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# Air pollution impacts from carbon capture and storage (CCS)

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# Executive summary

## Background

Carbon Capture and Storage (CCS) consists of the capture of carbon dioxide ($CO_2$) from power plants and/or $CO_2$-intensive industries such as refineries, cement, iron and steel, its subsequent transport to a storage site, and finally its injection into a suitable underground geological formation for the purposes of permanent storage. It is considered to be one of the medium term 'bridging technologies' in the portfolio of available mitigation actions for stabilising concentrations of atmospheric $CO_2$, the main greenhouse gas (GHG).

Within the European Union (EU), the European Commission's 2011 communication 'A Roadmap for moving to a competitive low carbon economy in 2050' lays out a plan for the EU to meet a long-term target of reducing domestic GHG emissions by 80–95 % by 2050. As well as a high use of renewable energy, the implementation of CCS technologies in both the power and industry sectors is foreseen. The deployment of CCS technologies thus is assumed to play a central role in the future decarbonisation of the European power sector and within industry, and constitutes a key technology to achieve the required GHG reductions by 2050 in a cost-effective way.

A future implementation of CCS within Europe, however, needs to be seen within the context of the wider discussions concerning how Europe may best move toward a future low-energy, resource-efficient economy. Efforts to improve energy efficiency are for example one of the core planks of the EU's Europe 2020 growth strategy and the European Commission's recent Roadmap to a Resource Efficient Europe, as it is considered one of the most cost-effective methods of achieving Europe's long-term energy and climate goals. Improving energy efficiency also helps address several of the main energy challenges Europe presently faces, i.e. climate change (by reducing emissions of GHGs), the increasing dependence on imported energy, and the need for competitive and sustainable energy sources to ensure access to affordable, secure energy. While CCS is therefore regarded as one of the technological advances that may help the EU achieve its ambitions to decarbonise the electricity-generating and industrial sectors by 2050, its implementation is considered a bridging technology and in itself should not introduce barriers or delays to the EU's overarching objective of moving toward a lower-energy and more resource-efficient economy. The technology should not, for example, serve as an incentive to increase the number of fossil fuel power plants.

In terms of emissions of pollutants, it is well known that efforts to control emissions of GHGs or air pollutants in isolation can have either synergistic or antagonistic effects on emissions of the other pollutant group, in turn leading to additional benefits or disadvantages occurring. In the case of CCS, the use of $CO_2$ capture technology in power plants leads to a general **energy penalty** varying in the order of 15–25 % depending on the type of capture technology applied. This energy penalty, which offsets the positive effects of $CO_2$ sequestration, requires the additional consumption of fuel, and consequently can result in additional 'direct' emissions (GHG and air pollutant emissions associated with power generation, $CO_2$ capture and compression, transport and storage) and 'indirect' emissions, including for example the additional fuel production and transportation required. Offsetting the negative consequences of the energy penalty is the positive direct effect of CCS technology, which is the (substantial) potential reduction of $CO_2$ emissions. It is thus important that the potential interactions between CCS technology implementation and air quality are well understood as plans for a widespread implementation of this technology mature.

## Report objectives

This report comprises two separate complementary parts that address the links between CCS implementation and its subsequent impacts on GHG and air pollutant emissions on a life-cycle basis:

Part A discusses and presents key findings from the latest literature, focusing upon the potential air pollution impacts across the CCS life-cycle arising from the implementation of the main foreseen technologies. Both negative and positive impacts on air quality are presently suggested in the literature — the basis of scientific knowledge on these issues is rapidly advancing.

Part B comprises a case study that quantifies and highlights the range of GHG and air pollutant life-cycle emissions that could occur by 2050 under a low-carbon pathway should CCS be implemented in power plants across the European Union under various hypothetical scenarios. A particular focus of the study was to quantify the main life-cycle emissions of the air pollutants taking into account the latest knowledge on air pollutant emission factors and life-cycle aspects of the CCS life-cycle as described in Part A of the report.

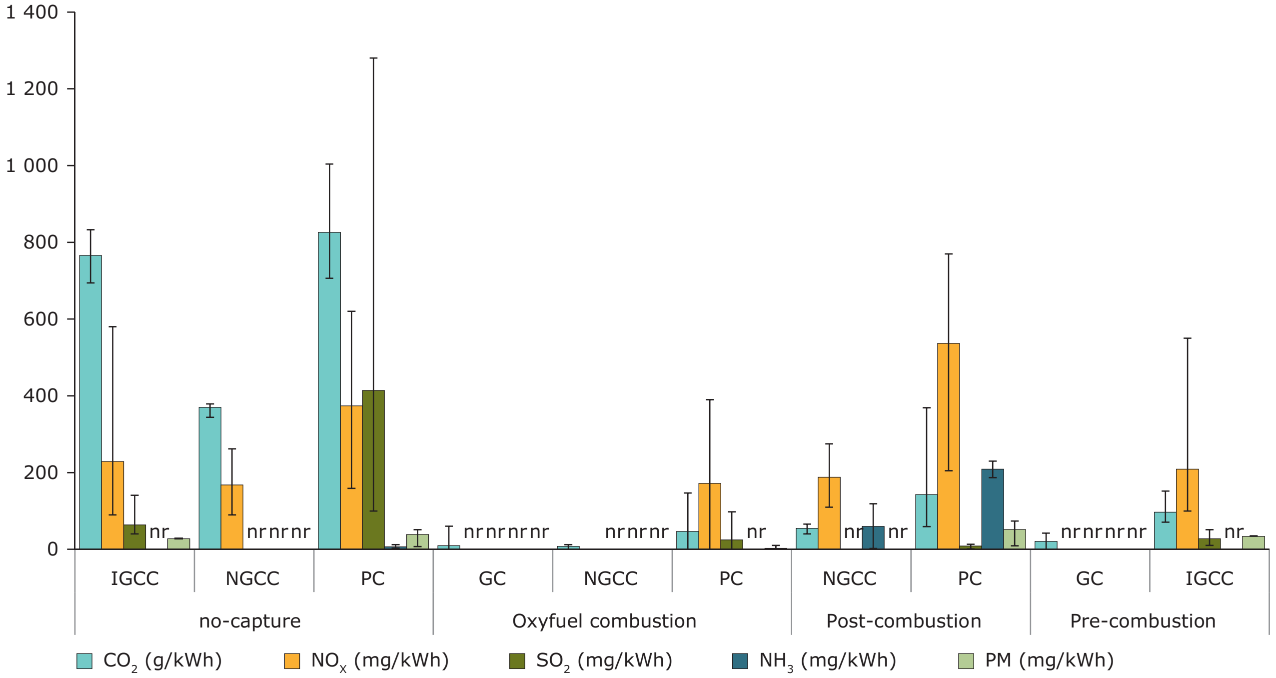
Pollutants considered in the report were the main GHGs $CO_2$, methane ($CH_4$) and nitrous oxide ($N_2O$) and the main air pollutants with potential to harm human health and/or the environment — nitrogen oxides ($NO_X$), sulphur dioxide ($SO_2$), ammonia ($NH_3$), non-methane volatile organic compounds (NMVOCs) and particulate matter ($PM_{10}$).

## Potential impacts of CCS implementation on air pollutant emissions — key findings

The amount of direct air pollutant emissions per unit electricity produced at future industrial facilities equipped with CCS will depend to a large extent on the specific type of capture technology employed. Three potential $CO_2$ capture technologies were evaluated for which demonstration scale plants are expected to be in operation by 2020 — post-combustion, pre-combustion and oxyfuel combustion.

Overall, and depending upon the type of $CO_2$ capture technology implemented, synergies and trade-offs are expected to occur with respect to the emissions of the main air pollutants $NO_X$, $NH_3$, $SO_2$ and PM. For the three capture technologies evaluated, emissions of $NO_X$, $SO_2$ and PM will

**Figure ES.1 Emission rates of various pollutants for different conversion technologies with and without $CO_2$ capture**



**Notes:** The indicated values are based on various fuel specifications and are dependent on the configuration and performance of the power plant and $CO_2$ capture process.
'nr' = not reported; IGCC = Integrated Gasification Combined Cycle; NGCC = Natural Gas Combined Cycle; PC = Pulverised Coal; GC = Gas Cycle.

**Source:** Horssen et al., 2009; Koornneef et al., 2010, 2011.

reduce or remain equal per unit of primary energy input, compared to emissions at facilities without $CO_2$ capture (Figure ES.1). However, the energy penalty which occurs with CCS operation, and the subsequent additional input of fuel required, may mean that for some technologies and pollutants a net increase of emissions per kilowatt-hour (kWh) output will result. The largest increase is found for the emissions of $NO_X$ and $NH_3$; the largest decrease is expected for $SO_2$ emissions. There is at present little available quantitative information on the effect of CCS capture technologies on NMVOC emissions.

In addition to the direct emissions at CCS-equipped facilities, a conclusion of the review is that the life-cycle emissions from the CCS chain, particularly the additional indirect emissions from fuel production and transportation, may also be significant in some instances. The magnitude of the indirect emissions, for all pollutants, can exceed that of the direct emissions in certain cases. Emissions from other stages of the CCS life-cycle, such as solvent production (for $CO_2$ capture) and its disposal are considered of less significance, as well as the third order emissions from the manufacturing of infrastructure.

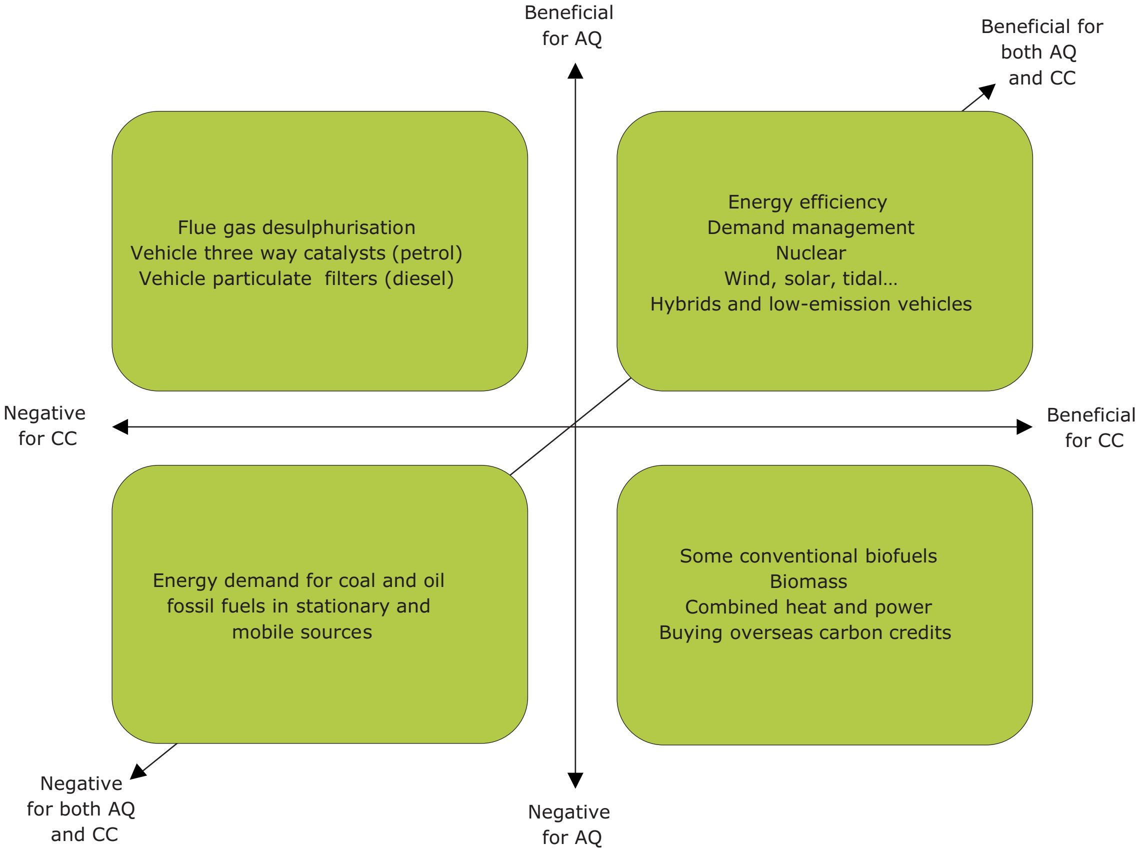
In considering both direct and indirect emissions together, key findings of the review are:

- increases of direct emissions of $NO_X$ and PM are foreseen to be in the order of the fuel penalty for CCS operation, i.e. the emissions are broadly proportional to the amount of additional fuel combusted;
- direct $SO_2$ emissions tend to decrease since its removal is a technical requirement for $CO_2$ capture to take place to avoid potential reaction with amine-based solvents;
- direct $NH_3$ emissions can increase significantly due to the assumed degradation of the amine-based solvent used in post-combustion capture technologies;
- indirect emissions can be significant in magnitude, and exceed the direct emissions in most cases for all pollutants;
- the extraction and transport of additional coal contributes significantly to the indirect emissions for coal-based $CO_2$ capture technologies, with other indirect sources of emissions including the transport and storage of $CO_2$ contributing around 10–12 % to the total;
- power generation using natural gas has lower emissions compared to coal based power generation, directly as well as indirectly. The switching from coal- to gas-fired power generation can have larger impacts on the direct and indirect emissions of air pollutants, depending on the technologies involved, than the application of $CO_2$ capture technologies. However, in itself, a shift to gas most likely will not be sufficient for the EU to achieve its 2050 goal of reducing domestic GHG emissions by 80–95 % and other issues, including energy security, relative costs, etc., must be taken into consideration.

It should also be noted that much of the information presently available in the literature concerning emissions of air pollutants for energy conversion technologies with $CO_2$ capture is most often based on assumptions and not on actual measurements. As the future $CO_2$ capture technologies move from laboratory or pilot phase to full-scale implementation, a proper quantitative analysis of emissions and environmental performance will be required. At present, much of the available information is merely qualitative in nature which limits the robustness of future studies in this field.

A sound understanding of these synergies and trade-offs between the air pollutants and GHGs is of course needed to properly inform policymakers. More generally, it is well established that efforts to control emissions of one group of pollutants in isolation can have either synergistic or sometimes antagonistic effects on emissions of other pollutants, in turn leading to additional benefits or disadvantages. Examples of these types of trade-offs that can occur between the traditional air pollutants and GHGs are shown in Figure ES.2. Based on the findings of the review, CCS technology may be considered to fall into the upper-right quadrant shown in the figure, i.e. the technology is considered to be generally beneficial both in terms of air quality and climate change. However, the potential increase in emissions of certain air pollutants (e.g. $NH_3$ and also $NO_X$ and PM) rather means that CCS would not be ranked very high on the 'beneficial for air quality' axis.

**Figure ES.2 Air quality (AQ) and climate change (CC) synergies and trade-offs**



**Source:** Adapted from Defra, 2010.

## A case study — air pollutant emissions occurring under a future CCS implementation scenario in Europe

The range of potential GHG and air pollutant life-cycle emissions that could occur in the year 2050 should CCS be widely implemented across the EU under a future low-carbon scenario was assessed, taking into account the latest knowledge on air pollutant emission factors and life-cycle aspects of the CCS chain.

Life-cycle emissions for four different hypothetical scenarios of CCS implementation to power stations in 2050 were determined (¹):

- a scenario without any CCS implementation;
- a scenario with all coal-fired power plants implementing CCS, where the additional coal (energy penalty) is mined in Europe;
- a scenario with all coal-fired power plants implementing CCS, where the additional coal (energy penalty) is mined in Australia and transported to Europe by sea;
- a scenario with CCS implemented on all coal-, natural gas- and biomass-fired power plants where the additional fuel (energy penalty) comes from Europe.

These scenarios were selected to assess the importance of life-cycle emissions with deliberately contrasting assumptions concerning the source (and hence transport requirements) of the additional required fuel, and across the different fuel types to which CCS may potentially be applicable. The third scenario involving coal transport from Australia was, for example, selected to maximise the potential additional emissions arising from the extra transport of fuel required within the CCS life-cycle. The deployment of CCS in industrial applications has not been considered.

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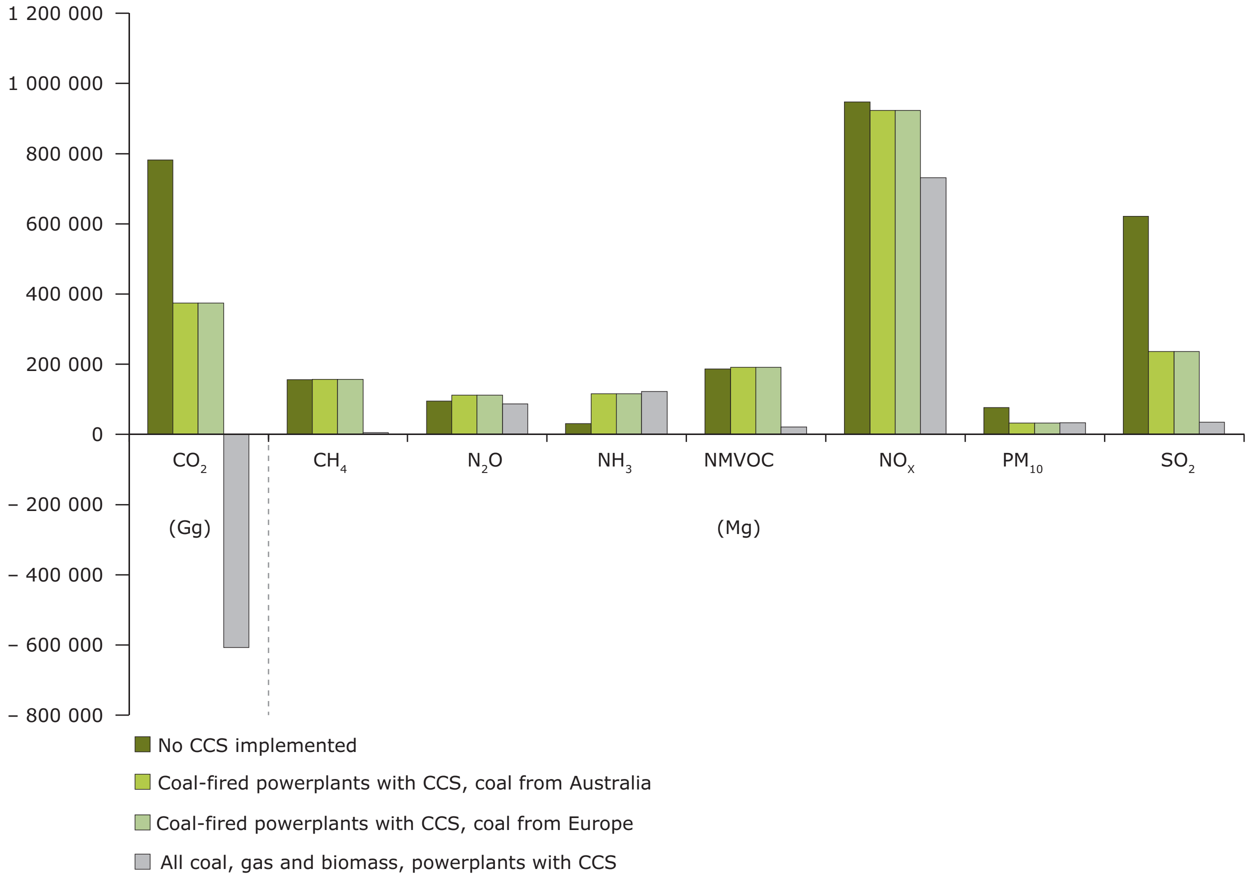
(¹) The CCS scenarios for 2050 were calculated using an energy baseline to 2050 constructed from the PRIMES EU energy forecast to 2030 and extrapolated to 2050 using a low carbon climate mitigation scenario from the TIMER/IMAGE models.

Figure ES.3 shows the modelled 'direct' emissions of the various pollutants that occur from the fuel combustion for power generation that occur in 2050 under the different scenarios. The additional 'indirect' emissions from the mining and the transport of the additional coal, needed because of the CCS fuel penalty, are calculated and included in the overall life-cycle results shown in Figure ES.4.

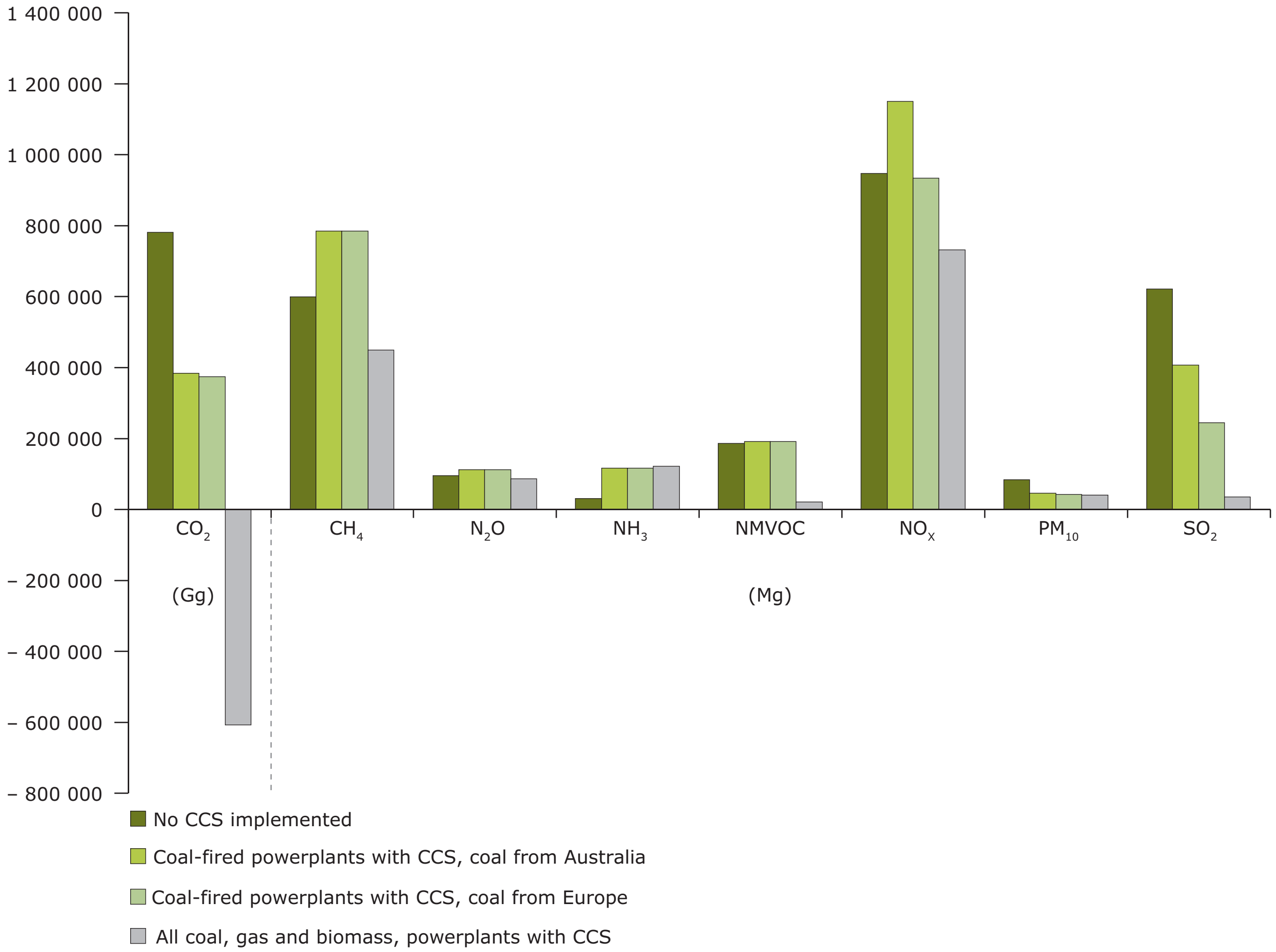
The life-cycle emissions of both **$CO_2$ and $SO_2$** are predicted to decline considerably compared to the scenario where no implementation of CCS occurs. Implementation of CCS to all coal-, natural gas- and biomass-fuelled power plants also leads to $CO_2$ emissions becoming 'negative' in 2050 under this extreme scenario. This is due to the significant increase in biomass use between 2040 and 2050 according to the energy scenarios upon which the results are based. The capture of $CO_2$ emissions from biomass combustion leads to a net removal of $CO_2$ from the atmosphere. This of course necessitates the assumption that all biomass is harvested sustainably, and no net changes to carbon stock occur in the European or international forests and agriculture sectors. A main reason for the reduction in $SO_2$ is the requirement within CCS processes to also remove $SO_2$ from the flue gas prior to the capture and compression of $CO_2$. This avoids both poisoning the $CO_2$ capture solvent and potential system corrosion. The transport of additional coal from Australia (or indeed any other location) will lead to an increase in $SO_2$ emissions from the international shipping involved to Europe. However, overall, total life-cycle $SO_2$ emissions will decrease as the reduction in direct emissions is larger than the increase due to the additional shipping.

**Figure ES.3 Direct emissions from power generation in 2050 under the different CCS implementation scenarios**



**Note:** Units in megagrams (Mg), except for $CO_2$ which is expressed in gigagrams (Gg).

**Figure ES.4 Direct and indirect emissions (incl. from the mining and transport of fuel) for the power generation sector in 2050 under the different CCS implementation scenarios**



**Note:** Units in Mg, except for $CO_2$ which is expressed in Gg.

The overall **$PM_{10}$ emissions** for the EU are also expected to decrease, by around 50 %. The decrease is caused by the low emission factors for CCS-equipped power plants. Low $PM_{10}$ emissions are required for the $CO_2$ capture process in order not to contaminate the capture solvent. The fuel penalty, because of the additional energy needed for the capture process, will lead to additional $PM_{10}$ emissions during the coal mining and transport stages of the CCS life-cycle, but overall these increases are smaller in magnitude than the reduction achieved at the CCS equipped power plants.

The **NMVOC** and **$NO_X$ emissions** from power plants remain more or less the same after the introduction of CCS, but decrease under the scenario of CCS implementation to all coal-, natural gas- and biomass-fired power plants. On a life-cycle basis, the overall $NO_X$ emissions are foreseen to increase under the scenario where additional coal is sourced from Australia due to increased emissions from shipping.

Ammonia **$NH_3$** is the only pollutant for which a significant increase in direct emissions compared to the non-CCS scenario is foreseen to occur. The increase is predicted due to the degradation of the amine-based solvents that are assumed in the current literature. Nevertheless, compared to the present-day level of emissions of $NH_3$ from the EU agricultural sector (around 3.5 million Mg (tonnes), or 94 % of the EU's total emissions), the magnitude of the modelled $NH_3$ increase is relatively small. There is also ongoing research into the environmental fate of amine-based solvents (and their degradation products, including nitrosamines) following for example a release from CCS capture processes. Nitrosamines and other amine-based compounds exhibit various toxic effects in the environment, and are potential carcinogens, may contaminate drinking water and have adverse effects on aquatic organisms. New solvents are under development, with potential to show less degradation.

In conclusion, it is clear that for the EU as a whole, and for most Member States, the overall co-benefits of the introduction of CCS in terms of reduced emissions of air pollutants could be substantial. There do remain, however, large uncertainties as to the extent to which CCS technologies will actually be implemented in all European countries over the coming decades. In addition, as described earlier, the implementation of CCS should be seen as a bridging technology and in itself should not introduce barriers or delays toward the EU's objectives of moving toward a lower-energy and more resource-efficient future economy.

# 1 Introduction

CCS is considered one of the medium-term 'bridging' technologies in the portfolio of mitigation actions for helping to stabilise atmospheric concentrations of $CO_2$, the main GHG. CCS itself is a term that is commonly applied to a number of different technologies and processes that reduce the $CO_2$ emissions from human activities.

In 2009, the EU agreed to a bundle of specific measures, the so-called EU 'climate and energy' package, to help implement the EU's '20-20-20' climate and energy targets (2). One of the pieces of legislation adopted as part of the package was Directive 2009/31/EC on the geological storage of $CO_2$, the CCS Directive, which establishes a legal framework for the environmentally safe geological storage of $CO_2$ within the EU (European Union, 2009). The directive covers $CO_2$ storage within geological formations in the EU, and lays down requirements covering the entire lifetime of a storage site. The Directive's purpose is to ensure the permanent containment of $CO_2$ in such a way as to prevent and, where this is not possible, eliminate as far as possible negative effects and any risk to the environment and human health. Other specific aspects are addressed to prevent adverse effects on the security of the transport network or storage site, and to clarify how CCS shall be considered within regulatory frameworks. Several guidance documents to accompany the CCS Directive have also been published (3).

The European Commission has recently also published the communication 'A Roadmap for moving to a competitive low carbon economy in 2050' (European Commission, 2011a). The 2050 Roadmap lays out a plan for the European Union to meet a long-term target of reducing domestic GHG emissions by 80–95 % by 2050. As well as a high use of renewable energy, the implementation of CCS technologies into both the power and industry sectors is foreseen. The deployment of CCS technologies thus is assumed to play a central role in the future decarbonisation of the European power sector and within industry, and constitutes a key technology to achieve the required GHG reductions by 2050 in a cost-effective way.

A future implementation of CCS within Europe, however, comprises just one part of the present debate concerning the future direction of European energy policy. It needs also to be considered within the context of the wider discussions concerning how Europe may best move toward a low-energy, resource-efficient economy with a high share of renewables, etc. Efforts to improve energy efficiency are one of the core planks of the EU's Europe 2020 growth strategy and the European Commission's recent Roadmap to a Resource Efficient Europe (European Commission, 2011b), as it is considered one of the most cost-effective methods of achieving Europe's long-term energy and climate goals. Improving energy efficiency helps address several of the main energy challenges Europe presently faces, i.e. climate change (through reducing emissions of GHGs), the increasing dependence on imported energy, and the need for competitive and sustainable energy sources to ensure access to affordable, secure energy (European Commission, 2011c).

While CCS can therefore be regarded as one of the technological advances that may help the EU achieve its ambitions to decarbonise the electricity-generating and industrial sectors by 2050, at the same time, it should be seen as a bridging technology and should not introduce barriers or delays to the EU's overarching objective of moving toward a lower-energy and more resource-efficient economy The technology should not, for example, serve as an incentive to increase the number of fossil fuel power plants (European Union, 2009). More detailed information on the foreseen role of CCS within the framework of EU policy may be found on the website of the European Commission (4).

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(2) The EU's '20-20-20' climate and energy targets to be met by the year 2020 comprise:
1. a reduction in EU greenhouse gas emissions of at least 20 % below 1990 levels;
2. twenty per cent of EU energy consumption to come from renewable resources;
3. a 20 % reduction in primary energy use compared with projected levels, to be achieved by improving energy efficiency.

(3) See http://ec.europa.eu/clima/policies/lowcarbon/ccs/implementation/index_en.htm.

(4) See http://ec.europa.eu/clima/policies/lowcarbon/ccs_en.htm.

## 1.1 CCS and air pollution — links between greenhouse gas and air pollutant policies

Anthropogenic emissions of GHGs and air pollutants occur from the same types of emission sources, e.g. industrial combustion facilities, vehicle exhausts, agriculture, etc. There are therefore many important interactions between the two thematic areas of climate change and air pollution, not only with respect to their sharing the same sources of pollution but also in terms of the various policy measures undertaken to reduce or mitigate the respective emissions. Often, however, policy development and the subsequent development and implementation of legislation tends to address *either* air pollutants *or* GHGs. Such instances can occur because at the national, regional and/or local scales, specific actions are deemed necessary in order to help achieve explicit targets for air quality or climate change that themselves have been agreed at a higher level, e.g. under national, EU and/or international legislation.

Efforts to control emissions of one group of pollutants in isolation can have either synergistic or sometimes antagonistic effects on emissions of other pollutants, in turn leading to additional benefits or disadvantages. Simple examples of these types of links that can occur between the traditional air pollutants and GHGs include (EEA, 2010) (see also Figure 1.1):

- energy efficiency improvements and other measures that encourage reducing fossil fuel combustion provide general benefits by also reducing emissions of air pollutants;
- the effect of renewable energy sources may be positive — the availability of wind and solar energy — or negative — the increased use of biofuels, while nominally $CO_2$ 'neutral', could lead to increased emissions of other air pollutants over a life-cycle basis;
- flue gas desulphurisation (FGD) at industrial facilities requires extra energy, leading to additional $CO_2$ emissions, as do some technologies for reducing vehicle emissions of air pollutants, etc.

It is important to identify, based on the best available science and knowledge, those instances where planned policies and measures may create additional benefits or disadvantages. In such evaluations, consideration of life-cycle aspects (⁵) can be invaluable in highlighting the intended or unintended consequences of any policy choice. For example, in fossil fuel-based power generation systems (both with and without CCS), emissions of air pollutants result not only from the direct combustion of the fuel at the industrial facility itself, but also indirectly from upstream and downstream processes that can occur at different points along a life-cycle path.

Thus, any policy proposal that will affect processes at a given industrial facility should be informed by knowledge of the potential changes that will also occur along the life-cycle path (in addition to the changes that will occur at the facility itself). A sound understanding of the synergies and trade-offs between air quality and climate change measures is needed to properly inform policymakers. Emissions of $CO_2$ and air pollutants occurring from CCS-equipped facilities are generally considered to fall into the upper-right quadrant shown in Figure 1.1, i.e. the technology is considered to be beneficial both in terms of air quality and climate change. However, the situation is often rather more complex than can be conveyed by such a simple categorisation, and more so when life-cycle emissions are taken into account.

Overall, however, implementation of many policies that address climate change mitigation do lead to positive outcomes for air pollution, and hence can lead to considerable additional benefits for human health and/or the environment. This is clearly seen for the European Union's 'climate and energy' package adopted in 2009. The costs of the package are estimated to be EUR 120 billion per year from 2020 (European Commission, 2008). If the policies and measures for meeting the package's targets are implemented, the costs of implementing future air pollution policy in Europe may be reduced by up to EUR 16 billion per year. Factoring air quality into decisions about how to reach climate change targets, and vice versa, thus can result in policy situations with greater benefits to society.

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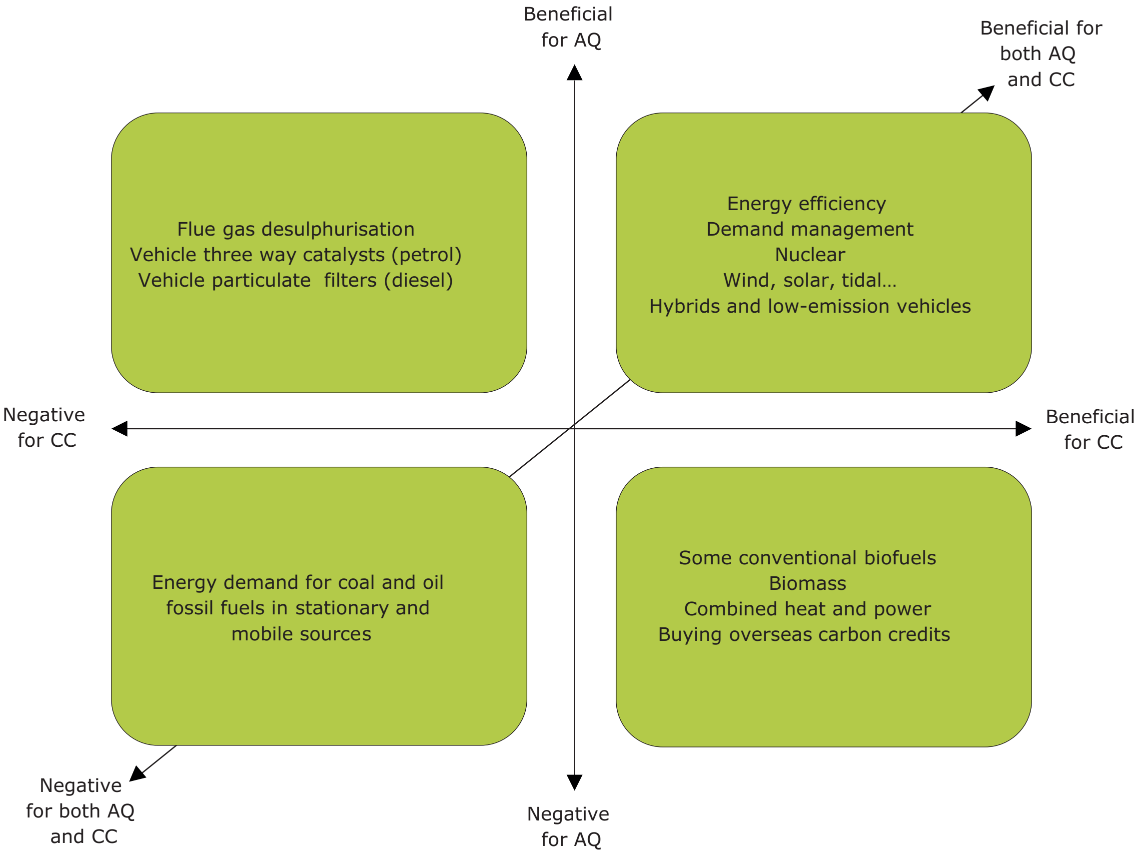
(⁵) Life-cycle Assessment (LCA) is a commonly used framework to assess the environmental impacts associated with a given product, process or service across the design, production and disposal stages.

**Figure 1.1 Air quality (AQ) and climate change (CC) synergies and trade-offs**



**Source:** Adapted from Defra, 2010.

## 1.2 Summary of the main CCS processes (capture, transport and storage) and life-cycle emission sources

As noted earlier, CCS is a term that is commonly used to encompass a range of different technological processes and steps. Three separate stages are commonly identified within a typical CCS process.

1. *$CO_2$ capture*
   CCS involves the use of technologies to separate and compress the $CO_2$ produced in industrial and energy-related sources. This process is referred to as $CO_2$ capture. $CO_2$ needs to be separated and compressed because it is not possible to simply take all of the flue gas from a power plant and store it underground. The flue gas has a low $CO_2$ content, typically 3–15 % by volume, with the remainder comprised of nitrogen, steam and small amounts of particles, and other pollutants.

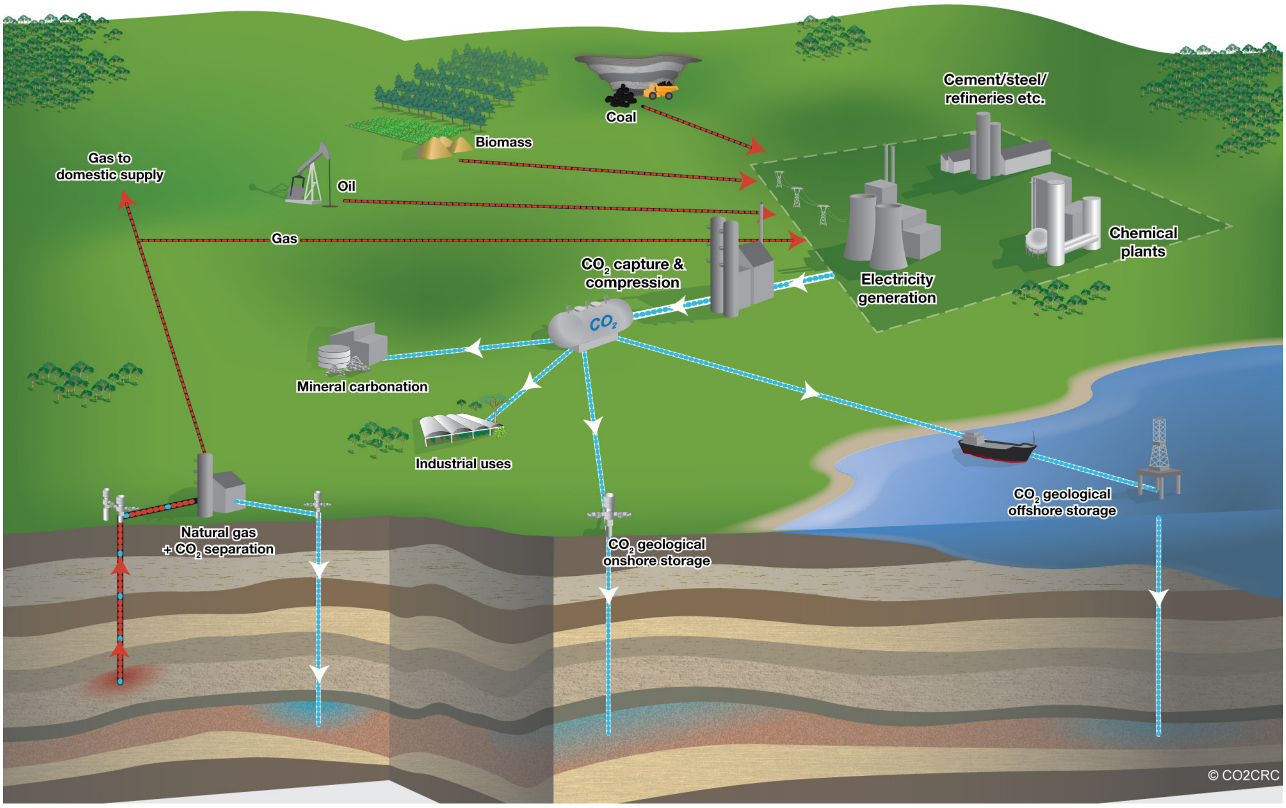
2. *$CO_2$ transport*
   The transport of $CO_2$ to a suitable storage location.

3. *$CO_2$ storage*
   The transported $CO_2$ has to be stored away from the atmosphere for a long period. The rationale behind CCS as a climate change mitigation measure is that $CO_2$ is not emitted to the atmosphere but can be stored safely and effectively permanently underground.

Figure 1.2 presents an overview of possible CCS systems and shows the three main components of the CCS process: capture, transport and storage of $CO_2$. Elements of all three components (i.e. $CO_2$ capture, transport and storage) occur in industrial operations today, although mostly not for the explicit purpose of $CO_2$ storage and not presently on coal-fired power plants at the scale needed for wide-scale mitigation of $CO_2$ emissions (IPCC, 2005).

The addition of $CO_2$ capture technology to power plants leads to a general **energy penalty** which varies depending on the capture technology applied. This energy penalty requires additional consumption of fuel and consequently results in additional direct and indirect emissions. Offsetting

**Figure 1.2** Schematic diagram of possible CCS systems showing examples of sources for which CCS technologies might be relevant, transport of $CO_2$ and storage options



**Source:** CO2CRC.

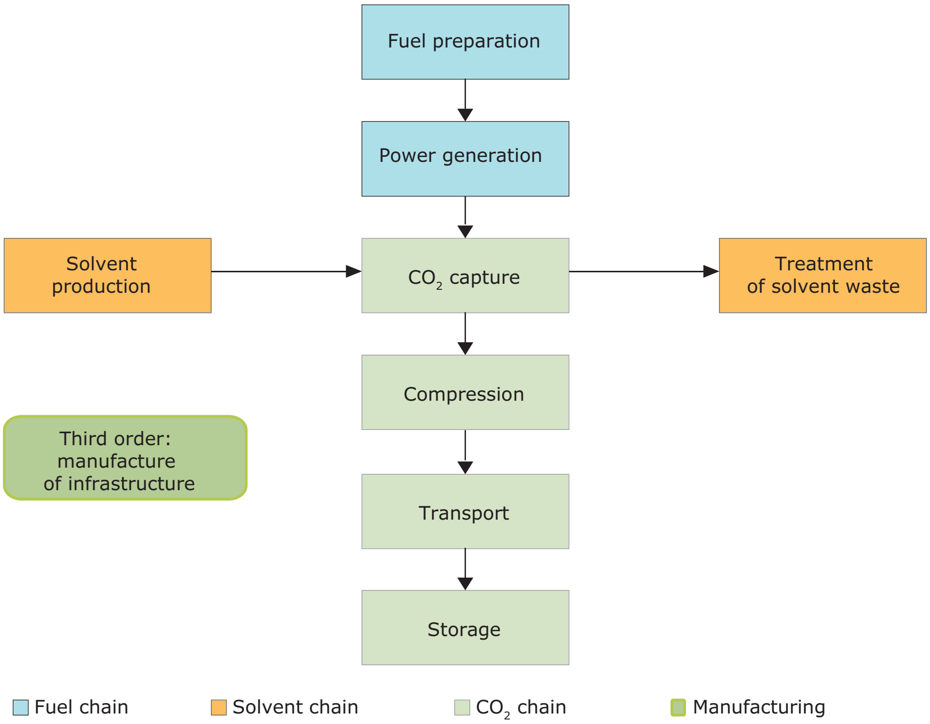
the energy penalty is the positive, direct effect of CCS technology, which is the (substantial) potential reduction of $CO_2$ emissions. It should further be noted that while $CO_2$ capturing from the power plant has the potential to reduce direct $CO_2$ emissions from the power plant itself, the indirect $CO_2$ emissions (and of course air pollutant emissions) upstream and downstream of the CCS facility cannot be captured, including the life-cycle emissions associated with the $CO_2$ transport and storage processes.

It is therefore clear that in assessing the potential impacts that CCS technologies may have on emissions of air pollutions, an integrated life-cycle type approach is needed in order that the emissions occurring away from the actual physical site of CCS capture can also be properly considered.

Potential sources of emissions across the CCS life-cycle stage are illustrated in Figure 1.3, with a division made into the separate fuel, solvent and $CO_2$ chains:

- the '$CO_2$ chain' encompasses the emissions arising from the three main CCS stages described previously:
  a) $CO_2$ capture;
  b) $CO_2$ compression and transport;
  c) $CO_2$ storage.
- emissions arising from fuel combustion at the CCS facility including the additional emissions occurring due to the energy penalty;
- indirect emissions arising from the 'fuel' and 'solvent' chains:
  a) fuel preparation including the mining and transport of fuel;
  b) manufacture of solvents;
  c) treatment of solvent waste.
- 'third order' emissions:
  a) manufacture of infrastructure.

**Figure 1.3 Potential life-cycle emission sources arising from power generation with CCS**



**Source:** Harmelen et al., 2008.

### 1.2.1 *Capture technologies*

Technologies for the capture of $CO_2$ can potentially be applied to a range of different types of large industrial facilities, including those for fossil fuel or biomass energy production, natural gas refining, ethanol production, petrochemical manufacturing, fossil fuel-based hydrogen production, cement production, steel manufacturing, etc. The International Energy Agency (IEA) and United Nations Industrial Development Organization (UNIDO) have recently published a roadmap concerning a future pathway to 2050 for the uptake of CCS in industrial applications (IEA/UNIDO, 2011).

There are four basic systems (⁶) for capturing $CO_2$ from the use of fossil fuels and/or biomass:

1. post-combustion;
2. pre-combustion;
3. oxyfuel combustion; and
4. established industrial processes.

Box 1.1 provides further explanation of these technologies; Figure 1.4 shows a schematic diagram of the main capture processes associated with each.

The idea of $CO_2$ capture is to produce a stream of pure $CO_2$ gas from a mixture of $CO_2$ and other gas components. All of the shown processes therefore require a step involving the separation of $CO_2$, hydrogen ($H_2$) or $O_2$ from a gas stream. There are many ways to perform this operation: via absorption or adsorption (separating $CO_2$ by using solvents or sorbents for absorption), membranes and thermal processes such as cryogenic or mineralisation. The choice of a specific capture technology is determined largely by the process conditions under which it must operate. Current post-combustion and pre-combustion systems for power plants could capture 80–95 % of the $CO_2$ that is produced. It is important to stress that CCS is always an 'add-on' technology. The capture and compression are considered to need roughly 10–40 % (⁷) more energy than the equivalent plant without capture (IPCC, 2005).

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(⁶) It is anticipated the first three $CO_2$ capture technologies are likely ready to be demonstrated before 2020 (Harmelen et al., 2008).

(⁷) Dependent upon the type of the capture and energy conversion technology.

**Box 1.1 Capture technologies**

**Post-combustion capture**

The $CO_2$ is captured from the flue gas following combustion of the fossil fuel. Post-combustion systems separate $CO_2$ from the flue gases produced by the combustion of the primary fuel in air. These systems normally use a liquid solvent to capture the small fraction of $CO_2$ (typically 3–15 % by volume) present in a flue gas stream in which the main constituent is nitrogen (from air). For a modern pulverised coal (PC) power plant or a natural gas combined cycle (NGCC) power plant, current post-combustion capture systems would typically use an organic solvent such as mono-ethanolamine (MEA) (IEA, 2009a; IPCC, 2005). One advantage of post-combustion systems is that they can be retrofitted (if physical space allows) to existing coal or gas power plants, industrial facilities, etc. While the technology is considered more mature than the alternatives of pre-combustion capture and oxyfuel combustion, it has not yet been demonstrated on a large scale.

**Pre-combustion capture**

Removal of $CO_2$ from the fossil fuel occurs prior to the combustion process. Pre-combustion systems process the primary fuel in a reactor with steam and air or oxygen to produce a mixture consisting mainly of carbon monoxide (CO) and $H_2$ (synthesis gas — 'syngas'). Additional $H_2$, together with $CO_2$, is produced by reaction of CO with steam in a second reactor (a 'shift reactor'). The resulting mixture of $H_2$ and $CO_2$ can then be separated into a $CO_2$ gas stream, and a stream of hydrogen. If the $CO_2$ is stored, the hydrogen is a carbon-free energy carrier that can be combusted to generate power and/or heat. Although the initial fuel conversion steps are more elaborate and costly, than in post-combustion systems, the high concentrations of $CO_2$ produced by the shift reactor (typically 15–60 % by volume on a dry basis) and the high pressures often encountered in these applications are more favourable for $CO_2$ separation. Pre-combustion could for example be used at power plants that employ integrated gasification combined cycle (IGCC) technology (IEA, 2009a; IPCC, 2005). The technology is only applicable to new fossil fuel power plants because the capture process requires strong integration with the combustion process. The technology is expected to develop further over the next 10–20 years and may be at lower cost and increased efficiency compared to post-combustion.

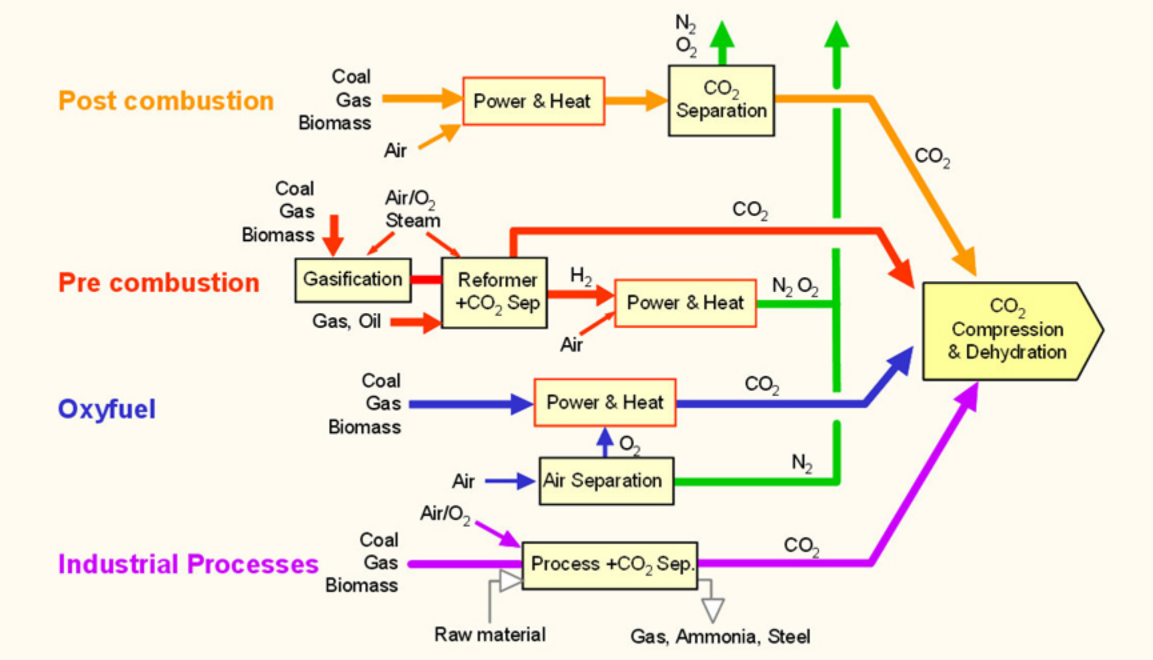
**Oxyfuel combustion capture**

Oxyfuel combustion systems use pure oxygen, instead of air for combustion of the primary fuel, to produce a flue gas that is mainly water vapour and $CO_2$. This results in a flue gas with high $CO_2$ concentrations (more than 80 % by volume). The water vapour is then removed by cooling and compressing the gas stream. Oxyfuel combustion requires the upstream separation of oxygen from air, with a purity of 95–99 % oxygen assumed in most current designs. Further treatment of the flue gas may be needed to remove air pollutants and non-condensed gases (such as nitrogen) from the flue gas before the $CO_2$ is sent to storage (IEA, 2009a; IPCC, 2005). In theory, the technology is simpler and cheaper than the more complex absorption process needed in for example the post-combustion $CO_2$ capture process and can achieve high $CO_2$ removal efficiencies. One disadvantage of the technology is, however, the high present cost of generating pure oxygen streams.

**Capture from industrial processes**

$CO_2$ has been captured by industry using various methods since the 1970s to remove $CO_2$ from gas streams where it is unwanted, or to separate $CO_2$ as a product gas. Examples of the processes include: purification of the natural gas, production of hydrogen containing synthesis gas for the manufacturing of ammonia, and alcohols and synthesis liquid fuels. Other $CO_2$-emitting industries are cement, iron and steel production (IPCC, 2005).

**Figure 1.4 Overview of $CO_2$ capture processes and systems**



**Source:** IPCC, 2005.

### 1.2.2 *Transport*

Except when power plants are located directly above a geological storage site, captured $CO_2$ must be transported (onshore or offshore) from the point of capture to a storage site (injection sink). This is the second step in the CCS chain. The captured $CO_2$ can be transported as a solid, gas, liquid or supercritical fluid. The desired phase depends on the way how the $CO_2$ is transported.

In general there are two main transport options, via:

- pipelines and/or
- shipping.

In theory, it is also possible to transport $CO_2$ by heavy goods vehicle or rail. However, the very large number of vehicles and/or rail units that would be required to transport millions of tonnes of $CO_2$ makes the idea impractical. Transport by heavy goods vehicle would be possible in the initial phases for small research or pilot projects. Hence, pipelines are considered the only practical option for onshore transport when CCS becomes commercially available and millions (or even billions) of tonnes of $CO_2$ will be stored annually. Transport by pipeline is also considered the most generally cost-effective option, although transport by ship could be economically favourable when large quantities have to be transported over long distances (> 1 000 km) (IPCC, 2005).

There is a large network of pipelines for $CO_2$ transport in North America as $CO_2$ has been transported there for over 30 years; over 30 million tonnes (Mt) of $CO_2$ from both natural and anthropogenic sources are transported per year through 6 200 km of $CO_2$ pipelines in the United States of America and Canada (Bellona, 2010; IEA, 2009a and 2009b). Maps showing an indicative future transport and storage network for $CO_2$ across the EU, within and between Member States, are shown in Figure 1.5.

### 1.2.3 *Storage*

The third step in the CCS chain is storage of the captured and transported $CO_2$. In the literature three main forms of $CO_2$ 'storage' are identified (IPCC, 2005) (see also Figure 1.2):

1. in deep geological media;

2. in oceans;

3. through surface mineral carbonation (involving the conversion of $CO_2$ to solid inorganic carbonates using chemical reactions) or in industrial processes (e.g. as a feedstock for production of various carbon-containing chemicals).

Of these forms, mineral carbonation is very costly and has a significant adverse environmental impact while ocean storage is as yet considered an immature technology which may endanger ocean organisms and have negative ecosystem consequences (Bachu et al., 2007; Hangx, 2009; IPCC, 2005). Both these methods are considered still to be in the research phase (IEA, 2009b; IPCC, 2005). Further, the EU CCS Directive (European Union, 2009) expressly forbids the storage of $CO_2$ in the water column.

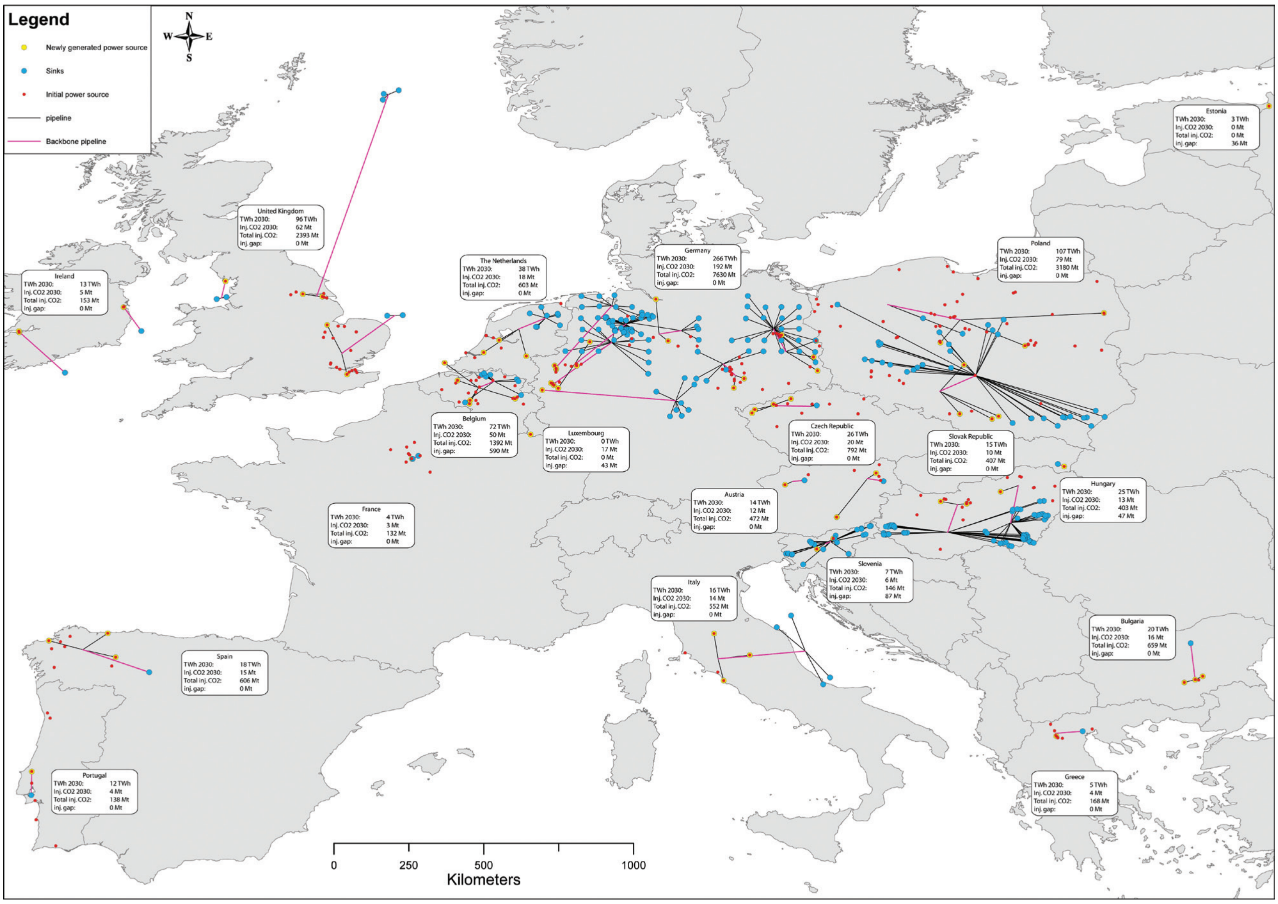
In contrast, geological storage of $CO_2$ is a technology that can benefit from the experience gained in oil and gas exploration and production. Moreover, this technology seems to offer a large $CO_2$ storage capacity, albeit unevenly distributed around the globe, and it has retention times of centuries to millions of years (IPCC, 2005). The injection of $CO_2$ in a supercritical state is done via wellbores into suitable geological formations. There are three options for geological $CO_2$ storage (IEA, 2008a and 2008b):

1. deep saline formations;
2. depleted oil and gas reservoirs;
3. deep non-mineable coal seams.

Of these, it is expected that saline formations will provide the opportunity to store the greatest

**Figure 1.5 Indicative transport and storage networks for $CO_2$ at a) intra-Member State and b) EU levels**

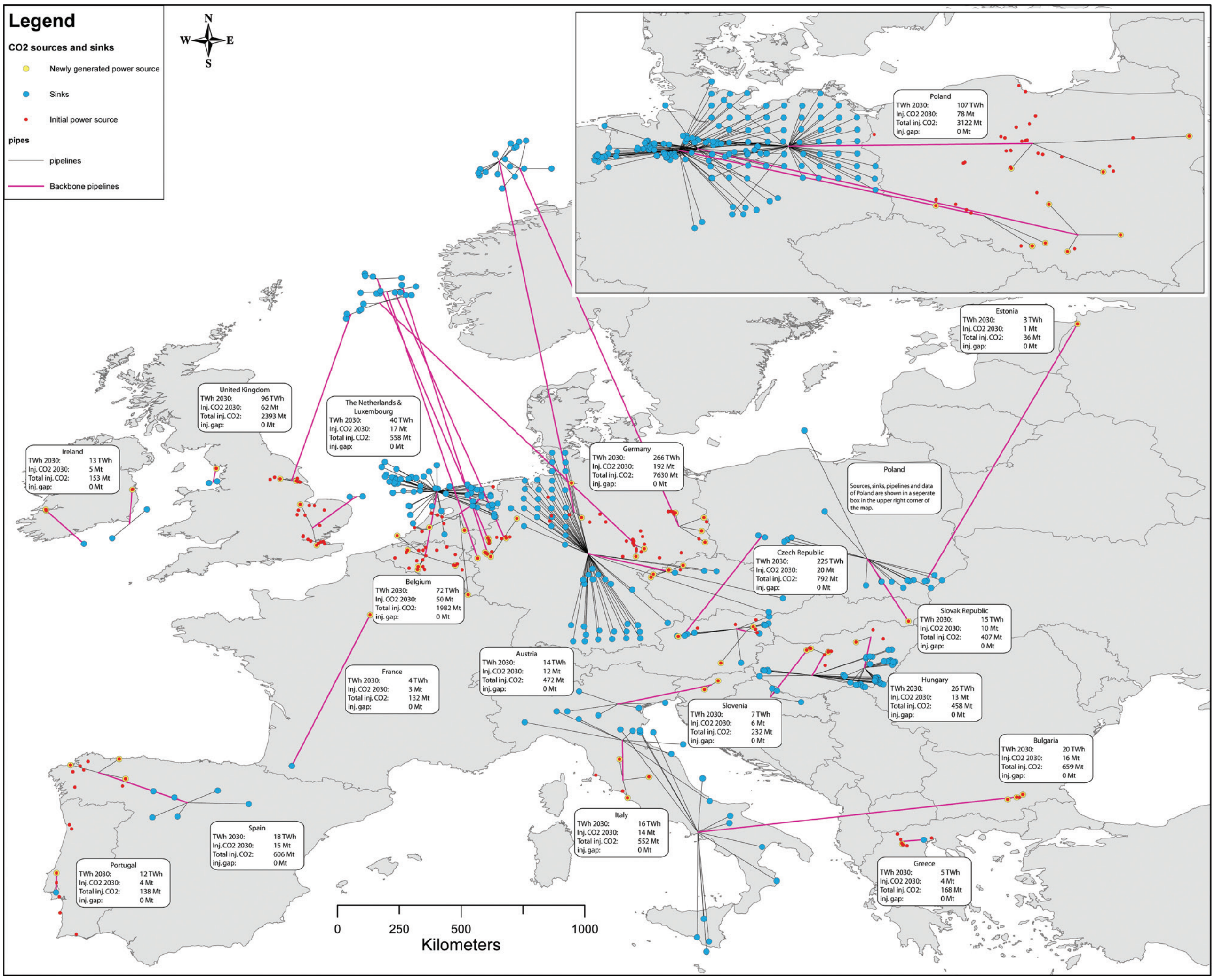
a)



**Source:** European Commission, 2008.

Figure 1.5 Indicative transport and storage networks for $CO_2$ at a) intra-Member State and b) EU levels (cont.)

b)



**Source:** European Commission, 2008.

quantities of $CO_2$, followed by oil and gas reservoirs. Monitoring data from projects worldwide that have involved injection into depleted oil and gas fields and saline formations has shown that the $CO_2$ performs as anticipated after injection with no observable leakage (Bellona, 2010; Hangx, 2009).

## 1.3 Objectives of this report

To evaluate the potential environmental impact of a future implementation of CCS then, in addition to the direct emissions from CCS-equipped facilities, it is clear that the life-cycle emissions from the CCS chain also need to be considered, particularly the additional indirect emissions arising from fuel production and transportation.

This report comprises two separate complementary parts that address the links between CCS and subsequent impacts on GHG and air pollutant emissions on a life-cycle basis:

1. **Part A** discusses and presents key findings from the latest CCS-related literature, focusing upon the potential air pollution impacts across the CCS life-cycle arising from the implementation of the main foreseen technologies. Both negative and positive impacts on air quality are presently suggested in the literature — the basis of scientific knowledge on these issues is rapidly advancing (Koornneef et al., 2011). The presented data are largely based upon a literature review, and build upon an earlier comprehensive set of studies that investigated

the impacts of $CO_2$ capture technologies on transboundary air pollution in the Netherlands (Harmelen et al., 2008; Horssen et al., 2009).

2. **Part B** comprises a case study that quantifies and highlights the range of GHG and air pollutant life-cycle emissions that could occur by 2050 under a low-carbon pathway should CCS be implemented in power plants across the European Union under various hypothetical scenarios. A particular focus of the study was to quantify the main life-cycle emissions of the air pollutants taking into account the latest knowledge on air pollutant emission factors and life-cycle aspects of the CCS chain as described in Part A of the report.

Pollutants considered in the literature review and accompanying case study were the main GHGs $CO_2$, $CH_4$ and $N_2O$ and the main air pollutants with potential to harm human health and/or the environment —$NO_X$, $SO_2$, $NH_3$, NMVOCs and $PM_{10}$ (Box 1.2).

**Box 1.2 The main air pollutants and their effects on human health and the environment**

**Nitrogen oxides ($NO_X$)**

Nitrogen oxides are emitted during fuel combustion, such as by industrial facilities and the road transport sector. As with $SO_2$, $NO_X$ contribute to acid deposition but also to eutrophication. Of the chemical species that comprise $NO_X$, it is nitrogen dioxide ($NO_2$) that is associated with adverse effects on health, as high concentrations cause inflammation of the airways and reduced lung function. $NO_X$ also contribute to the formation of secondary inorganic particulate matter and tropospheric (ground-level) ozone.

**Sulphur dioxide ($SO_2$)**

Sulphur dioxide is emitted when fuels containing sulphur are burned. It contributes to acid deposition, the impacts of which can be significant, including adverse effects on aquatic ecosystems in rivers and lakes and damage to forests.

**Ammonia ($NH_3$)**

Ammonia, like $NO_X$, contributes to both eutrophication and acidification. The vast majority of $NH_3$ emissions — around 94 % in Europe — come from the agricultural sector, from activities such as manure storage, slurry spreading and the use of synthetic nitrogenous fertilisers. A relatively small amount is also released from various industrial processes.

**Non-methane volatile organic compounds (NMVOCs)**

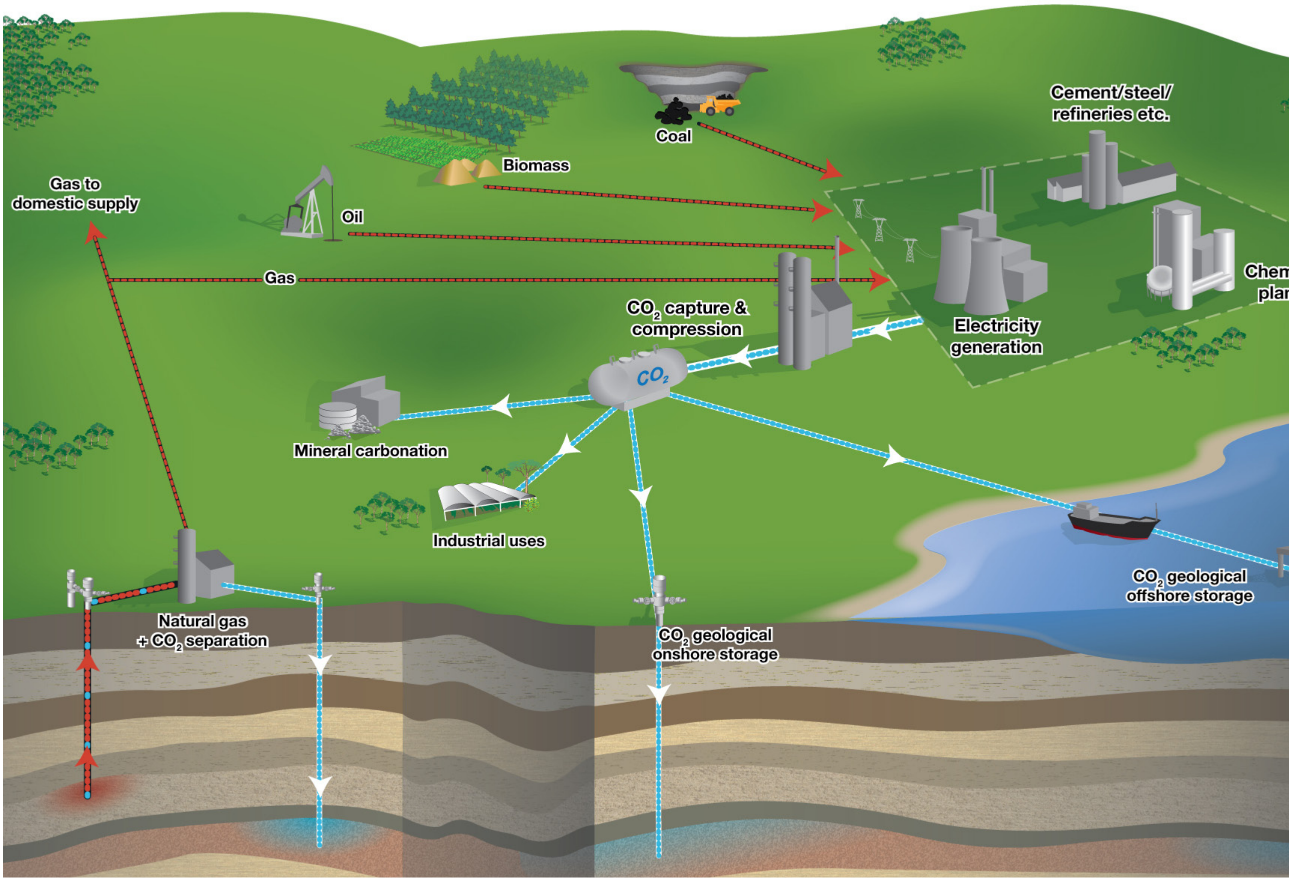
NMVOCs, important $O_3$ precursors, are emitted from a large number of sources including industry, paint application, road transport, dry cleaning and other solvent uses. Certain NMVOC species, such as benzene ($C_6H_6$) and 1,3-butadiene, are directly hazardous to human health. Biogenic NMVOCs are emitted by vegetation, with amounts dependent on the species and on temperature.

**Particulate matter (PM)**

In terms of potential to harm human health, PM is one of the most important pollutants as it penetrates into sensitive regions of the respiratory system. PM is emitted from many sources and is a complex heterogeneous mixture comprising both primary and secondary PM; primary PM is the fraction of PM that is emitted directly into the atmosphere, whereas secondary PM forms in the atmosphere following the oxidation and transformation of precursor gases (mainly $SO_2$, $NO_X$, $NH_3$ and some volatile organic compounds (VOCs)). References to PM in this report refer to primary PM.

**Source:** EEA, 2010.

# Part A Review of environmental life-cycle emissions



Schematic diagram of possible CCS systems showing examples of sources for which CCS technologies might be relevant, transport of $CO_2$ and storage options

**Source:** CO2CRC.

# 2 General considerations

## 2.1 General environmental issues — $CO_2$ leakage

$CO_2$ leakage, or the re-emission of transported and stored $CO_2$, is a main concern in relation to environment and safety associated with implementation of CCS. The actual impacts of any potential leakage will depend upon both the likelihood of leakages to occur at a given point along the CCS chain and of the mass of $CO_2$ released. If the stored $CO_2$ leaks, the $CO_2$ can harm local terrestrial and marine ecosystems close to the injection point. If very large volumes are released, the $CO_2$ can in theory replace oxygen leading to lethal conditions. For well selected, designed and managed geological storage sites, the Intergovernmental Panel on Climate Change (IPCC) estimates that risks are comparable to those associated with current hydrocarbon activities. $CO_2$ could be trapped for millions of years, and although some leakage occurs upwards through the soil, well selected storage sites are considered likely to retain over 99 % of the injected $CO_2$ over 1 000 years.

Thus, the risk of an accidental release from geological storage sites is considered relatively small, since the technologies deployed here are well understood and may be controlled, monitored and fixed on the basis of existing technologies (IPCC, 2005). It is considered that the primary leakage route will be via the wells or through the injection pipe rather than via any geological route (Natuurwetenschap en Techniek, 2009). It is acknowledged, however, that there is not yet a complete understanding of the potential mechanisms for possible $CO_2$ migration. Although the injection pipe is usually protected with non-return valves (i.e. to prevent release on a power outage), there is still a risk that the pipe itself could tear and leak due to the pressure (IPCC, 2005).

There are also potential geological and hydrogeological impacts of CCS. During pipeline operation, large releases of $CO_2$ into the soil from an accidental event could result in formation of carbonic acid ($H_2CO_3$) via the $CO_2$ being dissolved in soil pore water. There is a small risk that this could subsequently dissolve any limestone formations if present in the area, although this would require deep penetration and long contact times (see also Section 2.2 addressing local impacts).

In the event of loss of containment of underground reservoirs, geological and hydrogeological impacts could result from $CO_2$ storage. These risks will be highly site specific and cannot be assessed without detailed modelling. In saline reservoirs, injected $CO_2$ in supercritical phase will be lighter than brine and vertical migration of leaking $CO_2$ could be accompanied by dissolution in shallow aquifer waters, forming $H_2CO_3$. This could chemically react with and stress the cap-rock material, leading to changes in geochemistry and hydrogeology. Storage of $CO_2$ could also possibly be affected by regional groundwater flow. In comparison with depleted oil and gas fields, the characteristics of which are well understood by their operators, there is a lack of seismic data to accurately map most saline aquifers. Hydraulic continuity may extend tens of kilometres away, and at such distances, the probability is high that fractures or fault lines could exist, with possible connection to surface waters and underground sources of drinking water. The geological and hydrogeological setting of storage sites will therefore need to be carefully evaluated on a case-by-case basis to ensure that cumulative and instantaneous releases of $CO_2$ to the environment would not compromise the effectiveness and safety of the storage.

Upon the start of injection, appropriate survey methods will need to be used at regular intervals to monitor the movement of the injected $CO_2$ plume, to ensure that plume behaviour is as expected and, if not, to plan remediation options. It is assumed that effective site selection and good regulatory control of operational practices will ensure an acceptable and understood degree of risk.

As noted in the introduction, the EU CCS Directive (European Union, 2009) establishes a legal framework for the environmentally safe geological storage of $CO_2$. It covers all $CO_2$ storage within geological formations in the EU, and lays down requirements covering the entire lifetime of a storage site. The objective of environmentally safe geological storage is to help ensure permanent containment of $CO_2$ in such a way as to prevent and, where this is not possible, eliminate as far as possible negative effects and any risk to the environment and human health. Provisions included within the Directive concern site selection, monitoring, corrective measures, $CO_2$ stream acceptance and measures of leakage or significant irregularities. The characterisation and assessment of the potential storage complex and surrounding area shall be carried out in three steps, including data collection, building a three-dimensional static geological earth model, characterisation of the storage dynamic behaviour, sensitivity characterisation and risk assessment.

## 2.2 Local health and environmental impacts

The risk for human health and safety depends not only on the likelihood of leakages and the mass of $CO_2$ released, but also on the population density in the vicinity of CCS operations. A concentration of 10 % $CO_2$ in air is assumed to be fatal for an exposed population. Offshore releases are not expected to impose any risks to the general public. There will be risks to personnel working on the riser platform and injection plant, but it is assumed that these will be managed under existing health and safety legislation (European Commission, 2008).

Increased levels of air pollutant emissions (e.g. $NO_X$, $SO_2$ and $NH_3$) that can occur because of the combustion of additional fossil fuel may lead to additional localised impacts on health, crops and materials and to acidification and eutrophication. It is possible that the captured $CO_2$ stream may contain, as an impurity, concentrations of various air pollutants, meaning that the net atmospheric emissions of these impurities will be reduced, although this will be highly dependent on the future permitted levels of impurities in injected $CO_2$ streams. Box 1.2 describes some of the broad impacts of air pollutants on the environment and human health.

Waste generated during operation of $CO_2$ capture systems include slag and ash from increased coal usage, residues from FGD systems, recovered sulphur and spent sorbents. Significant amounts of waste will be generated from post-combustion plants in the EU although the disposal of such waste will be subject to strict regulation controlling its impact on the environment. During the construction of the $CO_2$ injection facilities, significant quantities of wastes and effluents may be produced as a by-product of well drilling. Quantities will depend on many factors, including the geology of the drilled area, drilling depth and method, and their impact will depend on the particular disposal location and method. Well drilling is a well established technology in the oil and gas industry, and there are strict controls on the management of wastes from these sectors which can be applied to minimise impacts (European Commission, 2008).

Biodiversity and cultural heritage may be affected significantly by the development of new pipelines, both permanently where pipeline routes cross sensitive areas or sever wildlife routes, and temporarily when construction activities lead to dust, noise and other disturbances. A pipeline right-of-way (ROW) typically occupies 15–30 metres in width and is required to protect the public and the security of the pipeline. Occupation of the ROW can result in restrictions on some activities including future development, mining and construction. Other less intrusive activities such as livestock grazing and crop rising may be permitted but subject to restrictions which may affect the livelihood and economy of neighbouring communities.

During pipeline operation, adverse impacts on cultural heritage (e.g. to buildings, statues, etc.) are considered unlikely but accidental releases could lead to adverse effects on neighbouring species and ecosystems through toxic effects. If a rupture occurs, wildlife trapped within the immediate vicinity of a released $CO_2$ plume could possibly be subject to asphyxiation.

Long-term fugitive releases could alter the chemistry of surrounding groundwater, seawater and/or soil through acidification, for example having adverse effects on benthic marine ecosystems or soil microorganisms. Acidification of soils could trigger increased leaching of certain minerals with long-term effects on soil quality. The regulation of releases that could lead to adverse impacts will be controlled under existing regulatory regimes but some significant impacts on biodiversity are likely to occur given the extent of the required network on- and offshore. Accidental and fugitive releases could also impact biodiversity at injection and storage facilities in the same way as releases from transport. These risks will therefore be taken into account in site selection and licensing of operations so that major impacts are avoided (European Union, 2009).

# 3 Capture technologies

Capturing $CO_2$ is an additional, integrated and energy-consuming process step within the energy production chain based on combusting fuels in order to produce electricity and/or heat. GHG emissions from CCS operations will occur not only as fugitive emissions or accidental releases, but also as a consequence of the increase in combusted fossil fuel, needed for the capture and compression process.

Primary energy use increases when applying $CO_2$ capture technologies because $CO_2$ capture and pressurisation requires energy. The energy penalty caused by CCS is estimated to fall within a range of 10–25 % and it varies greatly depending on the $CO_2$ capture technology applied (Horssen et al., 2009; IPCC, 2005). The increase in fuel consumption per kWh for plants capturing 90 % $CO_2$ using best current technology is in the range of 24–40 % for new supercritical PC plants, 11–22 % for NGCC plants, and 14–25 % for coal-based IGCC systems compared to similar plants without CCS (Davison, 2007; IPCC, 2005, Rubin et al., 2007). Moreover, $CO_2$ capture reduces overall energy efficiency (the so-called efficiency penalty). Typical efficiency losses are 6 to 12 percentage points, which translate into extra fuel consumption dependent upon the efficiency of the plant (European Commission, 2008; IPCC, 2005; IEA, 2008a; Natuurwetenschap en Techniek, 2009). This additional energy consumption results in a reduction of overall net power plant efficiency (8), so power plants require more fuel to generate each kWh of electricity produced. CCS technology is, however, still in the demonstration phase and as with most technologies it is likely that future improvements in energy efficiency may occur after commercialisation.

Due to the increased fossil fuel combustion, an increase in the air pollutant emissions may be observed. The increased fuel requirement results in increased emissions of most other pollutant emissions per kWh generated relative to new state-of-the-art plants without $CO_2$ capture and, in the case of coal, proportionally larger amounts of solid wastes (IPCC, 2005). The production and transport of the additional fuel will result in additional emissions of GHGs and air pollutants in the upstream phase of a CCS scheme. These upstream elements are described in Chapter 6.

Therefore, $CO_2$ capture has the potential to influence the emission of air pollutants of power plants and industries per produced unit of energy/product. Literature review has shown that different types of carbon capture technologies have different effects on the percentage $CO_2$ captured and air pollutant emissions. Table 3.1 presents a summary of the primary energy use and carbon capture quotients (CCQ) for different air pollution substances. The CCQ indicates the relative increase or decrease in the emission factor of a substance due to the application of a certain capture technology (Koornneef et al., 2010):

$$\mathrm{CCQ}_{x,y,z} = \frac{\mathrm{EF\ CCS}_{x,y,z}}{\mathrm{EF\ noCCS}_{x,y}}$$

where:

$\mathrm{CCQ}_{x,y,z}$ — Carbon capture quotient for air pollution substance 'x', given energy conversion technology 'y' and $CO_2$ capture technology 'z'.

$\mathrm{EF\ CCS}_{x,y,z}$ — Emission factor reported/estimated in the literature for air pollution substance 'x', energy conversion technology 'y' and $CO_2$ capture technology 'z'.

$\mathrm{EF\ noCCS}_{x,y}$ — Emission factor for air pollution substance 'x' and energy conversion technology 'y' reported/estimated for the reference plant without $CO_2$ capture.

The implementation of all capture technologies will result in very low $SO_2$ emissions. Changes in the emission of $NO_X$ strongly depend on the capture and conversion technology and on any additionally installed $NO_X$ mitigation measure. In contrast, emissions of $NH_3$ are expected to significantly increase — ammonia slip from $DeNO_X$ facilities is presently the main source of $NH_3$ emission from conventional fossil fuel-fired power plants. For the

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(8) Net electrical efficiency depends on the fuel used, conversion technique and the plant conditions (new plants vs. existing). New coal (PC) power plants have net electrical efficiencies in a range 43–47 %, and for new lignite (PC) it is 39–45 %, while the efficiency of the existing plants is within the range 30–40 %.

**Table 3.1 Average, minimum and maximum values and uncertainty distribution for the carbon capture quotients determined for primary energy, $CO_2$, $SO_2$, $NO_X$, PM and $NH_3$ for various combinations of energy conversion and $CO_2$ capture technologies**

| Capture technology | Conversion technology | Primary energy new capture | Primary energy retrofit | $CCQ_{CO2}$ | $CCQ_{SO2}$ | $CCQ_{NOX}$ | $CCQ_{PM}$ | $CCQ_{NH3}$ |
|---|---|---|---|---|---|---|---|---|
| Post-combustion | NGCC | 1.11<br>(1.11–1.22) | 1.11–1.22 | 0.13<br>(0.10–0.15) | – | 1.00<br>(0.92–1.04) | – | 1.25–30.30 |
| | PC | 1.22<br>(1.18–1.77) | 1.18–1.77 | 0.10<br>(0.04–0.20) | 0.15<br>(0.00–0.60) | 0.94<br>(0.86–1.00) | 0.71<br>(0.23–1.00) | 17.50–45.25 |
| Pre-combustion | GC | 1.14–1.21 | 1.14–1.21 | 0.05<br>(0.00–0.10) | – | – | – | – |
| | IGCC | 1.13<br>(1.13–1.28) | 1.13–1.28 | 0.11<br>(0.09–0.15) | 0.45<br>(0.07–0.85) | 0.85<br>(0.76–0.96) | 1.00<br>(0.99–1.01) | – |
| Oxyfuel combustion | GC | 1.20<br>(0.84–1.27) | 0.84–1.27 | 0.03<br>(0.00–0.16) | – | – | | – |
| | NGCC | 1.20<br>(1.15–1.25) | 1.15–1.25 | 0.02<br>(0.00–0.03) | – | 0 | – | – |
| | PC | 1.22<br>(1.18–1.43) | 1.18–1.43 | 0.05<br>(0.00–0.14) | 0.06<br>(0.00–0.24) | 0.42<br>(0.00–1.00) | 0.06<br>(0.00–0.13) | – |

**Note:** A value of 1.0 indicates no change in emission factor compared to a reference plant without $CO_2$ capture.

The most likely value for the CCQ for the primary energy use of new power plants equipped with $CO_2$ capture is directly taken from OECD/IEA (2008) and represents power plants built from the year 2020.

NGCC = Natural Gas Combined Cycle; PC = Pulverised Coal; GC = Gas Cycle; IGCC = Integrated Gasification Combined Cycle.

**Source:** Presented in Koornneef et al., 2010; based on the cases derived from: Alstom, 2006; Andersson and Johnsson, 2006; Chatel-Pelage et al., 2003; Chen et al., 2007; Croiset and Thambimuthu, 2001; DOE, 2007; DOE NETL, 2007a and 2007b; Energy Nexus Group, 2002; Harmelen et al., 2008; IEA, 2008a; IEA GHG, 2004 and 2005; IPCC, 2005; Kishimoto et al., 2008; Knudsen et al., 2006 and 2008; Koornneef et al., 2008; Kozak et al., 2008; Kvamsdal et al., 2007; Natuurwetenschap en Techniek, 2009; Nexant Inc., 2006; OECD/IEA, 2008; Peeters et al., 2007; Rao and Rubin, 2002; Rubin et al., 2005; Tan et al., 2006; Tzimas et al., 2007; White et al., 2008; and WRI, 2007.

mitigation of the extra $NO_X$ and $NH_3$ emissions per produced unit of energy, currently available technologies can be applied that do not significantly change the economic feasibility of the $CO_2$ capture. It is largely unknown whether and to what extent NMVOCs emissions are affected by the $CO_2$ capture concepts (9).

Moreover, the captured $CO_2$ stream may contain impurities which would have practical impacts on $CO_2$ transport and storage systems and also potential health, safety and environmental impacts. The types and concentrations of impurities depend on the type of the capture process but these are not considered within the scope of this report.

The following subsections describe further the emissions depending on $CO_2$ capture technology.

## 3.1 Post-combustion

This more mature but least energy-efficient technology could lead to increased air emissions as a result of energy penalty if no additional mitigation measures are taken.

### *3.1.1 Energy penalty*

As shown in Table 3.1, for every capture technology primary energy use increases when applying $CO_2$ capture. The additional energy is needed for $CO_2$ separation and compression to the pressure required for transport. For post-combustion capture technologies, this increase is mainly determined by the heat requirement for separation of $CO_2$ from the solvent in the capture process. Moreover, significant compressor power is required to pressurise $CO_2$ to

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(9) See for example Chatel-Pelage et al., 2003; Chen et al., 2007; Croiset and Thambimuthu, 2001; DOE, 2007; DOE NETL, 2007a and 2007b; Energy Nexus Group, 2002; Harmelen et al., 2008; Horssen et al., 2009; IEA, 2008a; IEA GHG, 2004 and 2005; Kishimoto et al., 2008; Knudsen et al., 2006 and 2008; Koornneef et al., 2008; Kozak et al., 2008; Kvamsdal et al., 2007; Nexant Inc, 2006; OECD/IEA, 2008; Peeters et al., 2007; Rao and Rubin, 2002; Rubin et al., 2005; Tan et al., 2006; Tzimas et al., 2007; White et al., 2008; and WRI, 2007.

the pressure required for transport (Koornneef et al., 2010).

### 3.1.2 *Direct emissions*

$CO_2$ CCQs or each of the various technology types are presented in Table 3.1. The magnitude of $CO_2$ emissions will depend on the fuel type, on the efficiency of the energy conversion and on the $CO_2$ removal efficiency. Post-combustion removal efficiency was found in the range 87–90 %.

$SO_2$ emissions per unit energy decrease for all coal-firing conversion technologies. The reason is that sulphur has to be removed in order to avoid $CO_2$ solvent degradation; additionally, power plants with $CO_2$ capture should be equipped with improved FGD facilities (Tzimas et al., 2007). In the coal-fired power plants equipped with post-combustion, $CO_2$ capture emissions are reduced significantly (on average it is 85 %) compared to a power plant without capture. As a result, power plants with post-combustion capture were found to emit the least $SO_2$ (Koornneef et al., 2010) (see also Table 3.1).

Emissions of $NO_X$ and $NH_3$ are expected to increase per kWh. $NO_X$ emissions per unit energy produced seem to increase almost proportionally with the increase in primary energy demand needed to run the capture unit. If an amine-based solvent is used, the reduction of $NO_X$ emissions per $MJ_{primary}$ is expected to be small (0.8–3) (Knudsen et al., 2006; Kishimoto et al., 2008). Thus, due to the energy penalty the result is a net increase in $NO_X$ emissions per kWh. As a consequence, additional $NO_X$ reduction measures are needed in order to achieve the same emission levels per produced unit of energy compared to power plants without capture.

A significant increase of $NH_3$ emission may be caused by degradation of the amine-based solvents that possibly will be used in post-combustion $CO_2$ capture. As indicated in Table 3.1, the uncertainty regarding the estimation of $NH_3$ emissions is high, as the scientific literature reports a range of values. In addition to the degradation of an amine-based solvent that may be used in post-combustion capture, $NH_3$ emissions are also caused by the slip of ammonia (in the case of the chilled ammonia concept). However, $NH_3$ emissions can be mitigated by implementing additional equipment or by solvent selection. It is possible to reduce the $NH_3$ emission with (acid) scrubbers, but this will lead to additional costs (and an additional energy penalty). The use of other solvents such as potassium carbonate and amine salts, a new but still expensive alternative, will not emit any $NH_3$ during the capture process. Another possibility being considered is the use of chilled ammonia. First results from this process show some increases in ammonia slip. It has been estimated that $NH_3$ emissions from power plants with capture are likely to increase by a factor of 10 to 25 compared to coal-fired power plants without capture (Horssen et al., 2009).

It is possible that VOC emissions are not influenced by the $CO_2$ capture process. In this instance, VOC emissions are expected to increase with the increase in the primary energy use (Knudsen et al., 2006).

PM emissions resulting from the combustion of coal, oil or biomass need to be removed for a stable capture process. Subsequently, some PM is expected to be removed in the post-combustion capture process itself. In absolute terms (per kWh), PM emissions are expected to increase somewhat, due to the efficiency penalty.

$CO_2$ capture is often performed in absorption processes with amines. Portions of the amines will degrade, leading to large volumes of degraded amine that must be handled as hazardous waste.

## 3.2 Pre-combustion

A less mature technology, pre-combustion capture at IGCC power plant promises both lower energy consumption and air pollutant emissions than conventional coal-fired plants with post-combustion carbon capture.

### 3.2.1 *Energy penalty*

Pre-combustion technology has the lowest increase in primary energy use and better environmental performance. In this technology the compressor power is substantially lower as the $CO_2$ is removed under process pressures higher than atmospheric pressure. Thus, the $CO_2$ removal process itself requires less energy in this technology.

### 3.2.2 *Direct emissions*

As described earlier, direct $CO_2$ emissions for the various technology types are presented in Table 3.1. These emissions depend on the fuel type, on the efficiency of the energy conversion and on the $CO_2$ removal efficiency. The pre-combustion removal efficiency is approximately equal to that for post-combustion, around 89–95 %.

IGCC power plants have low $SO_2$ emissions, either with or without $CO_2$ capture (see also Table 3.1). This is possibly due to the > 99 % removal efficiencies of sulphur compounds in the acid gas removal section and connected facilities. The application of $CO_2$ capture is likely to result in a decrease of the emission of $SO_2$ per $MJ_{primary}$ but depending on the efficiency penalty may result in an increase per kWh. The reduction per $MJ_{primary}$ is expected to be lower compared to the post-combustion and oxyfuel technologies.

During normal operation of the IGCC with $CO_2$ capture, $NO_X$ will be mainly formed during the combustion of the hydrogen rich gas. As shown in Table 3.1, the $NO_X$ CCQs per $MJ_{primary}$ are expected to decrease compared to the coal-fired power plant. For gas fired concepts equipped with pre-combustion capture, $NO_X$ emissions are expected to be typically higher than for conventional state-of-the-art NGCC (Kvamsdal and Mejdell, 2005). However, the data in the literature is very limited and the $NO_X$ formation process is complicated, in consequence it is difficult to make a clear conclusion about the $NO_X$ emissions.

$NH_3$ formed during gasification is effectively removed in the gas cleaning section in an IGCC. Therefore, emissions are considered to be negligible (Koornneef et al., 2010).

The already low PM emissions for IGCC power plants are not expected to be significantly affected due to the application of pre-combustion capture and thus will result in an increase per kWh due to the efficiency penalty. $CO_2$ capture may lower $PM_{2.5}$ emissions from an IGCC; quantitative estimates are, however, not available (Horssen et al., 2009).

In IGCC power plants there are two main origins of VOC emissions: the gas turbine section and the fuel treatment section. The formation of VOCs in the first is expected to be reduced due to $CO_2$ capture and the associated higher $H_2$ content of the fuel gas. The emissions from the fuel treatment section are expected to remain equal per $MJ_{primary}$. The net effect of both may thus be an increase or decrease per kWh. For gas fired cycles the replacement of natural gas with $H_2$ is expected to lower the emission of VOCs (Koornneef et al., 2010).

## 3.3 Oxyfuel combustion

As with pre-combustion technology, oxyfuel combustion promises lower energy consumption and air pollutant emissions than conventional coal fired plants fitted with post-combustion carbon capture.

### *3.3.1 Energy penalty*

Oxyfuel combustion of solid fuels shows about equal increases in primary energy use as shown in Table 3.1 for post-combustion technology. In oxyfuel combustion the separation of oxygen from the air is the main factor causing a drop in efficiency, i.e. about half of the efficiency penalty when comparing with a coal fired power plant. This capture technology requires significant compressor power to pressurise $CO_2$ to the pressure required for transport (Andersson and Johnsson, 2006; Koornneef et al., 2010).

### *3.3.2 Direct emissions*

Oxyfuel combustion processes promise to have the highest $CO_2$ removal efficiencies, within the range of 95–98 %.

As described previously, $SO_2$ emissions per unit energy decrease for all coal-firing conversion technologies. For oxyfuel combustion technologies, the $SO_2$ emissions will generally decrease compared to conventional coal-fired power plants. It has to be removed because a higher $SO_X$ concentration in the flue gas may poison the solvent and also may pose equipment corrosion problems. The variance shown in Table 3.1 is due to parameters that may vary case by case, e.g. the sulphur content in the coal, uncontrolled $SO_X$ emission, removal efficiency of the FGD section and removal in $CO_2$ purification section. However, this technology is not yet operational, hence there are large data uncertainties.

$NO_X$ emissions from oxyfuel concepts are in general expected to be very low, particularly for gas-fired power plants. The net $NO_X$ emissions per $MJ_{primary}$ are likely to decrease compared to conventional coal-fired power plants. $NO_X$ formation during oxyfuel combustion is found to be lower, as thermal $NO_X$ formation is suppressed and fuel $NO_X$ is reduced (Croiset and Thambimuthu, 2001; Koornneef et al., 2010; Tan et al., 2006). Overall, the reduction potential for $NO_X$ formation of oxyfuel combustion is in the range of 60–76 % (Andersson, 2007; Buhre et al., 2005; Chatel-Pelage et al., 2003; Farzan et al., 2005).

It is uncertain whether a power plant employing oxyfuel combustion technology will have higher or lower $NH_3$ emissions.

The results suggest that oxyfuel $CO_2$ capture from coal-fired plants can achieve more than 90 % reduction in PM emissions per unit output compared to emissions from conventional coal-fired plants without $CO_2$ capture. One of the reasons is that additional removal of these substances is expected in the $CO_2$ purification and compression process.

No information was found on the effects of oxyfuel combustion on the formation of VOCs.

# 4 Transport technologies

As described in the Introduction, pipelines are considered the preferred method for transporting large amounts of $CO_2$ for distances up to around 1 000 km. For amounts smaller than a few million tonnes of $CO_2$ per year, or for larger distances overseas, the use of ships could be more attractive. Shipping of $CO_2$, analogous to the shipping of liquefied petroleum gases, is economically feasible under specific conditions but is currently carried out only on a small scale due to limited demand. $CO_2$ can also be carried by rail and road tankers, but it is unlikely that these could be attractive options for large-scale $CO_2$ transportation (IPCC, 2005).

## 4.1 Pipelines

The development of sufficient pipeline infrastructure is critical for the long-term success of CCS. Simulations of potential European $CO_2$ networks indicate that, depending on the configuration of the network, between 30 000 km and 150 000 km of pipelines will be needed in Europe (IEA, 2005) (see also Figure 1.5). $CO_2$ pipelines are similar to natural gas pipelines. The $CO_2$ first requires dehydration to reduce the likelihood of corrosion. Pipelines are made of steel, which is not corroded by dry $CO_2$. The presence of impurities such as hydrogen sulphide ($H_2S$) or $SO_2$ can increase the risks associated with potential pipeline leakage from damage, corrosion or the failure of valves or welds. $CO_2$ itself presents no explosive or fire-related risks but gaseous $CO_2$ is denser than air and can accumulate in low-lying areas, where at high concentrations it can create a health risk (IEA, 2008a). In most gas pipelines, compressors at the upstream end drive the flow, but some pipelines need intermediate compressor stations.

There is a relationship between the pipeline diameter and the maximum flow rate of $CO_2$. A 0.61 m line can transport up to 20 Mt $CO_2$ per year and a 0.91 m pipe can carry more than 50 Mt $CO_2$ per year. Since $CO_2$ is transported in a supercritical state and since the assumed average distance between booster stations would be 200 km (compared to 120–160 km for natural gas), transporting $CO_2$ will require less energy than transporting natural gas over the same distance (IEA, 2008a).

## 4.2 Pipeline construction

A review of the environmental impact assessments of pipeline constructions (including $CO_2$ pipelines for enhanced oil recovery) reveals that the main impacts on air quality from this type of project under normal operation (10), will be during construction from:

a) movement of heavy equipment for trenching and transport of pipes;

b) trenching activities including storage of excavated materials;

c) movement of personnel; and

d) construction of the pump house and take-off stations.

The mechanical equipment, trucks and electric generator sets for the welding machines will themselves produce emissions of pollutants such as dust/PM, CO, $NO_X$ and $SO_2$ arising from fuel combustion (AMEC Earth & Environmental, 2005; Canadian Ministry of Health, 2004; Energía Mayacan, 1996; NETL, 2007; RSK, 2007; and TRC Environmental Corporation, 2004).

The review also showed that in all cases the significance of effects on air quality is considered to be minor as they will be localised, of small magnitude and of short duration. Furthermore, there are some standard responses to mitigating such impacts which affect most development projects of this type (e.g. application of dust suppressants such as water, calcium chloride or tree lignin for excavated material) and for which standard procedures and best practice can be applied.

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(10) The impacts of sudden releases of $CO_2$, $H_2S$ and other substances that could be emitted during a failure from either the pipeline transmission line or directly from the well head during underground injection (known as catastrophic failure) have not been taken into account. The assessment of the magnitude and importance of these kinds of impacts requires specific simulations in air dispersion models that take into account pipeline characteristics and meteorological conditions.

Finally, the energy requirement of transport of $CO_2$ is relatively low. For offshore long-distance high-pressure transport of natural gas, a value of 0.8 MJ per tonne-km (t.km) is given in Ecoinvent Centre (2007). Table 4.1 shows emission factors associated with the pipeline transport of $CO_2$; these values exclude the production and civil work for the pipeline itself.

The transport by pipelines of the highly pressurised $CO_2$, over distances shorter than 100 km does not require additional energy input, other than energy for the initial compression. The figures in Table 4.1 are therefore indicative for transport beyond 100 km only (Harmelen et al., 2008).

**Table 4.1 Estimation of emissions from pipeline transport of $CO_2$**

| | 1 t.km * pipeline transport | Unit |
|---|---|---|
| $NO_X$ | 160 | mg |
| $SO_2$ | 1.5 | mg |
| $PM_{10}$ | 0.6 | mg |
| NMVOC | 3.7 | mg |
| $NH_3$ | 0.013 | mg |

**Notes:** * t.km = tonne.kilometre (transport of 1 tonne of $CO_2$, over 1 kilometre)

**Source:** Harmelen et al., 2008, based on Ecoinvent Centre, 2007.

## 4.3 Ships

The intrinsic pressure, volume and temperature (PVT) properties of $CO_2$ allow it to be transported either in semi-refrigerated tanks or in compressed natural gas carriers. Existing engineering is focusing on ship carriers with a capacity within the range of 10–50 kilotonnes (kt). Transporting $CO_2$ by ship offers flexibility as it allows the collection and combination of product from several small- to medium-sized sources and thus a reduction in manufacture of infrastructure (IEA, 2008a).

The effect on the climate caused by a $CO_2$ leak from a ship is difficult to quantify. For any significant effect to take place it is likely that a large part of the ship inventory would have to be released over a short period of time. A release of $CO_2$ from a ship during transport would impact the surrounding ocean. The $CO_2$ would dissolve in the water, forming $H_2CO_3$. This would acidify the water, increasing its ability to solubilise sources of calcium carbonate present in the form of coral and the carbonaceous shells of clams and other shellfish. However, impacts of an individual release are likely to be limited to the pelagic zone and will disperse rapidly. During loading or unloading operations a leak of $CO_2$ would pose a significant hazard to people in the immediate vicinity of any release. Populations further afield may also be at risk since it is possible that the cloud may disperse inland due to the effects of weather (European Commission, 2008).

In general, while emissions from gas transport through pipelines are expected to be minimal, the emissions from $CO_2$ transport by sea (and road or rail where applicable) could be significant and should be better quantified to reflect the distance between the sources of supply and the injection site, the types of vehicles, their fuel source and the speed travelled (European Commission, 2008).

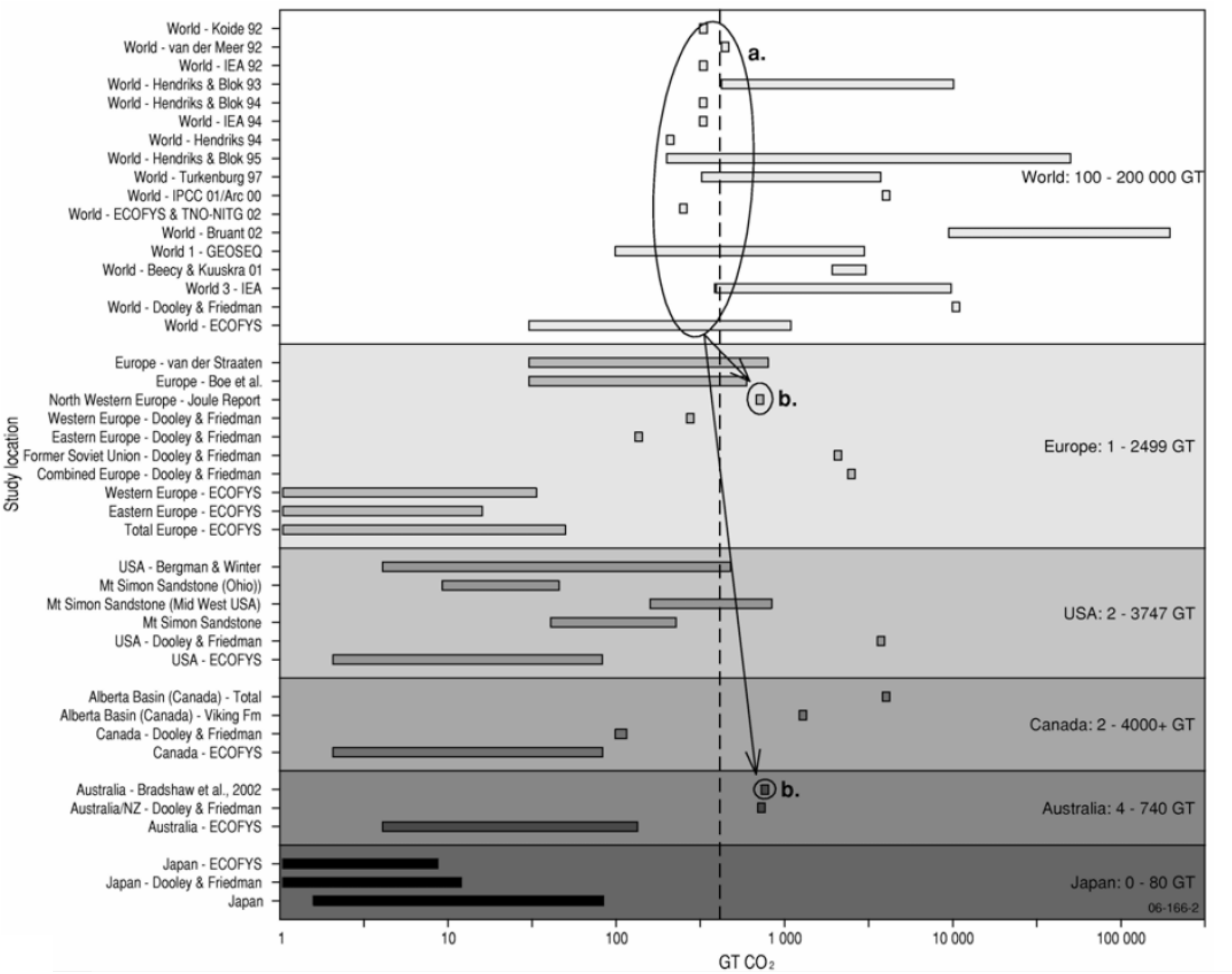
# 5 Storage technologies

As described in Section 1.2.3, $CO_2$ geological storage is the most mature technology out of the three main options identified for $CO_2$ storage. Storage of $CO_2$ in deep, on- or offshore geological formations uses many of the same technologies that have been developed by the oil and gas industry and has been proven to be economically feasible under specific conditions for oil and gas fields and saline formations, but not yet for storage in non-mineable coal beds (IPCC, 2005).

## 5.1 Storage capacity

Estimation of the capacity of a geological reservoir to store $CO_2$ is not a straightforward or simple process. Some authors have tried to make simplistic estimates at the regional or global level, but have largely been unsuccessful, as shown by widely conflicting results (e.g. Figure 5.1). At the global scale, estimates of the $CO_2$ storage potential are often quoted as 'very large' with ranges for the estimates in the order of 100–10 000 gigatonnes (Gt) $CO_2$ (Bradshaw et al., 2007; IEA, 2008a).

**Figure 5.1 A list of various estimates for $CO_2$ storage capacity for the world and its regions**



**Note:** Estimates are listed by region, and ordered internally by date of completion of the estimates. Note that there are some global estimates of storage capacity (a) that are smaller than regional estimates considered more 'robust' (b).

**Source:** Bradshaw et al., 2007.

Potential $CO_2$ storage sites are associated with sedimentary basins. Figure 5.2 shows a classification of basins with high, medium and low storage potential. Prospective storage areas include sedimentary basins where suitable saline formations, oil or gas fields or coal beds may be found. Locations for storage in coal beds are only partly included. 'Storage prospectivity' is a qualitative assessment of the likelihood that a suitable storage location is present in a given area based on the available information (IEA, 2008a; IPCC, 2005).

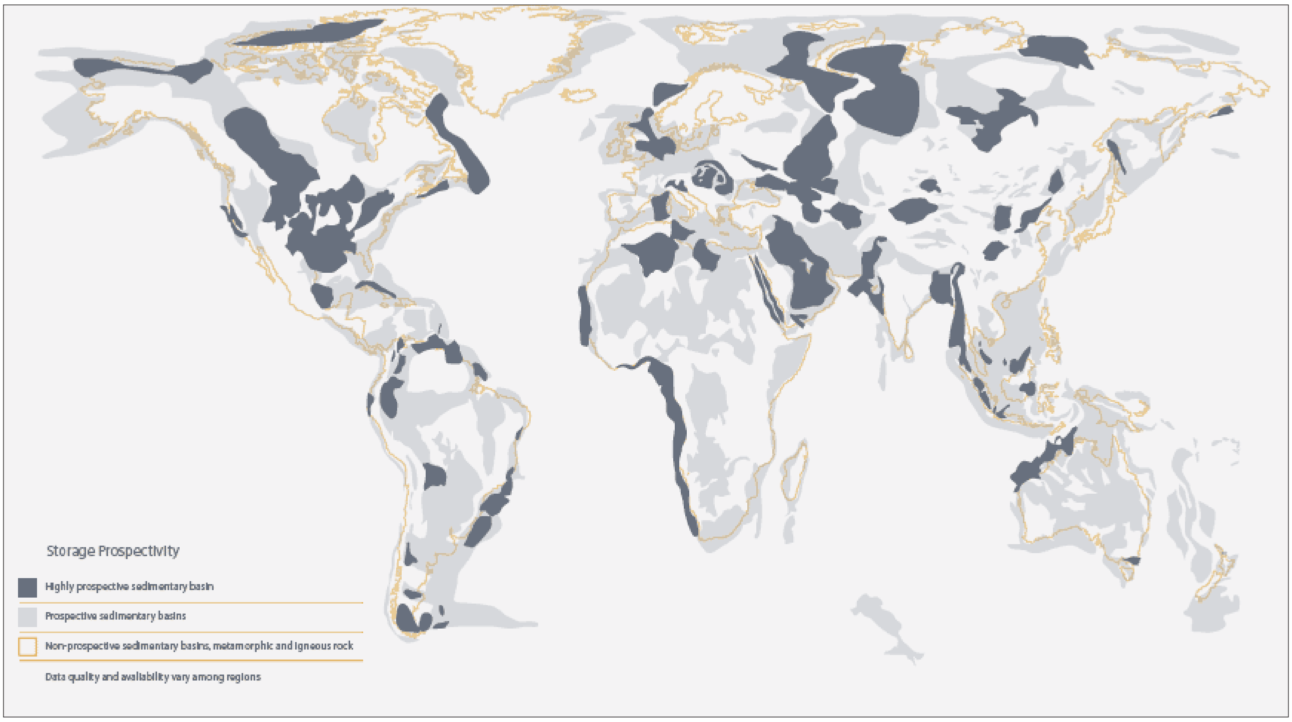
Geological basins that are highly prospective for $CO_2$ storage are found in Canada, Europe, the Middle East, North Africa, Siberia and the United States, and both on- and offshore.

## 5.2 Emissions from storage

Drilling wells for $CO_2$ storage would emit pollutants such as $NO_X$, CO, VOCs, $PM_{10}$ and $PM_{2.5}$. The specific sources of such pollutant emissions at well sites during the production phase would include combustion emissions from generators powering well site pumps ($NO_X$, CO, VOCs and formaldehyde) and fugitive particulate emissions from unpaved road travel and from wind erosion of disturbed areas such as the unreclaimed portions of well pads ($PM_{10}$ and $PM_{2.5}$). It should be noted that wells being used for gas and oil extraction could also be used for injecting $CO_2$. In such a case the only emission will be during the production phase.

Conversion of the existing depleted oil and gas fields to $CO_2$ storage would also require a compressor station in cases where the $CO_2$ is at the well at a pressure below 80 bar or during operation if higher pressures are required. Compressor stations will create noise and air pollution and involve handling small quantities of hazardous materials. However, most modern compressor stations are low-emission units and will be equipped with oxidation catalyst control for CO, VOC and formaldehyde emissions. As an example, Table 5.1 shows potential operational emission rates of a compressor station designed for underground gas storage. Although it is not possible at the moment to make realistic calculations on the amount of pollutants emitted during well construction and

**Figure 5.2 Prospective areas in sedimentary basins where suitable saline formations, oil or gas fields or coal beds may be found**



**Source:** IPCC, 2005; coal.infomine.com.

**Table 5.1 Summary of emissions from a gas-fired compressor station**

| Equipment | Natural gas compressor (hp) | Potential pollutant emissions (tonnes per year) | | | | |
|---|---|---|---|---|---|---|
| | | $NO_x$ | CO | VOC | $SO_2$ | $PM_{10}$ |
| Compressor caterpillar | 4 735 | 28.6 | 5.1 | 4.98 | 0.07 | 0.01 |
| Emergency generator | 1.4 | 1.1 | 1.4 | 2.48 | 0.01 | 0 |
| Glycol re-boiler | NA | 0.88 | 0.74 | 0.05 | 0.01 | 0.07 |
| Utility boiler | NA | 1.31 | 1.1 | 0.07 | 0.01 | 0.1 |
| Flare pilot | NA | 0.04 | 0.04 | 0 | 0 | 0 |
| Dehydrator | NA | ---- | ---- | 0.33 | ---- | ---- |
| Fugitive emissions | NA | ---- | ---- | 0.56 | ---- | ---- |

**Source:** Harmelen et al., 2008, based on EP Colorado Interstate Gas, 2007.

operation, from analogous situations, it is expected that $CO_2$ storage would have a minor and localised impact on air pollution at a local/national scale (Harmelen et al., 2008).

Table 5.2 shows an indication of the on-site emissions (11) and the indirect emissions related to geological storage of $CO_2$. The indirect emissions are a result of preparation of the fuel consumed by the pressurisation/pumping station. The emission levels mentioned in the table are relatively high because mining and transport infrastructure is also included.

**Table 5.2 Indicative air pollutant emissions arising from geological storage of $CO_2$**

| | Emissions per tonne of stored $CO_2$ | | |
|---|---|---|---|
| Substance | On-site emissions | Indirect emissions | Unit |
| $NO_x$ | 41 | 3.2 | mg |
| $SO_2$ | 0.1 | 0.5 | mg |
| $PM_{10}$ | 0 | 0.3 | mg |
| VOC * | 7 | 0.4 + 8.4 ** | mg |
| $NH_3$ | n.a. | 0.01 | mg |

**Note:** * Including methane
** Methane

**Source:** Harmelen et al., 2008, based on Ecoinvent Centre, 2007, and EP Colorado Interstate Gas, 2007.

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(11) EP Colorado Interstate Gas (2007) describes the installations' equipment. Under full load the combination is capable of pressurising and pumping 236 000 $m^3$ of natural gas per hour into a mine, with a fuel consumption of 79 GJ/h. This results in a fuel consumption of 0.29 $MJ/m^3$ under ideal circumstances. Starting from 100 bar of injection pressure (approximately 800 $kg/m^3$), this equals 0.36 MJ of fuel (natural gas) per tonne of $CO_2$.

# 6 Indirect emissions

Figure 1.3 showed the various elements of the indirect CCS life-cycle. This includes processes outside of the $CO_2$ capture, transport and storage chain, such as activities associated with the fuel chain (encompassing fuel preparation and power generation) and solvent chain (i.e. solvent production and treatment of waste). Each of these steps has potential to release additional emissions.

## 6.1 Fuel preparation

As discussed earlier, the energy penalty of $CO_2$ capture gives rise to additional fuel consumption per kWh of electricity, compared to power generation without $CO_2$ capture. The indirect emissions associated with fuel mining and preparation are very different for different fuels, e.g. coal and natural gas, but differ also among the countries reflecting their respective fuel mixes. Moreover, the upstream life-cycle emissions (both GHG and air pollutant emissions) depend a lot on coal type/form, place of origin, mode of transport to the destination place, etc. Thus, not only the fuel type but also more detailed characteristics are required to estimate the upstream life-cycle emissions.

The upstream life-cycle for coal includes the following stages:

- primary fuel extraction, either underground (deep) or surface (open pit) mining;
- fuel preparation/conversion (screening, drying, milling);
- transport;
- the material acquisition and manufacturing of all processes involved in those activities (mainly steel, and concrete) (ETC/ACC, 2009).

A paper from ETC/ACC (2009) presents modelled country-specific upstream life-cycle $CO_2$ and air pollutant emissions for different types of coal as well as natural gas ([12]).

The average results for the upstream emissions for coal and natural gas with respect to the national conditions, e.g. coal mix, are presented in Table 6.1. This table presents the European average which was calculated from the data from the following countries: Austria, Belgium, Czech Republic, Denmark, Finland, France (data for natural gas only), Germany, Greece, Hungary (data for natural gas only), Ireland, Italy, the Netherlands, Poland, Portugal, Spain, Sweden (data for coal only), and the United Kingdom.

As could be expected, the relatively energy-intensive process of coal mining, preparation and transport produces significantly higher air emissions than similar activities for natural gas.

Geological and hydrogeological impacts during the extraction of coal and natural gas may result from the additional fuel needed for the energy penalty associated with CCS activities. If the coal mine is located in a region of overlying aquifers, it may experience groundwater inflows/outflows with surrounding aquifers. Mine-induced fracturing could cause hydraulic property changes, thereby

**Table 6.1 Average $CO_2$ and air pollutant emissions from coal and natural-gas upstream life-cycles in Europe, 2005**

| | European average emissions | | |
|---|---|---|---|
| | **Coal** | **Natural gas** | **Unit** |
| $CO_2$-equivalent | 13.4 | 9.2 | kg/GJ |
| $CO_2$ | 6.5 | 5.7 | kg/GJ |
| $SO_2$ | 37.8 | 2.1 | g/GJ |
| $NO_X$ | 37.5 | 27.0 | g/GJ |
| Particulates $PM_{10}$ > 90 % | 5.8 | 1.1 | g/GJ |
| CO | 10.3 | 15.6 | g/GJ |
| NMVOC | 1.9 | 2.3 | g/GJ |

**Source:** ETC/ACC, 2009.

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([12]) For more detail see ETC/ACC, 2009.

changing groundwater behaviour. Some illustrative geological and hydrogeological impacts include:

- change of geological features of the surrounding area of the mine due to intrusive mining extraction methods;
- inflow of unconfined groundwater from siltstones/sandstones to the coal mines from fissures/fractures;
- outflow of deep groundwater from the coal seams and associated sediments into the near-surface aquifers;
- outflow of spoil dump water from the coal mines to the surrounding groundwater.

The changes in hydraulic flow patterns could result in impacts such as dry water wells, contaminated groundwater and contaminated surface water. The details of these impacts will depend on the specific conditions at individual mines, but it is possible that some small increases in localised adverse effects could result from additional mining required by CCS.

## 6.2 Manufacture of solvents

Solvents are used for both post- and pre-combustion capture. Amine-based solvents are used for post-combustion and are usually produced from basic chemicals like ammonia, methanol and ethylene oxide. MEA is distilled from a mixture of MEA, DEA and TEA (mono-, di- and tri-ethanolamine), produced in batch mode from ethylene oxide and ammonia. Methyl diethanolamine (MDEA) is a solvent used for pre-combustion and is manufactured in a way comparable to MEA — from ethylene oxide and mono-methylamine (MMA) — which in turn is distilled from the reaction between ammonia and methanol, resulting in MMA, DMA and TMA (mono-, di- and tri-methylamine). Selexol is a dimethylether of polyethyleneglycol (Harmelen et al., 2008).

Table 6.2 provides an indication of the emissions occuring from the production of 1 kg of solvent. For MEA, 75–85 % of the emissions originate from the raw material manufacturing, except for $NH_3$. For MDEA, raw material manufacturing contributes over 90 %.

**Table 6.2 Indicative air emissions due to solvent manufacturing**

| | Emission from manufacturing 1 kg of solvent (mg) | | | | |
|---|---|---|---|---|---|
| | $NO_X$ | $SO_2$ | $PM_{10}$ | NMVOC | $NH_3$ |
| Post-combustion | | | | | |
| MEA | 6 300 | 6 600 | 840 | 1 700 | 1 600 |
| Ammonia | 2 400 | 4 400 | 720 | 740 | 14 |
| Pre-combustion | | | | | |
| MDEA | 5 800 | 5 700 | 620 | 1 700 | 180 |
| Selexol | No data available | | | | |

**Note:** Data is based on version 1.2 of Ecoinvent Centre (2007) — raw material ratio adapted. Added distillation step has been modelled in Aspen (Harmelen et al., 2008).

**Source:** Harmelen et al., 2008, based upon Gijlswijk et al., 2006, and Ecoinvent Centre, 2007.

## 6.3 Treatment of solvent waste

MEA-based post-combustion capture and MDEA-based pre-combustion capture result in 3.2 and 0.024 kg of reclaimer sludge per tonne of $CO_2$ captured (Gijlswijk et al., 2006). Solvent sludge has to be treated as hazardous waste, for which the incineration is bound to strict regulations. A calculation has been made of the emissions resulting from the incineration of solvent sludge (Table 6.3). No detailed model was available for a hazardous waste incinerator, so a model of a municipal solid waste incinerator was used instead (Eggels and van der Ven, 2000). The figures are likely to be an overestimation, because hazardous waste incinerators should emit less due to stricter local pollutant regulations.

**Table 6.3 Indicative air emissions due to solvent residue incineration**

| | 1 kg of reclaimer sludge (mg) |
|---|---|
| $NO_X$ | 8 300 |
| $SO_2$ | 370 |
| $PM_{10}$ | 38 |
| NMVOC | 270 |
| $NH_3$ | 520 |

**Source:** Harmelen et al., 2008.

# 7 Third order impacts: manufacture of infrastructure

Third order processes in the 'power generation with $CO_2$ capture'-life-cycle include manufacturing and building the power plant, manufacturing and building the additional equipment for $CO_2$ capture, production of trucks and pipelines and preparation of the storage location. For the purposes of this comparison, it was assumed that capture equipment requires as much material as half the power plant. There is of course a high range of uncertainty around this assumption. Table 7.1 shows an indication of the emissions for equipment per megawatt hour (MWh) of electricity or per tonne of $CO_2$. The uncertainty of these data is considered to be very high.

IPCC (2005) provides total equipment costs for NGCC, PC and IGCC power plants with and without capture. Under the assumption that the environmental impact of manufacture of equipment correlates reasonably with total costs, this costs ratio has been used to extrapolate the environmental impact for capture.

**Table 7.1 Indicative air emissions resulting from material manufacturing of infrastructure**

| | **Natural gas fired power plant (NGCC), 1 MWh** | | **Coal-fired power plant (PC), 1 MWh** | | **Manufacturing and civil works pipeline (per t.km $CO_2$ transport)** | **Unit** |
|---|---|---|---|---|---|---|
| **Substance** | **Power plant** | **+ Capture** | **Power plant** | **+ Capture** | | |
| $NO_X$ | 530 | 400 | 13 000 | 8 200 | 9.6 | mg |
| $SO_2$ | 520 | 400 | 8 600 | 5 400 | 5.1 | mg |
| $PM_{10}$ | 170 | 130 | 5 700 | 3 600 | 4.6 | mg |
| VOC | 100 | 80 | 2 300 | 1 500 | 1.7 | mg |
| $NH_3$ | 12 | 9.1 | 190 | 120 | 0.10 | mg |

**Source:** Harmelen et al., 2008, based on IPCC (2005) and Ecoinvent Centre (2007).

# 8 Discussion and review conclusions

Harmelen et al. (2008) performed a detailed assessment of the total CCS chain effect on emissions of the main air pollutants. Figure 8.1 to Figure 8.5 summarise the direct (power generation, $CO_2$ capture, compression) and indirect emissions for the air pollutants $NO_X$, $SO_2$, NMVOCs, $NH_3$ and $PM_{10}$ for five different technological scenarios. Emissions arising from all parts of the chain are expressed per MWh of electricity. Detailed descriptions can be found in Harmelen et al. (2008). It should be noted that the detailed results presented are for the situation in the Netherlands and are indicative only.

Key findings from that study, and as evidenced by Figures 8.1–8.5, include:

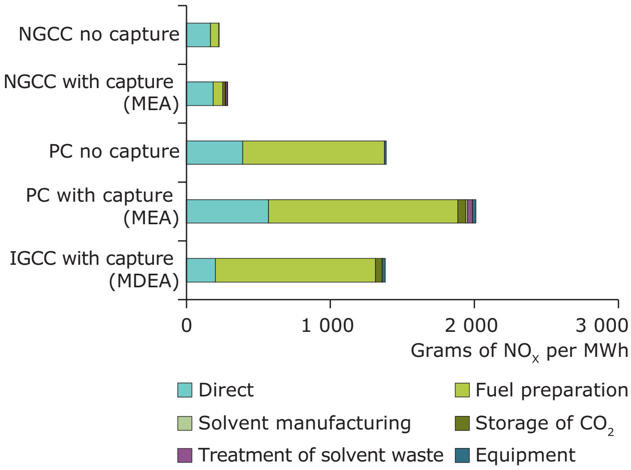
- increases of direct emissions of $NO_X$ and PM due to CCS are in the order of the fuel penalty associated with CCS;
- $SO_2$ emissions tend to decrease (since this is a requirement for $CO_2$ capture);
- $NH_3$ emissions can increase due to solvent emissions of MEA in post-combustion capture;
- power generation using natural gas has low emissions compared to coal-based power generation, directly as well as indirectly;
- the indirect emissions are not negligible, and exceed the direct emissions (emissions associated with power generation, $CO_2$ capture and compression) in most cases for all pollutants;
- the preparation of coal has a large part in the indirect emissions; other indirect emissions contribute 0–12 % for coal cases.

Table 8.1 provides an overview of the contribution of the different emissions sources for PC-based power generation with capture.

For gas-based power generation, fuel preparation determines 100 % of the emissions for $SO_2$, $PM_{10}$ and NMVOCs because no direct emissions are assumed. For $NO_X$, fuel preparation (and transport) contributes 25–35 %, other indirect emissions 11 % for NGCC with capture. Ammonia emissions are low in the NGCC cases, 50 % of their emissions are related to solvent production and slurry disposal.

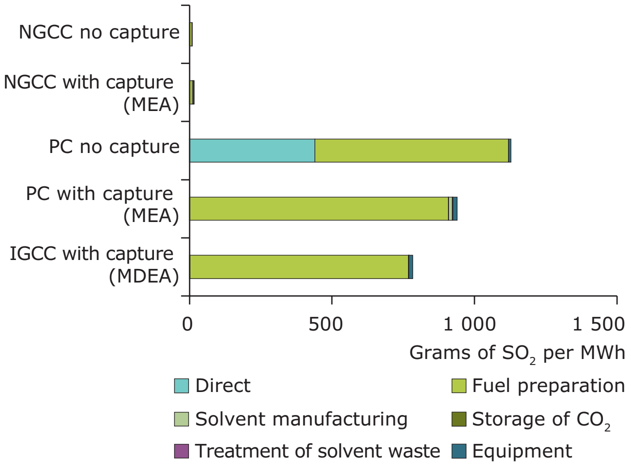
Viebahn et al., (2007) presented the life-cycle emissions for the five phases of fuel supply, power plant, capture and liquefaction, transport and storage. Although the $CO_2$ locally emitted at the power stations' stack are reduced by 88 %, the life-cycle analysis for post- and pre-combustion processes shows lower reduction of $CO_2$ emissions (minus 72–79 %) as well as of GHG in total (minus 65–79 %). Oxyfuel combustion with a $CO_2$

**Figure 8.1 Direct and indirect $NO_x$ emissions**



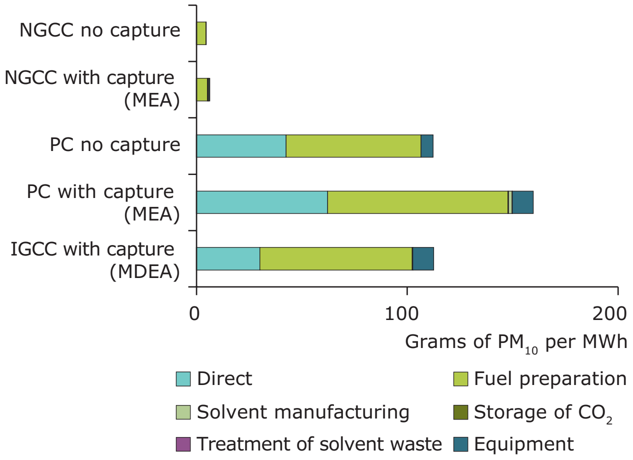
**Source:** Harmelen et al., 2008.

**Figure 8.2 Direct and indirect $SO_2$ emissions**



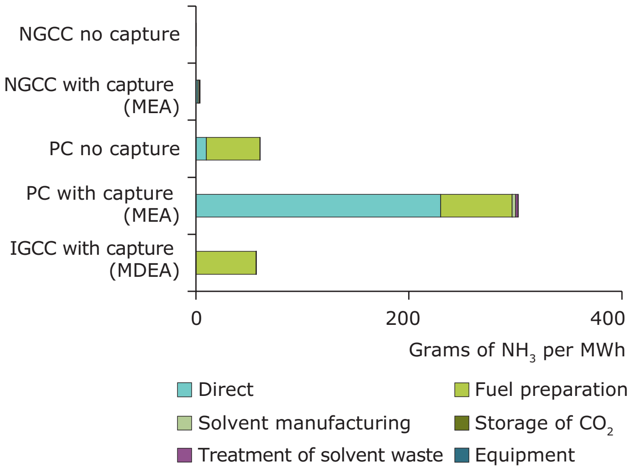
**Source:** Harmelen et al., 2008.

**Figure 8.3 Direct and indirect $PM_{10}$ emissions**



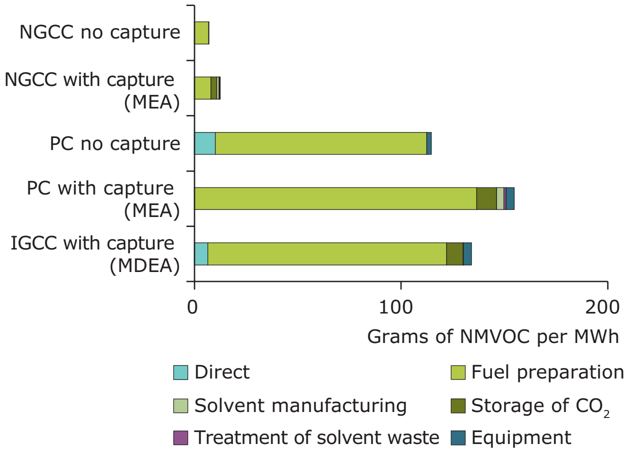
**Source:** Harmelen et al., 2008.

**Figure 8.5 Direct and indirect $NH_3$ emissions**



**Source:** Harmelen et al., 2008.

**Figure 8.4 Direct and indirect NMVOC emissions**



**Source:** Harmelen et al., 2008.

capture rate of 99.5 % results in a reduction of 90 % ($CO_2$) and 78 % (GHG), respectively. This is due to the fact that capture, transport and storage require a lot of additional energy so that $CO_2$ and $CH_4$ are also emitted during the fuel supply chain (Viebahn et al., 2007).

## 8.1 Sensitivity analysis of fuel preparation emissions

Since fuel preparation dominates the environmental impacts of power generation and hence via the fuel penalty, also for CCS, a more in-depth assessment of the contribution of emissions from this step was undertaken in order to test the validity and sensitivity of the findings.

**Table 8.1 Contribution of direct and indirect emissions for 1 MWh of electricity for a pulverised coal-fired power plant with MEA-based $CO_2$ capture**

| Substance | Direct | Fuel preparation | Storage of $CO_2$ | Solvent manufacturing | Treatment of solvent waste | Equipment |
|---|---|---|---|---|---|---|
| $NO_x$ | 28 % | 65 % | 3 % | 1 % | 2 % | 1 % |
| $SO_2$ | 0 % | 97 % | 0 % | 1 % | 0 % | 2 % |
| $PM_{10}$ | 39 % | 53 % | 0 % | 1 % | 0 % | 6 % |
| NMVOC | 0 % | 88 % | 6 % | 2 % | 1 % | 3 % |
| $NH_3$ | 76 % | 22 % | 0 % | 1 % | 1 % | 0 % |

**Source:** Harmelen et al., 2008.

The fuel preparation emissions in the presented case above are based upon Ecoinvent data version 1.2 (Ecoinvent Centre, 2007). It concerns a Dutch coal mix, with coal sourced from South Africa (26 %), South America (20 %), North America (17 %), Australia (15 %), China (12 %), Europe (9 %) and Russia (2 %). For this mix a distance of 11 000 km sea transport was calculated. This distance effectively doubles if all coal originates from Australia. In contrast, the distance can be close to 0 in situations where inland coal is available. This effectively sets the boundary conditions for sea transport emissions to ± 100 %.

In the Ecoinvent database, fuel preparation emissions concern only a few specific processes:

1. mining, constituting electricity consumption, diesel engines and, in particular, blasting;

2. transport by ship and train.

Dominant processes in the emission profiles are sea shipping and blasting, as illustrated in Table 8.2.

Figure 8.6 compares the emission factors for international sea shipping from three different sources, Ecoinvent (Ecoinvent Centre, 2007), TRENDS (Giannouli et al., 2006) and the 2007 EMEP Corinair Guidebook (EMEP/EEA, 2007). The emission factors are expressed here in gramme per t.km, meaning that both the energy efficiency of large bulk carriers and the emissions per amount of fuel combusted are included in these figures.

The comparison in Figure 8.6 indicates that the Ecoinvent emission factors for air pollutants are broadly comparable to those of the EMEP Corinair Guidebook. The TRENDS emission factors are considerably higher. Hence, it is concluded that it is quite probable that the fuel preparation emissions due to sea shipping are for most pollutants the dominant part.

**Table 8.2 Contribution to emissions of most important processes in preparation of coal**

| Process | $SO_2$ | $NO_X$ | $PM_{10}$ | NMVOC | $NH_3$ |
|---|---|---|---|---|---|
| Blasting | | 26 % | | 45 % | 90 % |
| Transport ship | 90 % | 65 % | 63 % | 45 % | 10 % |
| Transport train | | 3 % | 26 % | | |
| Power | 7 % | 3 % | | | |

**Source:** Based on Ecoinvent Centre, 2007.

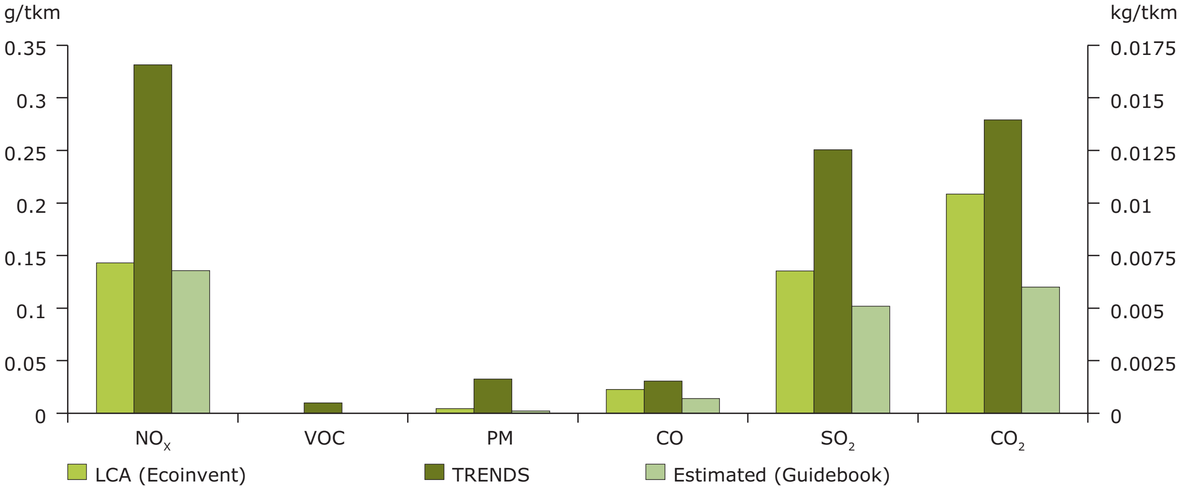
Exceptions to this may be for $NH_3$, VOCs and $NO_X$, for which considerable contributions are made by blasting. Emission factors for this source are not present in the EMEP Corinair Guidebook (EMEP/EEA, 2007). Emission estimates from blasting are subject to high uncertainty. Tovex is a commonly used explosive in mining and quarries. With an assumption that all explosives are conducted with Tovex, a probable chemical reaction was drawn up to estimate the emissions based on activities in Ecoinvent 1.2, as no further information was available. It was assumed that one third of the explosive will result in $NO_X$ and 6 % in $NH_3$. The uncertainty of the data is stressed in the documentation of Ecoinvent. Improved knowledge on emissions from blasting would be beneficial in lowering the uncertainty of emission estimates arising from this source.

It is therefore concluded that it is possible that fuel preparation emissions of $NH_3$, NMVOCs and $NO_X$ are considerably lower if blasting emissions are presently overestimated; however, it does not alter the case that fuel preparation emissions remain as important as the direct emissions. In that case, the main source is sea shipping. This conclusion applies for the Dutch coal mix, which is from a global perspective considered to be an average situation. Fuel preparation emissions can be 100 % higher (if all coal is transported from the other side of the world) but also 100 % lower (all coal from the country itself), depending on the country-specific situation.

## 8.2 Conclusions

In the previous chapters of this review it has been demonstrated that the introduction of CCS can have a considerable impact on emissions of both GHGs and the main air pollutants. This is mainly due to the fuel penalty of the $CO_2$ capture, transport and storage process which requires the additional consumption of energy depending on the technology type. This in turn leads to additional emissions of air pollutants, both direct and indirect emissions, the latter occurring due to the additional fuel production and transportation required. Rather than reflecting on the availability of information in the literature, the focus of the review has been more on the potential application of CCS in the power plant sector rather than in other $CO_2$-intensive industries such as refineries, cement, and iron and steel plants. However, as noted in the Introduction to this report, the assumed future application of CCS into these latter sectors will play an import part if Europe is to achieve its 2050 objective of reducing GHG emissions by 80–95 %.

**Figure 8.6 Comparison of international shipping emission factors in gramme per t.km of three different data sources (Ecoinvent 1.2, Trends and the EMEP Corinair Emission Inventory Guidebook)**



**Source:** Based on Ecoinvent Centre, 2007; TRENDS (Giannouli et al., 2006); and EMEP/EEA, 2007.

The amount of direct air pollutant emissions per unit electricity produced at future industrial facilities equipped with CCS will, however, depend to a large extent on the technology employed.

### *8.2.1 Direct emissions*

The effect of three types of $CO_2$ capture technologies (post-combustion, pre-combustion and oxyfuel) on air pollutant emissions has been discussed. The effects of these technologies on emissions of the main pollutants are summarised below, drawing upon the conclusions of Harmelen et al. (2008) and the discussions presented in Chapter 3.

It should be noted that emission factors presented in the literature for energy conversion technologies with $CO_2$ capture technologies are most often based on assumptions and not on measurements. As these technologies move from laboratory or pilot phase through to full-scale implementation, a proper analysis of emissions and environmental performance will be required. At present, much of the available information is only qualitative in nature.

#### $SO_2$

$SO_2$ emissions are generally expected to be very low for power plants equipped with $CO_2$ capture. For all coal-firing conversion technologies, the application of $CO_2$ capture results in a decrease of the emission of $SO_2$ per kWh as the sulphur must be removed to avoid solvent degradation in post-combustion processes. For natural gas, the sulphur content is in any case low and thus $SO_2$ emissions are expected to be negligible for gas-fired power plants with and without $CO_2$ capture. In pre-combustion and oxyfuel the required treatment of, respectively, the syngas and fluegas is similarly expected to result in low $SO_2$ emissions.

#### $NO_X$

$NO_X$ emissions are believed to be largely unaffected by the (amine-based) capture process in post-combustion technology, although there appears no clear consensus on this in the literature. The $NO_X$ emissions per kWh seem to increase proportionally with the increase in primary energy demand due to the addition of $CO_2$ capture. Both equal and higher $NO_X$ emissions per kWh are reported when applying pre-combustion $CO_2$ capture. $NO_X$ emissions from oxyfuel concepts are in general expected to be very low, particularly for gas. The situation is not clear about this for coal-fired plants.

#### $NH_3$

$NH_3$ emissions are estimated to significantly increase (by more than a factor of 20) for post-combustion capture technology. This is assumed to be caused by degradation of the amine-based solvent used in the post-combustion capture concept. However, the uncertainty regarding this estimate is considered to be high.

### Particulate matter

The removal of PM is necessary to ensure a stable capture process; it subsequently is expected to be removed in any post-combustion capture process. PM emissions per kWh are expected to increase as a result of the efficiency penalty. In the literature, however, assumptions vary considerably. It was found that the application of pre-combustion $CO_2$ capture may lower $PM_{2.5}$ emissions from an IGCC. For coal-fired oxyfuel concepts, PM emissions are also estimated to be lower per kWh, compared to conventional PC-fired power plants. The emission of particulate matter from natural gas-fired cycles in general can be considered negligible.

### NMVOCs

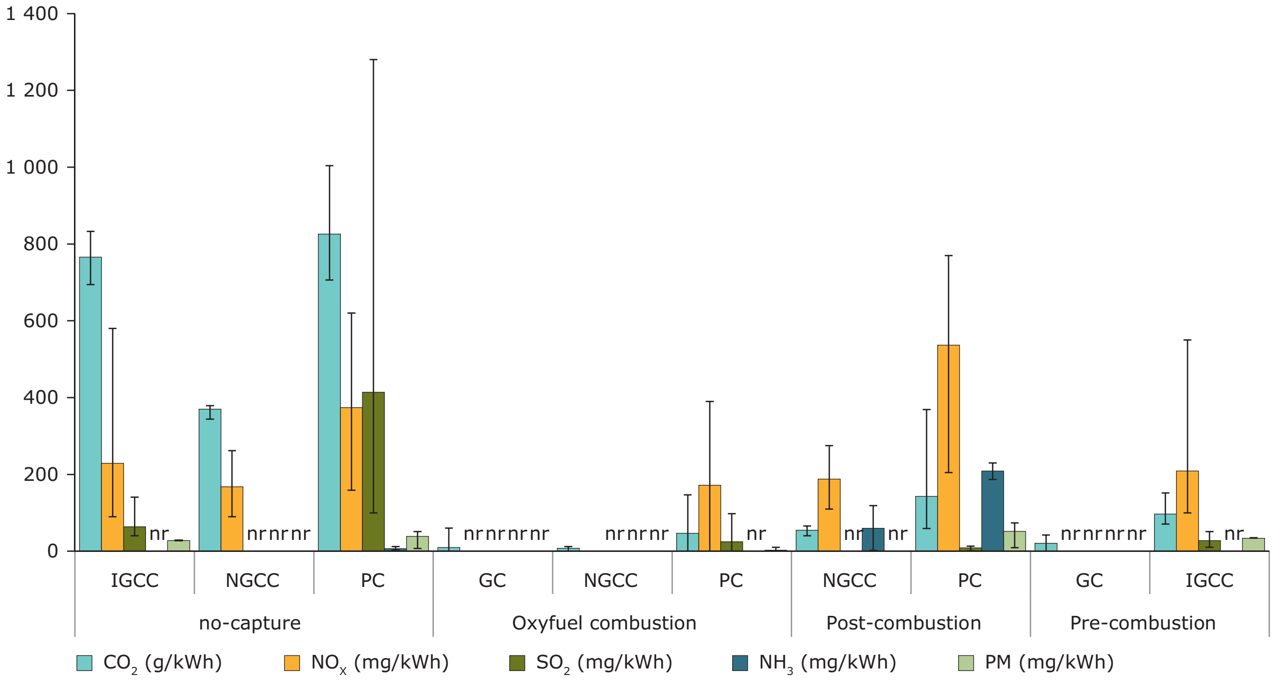
Pre-combustion $CO_2$ capture can increase or decrease the emission of NMVOCs; however, quantitative estimates of this reduction are absent in the literature. It is largely unknown whether and to what extent NMVOC emissions are affected by the $CO_2$ capture process in the oxyfuel and post-combustion concepts.

The effect of biomass (co-)firing in power plants with pre- or post-combustion $CO_2$ capture is not well researched, although it seems likely that both $SO_2$ and $NO_X$ emissions will be lower since the sulphur content and the flame temperature will be lower for biomass than for coal. Effects of biomass (co)-firing using oxyfuel technologies are currently also unknown.

### 8.2.2 *Indirect emissions*

In addition to direct emissions at CCS-equipped facilities, it is clear that the life-cycle emissions from the CCS chain, particularly the additional indirect emissions from fuel production and transportation, may also be significant, exceeding the direct emissions in most cases for all pollutants. Emissions from solvent production and disposal are considered of less significance, as well as the third order effects of the manufacturing of infrastructure (Table 8.3).

**Figure 8.7 Emission rates of various pollutants for different conversion technologies with and without $CO_2$ capture**



**Notes:** The indicated values are based on various fuel specifications and are dependent on the configuration and performance of the power plant and $CO_2$ capture process.

'nr' = not reported; IGCC = Integrated Gasification Combined Cycle; NGCC = Natural Gas Combined Cycle; PC = Pulverised Coal; GC = Gas Cycle

**Source:** Koornneef et al., 2011.

## Table 8.3 A summary of the life-cycle emissions from the CCS chain

| **Life-cycle phase** | **Emissions** |
|---|---|
| **Construction phase** | |
| Construction of power plant, capture plant, transport pipeline and injection facilities | Previous studies (Odeh and Cockerill, 2008) show that life-cycle emissions from the construction phase (due to fuel consumption) are negligible on a g/kWh basis (less than 2 % of total life-cycle emissions of power plants with CCS). |
| **Operation phase** | |
| Flue gas treatment cycle | |
| Production of materials for flue gas treatment in the power plant (limestone for FGD, ammonia for selective catalytic reduction (SCR), etc.) | Indirect emissions result from upstream raw material production and transport and downstream waste disposal/recycling. These emissions are considered small on a g/kWh basis in comparison to other life-cycle emissions. |
| Production of chemicals used in the capture process | Results from Harmelen et al. (2008) show that emissions associated with the solvent cycle are small in comparison to other life-cycle emissions for PC with post-combustion capture and IGCC with pre-combustion capture. |
| Waste disposal | Waste disposal emissions can result directly from the disposal process. Life-cycle air emissions resulting from waste disposal, treatment and transport (such as the conversion of gypsum from FGD, and ash from boilers to useful building materials) and degenerated solvents from the CO2 capture process are small in comparison to other emissions. |
| Fuel cycle | |
| Fuel production (i.e. coal mining) | Coal mining is associated with $NO_X$, $SO_2$, NMVOCs, CO, $CO_2$, PM and $CH_4$ (from potential leakage) emissions (Spath et al., 1999). Mining emissions depend on the mining technology used and on the type of the mine (deep or surface mining). |
| Fuel transport | Coal transport within Europe is via rail but if coal is imported from outside Europe then ship or tanker is the means of transport. |
| Fuel combustion | Direct emissions from fuel combustion (or gasification) are the main contributor to life-cycle emissions. For CCS, additional emissions may result from the capture, transport and injection of $CO_2$. |
| Waste disposal | Waste disposal emissions can result directly from the energy/fuel consumption. Ash from coal boilers is usually used in the construction industry. This is associated with savings but may also result in additional emissions. These emissions are negligible in comparison to other emissions from the coal life-cycle. |

**Notes:** Processes in the life-cycle stages considered to lead to significant levels of emissions are indicated in green, while processes considered of less significance are indicated in orange shade.

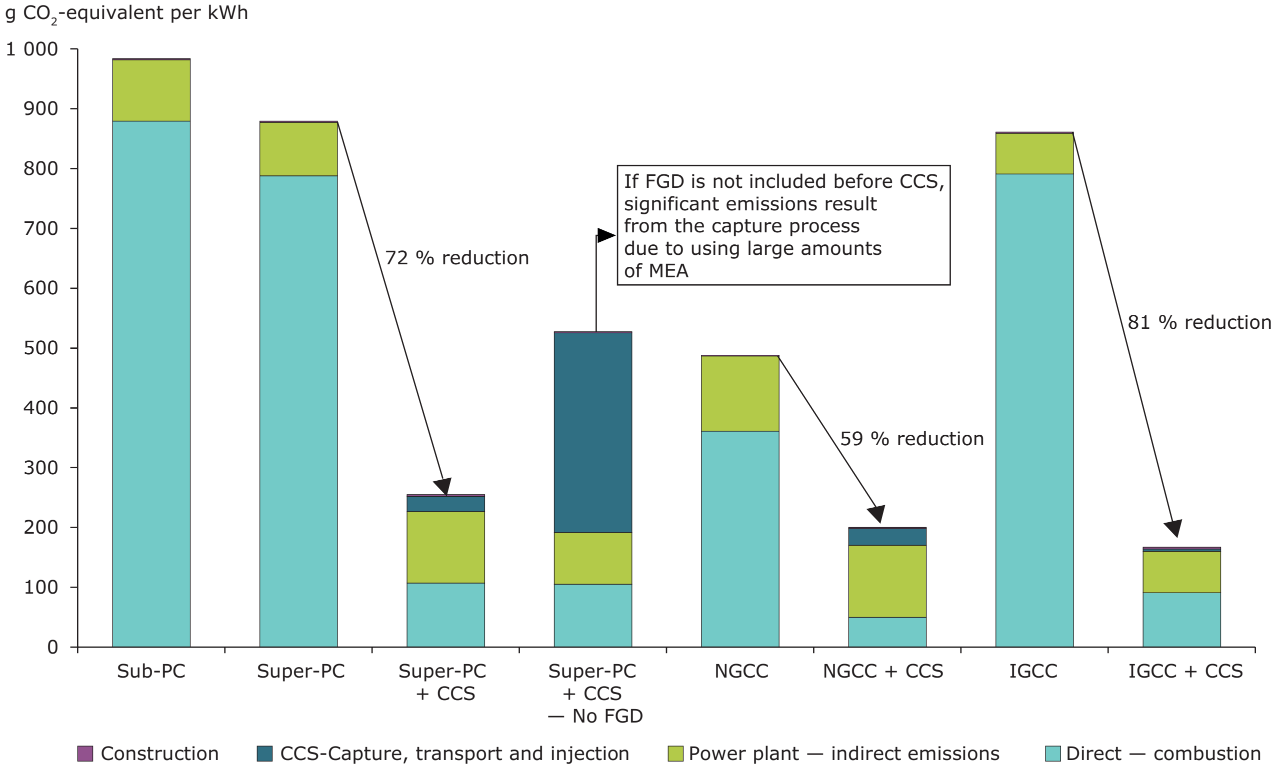
There is presently a significant amount of research being conducted into new possible $CO_2$ capture technologies. Some of the challenges ahead relate directly to limiting the direct and indirect emissions of air pollutants. Initiatives in this area include the development of potential capture processes achieving reduced energy consumption (e.g. the chilled ammonia process) and the development of amine-based salts that do not degrade. Such developments could, for example, lead to a decrease in emissions of $NO_X$, $NH_3$ and possibly also PM (Harmelen et al., 2008).

The results from life-cycle analysis between CCS and non-CCS technologies show that all systems with CCS provide a large reduction in life-cycle GHG emissions. The highest reductions from the reference case are obtained with IGCC followed by NGCC. A summary of the contribution of different sections of the life-cycle to GHG emissions is shown in Figure 8.8. It is for example evident that some emissions, e.g. from the construction phase, are negligible both for CCS and non-CCS systems when compared with other life-cycle emissions (Odeh and Cockerill, 2008).

A final point to note is that power generation based upon combustion of natural gas typically produces only low amounts of the main air pollutants compared to coal-based power generation (both direct and indirect emissions). The switching from coal- to gas-fired power generation can, in some instances, have larger impacts on the direct and indirect emissions of air pollutants than the application of $CO_2$ capture technologies themselves (Harmelen et al., 2008). However, this will be dependent on the technologies involved (see Figure 8.8).

The costs of different energy-generating options will of course also play an important part in deciding the future energy mix. The relative attractiveness of different technologies will depend on factors such as power plant cost levels, fuel prices and market

**Figure 8.8 Comparison of GHG emissions from different technologies with and without CCS**



**Source:** Odeh and Cockerill, 2008.

positioning, whereas the technological applicability will mainly be determined by the nature of the load regime (ZEP, 2011). There are ongoing initiatives to better assess the relative costs of different power generation technologies employing CCS (e.g. IEA, 2010; ZEP, 2011). The 2010 IEA report on the future costs of generating electricity (IEA, 2010) indicates that the assumed costs of post-demonstration phase CCS with coal (EUR 70–90/MWh) and gas (EUR 70–120/MWh), will be cost competitive with other low-carbon power options, including on-/offshore wind, solar and nuclear power.

# Part B Case study — air pollutant emissions occurring under a future CCS implementation scenario in Europe

**Photo:** Vattenfall's Schwarze Pumpe pilot carbon capture and storage facility, Germany © Vattenfall

# 9 Case study introduction and objectives

Part A of this report demonstrated that CCS may have a considerable impact on the emissions of both GHGs and air pollutants, mainly due to the additional fuel penalty associated with the $CO_2$ capture, transport and storage process, but also through changes to the indirect life-cycle emissions. As illustrated earlier (see for example Figure 1.3) the direct and indirect components across a full CCS life-cycle can be summarised as:

- fuel penalty and direct emissions
  a) $CO_2$ capture technologies;
  b) $CO_2$ compression and transport technologies;
  c) $CO_2$ storage technologies.

- indirect emissions
  a) fuel preparation;
  b) manufacture of solvents;
  c) treatment of solvent waste.

- third order emissions
  a) manufacture of infrastructure.

It is clear that in order to evaluate the potential environmental impact of a future implementation of CCS then, in addition to the direct emissions from CCS-equipped facilities, the life-cycle emissions from the CCS chain also need to be considered, particularly the additional indirect emissions arising from fuel production and transportation.

The objective of this case study was to quantify and highlight the range of GHG and air pollutant life-cycle emissions that could occur by 2050 under a low-carbon pathway should CCS be implemented in power plants across the European Union under various hypothetical scenarios. A particular focus of the study was to quantify the main life-cycle emissions of the air pollutants taking into account the latest knowledge outlined in Part A on air pollutant emission factors and life-cycle aspects of the CCS chain. The deployment of CCS in industrial applications has not been considered.

Two earlier studies undertaken for the European Commission have to some extent also looked into the impacts that CCS implementation in Europe may have on emissions of air pollutants. The impact assessment (European Commission, 2008) that accompanied the EU CCS Directive (European Union, 2009) included various scenarios that looked at the potential impacts arising from different possible types and scales of CCS implementations in Europe. The impact assessment presented a short analysis of the pollution impacts to 2030 arising from the different CCS scenarios. The modelling approach used for that assessment found that reducing $CO_2$ by implementing CCS had an overall positive effect in terms of reducing the aggregated air pollution control costs.

The European Commission's communication 'A Roadmap for moving to a competitive low carbon economy in 2050' (European Commission, 2011a) lays out a plan for the European Union to meet a long-term target of reducing domestic emissions by 80–95 % by 2050. Within the 2050 Roadmap, the implementation of CCS technologies in both the power and industry sectors is foreseen. Overall, the reductions in GHG emissions under different decarbonisation scenarios were found to also lead to positive impacts for air pollution in the Roadmap scenario. At the time the case study described in this report was performed, the detailed underlying data from the 2050 Roadmap were not yet available, and thus it was not possible to perform a detailed comparison of the results from this study with those from the 2050 Roadmap. Aggregated results from the 2050 Roadmap indicate that, for the energy scenarios evaluated, reducing GHG emissions in 2050 will further reduce emissions of $PM_{2.5}$, $SO_2$ and $NO_X$ in the EU compared to a reference case. Under the Roadmap's 'effective technologies' scenario, air pollution from these substances is foreseen to reduce some 29% in 2050 compared to a reference scenario. No data concerning $NH_3$ emissions (which might be expected to increase) is provided.

Information used in this case study concerning the likely magnitude of air pollutant emissions occurring from each of the various life-cycle stages of the CCS chain was based upon the preceding literature review (Part A of this report). Table 8.3 included in Part A summarised the different sources of life-cycle emissions and indicated those sources for which emissions of GHGs and air pollutants were considered likely to be of relative significance (shaded green). This includes emissions arising from the life-cycle stages associated with fuel production (i.e. coal mining), its subsequent transport and finally fuel combustion. Sources of potential emissions considered insignificant (shaded orange) were not included in the scope of this case study.

# 10 Case study methodology

## 10.1 Overview

To assess the impacts of the potential wide-scale implementation of CCS in Europe on the emissions of air pollutants in the period until 2050, a four-step approach was used (Figure 10.1). A description of the data and approaches taken in each of these respective steps is provided in the following sections.

## 10.2 Development of an energy baseline 2010–2050

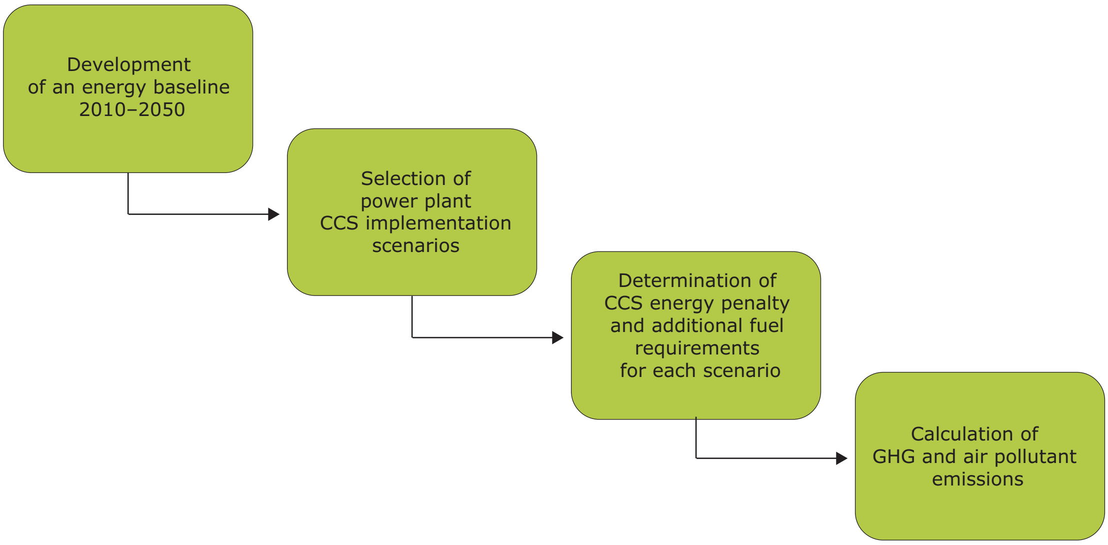
An energy baseline for the period 2010–2050 was constructed to define the energy consumption for the power generation sector in each of the EU-27 Member States where a future potential CCS implementation could be assumed. The energy baseline was based upon data from the following sources:

1. PRIMES energy model baseline 2009 scenario (2010–2030) (Capros et al., 2010 (see Box 10.1) complemented by GAINS activity data (2010–2030) (IIASA, 2010).

2. TIMER/IMAGE model representative concentration pathways (RCP3) scenario (2030–2050) (Van Vuuren et al., 2010a and 2010b) (see Box 10.2).

The GAINS activity data were used together with PRIMES in order to obtain a more detailed dataset per country on the different fuels and technologies than is available from PRIMES alone.

**Figure 10.1 General methodological approach used**

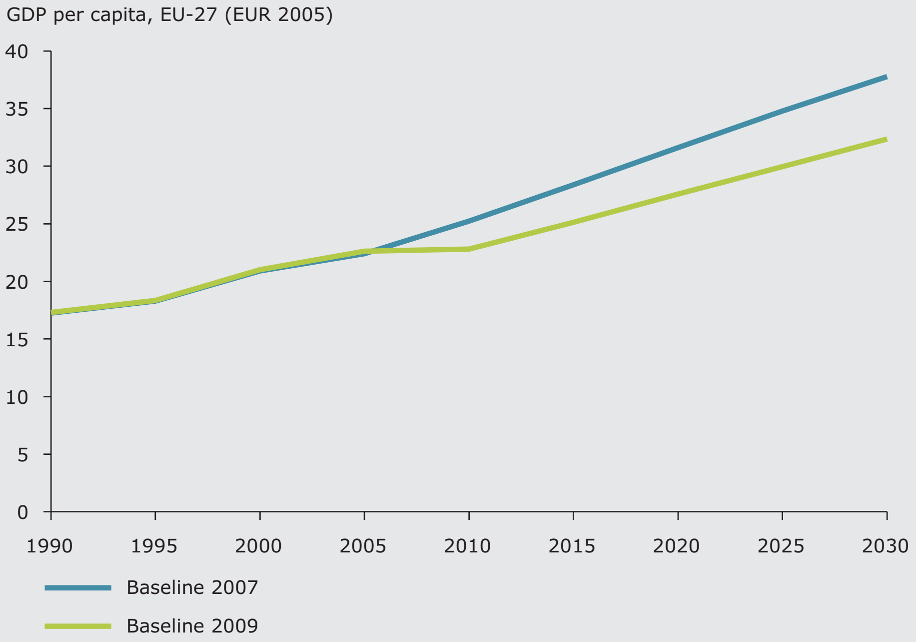


### Box 10.1 The PRIMES energy model — 2009 baseline scenario

The PRIMES model simulates the European energy system and markets on a country-by-country basis and provides detailed results about energy balances, $CO_2$ emissions, investment, energy technology penetration, prices and costs by five-year intervals over a time period 2000 to 2030.

The 2009 Baseline scenario (for more detail see Capros et al., 2010) reflects the recent economic downturn, followed by sustained economic growth assumed to resume after 2010. Gross domestic production (GDP) projections for the short term (2009–2010) mirror economic forecasts from the European Commission (European Commission, 2009a), which complement up to date statistics for 2005–2008 from Eurostat. The medium and long-term growth projections follow the 'baseline' scenario of the 2009 Ageing Report (European Commission, 2009b). The PRIMES 2009 Baseline assumes that the recent economic crisis has long-lasting effects leading to a permanent loss in GDP (Figure 10.2). The Baseline scenario includes concrete national and EU policies and measures implemented until April 2009. This includes the European Union Emission Trading System (ETS) and several energy efficiency measures, but excludes the renewable energy target and the non-ETS sector targets.

**Figure 10.2 GDP per capita development for 1990–2030 for the PRIMES 2009 and earlier 2007 baseline showing the assumed long-lasting effects of the economic crisis**



**Source:** Capros et al., 2010.

The PRIMES 2009 energy projections are based on a relatively high oil price environment compared with previous projections, with oil prices reaching USD 88 '08/bbl (EUR 73 '08/bbl) in 2020 and USD 106 '08/bbl (EUR 91 '08/bbl) in 2030. Driven by the above mentioned policies and also because of the economic crisis, the baseline shows energy-related $CO_2$ emissions declining continuously until 2030. The reduction attains 8.4 % in 2020 from 1990 levels and 21.8 % in 2030. The carbon capture technology and the carbon transport and underground storage infrastructure are assumed to develop and become gradually technologically and commercially mature after 2020, when the first demonstration CCS plants start to be commissioned. The development of CCS post-2020 depends on the ETS carbon prices. The Baseline 2009 findings show that predicted carbon prices close to 2030 are likely to allow CCS expansion, on a market basis. Hence, CCS also contributes to some of the foreseen emission reduction in the power generation sector by 2030.

**Box 10.2 TIMER/IMAGE models — representative concentration pathway (RCP3) (2030–2050)**

The global energy model TIMER describes the energy demand and production and the related emissions of GHGs and regional air pollutants. The IMAGE integrated assessment model consists of a set of linked and integrated models. In combination, these models describe important elements in the long-term dynamics of environmental change, such as air pollution, climate change and land-use change (Van Vuuren et al., 2010b).

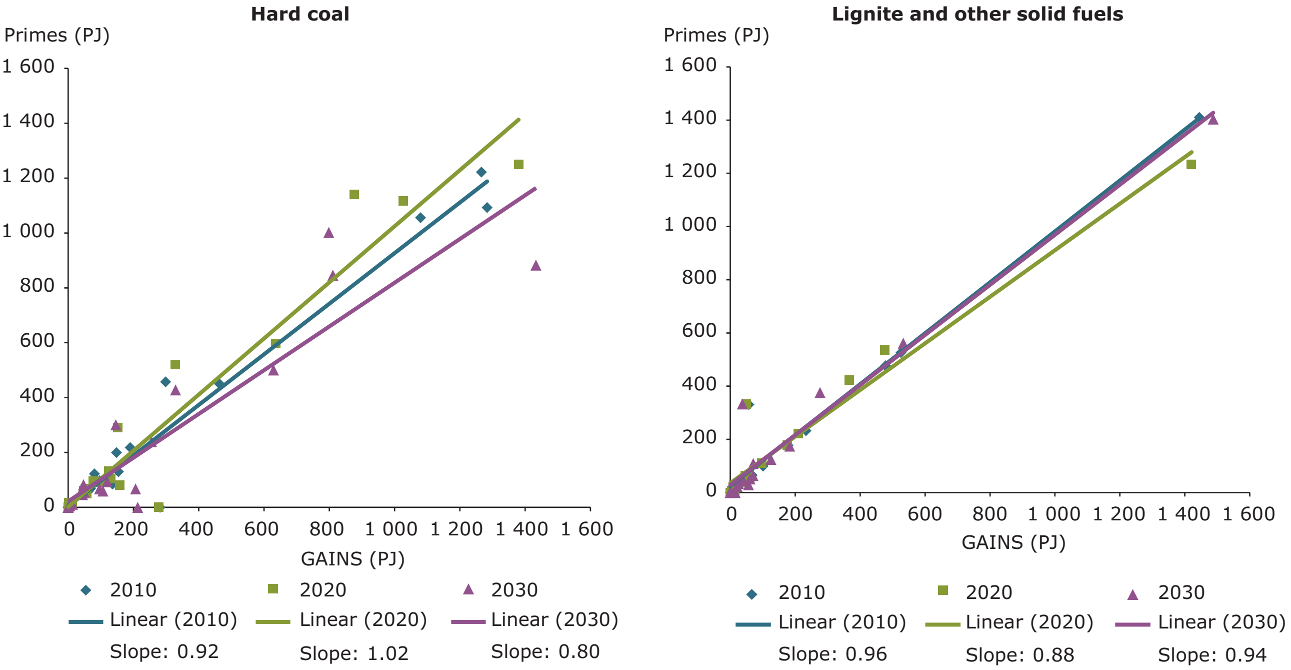
The representative concentration pathways (RCPs) are a set of four new scenarios developed for the climate modelling community as a basis for future long-term and near-term modelling experiments. The RCP3-PD scenario, used in this report and developed using IMAGE/TIMER, is a climate mitigation scenario that would lead to very low GHG concentration levels. It is a so-called 'peak' scenario: its radiative forcing level first reaches a value around 3.1 W/m$^2$ mid-century, returning to 2.6 W/m$^2$ by 2100.

Global primary energy use in the RCP3-PD scenario is reduced by around 25 %, compared to the situation in the RCP baseline scenario. The specific reductions vary per energy carrier; in the short term, the largest reductions occur for coal, with the remaining coal consumption being primarily used in electric power stations that use CCS which accounts for a major proportion of the emission reductions (up to a third of the reductions in energy-related $CO_2$ emissions). Coal is favoured over natural gas as, for the latter, prices will rise because of depletion. Further details of the RCP3-PD scenario may be found in Van Vuuren et al. (2007, 2010a and 2010b).

Although the general picture between the GAINS and PRIMES datasets is relatively similar, for some countries differences do occur (Figure 10.3). The PRIMES dataset tends to show generally lower fuel uses in later years than the GAINS dataset, as indicated by the regression line slopes.

The PRIMES/GAINS energy baseline scenarios have a time horizon of 2030. In order to extend the study period to 2050 (a year by when CCS implementation in Europe is expected to be more common than in 2030), the 2030 data were extrapolated using growth factors derived from the TIMER/IMAGE model.

**Figure 10.3 Comparison of PRIMES and GAINS energy use data; points represent the different EU Member States**



In Table 10.1, the main energy assumptions, as derived from the PRIMES and TIMER/IMAGE scenarios, are compared for the period 2020–2030 for the EU-15. The best fit was obtained by scaling back the scenario results for the RCP3 scenario by 10 years, which was applied to derive the scaling factors for the period 2030–2050 (see Table 10.2). This scaling was required as the RCP3 scenario represented a more extreme climate mitigation scenario than the PRIMES 2009 Baseline. De facto the RCP3 2040 results are used to construct the 2050 baseline that best fits the extrapolation of the PRIMES 2030 baseline.

**Table 10.1 Comparison of the PRIMES 2009 Baseline and the TIMER/IMAGE RCP3 scenario for the EU-15/ Western Europe for the period 2020–2030**

| Ratio TIMER:PRIMES | 2020 | 2025 | 2030 |
|---|---|---|---|
| Coal | 1.18 | 0.97 | 0.84 |
| Gas | 0.90 | 1.35 | 1.25 |
| Oil | 1.04 | 1.00 | 0.93 |
| Biomass | 0.90 | 1.07 | 1.64 |
| Other renewables | 0.96 | 0.88 | 0.98 |
| Nuclear | 0.92 | 1.02 | 0.91 |
| Total primary energy | 0.99 | 1.03 | 1.04 |

## 10.3 Selection of CCS implementation scenarios

Both the PRIMES and the GAINS scenarios assume some degree of CCS implementation to already have occurred by 2020 and 2030, so the energy use data from these scenarios already includes the additional energy consumption connected to the CCS fuel penalty. Four deliberately contrasting CCS implementation scenarios were derived, based on the same total final energy demand expectations:

- a scenario without any CCS;
- a scenario with all coal-fired power plants implementing CCS, where the additional coal (energy penalty) is mined in Europe;
- a scenario with all coal-fired power plants implementing CCS, where the additional coal (energy penalty) is mined in Australia;
- a scenario with CCS implemented on all coal-, natural gas- and biomass-fired power plants, where the additional coal (energy penalty) is from Europe.

These scenarios were selected to assess the importance of life-cycle emissions with contrasting assumptions concerning the source (and hence transport requirements) of the additional required

**Table 10.2 Scaling factors applied for the period 2030–2050 and share of the main energy sources for the EU-15/Western Europe and the EU-12/Central Europe**

| EU-15/Western Europe | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|
| Change coal | | | | 1 | 0.68 | 0.45 | 0.20 | 0.23 |
| Change gas | | | | 1 | 1.06 | 1.09 | 1.09 | 1.06 |
| Change oil | | | | 1 | | | | |
| Change biomass | | | | 1 | 1.76 | 2.82 | 3.20 | 3.16 |
| Change other renewables | | | | 1 | | | | |
| Change nuclear | | | | 1 | | | | |
| Change total primary energy | | | | 1 | 1.01 | 1.01 | 1.01 | 1.01 |
| % CCS-coal | 0.0 % | 0.4 % | 0.9 % | 4.1 % | 11.0 % | 17.9 % | 52.6 % | 78.0 % |
| % CCS-gas | 0.0 % | 0.5 % | 1.0 % | 2.1 % | 7.7 % | 12.4 % | 23.8 % | 36.1 % |
| % CCS-biomass | 0.0 % | 1.7 % | 3.5 % | 11.4 % | 19.5 % | 27.3 % | 33.3 % | 36.9 % |
| **EU-12/Central Europe** | | | | | | | | |
| Change coal | | | | 1 | 0.67 | 0.45 | 0.37 | 0.39 |
| Change gas | | | | 1 | 1.12 | 1.24 | 1.38 | 1.40 |
| Change biomass | | | | 1 | 1.82 | 3.04 | 3.27 | 3.30 |
| Change total primary energy | | | | 1 | 1.02 | 1.09 | 1.15 | 1.18 |
| % CCS-coal | 0.0 % | 0.2 % | 0.4 % | 2.1 % | 10.4 % | 41.6 % | 82.8 % | 88.2 % |
| % CCS-gas | 0.0 % | 0.6 % | 1.2 % | 2.8 % | 18.7 % | 32.8 % | 43.1 % | 46.6 % |
| % CCS-biomass | 0.0 % | 0.6 % | 1.2 % | 2.0 % | 20.4 % | 39.2 % | 47.6 % | 50.3 % |

fuel, and across the different fuel types to which CCS may potentially be applicable. The third scenario involving coal transport from Australia was, for example, selected to maximise the potential additional emissions arising from the extra transport of fuel required within the CCS life-cycle.

## 10.4 Determination of the CCS energy penalty and additional fuel requirement

As all scenarios should ensure the same amount of final energy production is delivered, the primary energy use in each of the different CCS implementation scenarios will be different, due to the differing energy penalty inherent in each.

Using the GAINS abatement technology information, the implicit additional fuel use needed due to the energy penalty was estimated, assuming that CCS requires a 25 % energy penalty for coal- and biomass-fuelled power plants and 20 % for natural gas-fired power plants. It was further assumed that the CCS is implemented in GAINS as much as possible at 'new' power plants. The choice of the average energy penalties is clearly a sensitive parameter. As described in Part A to this report, the energy penalty caused by CCS ranges between around 10 % and 40 %, depending greatly on the $CO_2$ capture method. The increase in fuel consumption per kWh for plants capturing 90 % $CO_2$ using best current technology ranges from 24–40 % for new supercritical PC plants, 11–22 % for NGCC plants, and 14–25 % for coal-based IGCC systems compared to similar plants without CCS (Davison, 2007; IPCC, 2005).

Table 10.3 shows the results of the calculation of the additional energy input for the respective CCS

**Table 10.3 Fuel input (PJ/year) in the European power plants and estimated fuel penalty due to CCS for each of the scenarios**

| | | | Energy penalty | | | |
|---|---|---|---|---|---|---|
| **Year** | **Fuel** | **BL2009** | **No CCS implemented** | **Coal-fired powerplants with CCS, coal from Europe** | **Coal-fired powerplants with CCS, coal from Australia** | **All coal, gas and biomass powerplants with CCS** |
| **2010** | Solids | 9 010 | – | 2 252.5 | 2 252.5 | 2 252.5 |
| | Liquids | 536 | – | – | – | – |
| | Gas | 5 687 | – | – | – | 1 137.5 |
| | Biomass | 1 439 | – | – | – | 351.5 |
| | Waste | | – | – | – | – |
| 2010 Sum | | 16 673 | – | 2 252.5 | 2 252.5 | 3 741.5 |
| **2020** | Solids | 9 126 | – | 2 281.4 | 2 281.4 | 2 281.4 |
| | Liquids | 455 | – | – | – | – |
| | Gas | 5 986 | – | – | – | 1 197.3 |
| | Biomass | 2 003 | – | – | – | 445.7 |
| | Waste | | – | – | – | – |
| 2020 Sum | | 17 569 | – | 2 281.4 | 2 281.4 | 3 924.3 |
| **2030** | Solids | 8 166 | – | 2 041.5 | 2 041.5 | 2 041.5 |
| | Liquids | 347 | – | – | – | – |
| | Gas | 5 431 | – | – | – | 1 086.3 |
| | Biomass | 2 540 | – | – | – | 543.1 |
| | Waste | | – | – | – | – |
| 2030 Sum | | 16 485 | – | 2 041.5 | 2 041.5 | 3 670.8 |
| **2040** | Solids | 6 336 | – | 1 583.9 | 1 583.9 | 1 583.9 |
| | Liquids | 226 | – | – | – | – |
| | Gas | 5 784 | – | – | – | 1 156.7 |
| | Biomass | 6 893 | – | – | – | 1 473.3 |
| | Waste | | – | – | – | – |
| 2040 Sum | | 19 238 | – | 1 583.9 | 1 583.9 | 4 213.9 |
| **2050** | Solids | 4 806 | – | 1 201.5 | 1 201.5 | 1 201.5 |
| | Liquids | 193 | – | – | – | |
| | Gas | 5 388 | – | – | – | 1 077.6 |
| | Biomass | 7 477 | – | – | – | 1 598.7 |
| | Waste | | – | – | – | – |
| 2050 Sum | | 17 864 | – | 1 201.5 | 1 201.5 | 3 877.8 |

implementation scenarios. The additional energy requirements are listed in the column 'Energy Penalty', whereas the column 'BL2009' provides the energy that is needed to generate the required electrical energy if no CCS would be installed. In 2020, the CCS implemented according to GAINS would lead to an additional fuel use of 58.7 PJ relative to a total of 17 569 PJ (i.e. 0.3 %) due to the energy penalty. In 2030 this would amount to 579.7 PJ on a total of 16 485 PJ (3.5 %).

A scenario without CCS was thus generated by adding the additional energy in the 'Energy Penalty' column from the PRIMES baseline. For the 'CCS' scenarios, the same BL2009 energy use is complemented with the energy penalty for all power plants equipped with CCS. For the scenario with the additional coal being sourced from Australia, the additional emissions due to maritime transport from Australia to Europe are added directly, without calculating the additional transport energy.

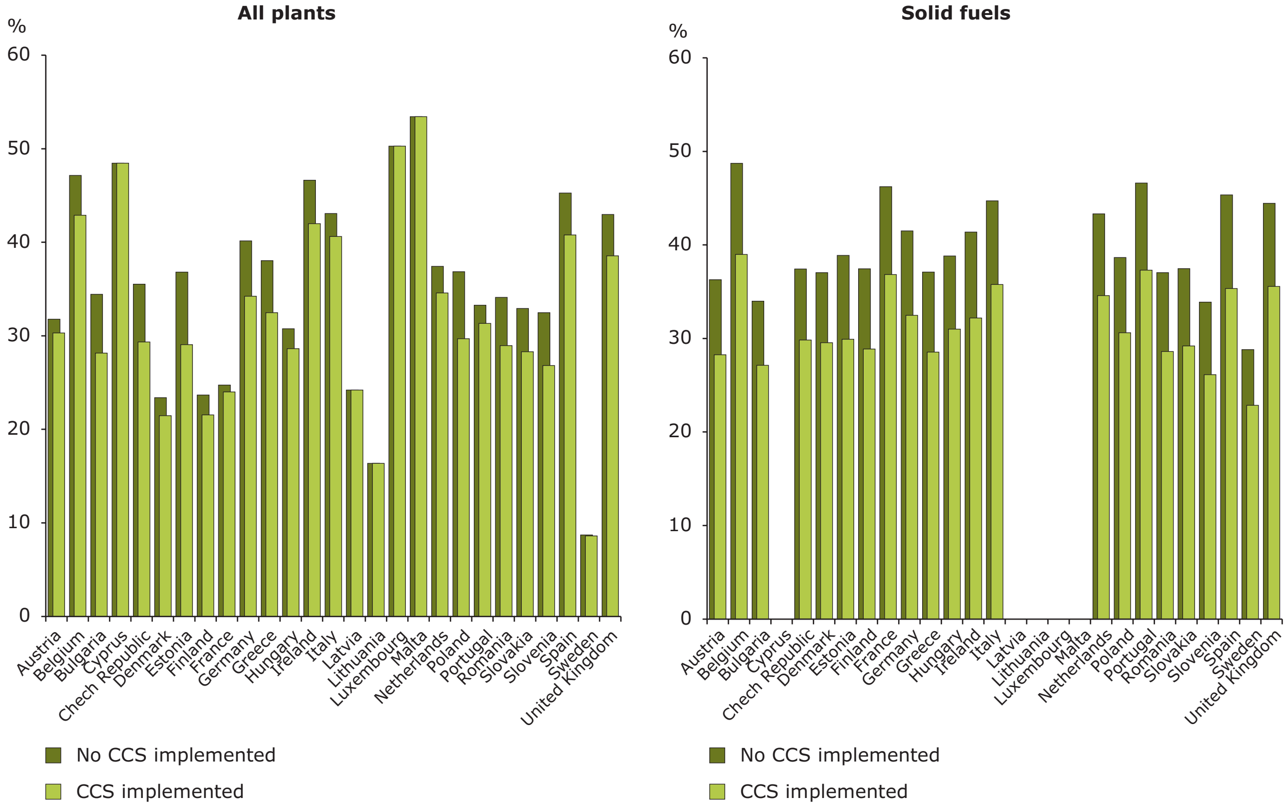
The increased fuel use, due to the energy penalty of CCS, obviously decreases the conversion efficiency of the power generation in each country. This loss in overall energy efficiency (the so-called efficiency penalty) typically ranges from around 6 to 12 percentage points dependent upon the efficiency of the plant (Chapter 3). The calculations show that the overall efficiency in thermal power plants in Europe would decrease from 38.5 % if no CCS were implemented in 2050, to 33.9 % if all power plants in Europe would use CCS (Figure 10.4). The decrease for solid fossil fuel-fired power plants would be from 41.1 % with no CCS to 32.4 % with full implementation of CCS in these plants. Differences among the EU Member States reflect national specific circumstances like biomass co-firing, age and condition of the power plants and the exact fuel mix and quality in the country.

### *10.4.1 Additional fuel transport*

In addition to the direct energy penalty at CCS-equipped facilities occurring because of the additional fuel consumption required, additional energy is also required to transport the additional fuel.

Table 10.4 shows the energy use in the PRIMES baseline 2009 for the no-CCS scenario and the additional energy needed for the fuel penalty. Based on the additional energy, the amount of coal was

**Figure 10.4 Energy efficiency loss by introducing CCS in solid fuel-fired power plants**



**Note:** 2030 data.

**Table 10.4 Additional amount of coal and coal transport needed for the scenario with all coal-fired power plants equipped with CCS**

| Year | Energy BL2009 — no CCS (PJ) | Energy Penalty — all coal-fired power plants with CCS (PJ) | Additional coal (Mtonne) | Additional transport — Australia (Mtonne.km) | Additional transport — Europe (Mtonne.km) |
|---|---|---|---|---|---|
| 2010 | 9 010 | 2 645 | 150 | 2 993 630 | 149 681 |
| 2020 | 9 126 | 2 583 | 144 | 2 885 891 | 144 295 |
| 2030 | 8 166 | 2 193 | 127 | 2 536 282 | 126 814 |

**Note:** Assumptions:
- NCV (hard coal) = 25.8 MJ/kg, NCV (brown coal) = 11.9 MJ/kg (IPCC, 1996);
- Assumed transport distance from Australia = 20 000 km; inside Europe = 1 000 km.

calculated using the respective net caloric values (NCV) of hard coal (HC) and brown coal (BC). The additional water borne coal transport in Mtonne.km was then calculated using representative transport distances of 20 000 km for coal sourced from Australia and 1 000 km for coal mined within Europe.

## 10.5 Emission factors for the calculation of GHG and air pollutant emissions

The emission factors for power plants without CCS are derived from the GAINS model database (IIASA, 2010). The emission factors were averaged over the years 2010, 2020 and 2030, but remained country specific. The emission factors related to the various CCS technologies and processes are derived from a literature review (Horssen et al., 2009). The emission factors are based on state-of-the-art technologies. No progress in technology development which could result in more efficient and less polluting technologies is implemented in the scenarios towards 2050.

**Table 10.5 Mean emission factors derived from BOLK study (g/GJ)**

| | PC | IGCC |
|---|---|---|
| $SO_2$ | 0.6 | 1 |
| $NO_X$ | 49 | 20 |
| $NH_3$ | 15 | 0 |
| $PM_{10}$ | 4 | 3 |

**Notes:** PC = Pulverised Coal; IGCC = Integrated Gasification Combined Cycle.

**Source:** Horssen et al., 2009.

With the introduction of CCS, the $CO_2$ emissions are assumed to be reduced by 90 %. For the other pollutants the mean emission factors from Horssen et al. (2009) were used (Table 10.5). These are derived from data for coal-fired plants, and specifically IGCC with pre-combustion and PC with post-combustion. In general, this means a reduction for all emissions except for $NH_3$. The increase of $NH_3$ emissions is a result of the assumption that amines (specifically MEA (13)) are used in the post-combustion carbon capture process. $NH_3$ is one of the degradation products of the solvent.

The approach applied with respect to emission factors is illustrated in the following paragraphs with reference to $SO_2$. The emissions of $SO_2$ are significantly lower with CCS, as an additional deep removal of $SO_2$ is needed before the capture process to prevent its reaction with the amine solvent and/or to avoid potential system corrosion issues. In Figure 10.5, the country-specific emission factors (logarithmic scale) with and without CCS are shown for existing and two new types of hard coal (HC)-fired power plants ('type A' and 'type B').

Without $CO_2$ capture, the $SO_2$ emissions vary from 20 to 1 840 g/GJ. The highest values are assigned to 'existing' power plants in some countries of Eastern Europe. New types of power plants in these countries already perform better than these levels. With CCS, all $SO_2$ emission factors are assumed to be 0.6 g/GJ (i.e. the value from Horssen et al. (2009)), irrespective of the country or whether the CCS is equipped to an existing or new type of power plant. Information on the effect of different CCS capture technologies on emissions of air pollutants is discussed in Chapter 3.

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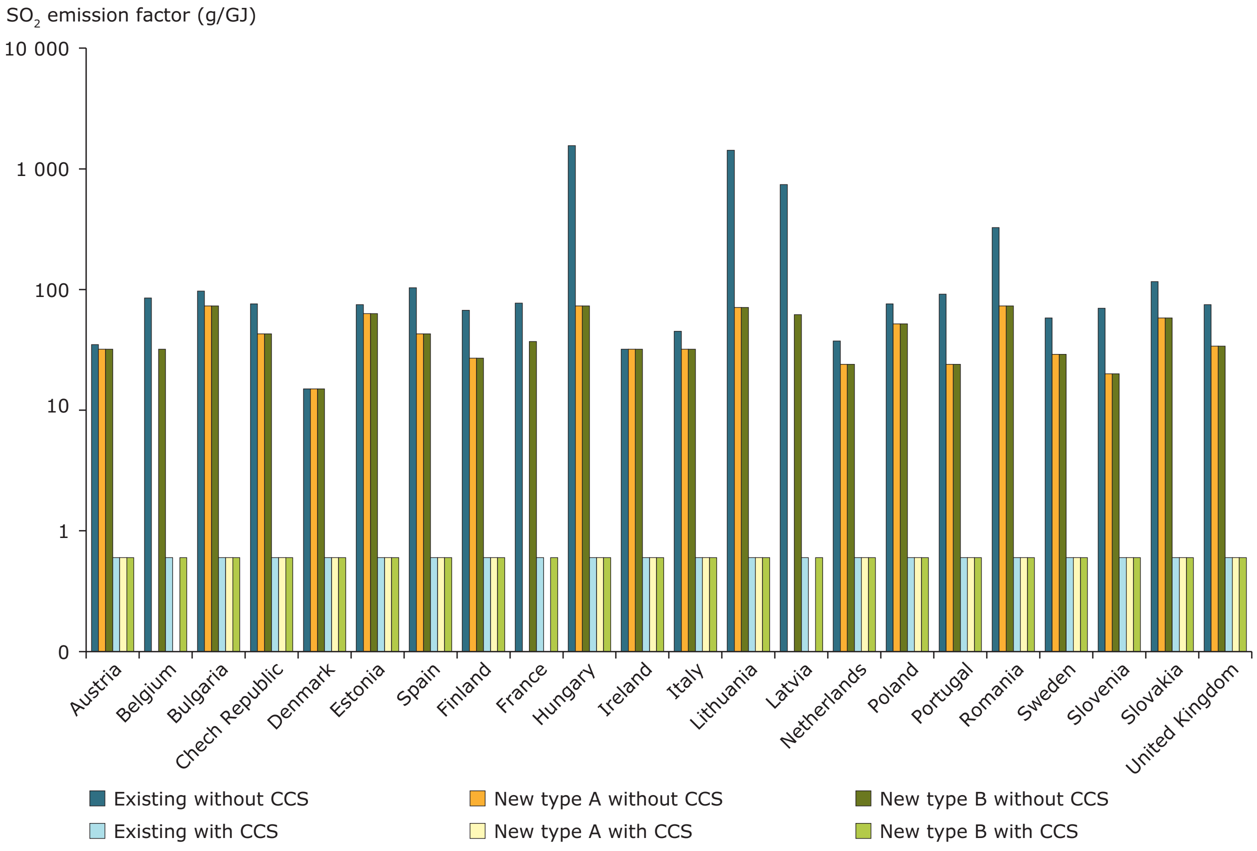
(13) MEA (mono ethanol amine): used in industry and the most studied solvent in relation to CCS capture technologies.

**Figure 10.5 $SO_2$ emission factors (logarithmic scale) for existing and two new types (type A and type B) of hard coal fired power plants without CCS and equipped with CCS**



# 11 Case study results and conclusions

GHG and air pollutant emissions for the EU power generation sector were calculated for the four selected CCS implementation scenarios. The scenarios were:

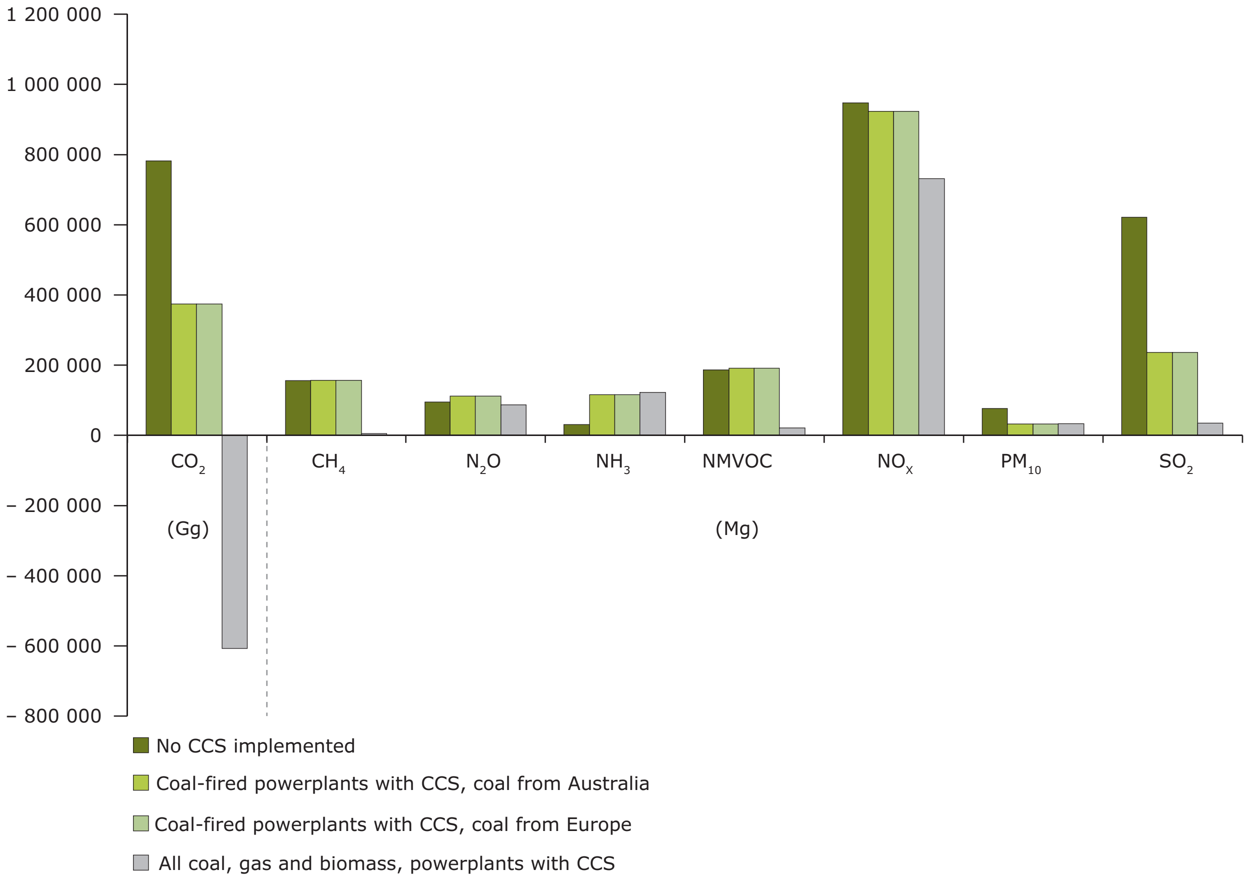
1. no CCS implemented;
2. all coal-fired power plants have CCS — additional coal (fuel penalty) from Australia;
3. all coal-fired power plants have CCS — additional coal (fuel penalty) from Europe;
4. all coal, natural gas and biomass power plants have CCS implemented — additional coal (fuel penalty) from Europe.

Figure 11.1 shows the estimated direct emissions arising from the implementation of CCS at power and heat generation facilities (i.e. power plants) including emissions arising from the additional energy penalty.

The life-cycle emissions resulting from the mining (fugitive emissions) and transport of the additional coal needed because of the CCS fuel penalty are added to the direct power generation emissions illustrated in Figure 11.1 and are shown in Figure 11.2.

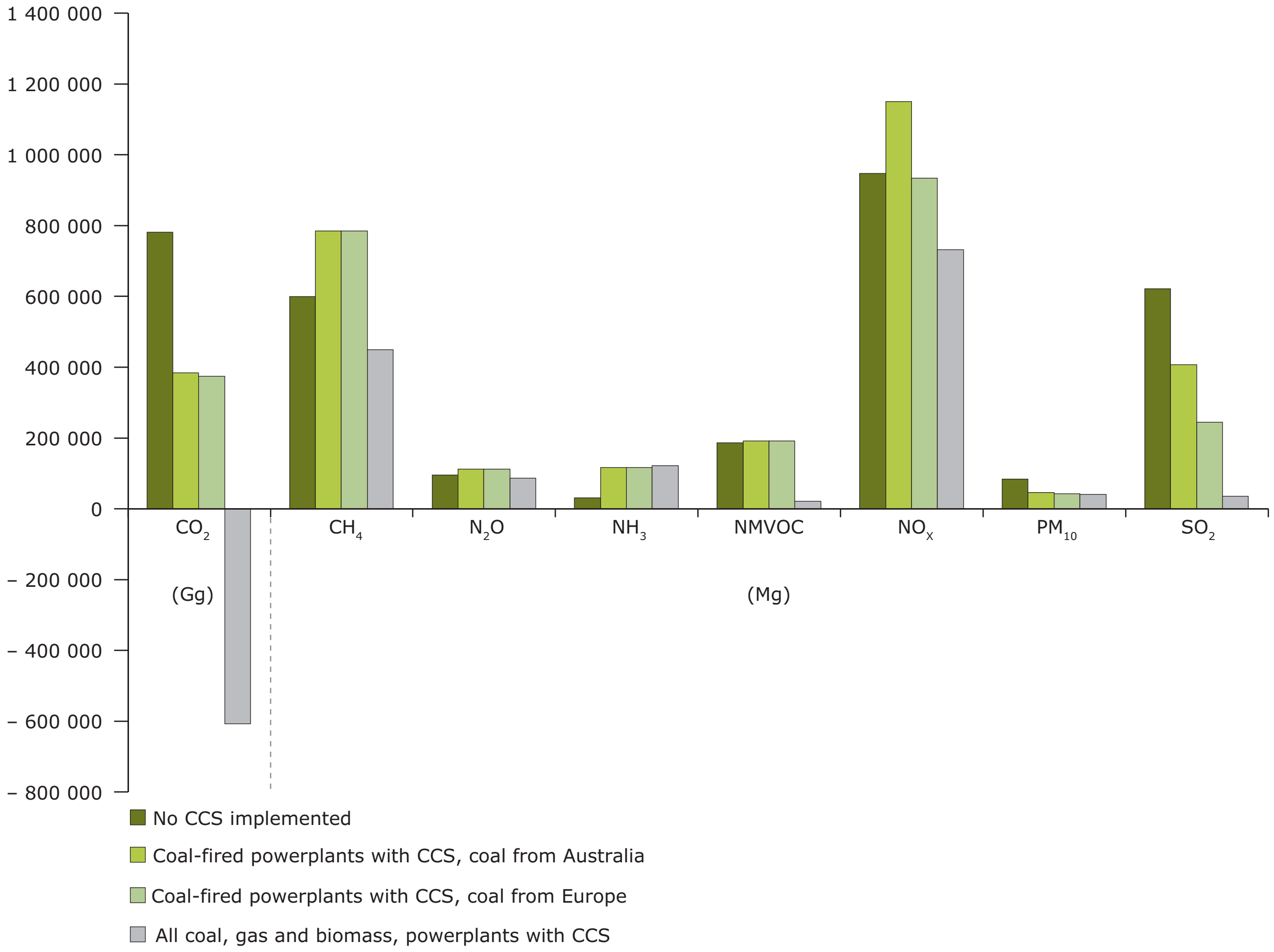
From the two charts presented above, the following observations and key findings are drawn concerning the emissions of the respective pollutants.

**Figure 11.1 Direct emissions from power generation in 2050 under the different CCS implementation scenarios**



**Note:** Units in Mg, except for $CO_2$ which is expressed in Gg.

**Figure 11.2 Direct and indirect emissions (incl. from the mining and transport of additional fuel) for the power generation sector in 2050 under the different CCS implementation scenarios**



**Note:** Units in Mg, except for $CO_2$ which is expressed in Gg.

Overall, **$CO_2$ emissions** decrease by approximately 60 % by applying CCS to all coal-fired power plants in Europe compared to the non-CCS scenario. The additional $CO_2$ emissions from the transport of additional coal are negligible compared to the overall direct emissions arising from the power-generating facilities. Implementation of CCS to all coal-, natural gas- and biomass-fuelled power plants leads to $CO_2$ emissions becoming negative in 2050. This is due to the increase in biomass use between 2040 and 2050 according to the PRIMES and TIMER/IMAGE fuel mix assumptions. In this most extreme scenario, the power sector is effectively converted into a net $CO_2$ sink. This obviously assumes that all biomass is harvested in a sustainable way, not leading to any carbon stock changes in the European or international forests and agriculture sectors.

The **$CH_4$ emissions** are for the most part caused by the mining of coal. These emissions will increase for scenarios 2 and 3 relative to the non-CCS scenario because of the additional coal needed to compensate for the CCS fuel penalty. Where these emissions will occur geographically will depend upon the location where the additional coal will be mined — i.e. either in Europe or in Australia in the scenarios used.

The overall **$PM_{10}$ emissions** for Europe will decrease by around 50 %. The decrease is caused by the low emission factors for CCS-equipped power plants. Low $PM_{10}$ emissions are required for the $CO_2$ capture process in order not to contaminate the capture solvent. The fuel penalty, because of the additional energy needed for the capture process, will lead to additional $PM_{10}$ emissions during the coal mining and transport stages of the CCS life-cycle, but overall these increases are smaller in magnitude than the reduction achieved at the CCS-equipped power plants.

For **$SO_2$ emissions** an even greater reduction is noted compared to the level of emission calculated under the non-CCS scenario. A deep removal of $SO_2$ is needed before the capture process to prevent the reaction of $SO_2$ with the capture solvent and to avoid potential corrosion issues within the CCS system. The transport of additional coal from Australia (or indeed any other location) will lead to an increase in $SO_2$ emissions from the international shipping involved to Europe. However, overall, total life-cycle $SO_2$ emissions will decrease as the reduction in direct emissions is larger than the increase due to the additional shipping.

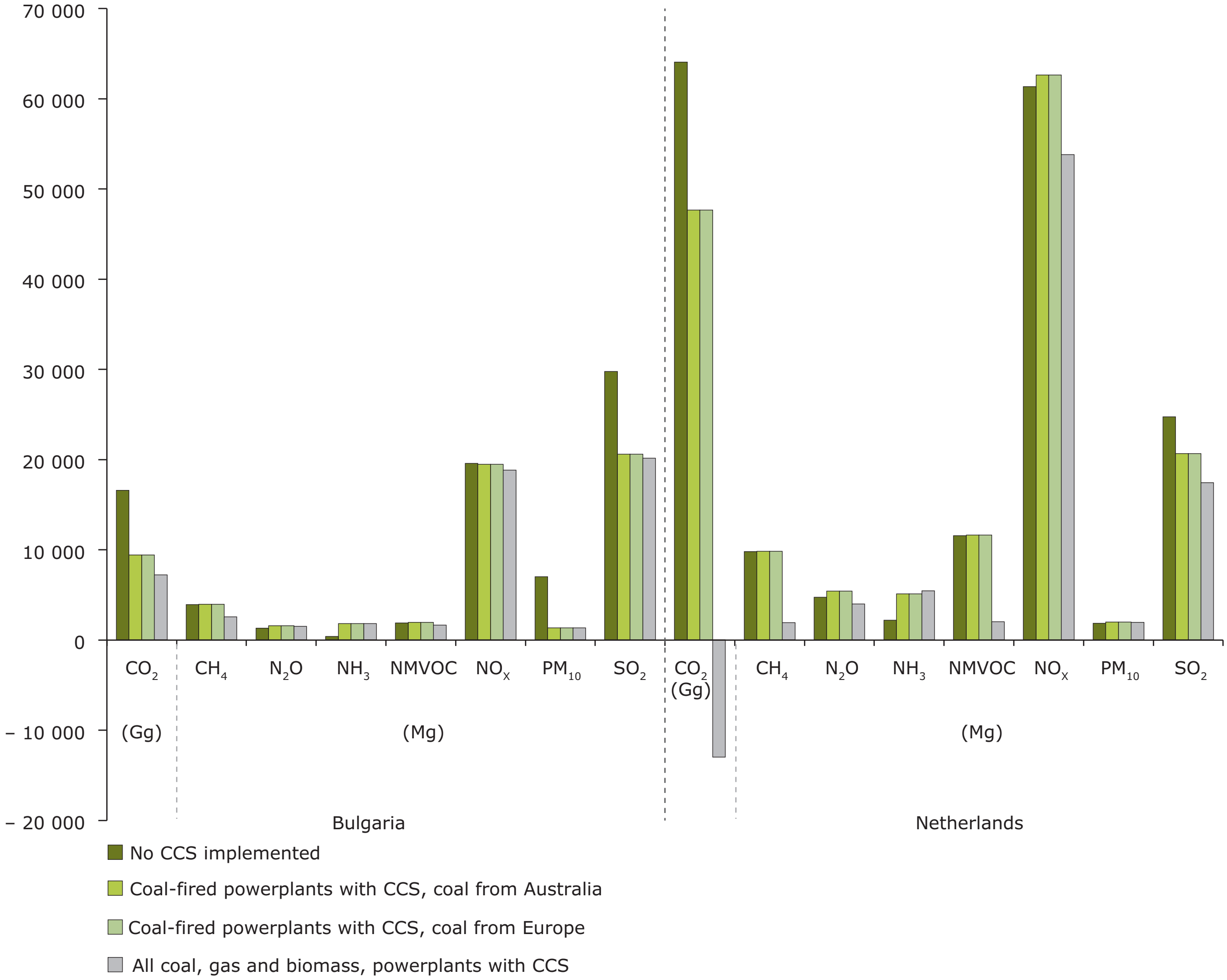
The **$NO_x$ emissions** from power plants remain more or less the same after the introduction of CCS, but will decrease under the scenario of implementation of CCS to all coal, natural gas and biomass power plants. On a life-cycle basis, the overall $NO_x$ emissions are foreseen to increase under the scenario where additional coal is sourced from Australia due to increased emissions from shipping.

**$NH_3$ emissions** are the only instance in which a significant increase of direct emissions compared to the non-CCS scenario is foreseen. The increase is predicted due to the degradation of the amine-based solvent that is assumed in the current literature. New solvents are under development, with potential to show less degradation. Nevertheless, compared to the present day level of emissions of $NH_3$ from the EU agricultural sector (around 3.5 million Mg (tonnes), or 94 % of the EU's total emissions (EEA, 2011)), the magnitude of the foreseen $NH_3$ increase is relatively small.

The modelling results also show that there are large differences expected in the impact of the introduction of CCS for different Member States. Figure 11.3 shows the calculated emissions for two selected countries, Bulgaria and the Netherlands. In Bulgaria, the $PM_{10}$ and $SO_2$ emissions strongly decrease with the implementation of CCS to coal-burning facilities, whereas in the Netherlands the $SO_2$ emissions decrease to a lesser extent and the $PM_{10}$ emissions are even forecast to potentially slightly increase. These differences are directly related to the large differences in the emission factors assumed for the non-CCS power plants between the countries, for example as indicated in Figure 10.5 earlier. In contrast, as described in section 10.5, emissions of all CCS power plants are assumed for technological reasons to be equal over Europe regardless of location.

In conclusion, it is clear that for the EU as a whole, and for most Member States, the overall co-benefits of the introduction of CCS in terms of reduced emissions of most air pollutants could be substantial (particularly, for example, for those countries in Eastern and Southern Europe). There do of course remain large uncertainties, however, as to the extent to which CCS technologies will actually be implemented in all such countries over the coming decades. In addition, as was mentioned in the Introduction to this report, the implementation of CCS should be seen as a bridging technology and in itself should not introduce barriers or delays to the overarching objective of moving toward a lower-energy and more resource-efficient economy.

**Figure 11.3 Emissions in 2050 following modelled CCS implementation in Bulgaria and the Netherlands**



**Note:** Units in Mg, except for $CO_2$ which is expressed in Gg.

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# Annex 1 Status of CCS implementation as of June 2011

$CO_2$ capture and storage is receiving an increasing amount of attention as a potential $CO_2$ mitigation technology and has continuously advanced on the list of political and business priorities over the last decades. As described earlier in this report, $CO_2$ capture has been used since the 1970s by industry to remove $CO_2$ from gas streams where it is unwanted, or to separate $CO_2$ as a product gas. Nevertheless, no full-scale or industrial power plant has yet fully implemented CCS technology in order to reduce their $CO_2$ emissions. $CO_2$ capture has only been demonstrated in small-scale test plants and not yet full-scale ones. Moreover, infrastructure for transport and storage of $CO_2$ must be established prior to implementation of capture technologies or there is no reason to capture $CO_2$.

Nevertheless, a number of CCS pilot initiatives have launched worldwide and others are planned. In the EU, there are plans to build a number of demonstration plants for $CO_2$ capture and storage by 2015 and thereby potentially commercialise the technology by 2020. Additionally, the IEA CCS Road Map has set out the case for 100 demonstration projects by 2020 and 3 000 by 2050 (Gale, 2010).

In June 2010, the IEA reported back to G8 countries on their past commitments to develop $CO_2$ capture and storage by pointing out that the world is failing to meet its targets. At a summit in Japan in 2008, eight of the world's leading economies had backed an IEA initiative to launch 20 large-scale projects by 2010. Currently, there are around 80 large scale projects at various stages of development around the world but only a few are operational. All of the projects in operation were commissioned prior to the 2008 summit. Moreover, none of the existing projects test the full chain of CCS processes (IEA/CSLF, 2010).

The technologies involved in CCS stand at various stages of commercial readiness (14). Thus, different types of carbon capture technologies have different development phases and different advantages and disadvantages (economically, $CO_2$ avoidance costs, fuel use, emissions and waste, etc.). However, post-combustion $CO_2$ capture using solvent

**Table A1.1 The overview of number of CCS projects worldwide**

| **CCS projects** | **Number of projects** |
|---|---|
| **Project status** | |
| All | 87 |
| Possible | 57 |
| Speculative | 21 |
| Operating | 9 |
| **Capture concept** | |
| All | 87 |
| Post-combustion | 33 |
| Pre-combustion | 23 |
| Gas processing | 12 |
| Oxyfuel | 10 |
| Undecided | 5 |
| Industrial process | 4 |
| **Capture technology** | |
| All | 87 |
| Undecided | 59 |
| Amine absorption | 11 |
| Condensation | 10 |
| Chilled ammonia absorption | 3 |
| Carbonate absorption | 1 |
| Chilled methanol absorption | 1 |
| Cryogenic separation | 1 |
| Chemical looping combustion | 0 |
| Membranes | 0 |
| **Storage** | |
| All | 87 |
| Deep saline aquifer | 28 |
| Depleted oil & gas field | 23 |
| Undecided | 17 |
| Enhanced oil recovery | 16 |
| Enhanced coal bed methane recovery | 2 |
| Basalt | 1 |
| **$CO_2$ transport** | |
| All | 87 |
| Pipeline | 79 |
| Unknown | 5 |
| Ship | 3 |

**Source:** Bellona, 2010.

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(14) Post-combustion capture demonstrated at 1 Mt scale on natural gas (pilot plants on flue gas need to be scaled up), Pre-combustion capture (IGCCS) not yet demonstrated in integrated mode at scale, Oxyfuel combustion — pilot plants need to demonstrate technology then scale up as needed).

scrubbing is one of the more established processes for $CO_2$ capture, and there are currently several facilities at which amine solvents are used to capture significant flows of $CO_2$ from flue gas streams. Oxyfuel combustion has been demonstrated in the steel manufacturing industry at plants up to 250 MW in capacity, and the related oxy-coal combustion method is currently being demonstrated. Pre-combustion $CO_2$ capture from an IGCC power plant has yet to be demonstrated; however, elements of the pre-combustion capture technology have already been proven in other industrial processes (Gale, 2010; Henderson and Mills, 2009; IPCC, 2005). Additional aspects that require future consideration and resolution before CCS can be applied on a large scale include a number of technical, legal and societal issues. Moreover, public confidence is required on the environmental performance and safety issues (IPCC, 2005).

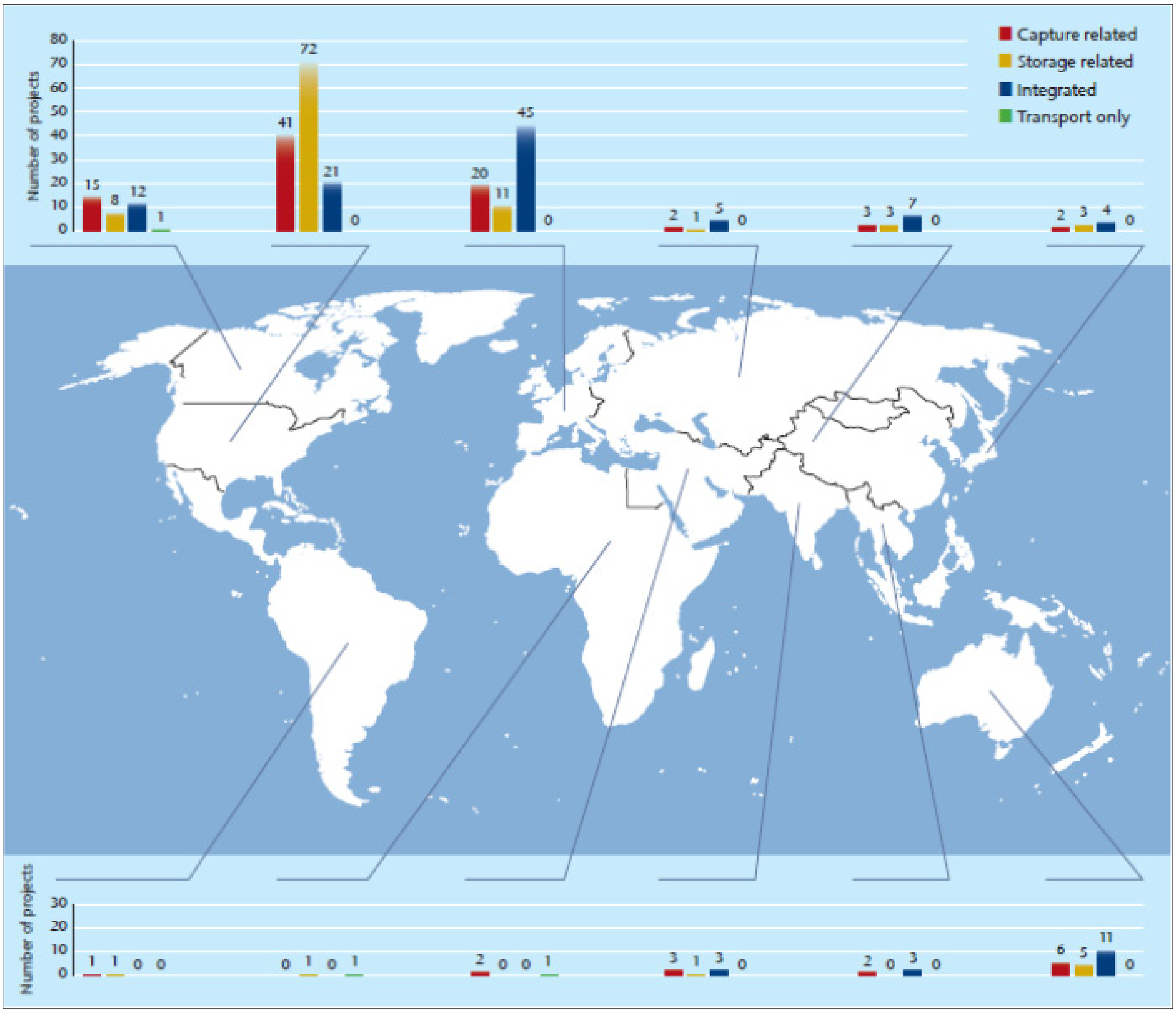
Table A1.1 shows a global overview of planned CCS projects, including the different types of technologies that they may employ (see also Figure A1.1). Several projects addressing various aspects of the CCS chain are presently in operation. Details of six such projects are provided in Table A1.2.

**Table A1.2 Examples of current CCS projects**

| | |
|---|---|
| Demonstration projects | Sleipner West (Norway). StatoilHydro and IEA began injecting $CO_2$ from a natural gas field into a saline formation under the North Sea in 1996. Currently, they store 1 Mt of $CO_2$ per year with no leakage and plans are to store more than 20 Mt per annum (Mtpa) during the life of the project. Extensive monitoring has been carried out, including the use of 4-D (time lapse) seismic monitoring to track the progression of $CO_2$ in the reservoir. The projected cost is more than EUR 350 million (Storage). |
| | Weyburn $CO_2$ Flood Project (United States, Canada). Over 1.7 Mtpa of $CO_2$ is captured from a North Dakota (USA) coal gasification plant, compressed and transported via 330 km of land pipeline to the Weyburn field in Canada. The field is operated by EnCana which began storing $CO_2$ from enhanced oil recovery (EOR) in 2000. During Phase 1 (2000–2004), more than 7 Mt of $CO_2$ were stored, and the geology has been found suitable for long-term storage. The site will be maintained in order to study long-term sequestration. The second phase will include site characterisation, leakage risks, monitoring and verification and a performance assessment. A large-scale monitoring programme involving Canadian partners, the IEA Greenhouse Gas R&D Programme and the European Union (DG Research) is studying the interaction between the injected $CO_2$ and the formation/wellbores (Storage). |
| | In Salah (Algeria). Sonatrach, BP and Statoil began capturing $CO_2$ from natural gas production in 2004 and storing it in depleted gas reservoirs. They store about 1 Mt of $CO_2$ per year which is separated by usage of a chemical solvent (ethanol-amino solution). A total of 17 Mt of $CO_2$ will be stored. The projected cost for the project is USD 1.7 billion. This is the world's first full-scale $CO_2$ capture and storage project at a gas field (Storage). |
| | Snøhvit (Norway). The field operated by StatoilHydro is located in the Barents Sea. Statoil began storing $CO_2$ from gas production beneath the seabed in April 2008. The $CO_2$ is separated from natural gas onshore, at the Hammerfest facility which is located 160 km from the field. At full capacity, it is supposed to store 0.7 Mt of $CO_2$ a year. The $CO_2$ is compressed and transported back offshore to an injection layer 2 600 m underneath the gas-producing zone. The projected cost is USD 110 million (Storage). |
| | K12B (Netherlands). Gaz de France is investigating the feasibility of $CO_2$ storage in depleted natural gas reservoirs on the Dutch continental shelf. The $CO_2$ is injected in the same place from where it came. Injection started in 2004 (Storage). |
| | La Barge (Wyoming). ExxonMobil captures 4 Mt of $CO_2$ per year from gas production, which is stored in depleted gas reservoirs (Storage). |
| Pilot projects | Fenn Big Valley (Canada). The Alberta Research Council began injecting $CO_2$ into deep coal beds for enhanced coal bed methane in 1999, with a project cost of CAD 3.4 million. Thus far, all testing has been successful, and they are assessing the economics of the project (Enhanced coal bed methane) |
| | Ketzin (Germany). GFZ Potsdam, as part of the European research project, CO2SINK, began storing $CO_2$ in aquifers at a depth of 600 m on 30 June 2008. It plans to store up to 60 000 tonnes of $CO_2$ over 2 years, at a cost of EUR 15 million (Storage). |
| | Schwarze Pumpe (Germany). Vattenfall opened its pilot 30 MW coal oxyfuel combustion plant with $CO_2$ capture on 9 September 2008 (Coal plant with capture). |

**Source:** Gale, 2010; European Commission, 2008; IEA, 2008b; NETL, 2010; National Mining Association, 2010.

**Figure A1.1 Planned and operational large-scale (> 1 Mt $CO_2$/year) CCS projects**



**Source:** IEA, 2009a.

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