, if the formation is chosen properly, and as shown from studies of analogue fields, there is no reason to doubt the ability of underground formations to retain CO₂ for very long periods. Natural CO₂ fields indicate that under favourable conditions CO₂ can be retained in the subsurface for millions of years (Holloway et al., 2007). Several large scale CCS projects are already being implemented. Currently, more than three million tonnes of anthropogenic CO₂ are injected each year underground in three major storage projects: Sleipner in Norway (Statoil), Weyburn in Canada (EnCana) and In Salah in Algeria (BP, Sonatrach). No seepage has been detected for any of these projects – Sleipner has been injecting 1 million tonnes a year of CO₂ since 1996.

All the enhanced hydrocarbon recovery processes result in permanent storing of a certain fraction of CO₂. While more than 50% of the injected CO₂ returns with the produced oil in the case of EOR, it is usually separated and re-injected into the reservoir to minimise operating costs (IPCC, 2005). For example, in the Rangely CO₂-EOR project operated by Chevron in Colorado, USA, of the total 2.97 Mt injected annually, recycled CO₂ comprised around 2.29 Mt and purchased gas about 0.74 Mt. Surface release from the storage reservoir is below the detection limit of 170 tonnes per year or an annual leakage rate of less than 0.00076% of the total stored CO₂ (IPCC, 2005). Nevertheless, not all CO₂ will be recovered and some may remain mixed with the gas which is either flared or used for commercial purposes. Usually, marketed natural gas contains 0.5% CO₂, and suppliers avoid selling natural gas with more than 2.5 % CO₂ through pipelines (and much less as LNG), but there is no universally accepted specification system for marketed natural gas.

The demonstration CCS projects currently underway have already led to a significant accumulation of operational experience. It is thus very likely that the storage part of the CCS chain will be sufficiently proven by the time any CCS project is implemented under the CDM. The risk of leaks during the transport of CO₂ by pipelines or ships can be mitigated effectively. The operational safety record of CO₂ pipelines in the US shows a much lower rate of incidents than in gas pipelines, whose track record has been so far excellent.

The risk of CO₂ leaking from its storage site depends on several factors. These include the distance to the source of CO₂, site storage capacity, depth, porosity, permeability, and existence of fractures and faults in the seal above the reservoir, and well completion components, among other parameters. In the case of CCS in former oil or gas fields an account of all abandoned wells, including the condition of their sealing, is needed. The next step should involve modelling of the behaviour of CO₂ during the injection phase and afterwards.

The IPCC inventory guidelines consider the storage reservoir as a source of emissions. As a consequence, an amount of stored CO₂ can be measured as a difference between an amount injected and amount emitted from the reservoir (if leaks occur). This offers a significant advantage over an underground storage inventory approach, mostly due to low accuracy of *in situ* accounting of CO₂ (Benson, 2006), when all trapping mechanisms would have to be taken into consideration.

3.3 Monitoring

As leaks from the CO₂ storage site may occur mostly through the point sources, faults and wells, monitoring of this site should include two elements. This includes monitoring of the subsurface CO₂ plume, and some above-ground monitoring (e.g. relatively small areas – where the plume may meet faults or wells, allowing for easier detection and remediation). Only the CO₂ trapped via primary mechanisms (stratigraphic and structural) has a potential to be released through fractures and faults or wells and any such leaks are likely to be relatively slow. Remediation techniques include reducing injection or reservoir pressure, sealing damaged wells and, in the extreme case, emptying the reservoir and re-injecting of CO₂ in a different location.

A large number of monitoring techniques exist and a specific mix will be applied to every particular storage site (IPCC, 2005, IPIECA, 2007). Proven technologies used in the oil and gas sector are available for estimating potential leaks. They have been used for a number of projects. The IEA GHG R&D programme has produced an on-line toolbox to help select applicable monitoring technologies⁵. It is possible to distinguish emissions from a reservoir from background emissions at sufficiently low CO₂ concentrations and seepage can be detected and assessed with the accuracy required by the CDM accounting principles (Benson, 2006). Further research remains required, in particular to reduce costs.

Any leaks that have been identified and measured during the crediting period should be included in the calculation of the total amount of CO₂ stored. Assessment of avoided emissions from a CCS CDM

⁵ See http://www.co2captureandstorage.info/co2tool_v2.1beta/index.php

activity will also include all other project-related emissions, such as emissions of CO₂ from enhanced recovery operations (as the recycling of CO₂ involves some CO₂ losses to atmosphere, in particular due to energy-intensive separation processes) – including the CO₂ that may remain mixed with the gas flared or sold.

Very long term physical leakage is unlikely if sites are carefully selected and appropriately managed, including any remediation measures, and if monitoring is ensured during the injection phase and a few decades thereafter. Therefore, appropriate site selection procedures, risk management plans and careful management of the reservoir are key to achieve a high storage security. A framework to enable CCS in the CDM should provide strong incentives to achieve this.

Nevertheless, even short-term carbon storage could be useful. For example, as Holloway et al. (2007) have put it, “short-term storage of a few hundred years could be very valuable in shaving the expected peak levels of CO₂ in the atmosphere that might occur near the end of the fossil fuel era”. After that time period, atmospheric CO₂ levels are likely to begin a slow decline. Analysts have suggested that for yearly seepage rates less than 0.01% of the cumulative amount stored, geological storage would be highly effective as a greenhouse gas mitigation technique (Hepple and Benson, 2004). Seepage below that rate would ensure that at least 90% of the stored CO₂ remains stored after one thousand years.

While it would not be desirable for significant amounts of stored CO₂ to be released until there had been a significant decline in atmospheric CO₂ levels, its consequences must be considered in the context of this distant future. Overall, the very-low probability of such an event should not preclude the deployment of CCS technologies, including through the CDM. Requesting from project developers very long term guarantees and proofs that could be impossible to provide may inhibit uptake of these promising mitigation technologies.

Considerations of necessary retention times and storage effectiveness must not be misinterpreted. Conclusions that certain seepage rates will still make CO₂ storage effective in terms of greenhouse gas mitigation and information that (at least) a certain percent of CO₂ would be permanently stored over thousands years do not mean that seepage will in fact occur, or that an emission factor should be assigned to a storage reservoir (Benson, 2006). None of existing storage projects experienced CO₂ seepage, so there is no experimental data to develop default “seepage” factor (except during the operations).

4. Project Boundary and Liability Issues

According to the Marrakech Accords, CDM project activities need to include in the project boundary “all anthropogenic emissions (...) under the control of the project participants that are significant and reasonably attributable to the CDM project activity”. The project boundary for a CCS project can therefore include more than one gas (e.g. CO₂ and CH₄ from fuel combustion) from more than one source (e.g. separation and transport of CO₂) emitted in more than one location (e.g. that of CO₂ production and of CO₂ storage). Parties’ interventions at the UNFCCC workshop on CCS in the CDM held in May 2006 agreed that all emission sources should be included in the project boundary, i.e. separation/capture, transport, storage (UNFCCC 2006a).

A more contentious point is how to define the geographical project boundary for a CCS CDM project activity and who is liable during and after a CDM project’s crediting period if there is CO₂ seepage or major CO₂ emissions following a breach of the CO₂ reservoir. Determining liability can be quite complex in some cases – for example, if a CCS project occurs in international waters, or if several CCS projects use the same reservoir. This section highlights issues relevant to determining project boundaries and liability for storage of CO₂.

4.1 Geographical extent of the project boundary

Defining the geographical extent of the CDM project boundary is simple for most CDM project activities. This is because most CDM project activities involve reducing emissions from a single site. A CCS project is different, because the storage reservoir can be very large, as can the distance between CO₂ injection and CO₂ seepage.

The key question in defining the geographical boundary for a CCS CDM project activity is whether the project boundary should extend to the whole of the reservoir, or just focus on the area around the CO₂ injection site. The answer to this question will affect the cost and could also affect the environmental integrity of CDM CCS projects.

Defining the CDM CCS project boundary to include the whole reservoir would ensure a high level of environmental integrity and reduce the importance of leakage (by ensuring that any leaks from the reservoir are accounted for inside the project boundary). While in theory seepage beyond the project boundaries should be accounted for as leakage, it runs the risk of simply being unnoticed. One possible complication in extending the geographical boundary to include the whole reservoir might be administrative: if the project boundary is defined to extend across different jurisdictions, all jurisdictions may need to approve participation in the particular project (liability issues associated with such a decision are discussed below).

The decision on whether or not a project's boundary should include the whole reservoir may need to vary by the type of CCS CDM project as well as by site-specific factors. For example, EOR projects can involve injecting CO₂ at some distance from the oil production wells. It would therefore seem appropriate to have a wide geographical project boundary for this project type. Conversely, a more narrowly-defined project boundary might be appropriate for CCS projects that take place in reservoirs with a very low risk of seepage (e.g. with no faults or abandoned oil/gas wells).

4.2 Influence of storage type and location on liability issues

There is a risk that CO₂ stored in a CDM CCS activity could be re-emitted either via seepage or via a major breach of the CO₂ reservoir after the end of the crediting period of a CDM project. This could have both environmental and economic impacts. Who bears liability for such potential leaks should be determined up-front.

Section 3 highlighted that the level of CO₂ leaks is likely to vary according to site-specific factors as well as by type of CO₂ storage options. Site-specific factors are also likely to play a key role in the (unlikely) possibility of a major CO₂ release, e.g. following the breach of a CO₂ reservoir. Environmental effects of CO₂ release can also vary: they can be local (e.g. a massive release of CO₂ can cause fatalities to humans and animals, and modify the vegetation) or global (via their impact on greenhouse gas emissions).

The issue of liability is complicated by the fact that since underground CO₂ reservoirs may be large, they could potentially contain many different projects (including CCS and oil/gas extraction projects) and stretch across national boundaries – or indeed into international waters. Further, because CO₂ can migrate within a reservoir, seepage in one part of a reservoir can be caused by storage in another.

There are several different aspects relevant to the issue of determining who is liable for any re-emissions of CO₂ from a CDM CCS project's storage site⁶. These factors include:

- The number of jurisdictions that the CO₂ reservoir stretches over. This could potentially include more than one non-Annex I country, a mixture of non-Annex I and Annex I countries, or a non-Annex I country and international waters.

⁶ These issues are less important for the other parts of the CCS chain. This is partly because any CO₂ leaks during capture and transport will occur during the project's crediting period and therefore be routinely monitored.

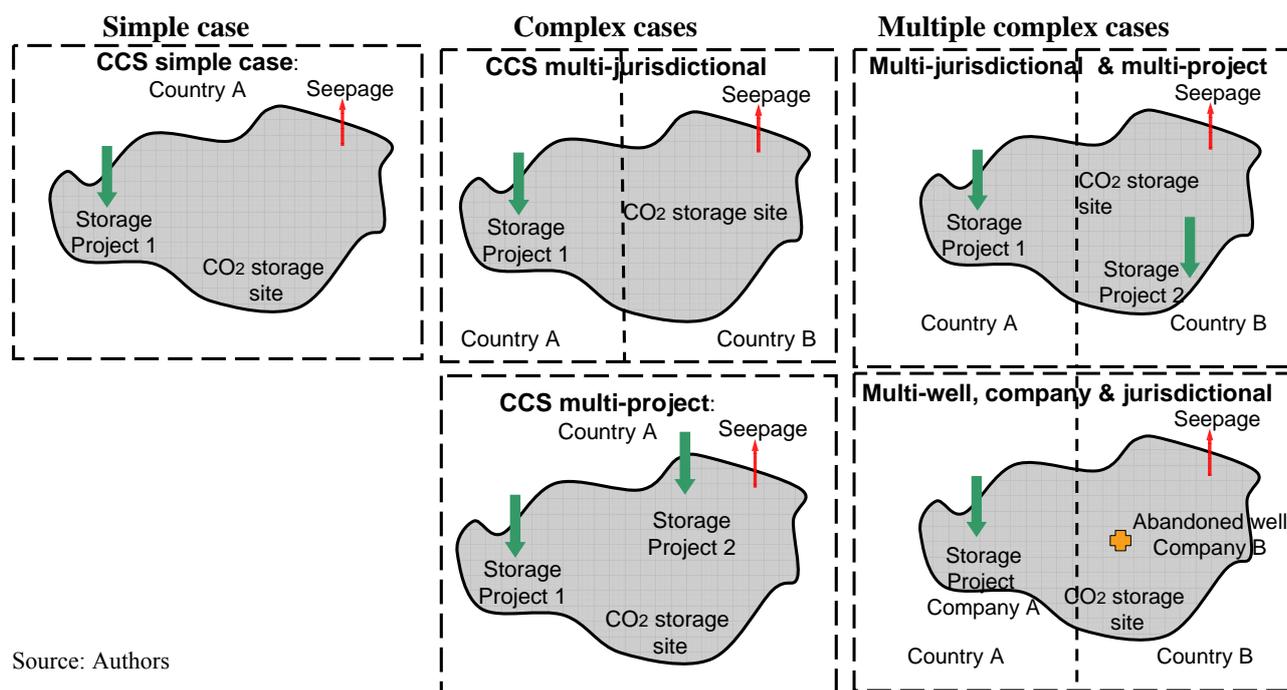
- The number of CCS projects per reservoir. As reservoirs can sometimes be large, it is feasible that more than one CCS project might use a particular reservoir.
- Whether fossil fuels are currently being extracted from the reservoir into which CO₂ is injected. This is important, as it affects the rate of CO₂ seepage (as well as the economic benefits generated by CO₂ injection).
- Whether fossil fuels have previously been extracted from the reservoir into which CO₂ is injected (e.g. whether there are any abandoned oil fields).

A one-reservoir, one-project, one-country case (the “CCS simple case” in Figure 4 below) would be the simplest case to determine liability for potential CO₂ release. In such a case, liability for CO₂ release would presumably rest with the project developer – at least during the project’s crediting period and any subsequent period during which the project developer has monitoring requirements. However, the host country government may need to take on at least some liability beyond the end of a project’s crediting period, given that a particular company may no longer be in operation decades or even centuries after the end of a project’s crediting period. This and alternative solutions to ensure proper long-term management of the reservoirs are further considered below in section 4.3.

Determining who is liable for potential CO₂ emissions is more complicated in cases where there are many projects and/or many jurisdictions and/or fossil fuel production facilities in the reservoir where the CCS project occurs. There are many such project types, some of which are also illustrated in Figure 4 below.

There are many different types of possible multi-jurisdictional CCS projects. These include projects where the reservoir stretches across: two (or more) non-Annex I countries; an Annex I and a non-Annex I country; a non-Annex I country and international waters. Because CO₂, once re-injected, can migrate within a reservoir, seepage may occur at locations far removed from the point of re-injection. This means that although CO₂ might be injected in a reservoir in one country, seepage (or other CO₂ release) from this reservoir may occur in another jurisdiction. It would thus be prudent to decide up-front if a country (e.g. country B in figure 5) that is not the host country for a CDM CCS project can be liable for CO₂ releases from a CCS project where re-injection occurs in country A and where the reservoir extends over both countries. If both countries are liable for CO₂ release, would a “non host” country also need to approve participation in CDM projects and/or would they expect a share of any associated credits generated from the CDM project? Would liability provisions need to be different if country B was an Annex I country, or if a reservoir extended over national and international areas?

Figure 4: Seepage and liability issues for different types of CCS CDM projects



Source: Authors

Reservoirs with multiple CCS and/or abandoned oil/gas extraction projects raise similar liability issues. If there are multiple re-injection projects into a reservoir, how could or should liability for any CO₂ release be shared between the different project participants and host countries? Are liability questions any different if one re-injection project is done under the CDM and another is not? What if a CCS CDM project involves re-injecting into a reservoir where there are abandoned oil/gas wells (where the risk of seepage is higher)? Would the CDM project participant be required to monitor seepage emissions from the abandoned wells of another company (and potentially in another country)? Is this feasible from a commercial confidentiality standpoint?

4.3 Suggested ways forward for the CDM

Different CO₂ storage types are likely to have different “seepage rates” during the injection phase. In particular, enhanced hydrocarbon recovery projects may have continuous CO₂ emissions at the storage site, some of which due to the re-emission of injected CO₂. These emissions must be taken into account as project emissions, along with, e.g., those associated with fossil fuel consumption required by the storage operations themselves. Emissions due to the re-emitted CO₂ content of the sold natural gas could be accounted for as leakage.

With respect to long term storage and permanence, however, there is little ground to distinguish between the various project types. Once leaks have been monitored during injection and a few decades after the end of operations, if no leaks have been revealed or if any occurring seepage has been properly addressed through remediation, there is a very low probability that CO₂ will leak in the future. As more and more CO₂ becomes permanently fixed by secondary storage mechanisms, the pressure decreases and the risk of accidental release of CO₂, due for example to some fragmentation of the rock, also decreases.

It will be important to determine up-front who is liable for any release of CO₂ from CCS CDM projects in the long term. However, the impact of such decisions will be most significant only if some CO₂ actually leaks to the atmosphere. Because long-term CO₂ leaks are unlikely in most situations over the long-term (given an appropriately-chosen and managed storage site), a first step of allowing CCS offset projects might be to make CDM projects eligible where liability is easy to assess (e.g. projects that occur in reservoirs in one jurisdiction) and knowledge about risks is important. Since there is only a very low

risk of seepage from these project types, they could generate “permanent” emission credits (i.e. credits that do not expire after a certain period of time, as for credits from other emission-reduction projects).

Several options have been suggested to address the possibility of leaks. The three main options are:

1. “Discount” any credits generated by CCS projects by a certain amount;
2. Allow CDM projects to generate only “temporary” CDM credits;
3. Allow CDM projects to issue “permanent” CDM credits.

The first option would be appropriate if leaks were almost certain to take place. However, it is unlikely that CDM CCS projects would be approved if it was thought that they were likely to lead to significant levels of re-emissions. Determining an appropriate level of “discount” might also be challenging. Furthermore, discounting the credits in any case would provide no incentive for remediation of leaks.

The second option would be appropriate if the risks of leaks were high, as in the case of sinks projects. In the case of CCS projects, it may be too strong an impediment. Both “temporary credits” (tCERs) and “long-term credits” (lCERs) as defined for afforestation and reforestation project activities eventually expire, whether the carbon remain stored or not as a consequence of these activities. This expiration takes place at the end of the commitment period following the one for which tCERs were issued, or at the end of the crediting period, i.e. maximum 60 years, for lCERs. This explains the lower market value of tCERs and lCERs. Moreover, any kind of temporary credits would not provide an incentive for avoiding leaks in the long run (after maximum 60 years). Temporary credits for CCS CDM projects would thus weaken, not strengthen, the incentives for long term monitoring and remediation.

The third option would ensure full fungibility of the CERs in the international carbon market (unless some countries were to limit eligibility in their domestic emissions trading schemes) but there is a need to ensure proper accounting of any leaks and to assign liability in a way that favours effective storage site remediation over simple replacement of allowances if leaks occur. There are several possible sub-options regarding liability provisions if CCS projects generate permanent CDM credits:

- a. Make the buyers fully liable for any long-term leaks. Private buyers, before the CERs are surrendered by a country, and Annex I countries, after the CERs have been surrendered, would have to replace CERs from a CCS project if some leaks have occurred, in proportion of the CO₂ leaked.
- b. Make the project participants liable for some time after the crediting period while ensuring effective monitoring and remediation through insurance contracts and oversight from designated operational entities, plus an up-front agreement with the host country for the very long term liability.
- c. Make the host country liable (as a default) for potential leaks. The host country could then pass on such liability to project participants for a length of time and under conditions that could be laid out in its letter of approval of a proposed project. (This has institutional implications for the host country).

The first option (a) would turn the liability to the users of the CERs. The liable entities would first be the capped entities in Annex I countries as they use the CERs for their compliance purposes. Ultimately, the liability would be turned to the Annex I Parties using the CERs against their own targets. While it is easy to consider that they would need to replace the CERs from a CCS project – or part of them - in case of any leaks from the reservoir, it is much less clear, however, how buyer liability would provide the right incentive for the proper remediation of the reservoirs, if the reservoir leaks, as the liability may be shared by several entities – all of which having no hand on the project management. Moreover, the incentive for monitoring would thus be likely insufficient, and the risk is that any leaks would simply go unnoticed.

The second option (b) seems to be more promising, but details must be further elaborated. One difficult issue is to assess the exact extent of required monitoring activities. A few decades after the end of the injection operations is very likely to be enough to demonstrate the permanence of a given storage site – in

any region sufficiently calm from a geological standpoint. Benson (2007) has suggested – but not in the context of CDM – that liability be progressively turned from a private-sector one to a public-sector one some time after the end of injection.

In the case of the CDM, it might be appropriate to distinguish two periods after the crediting period, as indicated on Figure 5 below. During the first few decades after injection has stopped, some monitoring and possibly some remediation would be necessary – and must be ensured. This would best be achieved if liability for any CO₂ release remains with the project developers during this period - and could potentially be backed by some e.g. “accredited” insurance company – in case the project developer goes bankrupt or simply cannot fulfil its commitment. In such a case it is likely that the insurer would exert hard pressure on the project participants or any succeeding entity with respect to remediation. Control or supervision by the DOEs might be necessary with respect to monitoring, however, as otherwise both the insurer and the insured party may share little interest in detecting any leaks (and associated reduction in CERs). The exact length of this monitoring period may depend on the characteristics of the projects, but also on the possible events. It could last, for example, for ten-twenty years after the most recent of these three events – the last injection, the last detected leak or the last remediation.

After the extended monitoring period, liability could be turned to the host country, whether or not it has committed to a quantified GHG emissions limit. The probability of “spontaneous” leaks from the reservoir would then be so low that the most important remaining risk may be that of an accidental man-made damage to the integrity of the subsurface storage. The host country, being able to decide who can use the subsurface and for what, would be best placed to prevent this from occurring. More sporadic monitoring may be appropriate during this time period.

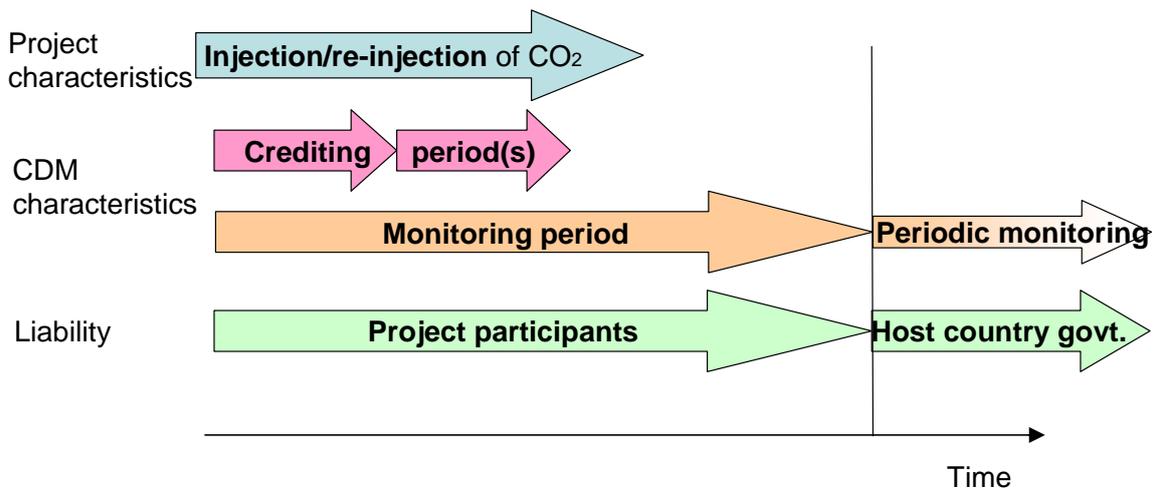
The third solution (c) would allow for case-by-case variations in liability. Thus, the host country could turn its liability to the project participants for some time after the crediting period. While perhaps simpler for the international community, this solution may be more demanding for the host country in terms of capacities and negotiating power with the project participants.

Under the second and third options (b and c), the liability would eventually fall on the host country. If at the time this country has accepted a binding constraint on its emissions any leaks from CCS storage will be traced in its emission inventories. If it has no binding constraint on its emissions, its liability would remain limited to compensating for the CO₂ leaked, through other CDM projects or through the international carbon markets – presumably giving the country similar incentives for proper remediation of the storage site⁷. One additional possibility might be to require that the project participants and/or the host country transfer other valid Kyoto units in a special cancellation accounts in case any leaks occurred.

In any case, for the purpose of securing long-term and safe accessibility of site-specific storage information, a new international database management and/or archival institution, possibly under the United Nations, may also be required, as suggested by Vajjhala et al. (2007).

⁷ A country with a non-binding target may fall within either regime depending on the circumstances. If it achieves its target, the leaks from a CCS CDM projects could simply be part of its GHG inventory. But if it does not achieve its target, the country should still be liable for these leaks.

Figure 5: Possible structure of crediting periods, monitoring period and liability



Source: Authors

Overall, agreed “modalities and procedures” for CDM CCS projects could include:

- **Site eligibility checks:** e.g. a requirement that the designated operational entity (DOE) checks the suitability of the proposed CO₂ storage site as a site with low risk of leaks. This would in turn require that agreed criteria against which the DOE can check the requirements exist. Such criteria still need to be developed, but could be done so e.g. following expert input to the CDM EB.
- **Sound monitoring requirements** during the project activity as well as after the crediting period. This would necessitate an agreement on setting detection limits for monitoring emissions, below which emissions – if any – are considered to be negligible and below detection (Benson, 2006). It might also need to stipulate possible continued oversight of monitoring (beyond the crediting period) by a DOE.;
- **A requirement for up-front liability agreements.** The form and scope of such an agreement could vary between particular projects, as well as between countries. There could also be different agreements developed for short- and long-term liability. Such agreements could include a shorter-term agreement between the project participants and an insurance company, and a longer-term agreement with the host country government, for the longer term (solution 5) or simply an agreement with the host country government (solution 6).

4.4 Complicated liability cases

As illustrated in Figure 4 above, there are some potential CCS CDM projects where the assessment of liability could be more complicated, or where the assessment of risk would be more demanding. This may include projects where there are several storage projects in a single reservoir (although there may be monitoring-related benefits associated with such project types), and projects in a reservoir with abandoned wells. Storage projects where the reservoir stretches across more than one jurisdiction, and enhanced coal-bed methane recovery projects where the coal seam is subsequently mined, raise even more complex liability and risk assessment issues. These complications are due to the number of entities and/or countries that may need to be liable for any release of CO₂ and to the possibly large variations in CO₂ release over time, in particular for ECBM projects where the coal seam is mined. It may be appropriate to limit CDM eligibility in a first phase with to relatively simple CCS CDM project types until more experience and knowledge has been gained. This would enable “learning by doing” while minimising environmental and economic risks associated with unanticipated CO₂ release from underground storage reservoirs.

5. Leakage

Leakage under the Clean Development Mechanism has been defined in the Marrakech Accords as “the net change of anthropogenic emissions by sources of greenhouse gases which occur outside the project boundary, and which is measurable and attributable to the CDM project activity.” If the project boundary includes capture but not storage then leaks from the storage site must be accounted for under the leakage provisions. If, however, the project boundaries include storage, any leaks must be clearly distinguished from the issue of leakage in the CDM sense.

An important aspect of leakage is linked to the energy requirements for capture and storage. Upstream emissions (say, in refineries) due to the additional energy consumption imposed by the energy penalty of capture and storage must be accounted for under the leakage provisions (while the emissions resulting from on-site combustion of the fossil fuels should be accounted for as project emissions).

IEA GHG (2007) notes that this will affect new power plant projects but not retrofit projects, as their fuel inputs would remain the same. This view can be challenged, however, as in case of retrofit projects the electrical output would be reduced, most likely creating a need for replacement and associated emissions, which should be accounted for as suggested by Haefeli et al. (2004).

Some difficult issues, however, arise when storage is linked to some enhanced hydrocarbon recovery (EHR). CO₂ emissions due to the CO₂ content of natural gas from enhanced oil recovery operations, when combusted beyond the project boundaries, can easily be assessed and accounted as leakage. It has been further argued, however, that EHR would lead to increased global emissions, beyond those resulting from the CO₂ content, due to increased oil and gas availability as fuels, and that this increase in emissions should be accounted for in the leakage provisions. For example, Michaelowa and Hayashi (2006) state that *“It is also important to account for CO₂ emissions increase due to enhanced production of fossil fuel, e.g. enhanced oil recovery (EOR), enhanced gas recovery (EGR), and enhanced coal bed methane recovery (ECBM). It should be recognised that the Weyburn EOR project in Canada has been essentially increasing CO₂ emissions as more oil is made available. Since it is not practical to account for such emissions within a project boundary, they must be taken into consideration as leakage”*. Miguez (2006) goes a step further in arguing that *“CCS under CDM would (...) create a positive incentive for further fossil fuel production (EOR) in developing countries contrary to [the] ultimate objective of the convention”*.

Other analysts consider this not necessary – without giving long explanations. For example, the IEA GHG (2007) considers that *“projects including the application of CO₂-EHR techniques do not need to account for leakage arising from additional hydrocarbon production”*.

Indeed, the assumption that CCS in association with EHR operations does increase the level of emissions outside the project boundary rests on a series of unproven assumptions, which are the following:

- These EHR-operations would not take place in the absence of the captured CO₂ stream. While this may be the case, in particular in the absence of any other possible fluid to play the same role, it is equally possible that similar operations would take place using CO₂ from another source, for example a natural reservoir, or more probably water;
- These EHR recovery operations increase global emissions; this would suppose that this additional amount of oil or gas made available is used in substitution of energy fuels with lower carbon content, such as nuclear or renewables – or gas in case of oil.
- Alternatively, one may argue that, without any substitution, EHR-operation simply add to the global supply, thus modifying the balance between supply and demand, reducing both extraction costs and oil or gas prices and finally increasing energy consumption – in a proportion equal to the increased amount of oil or gas made available through the project;

- These increased emissions, if any, take place in the host or another non Annex I country (for if the fuel were exported to an Annex I country that has ratified the Kyoto Protocol, and substitute there for non or lower carbon fossil fuel, this increase would remain under control of their Kyoto target and need not being accounted for under the provisions for leakage under the CDM).

However, it is equally likely that this oil or especially this gas comes in substitution of energy fuels with greater carbon content, such as coal or non-conventional oil resources⁸, in which case it further reduces global emissions instead of increasing them. And, as far as oil is concerned, the increase in global oil resources due to EHR operations in one single CCS CDM project activity will likely be too small to have any measurable effect on the global oil market. Possible net changes in emissions beyond the project boundary attributable to increased oil activity are remote and hardly measurable, all the more as even their mere sign is uncertain.

As natural gas does not constitute a truly global market, but rather regional markets, the burden of the proof might be more demanding than in case of oil. A comparison with how leakage in gas flaring reduction projects has been addressed might be helpful here. The gas is often directly sent to end-users. The Approved Baseline Methodology AMM009, which is based on the first gas flaring reduction project ever submitted to the CDM Executive Board, the Rang Dong project, states that:

“Project participants should assess:

- *Whether the supply of additional fuels by the project activity to the market will lead to additional fuel consumption, and*
- *Whether the fuels of the project activity substitute fuels with a lower carbon intensity (e.g. if electricity generation with the recovered gas substitutes renewable electricity generation).*

For this purpose the market of the products should be analyzed. If such leakage effects may result from the project activity, emission reductions should be adjusted for these leakage effects respectively in a conservative manner. Where the fuels of the project activity substitute fuels with higher carbon intensity, emission reductions should as a conservative assumption not be adjusted.”

In the case of the Rang Dong gas recovery CDM project, the impacts of recovered gas on the regional gas and other product (LPG, etc.) markets were considered small compared to the additional emission reductions resulting from the substitution of this gas to a mix of natural gas and diesel fuel from other sources. These additional emission reductions were not attributed to the project, but no other adjustment to the emission reductions was made either.

In some other gas flaring reduction projects, the gas is re-injected on current oil production through enhanced oil recovery. The comparison here with EHR operations associated with CCS is straightforward. However, *“it is unlikely that these increases in production are measurable and can be attributed to the project as leakage”* (The World Bank, 2005)

More generally, as the World Bank (2005) puts it, *“if the downstream emissions cannot be quantified, then changes in emissions, while outside of the project boundary, are not “measurable and attributable” and, therefore, cannot be counted as leakage. For example, if the gas captured goes into a pipeline that has multiple sources and multiple users, then the impact of the gas on end-use emissions is not quantifiable. This, therefore, could not be treated as leakage.”*

In sum, the view that EHR associated with CCS would increase global emissions and should thus prevent CCS to be considered possible CDM project activities seems groundless, although various cases might be distinguished. They are the following:

⁸ Oil from non-conventional resources has the same carbon content than other oil per unit of available energy, but has greater upstream emissions. Similarly, coal-to-liquid fuels have the same carbon content as petroleum products but much greater upstream emissions.

- In case of EOR it seems impossible to take account of possible additional emissions beyond the project boundary as they are not measurable and as it is equally probable that global downstream emissions are reduced, not increased, thanks to substitution effects.
- In case of ECBM or EGR, due to the regional/local nature of the markets adjustments to emission reductions to account for this type of leakage might be considered if enough information is available and shows a measurable increase in emissions attributable to the CDM project activity.

In both cases, the Methodological panel and the Executive Board are responsible for addressing leakage issues and would not require further guidance from the Conference of the Parties on these issues.

6. Conclusions

Carbon dioxide capture and storage (CCS) is a potentially promising means to address greenhouse gas emissions worldwide as geological formations can store large amounts of CO₂ safely for thousands of years. Geological CCS covers a huge range of potential project types. These vary in terms of the origins of the CO₂, the technology used to separate and transport CO₂, as well as storage type and cost. The technical potential of CCS activities in non-Annex I countries also varies by more than a factor of twenty depending on whether it is assessed in the short or long-term.

CO₂ re-emissions from CCS in geological formations cannot be excluded. However, the risk of such emissions by CCS activities is unlikely to be significant if storage sites are carefully selected and well-managed. Further, liability issues for CCS projects could differ substantially according to site-specific conditions.

CCS potential in the CDM

Carbon dioxide capture and storage technologies can help in mitigating greenhouse gas emissions worldwide. Developing countries, in particular, are likely to increase their use of fossil fuels in the next decades. There is a huge variation in the short and long-term potential for CCS activities in the CDM.

Except possibly for some enhanced hydrocarbon recovery (EHR) operations, CCS projects are unlikely to be undertaken in developing countries without some financial (or other) incentive. Therefore, providing incentives for increased CCS – e.g. via the CDM or any future mechanism – would help encourage greater take-up of CCS projects.

As they might be large projects, CCS projects are likely to have relatively low unit transaction costs in the CDM. While this may offer them an advantage over smaller CDM projects, this advantage will not offset their high investment and operating cost – except maybe for some EOR CCS projects. Furthermore, the long lead time of CCS projects means that the risk of CCS projects crowding out other project types is slight – particularly in the short term.

Leaks, permanence and project boundaries

The importance of project emissions from CCS activities varies depending on the type of activity and site-specific conditions, as well as on the time-scale considered. Project emissions can include emissions from fossil fuel combustion, as well as potential leaks of the CO₂ stored. Some re-emission of CO₂ is likely in the short term for certain CCS activities, such as enhanced oil and gas recovery, through CO₂ mixed with the gas or oil produced. However, such re-emissions may be separated and recycled. Thus, the risk of long-term leaks could be small from all CCS project types – as long as the reservoir is well chosen and appropriately managed.

Potential reservoirs for geological storage often extend over very large areas. Defining broad project boundaries beyond the injection sites would ensure that any seepage is duly monitored and accounted for

as project emissions. (Seepage beyond the project boundaries should be accounted for as leakage. However, it runs the risk of simply being unnoticed.)

Good site selection and appropriate monitoring and management during and after the injection of CO₂ are key pre-requisites for CCS projects, and their verification must be part of the approval process of CCS projects under the CDM. Any observed leaks, as well as emissions associated with the project from separation, capture, transport and storage – including emissions caused by separating and re-injecting any CO₂ that has been re-emitted during the operation of an EHR project, should be accounted as project emissions. Significant long-term CO₂ leaks are unlikely in most situations over the long-term, given an appropriate and well-managed reservoir.

If CCS projects are allowed under the CDM, adequate incentives will be needed to ensure that project participants monitor the CO₂ storage site for several decades after injection has stopped, and that proper remediation is brought if any leak is detected. If the appropriate incentives are in place, negotiators may consider that the risks of a major release of CO₂ are so small that CCS projects can generate “permanent” CDM credits. The assessment of an appropriate crediting period length, as well as the optimal period of time for monitoring the storage sites after the injection has stopped, would need to be further considered.

Liability issues

During the project’s operation (which could extend beyond its CDM crediting period), full buyer liability could ensure compensation for leaks but may not provide the right framework for site remediation, which seems preferable. A more promising option may be that liability rest with the CCS project participants. This will provide project participants with incentives to ensure that leaks are minimised and that any re-emission of CO₂ is recycled and re-injected (or alternatively, is offset against the net GHG mitigation effect of the project). As the ‘monitoring period’ for a CCS CDM project may extend beyond its crediting period, the project developers could be requested to take out some form of insurance covering their liability for some time after the crediting period, to ensure proper monitoring and management of the reservoirs (or compensation) even if the project participants themselves fail or disappear. Supervision of such monitoring (past the end of the crediting period) by the Designated Operational Entities may also be required. In the longer term, liability could be turned to the host country government, who is best placed to prevent accidental CO₂ release from inadvertent anthropogenic action damaging the reservoir. An alternative option would be to place “default” liability after the crediting period with the host country, which could (or not) transfer that liability to the project participants on a case-by-case and country-by-country basis.

In the first instance, projects could be made eligible under the CDM where sufficient knowledge can ensure that risk of leaks is very low and where liability is easy to assess (e.g. projects where the reservoir is contained within one jurisdiction).

Project types with risks more difficult to assess with current knowledge (e.g. coal bed methane), and complex liability cases could be examined on a case-by-case basis when they arise. The diversity of conceivable complexities combined with the likely scarcity of such cases may not warrant the effort of developing up-front a framework to allocate liability for these cases.

Leakage

Leakage from CDM CCS projects could occur if the project results in increased emissions outside the project boundary. This issue has been raised particularly in the context of using CDM CCS projects to increase hydrocarbon production. However, there is little evidence that enhanced oil recovery operations would create leakage. Nevertheless, this possibility must be assessed on a case-by-case basis for the other EHR operations.

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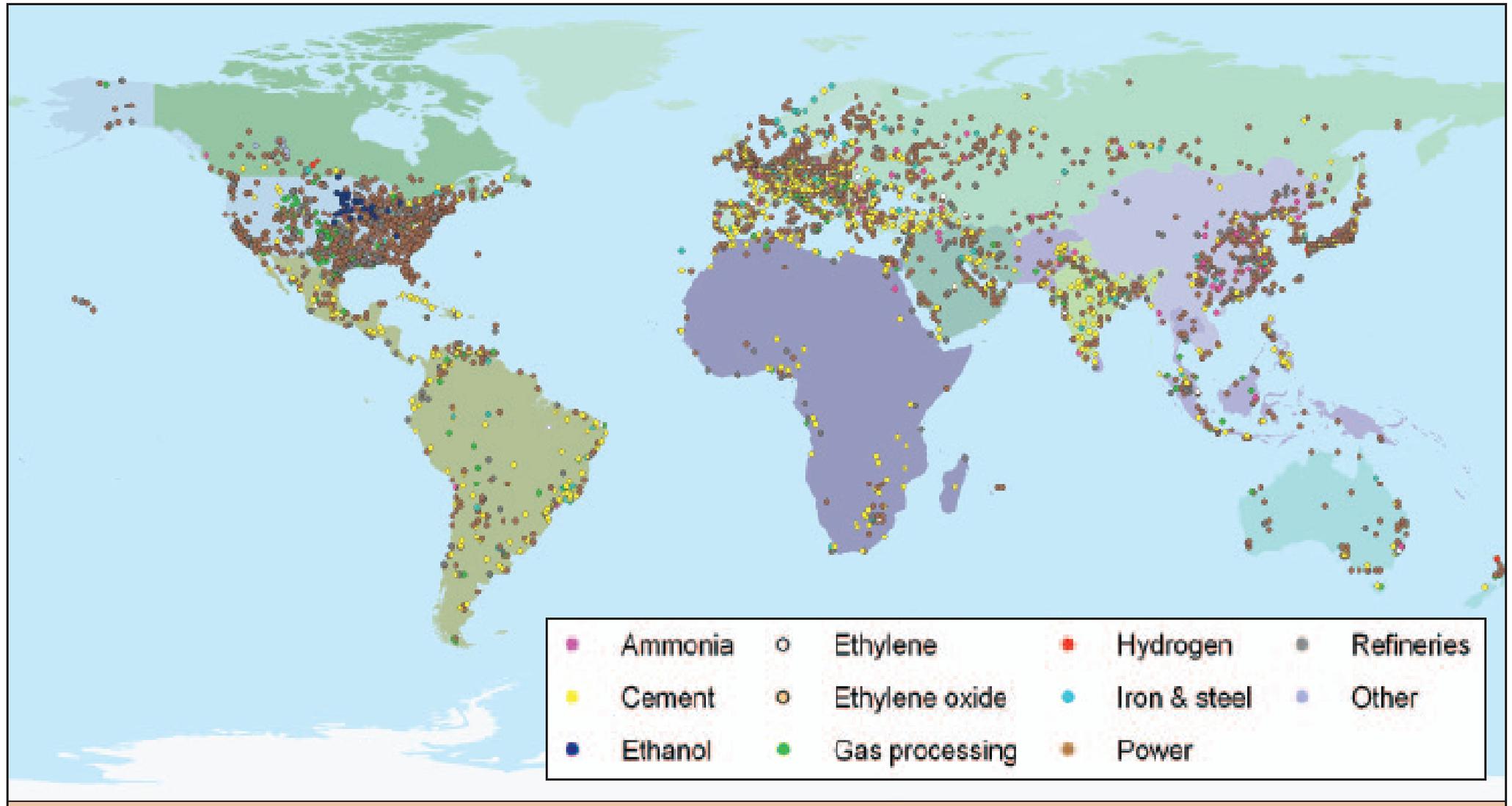
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Glossary

ACT	Accelerated Technology scenarios in the ETP
CBM	Coal Bed Methane
CCS	Carbon dioxide Capture and Storage
CDM	Clean Development Mechanism
COP	Conference of the Parties (to the UNFCCC)
DOE	Designated Operational Entities
EB	Executive Board (of the CDM)
ECBR	Enhanced Coal Bed Recovery
EGR	Enhanced Gas Recovery
EHR	Enhanced Hydrocarbon Recovery
EOR	Enhanced Oil Recovery
ETP	(2006 IEA's) Energy Technology Perspectives (publication)
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IPCC SR	(2005) IPCC Special Report (on CCS)
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
Map	ACT Map scenario: the most comprehensive ACT scenario
MOP	Meeting of the Parties (to the Kyoto Protocol)
NG	Natural Gas
Tech Plus	Scenario in the ETP with the most favourable hypotheses

Figure 6: Localisation of the world's largest emitting facilities



Source: Dooley et al. 2006