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CCS Global

Prospects of Carbon Capture and Storage Technologies (CCS) in Emerging Economies

Final Report

to the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU)

Part I:

General Status and Prospects of CCS

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Final Report

The total report consists of 6 parts:

Concluding Hypotheses / Zusammenfassende Thesen
I.   General Status and Prospects of CCS
II.   Country Study India
III.   Country Study China
IV.   Country Study South Africa
V.   Comparative Assessment of Prospects of CCS in the Analysed Countries

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List of Abbreviations, Units and Symbols

Abbreviations

BAU	Business as usual
BECCS	Bio-energy with carbon capture and storage
BFB	Bubbling fluidised bed
BMU	German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety
CAR	Ceramic autothermal recovery
CBM	Coalbed methane
CCGT	Combined cycle gas turbine
CCS	Carbon (dioxide) capture and storage
CFB	Circulating fluidised bed
CH_4	Methane
CHP	Combined heat and power plant
CISA	China – India – South Africa
CLC	Chemical looping combustion
CO	Carbon monoxide
CO_2	Carbon dioxide
CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies (AUS)
CSLF	Carbon Sequestration Leadership Forum
CTL	Coal to liquid
Daf	Dry and ash free
DRI	Direct reduced iron
ECBM	Enhanced coalbed methane
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
EREC	European Renewable Energy Council
EU	European Union
FCC	Fluid catalytic cracking
FGD	Flue gas desulphurisation
FTSM	Feed-in Tariff Support Mechanism
GDR	Greenhouse Development Rights
GHG	Greenhouse gas
GHGT	International Conference on Greenhouse Gas Control Technologies
H_2	Hydrogen
H_2S	Hydrogen sulfide
HHV	Higher heating value
HRSG	Heat recovery steam generator
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
LCA	Life cycle assessment
LCOE	Levelised cost of electricity

LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LR	Learning rate
MEA	Monoethanolamine
N_2	Nitrogen
NGCC	Natural gas combined cycle
NGO	Non-governmental organisation
NO_x	Nitrous oxides
NRW	North Rhine-Westphalia
O_2	Oxygen
OECD	Organisation for Economic Co-operation and Development
PC	Pulverised coal
PCC	Pulverised coal combustion
PR	Progress ratio
PV	photovoltaic
R&D	Research & development
SC	Supercritical
SCCS	Scottish Centre for Carbon Storage
SO_2	Sulphur dioxide
STP	Standard temperature and pressure
TGR-BF	Top gas recycling-blast furnace
UBA	German Federal Environment Agency
UCG	Underground coal gasification
ULCOS	Ultra Low CO_2 Steelmaking
USC	Ultra supercritical
WI	Wuppertal Institute for Climate, Environment and Energy
WTT	Well to tank

Units and Symbols

°C	degree Celsius
a	annum
A	surface area of coal basin
B_g	gas expansion factor
C	completion factor
c_p	compressibility of pores or rock
c_W	compressibility of formation water
E	efficiency factor
el	electric
E_V	volumetric efficiency
EUR	euro
FVF	formation volume factor
GC	gas content
Gt	gigatonne (1 billion tonnes)
GW	gigawatt
h	cumulative thickness of the coal
hPa	Hectopascal
km	kilometre
km^2	square kilometre
m	metre
$m_{CO2, effective}$	effective gravimetric storage capacity
$m_{CO2, theoretical}$	theoretical gravimetric storage capacity
mD	millidarci
mm	millimetre
MPa	megaPascal
Mt	megatonne (1 million tonnes)
MW	megawatt
n/g	net-to-gross ratio (proportion of sediment structures with porosity and permeability suitable for absorbing CO_2)
ppm	parts per million
R_f	recovery
TJ	terajoule
traps%	proportion of traps in the total volume
USD	United States dollar
V_b	volume of the potential storage
$V_{gas}(STP)$	cumulative production volume under standard conditions
ρ_{CO2}	density of CO_2
ρ_{coal}	bulk coal density
ϕ	Porosity
Δp	maximum pressure increase
%	per cent

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I.   General Status and Prospects of CCS

The aim of this study is to explore whether carbon capture and storage (CCS) could be a viable technology option for significantly reducing CO_2 emissions in emerging countries such as China, India and South Africa. These key countries have been chosen as case studies because all three, which hold vast coal reserves, are experiencing a rapidly growing demand for energy, currently based primarily on the use of coal.

The analysis is designed as an integrated assessment, and takes various perspectives. The main objective is to analyse how much CO_2 can potentially be stored securely and for the long term in geological formations in the selected countries. Based on source-sink matching, the estimated CO_2 storage potential is compared with the quantity of CO_2 that could potentially be separated from power plants and industrial facilities according to a long-term analysis up to 2050. This analysis is framed by an evaluation of coal reserves, levelised costs of electricity, ecological implications and stakeholder positions. The study finally draws conclusions on the future roles of technology cooperation and climate policy as well as research and development (R&D) in the field of CCS.

The following sections present introductions to the individual country with profiles for India (Part II), China (Part III) and South Africa (Part IV). First of all, in Part I, a number of global low CO_2 energy scenarios are analysed according to whether they include country-specific CCS-based scenarios which could be used in the country analyses (section 1). Section 2 reviews technology options and the state of developments in the field of CO_2 capture processes. Furthermore, different types of uses for CO_2 capture are discussed. In section 3 an overview of the technical, financial and infrastructural challenges facing the transportation of CO_2 is given whilst section 4 gives an introduction to types of storage formation, mechanisms for CO_2 storage and methods for assessing storage potentials. Finally, in section 5 a short overview is given of the methods used in the supplementary technology assessment.

1 Perception and Relevance of CCS in Global CO$_2$ Mitigation Scenarios

1.1 Introduction

The aim of this section is to assess the role that CCS technologies could play on the international stage. In the first step, a number of different global low CO$_2$ energy scenarios are analysed. Secondly, there is a comparison of the extent to which CCS could contribute to overall CO$_2$ reduction, both in the energy sector and in the industrial sector. Furthermore, low CO$_2$ energy scenarios for India, China and South Africa are reviewed from a CCS perspective. These scenarios could serve as a basis for further analytical work regarding the framework conditions for CCS in country-specific energy sectors.

It should be noted that in the sections below, generally no distinction is made between "hard coal" and "lignite", so "coal" can refer to either type of coal.

1.2 Global Scenario Studies Analysed

Various global energy scenario studies have been published in recent years by non-governmental organisations (NGO) (for example, EREC and Greenpeace International (2008a)), companies (for example, Shell (2008)) and international agencies (for example, IEA and OECD (2009)). For this section, four different scenario studies are analysed:

- *How to Combat Global Warming – The Bellona Scenario* (Bellona Foundation 2008);

- *Energy Technology Perspectives 2010* (IEA 2010);

- *World Energy Outlook 2010* (IEA and OECD 2010);

- *Energy [R]evolution – A Sustainable World Energy Outlook 2010* (EREC and Greenpeace International 2010).

These studies were chosen because they have all been published within the last two years and all include at least one scenario that attains ambitious climate protection goals.

How to Combat Global Warming – The Bellona Scenario describes a climate protection scenario up to 2050, which by then achieves a reduction in global greenhouse gas (GHG) emissions of 85 per cent compared to 2005 levels, despite an envisaged nuclear phase-out. A spreadsheet model is used to build the scenario whilst data input comes from a large variety of sources. Contrary to most other scenarios, this one encompasses all greenhouse gases and not just carbon dioxide. Furthermore, it aims to describe "the optimal technological path for considerably reducing global GHG emissions" instead of achieving it via a mix of technologies through economic optimisation (Bellona Foundation 2008).

As well as a Reference Scenario (*Current Policies Scenario*), the *World Energy Outlook (WEO) 2010* from the International Energy Agency (IEA) also describes a *450 Scenario* that aims to stabilise the concentration of greenhouse gases in the atmosphere at 450 parts per million (ppm) of carbon dioxide equivalent in the long term. Unlike the other scenarios analysed in this paper, which all run until the middle of the century, the scenarios of the WEO

2010 are described in detail only up to 2035. Consequently, the figures on coal power generation do not go beyond this date.

Energy Technology Perspectives (ETP) 2010 is the third publication in the ETP series, following previous ones published in 2006 and 2008. As the title suggests, a theme of these publications is the various technological options regarded as essential in reaching "a more secure, sustainable and affordable energy future" (IEA 2010). ETP 2010 describes a number of different scenarios for the global energy system up to 2050. In addition to a Baseline Scenario, a main alternative scenario named *BLUE Map* and other variations on the *BLUE Map Scenario* are developed. In all versions of the BLUE scenario, the global energy-related CO_2 emissions are reduced to 50 per cent of 2005 levels by 2050. Based on the IEA assumptions, the *BLUE Map Scenario* is the most cost-effective way of achieving this goal.

However, it should be noted that, according to climate research findings, a 50 per cent reduction target will not be sufficient to limit the rise in temperature to 2 degrees. In fact, the IPCC assumes that a minus 50 to minus 85 per cent global reduction in greenhouse gas emissions on year 2000 levels by 2050 is quite likely to be required to achieve temperature targets (IPCC 2007). Not even the 50 per cent reduction within the BLUE scenario set would fulfil the IPCC requirements since the scenarios use 2005 as their basis and not 1990, as the WEO does.

The *BLUE Map Scenario* does focus separately on India and China, but there are no detailed figures on the development pathways up to 2050.

The *2010 Energy [R]evolution study* is the third in a series of studies, of which the first were published in 2007 and 2008 (see, for example, EREC and Greenpeace International (2008b); Krewitt et al. (2009)). It aims to show how the global energy system could be transformed up to 2050 to comply with stringent climate protection goals without relying on new nuclear power plants or on CCS technology. The study includes two scenarios which envisage drastic improvements in energy efficiency, an ambitious increase in the use of all forms of renewable energy and a global phase-out of nuclear energy. Whilst the *Energy [R]evolution Scenario* achieves a reduction in global energy-related CO_2 emissions of 51 per cent by 2050 compared to 1990 emissions, the more ambitious *Advanced Energy [R]evolution Scenario* would achieve a reduction of 84 per cent by 2050. Since both scenarios are broken down into IEA world regions and single countries, individual scenarios for India, China and South Africa can be used.

Three of the analysed studies consider CCS as part of their low CO_2 energy scenarios. These scenarios and their focus on CCS are described in section 1.3:

- *How to Combat Global Warming – The Bellona Scenario* (Bellona Foundation 2008);

- *World Energy Outlook 2010* (IEA and OECD 2010);

- *Energy Technology Perspectives 2010* (IEA 2010).

Although the *Energy [R]evolution study* does not consider CCS, its *Energy [R]evolution Scenario 2010* (EREC and Greenpeace International 2010) is also analysed. In the country-specific scenarios its country reports will be used to illustrate a low coal-based strategy. This scenario is described in section 1.4.

1.3   CCS-Based Electricity Generation in Global Low CO$_2$ Energy Scenarios

1.3.1   The Bellona Scenario

The Bellona Business-as-Usual (BAU) scenario is mainly based on rather conservative assumptions of both the Reference Scenario in the IEA World Energy Outlook 2007 (IEA and OECD 2007) and the Baseline Scenario in the IEA Technology Perspectives 2006. Under BAU conditions, global GHG emissions would increase from 44.9 Gt of CO$_{2-eq}$ in 2005 to 81 Gt of CO$_{2-eq}$ by 2050. In comparison, the *Bellona Scenario* assumes that changes in lifestyle will "reduce the growth in energy demand and resulting GHG emissions through reduced consumption and improved availability and use of low carbon products and solutions." The main development issues within this scenario are:

- An increase in global primary energy demand of 23 per cent between 2005 and 2050;

- A decreased dependency on fossil fuel from 81 per cent in 2005 to 40 per cent in 2050;

- Renewable energy accounting for 60 per cent of total energy supply by 2050;

- A decrease in global GHG emissions by 84 per cent (37.7 Gt CO$_{2-eq}$/a) between 2005 (44.9 Gt CO$_{2-eq}$) and 2050 (7.1 Gt CO$_{2-eq}$) and a decrease of 91 per cent (74 Gt CO$_{2-eq}$/a), if compared with BAU 2050 figures;

- A peak in global GHG emissions before 2015 (see Fig. 1-1).

Bellona regards CCS as one of the main low carbon technologies and considers the use of this technology for clean energy development as "ambitious, but also realistic." The potential for CCS is based on another Bellona study (Stangeland 2007) "which concluded that CCS can reduce CO$_2$ emissions from fossil fuelled power plants by 80 per cent in OECD countries by 2050", but for the *Bellona Scenario* this assumption is enhanced to a CCS share of 100 per cent. Furthermore, it is assumed that CCS can be implemented in 50 per cent of industrial plants and fuel transformation plants, respectively, and in 80 per cent of biomass-based power plants.

In general, the potential for non-OECD countries is set at 75 per cent of the potential for OECD countries. Tab. 1-1 summarises the assumptions of the CCS contribution to CO$_2$ reduction.

Tab. 1-1   Share of plants assumed for CCS implementation

Sector	Share of CO$_2$ emissions where CCS is introduced in 2050			
	OECD countries		Non-OECD countries	
	2030	2050	2030	2050
	%	%	%	%
Fossil-fired power plants	33	100	25	75
Biomass-fired power plants	26.7	80	20	60
Industry and fuel transformation	16.7	50	12.5	37.5

Source: Bellona Foundation (2008)

The main assumptions on which the calculation of CO$_2$ reduction by CCS are based are

- Commercial availability of CCS by 2020;

- A capture rate of 80 per cent by 2015, increasing to 90 per cent by 2050;

- An increased energy demand, given as a percentage of the power production from a power plant, of 15 per cent by 2015, decreasing to 10 per cent by 2050. This equates to a penalty load of 5 to 6 percentage points for existing power plants, decreasing to 3 to 5 percentage points by 2050.

Fig. 1-1 shows the development of global GHG emissions between 2005 and 2050 (minus 84 per cent) as well as the share of the considered low carbon technologies on the total GHG reduction by 2050, if one compares the 2050 figures between BAU and Bellona (minus 91 per cent). Nearly 23 Gt of CO_{2-eq}/a or 31 per cent of the total reduction abatement by 2050 (74 Gt CO_{2-eq}/a) is assumed to be enabled by the implementation of CCS.
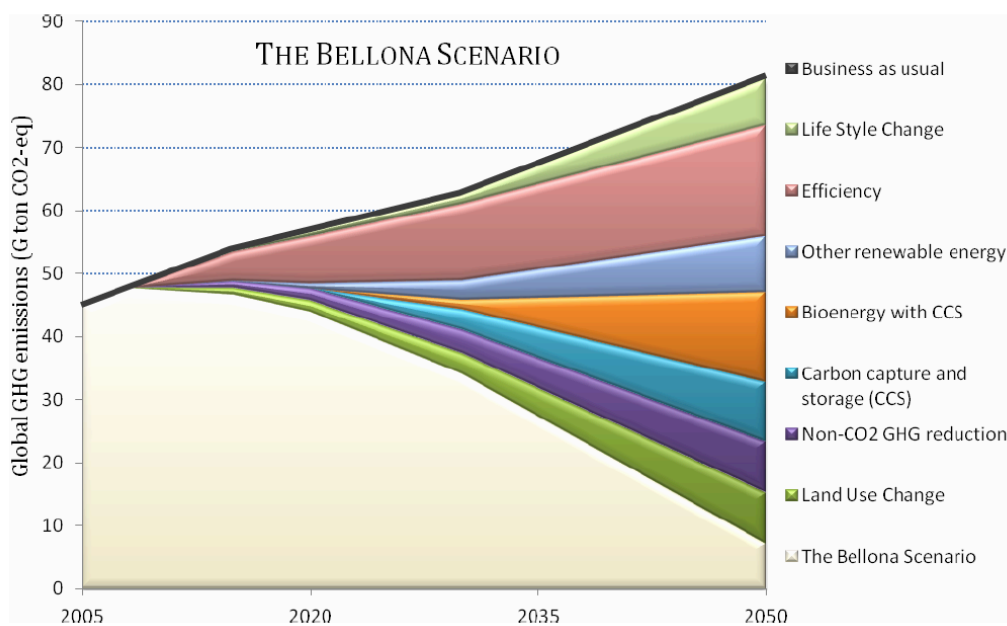
Fig. 1-1   Contribution of different technology options to reduce greenhouse gas emissions by 84 per cent between 2005 and 2050 under the *Bellona Scenario*

Source: Bellona Foundation (2008)

Whilst the diagram shows only the differentiation between bioenergy-based CCS (60 per cent) and other CCS sources (40 per cent), Tab. 1-2 illustrates the allocation to individual sources. It shows that only a minor share comes from fossil fuelled power production (24 per cent) and from industrial sources (7 per cent), whilst the majority is enabled by CCS from large biomass power plants (40 per cent) and from other biomass-based sources (20 per cent). Biomass power plants applying CCS combines two effects – replacing fossil fuels with biomass and, additionally, capturing the CO_2, also referred to as "carbon negative energy". The high level indicated seems to be quite ambitious, especially considering that today only small-scale biomass based plants exist. This is why Bellona argues "how important it is to deploy large-scale bio power plants with CCS." Another conclusion is that "the CCS potential is relatively evenly distributed across OECD and non-OECD regions, which is a compelling reason for deploying CCS in developing countries as well as in developed countries" (Bellona Foundation 2008).

Tab. 1-2   CCS contribution to global greenhouse gas emission reduction by 2050 using the *Bellona Scenario*

Source and technology	GHG emission reduction in 2050	
	Gt $CO_{2\text{-eq}}$/a	%
Biomass	**13.6**	**60**
Biomass for power production and fuel transformation (with CCS)	4.4	20
CCS from bioenergy-based sources	9.2	40
Non-biomass	**9.2**	**40**
CCS for fossil-fired power production	5.6	24
CCS for fuel transformation from fossil-fired sources	2.1	9
CCS for industrial sources	1.7	7
Total	23	100

Source: Based on Bellona Foundation (2008)

1.3.2   The ETP-BLUE Map Scenario 2010

The *ETP 2010 Baseline Scenario* is based on the *Reference Scenario* published in the IEA World Energy Outlook 2009 (IEA and OECD 2009), which anticipates developments up to 2030, and presents its own projections for the period between 2030 and 2050. Under BAU conditions, global CO_2 emissions would increase from 29 Gt of CO_2 in 2007 to 40 Gt of CO_2 by 2030 and to 57 Gt of CO_2 by 2050 (which is a total growth of 28 Gt, or 97 per cent). It is assumed that nearly all the growth (96 per cent) in global CO_2 emissions in the Baseline Scenario will come from outside the OECD. In this study, it is worth noting that "CO_2 emissions in India show the largest relative increase, rising nearly fivefold by 2050."

In contrast, in its *BLUE Map Scenario* the IEA estimates that a 50 per cent reduction in global CO_2 emissions by 2050 (compared to the 2005 level) would require a 43 Gt reduction in CO_2 compared to the Baseline Scenario (IEA 2010). The main developments within this scenario, the target of which is consistent with the 450 ppm IPCC scenario, are

*   A 50 per cent (14 Gt CO_2/a) decrease in global CO_2 emissions between 2005 (29 Gt CO_2) and 2050 (15 Gt CO_2) and a decrease of 75 per cent (43 Gt $CO_{2\text{-eq}}$/a), if compared with the Baseline 2050 figures;

*   A peak in global CO_2 emissions at below 31 Gt between 2015 and 2020 (see Fig. 1-3).

According to the IEA, this ambitious CO_2 reduction target "will require the development and deployment of a wide range of energy-efficient and low-carbon technologies across every sector of the economy." But from 2030, existing technologies and measures would no longer be sufficient and would have to be supplemented by the widespread introduction of CCS (and other) technologies. The calculation of CO_2 reduction through CCS is chiefly based on the assumptions that:

*   New CCS-based power plants are mainly erected between 2030 and 2050;

*   The retrofit of existing power plants with CCS "is expected to play a significant role before 2030," which requires that "new fossil-fired plants built over the next 10 to 20 years utilise technologies and practices that enable such retrofitting to take place";

- For CCS-based power plants, a reduction of electrical efficiencies for coal at a level of around 7 per cent; for natural gas a figure of around 9 per cent is assumed (Fig. 1-2).
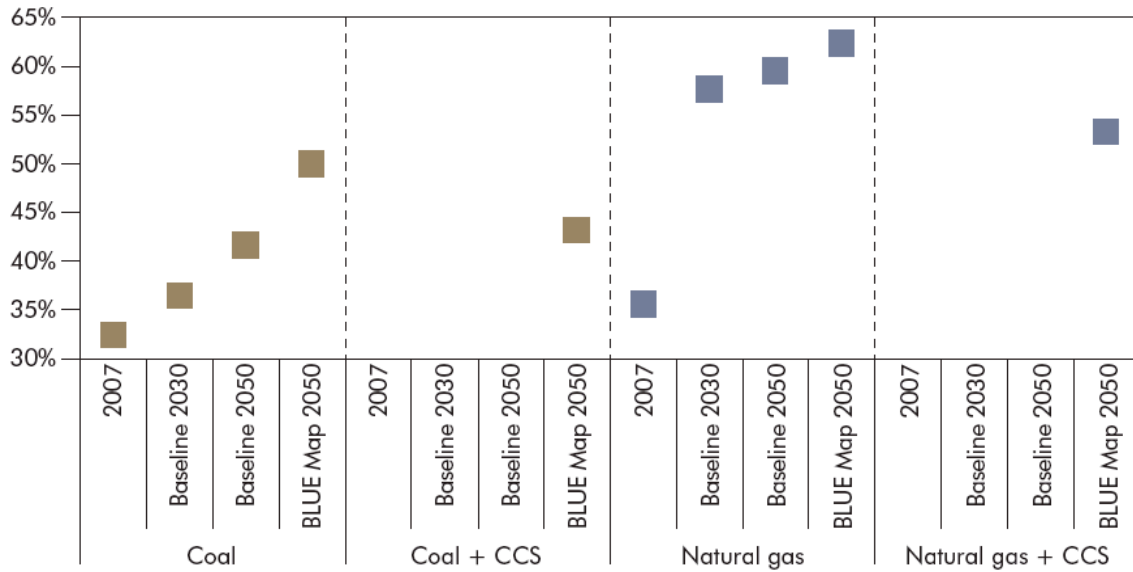
Note: Data refer to the average efficiency of the installed capacity in each year.

Fig. 1-2   Net electricity generation efficiencies of fossil-fired power plants by different scenarios, with and without CCS

Source: IEA (2010)

Taking these assumptions into account, it has been calculated that CCS can make a 19 per cent contribution to the decrease in CO_2 emissions in the *BLUE Map scenario*, with the CO_2 being captured from power stations (10 per cent) and industrial sites and fuel transformation plants (9 per cent) in roughly equal measures (see Fig. 1-3). This means that 55 per cent of the captured CO_2 comes from the energy sector and 45 per cent from industry and transformation. The latter comprises cement kilns, ammonia plants and combined heat and power plants (CHP) in industry as well as refineries, synthetic fuel production (synfuels) and blast furnaces in the fuel transformation sector.
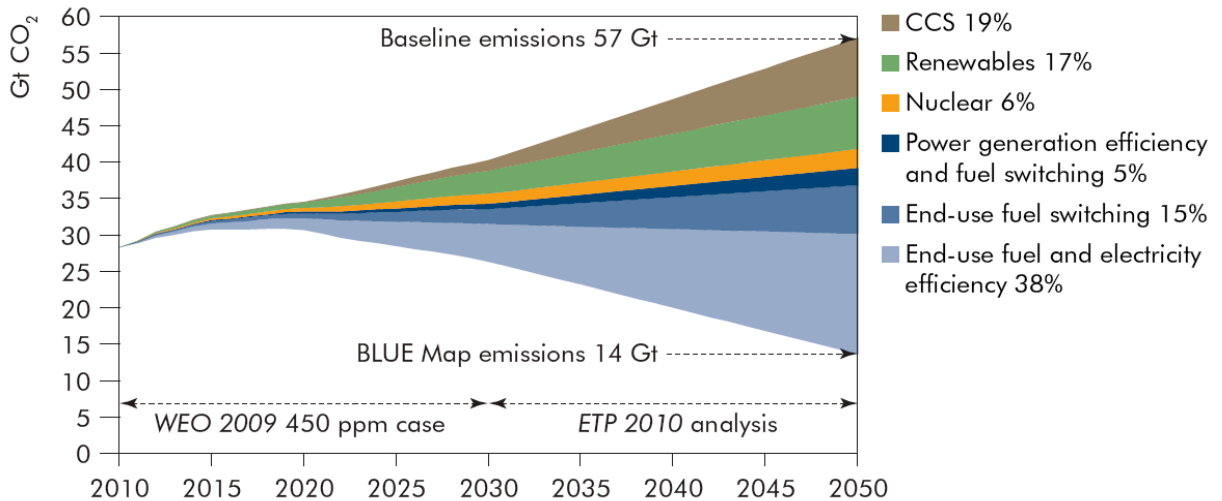
Fig. 1-3   Contribution of different technology options to reduce CO_2 emissions by 50 per cent up to 2050 under the *BLUE Map Scenario*

Source: IEA (2010)

The maximum reduction in CO_2 as a result of using CCS is 8.2 Gt/a, 4.5 Gt/a of which is contributed by the energy sector and 3.7 Gt/a by industry and transformation. The total amount is equivalent to 28 per cent of current CO_2 emissions (these figures already take into account that CCS would require an additional amount of fuel due to efficiency losses). Consequently, CCS would make a substantial contribution to achieving the 50 per cent reduction target.

Taking the power plant sector in isolation, Fig. 1-4 and Fig. 1-5 show the share of different fuels within total CCS-based power generation (Fig. 1-4 illustrates the share within generated electricity in total; Fig. 1-5 shows the share from installed capacity).
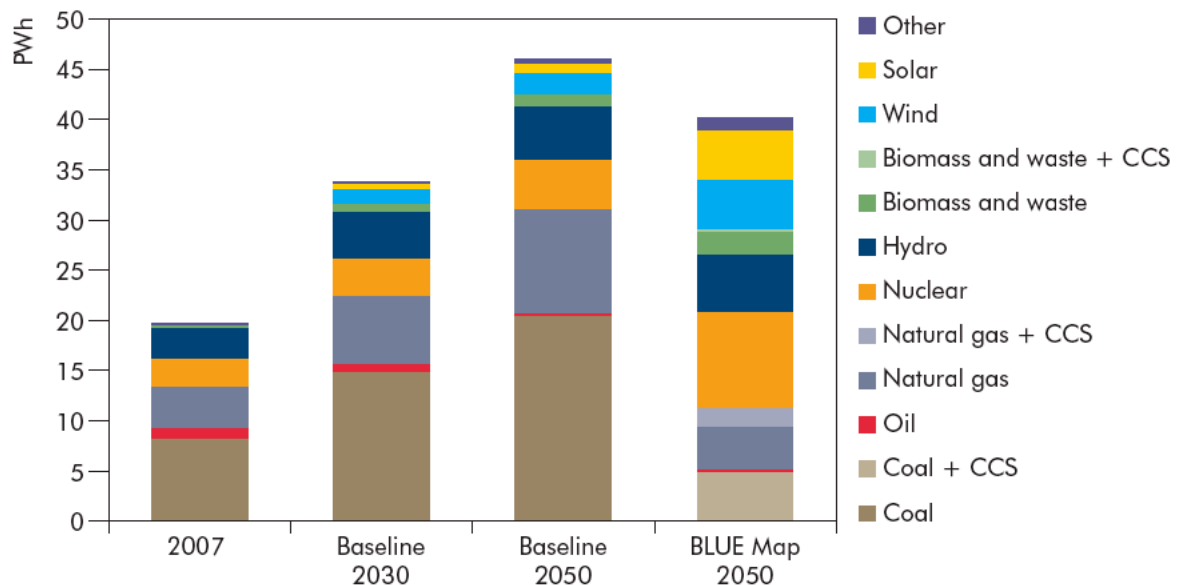
Note: Other includes electricity generation from geothermal and ocean technologies.

Fig. 1-4   Global electricity production in 2050 under the *BLUE Map Scenario*

Source: IEA (2010)

CCS capacity 1 011 GW

Coal
66%

Natural gas
29%

Biomass and waste
5%

CO₂ captured 5.4 Gt

Coal
86%

Natural gas
12%

Biomass and waste
2%
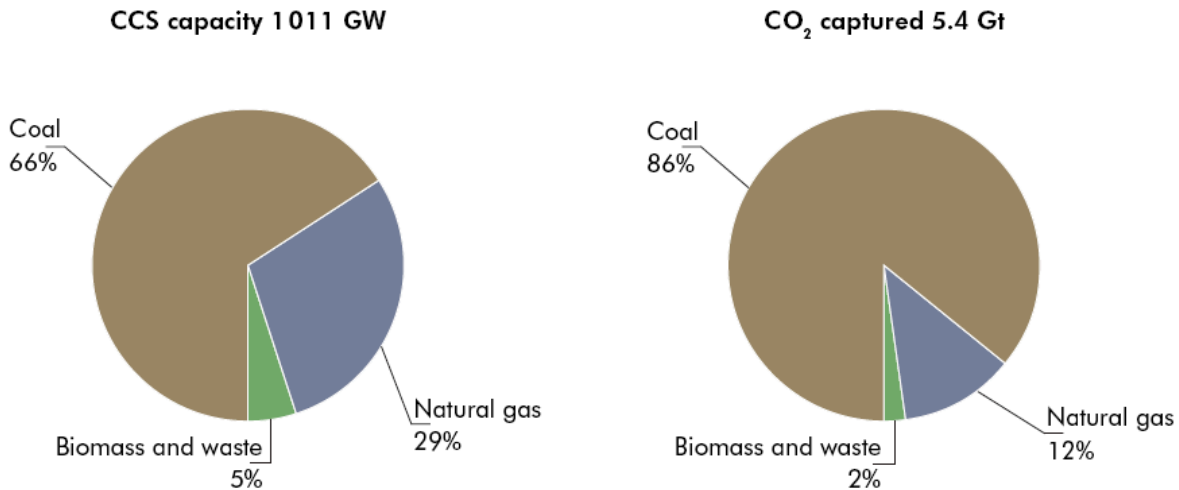
Fig. 1-5   Globally installed power plant capacity fitted with CCS and captured CO₂ emissions in 2050 under the BLUE Map Scenario

Source: IEA (2010)

Combining both pie charts in Fig. 1-5 produces Fig. 1-6, which shows that CCS could contribute 31 per cent of CO₂ reduction in electricity generation, equalling 4.34 Gt of CO₂ (of 14 Gt CO₂ in total). This quantity of reduced CO₂ emissions is lower than the amount of captured CO₂ given in Fig. 1-5 (5.4 Gt CO₂/a) due to the energy (and therefore CO₂) penalty of the capture process.

BLUE Map 14 Gt CO₂ reduction

Fuel switching coal to gas
7%

Gas efficiency
2%

SC/USC coal
3%

IGCC coal
4%

CCS
31%

Geothermal
3%

Solar CSP
9%

Solar PV
7%

Wind
11%

Hydro
2%

Nuclear
19%

Biomass and waste
2%
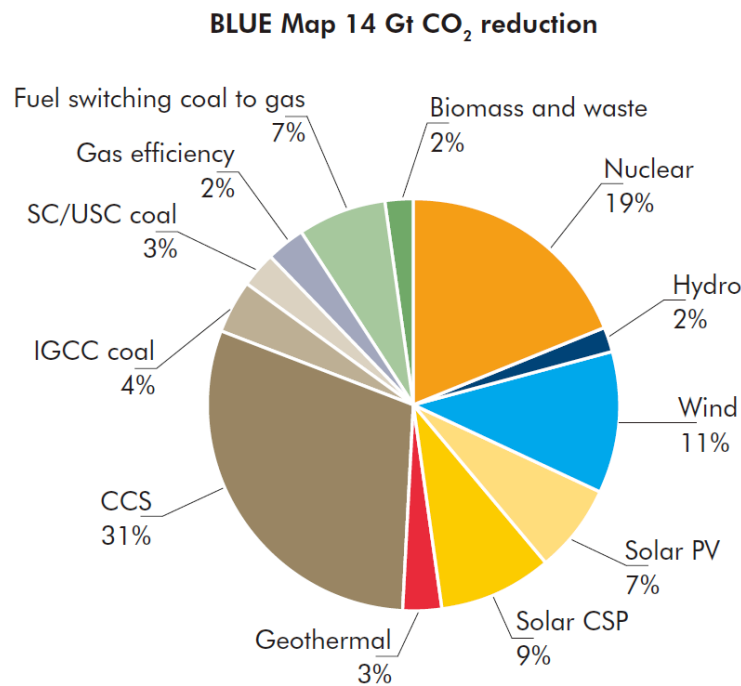
Fig. 1-6   Contribution of CCS to reductions of CO₂ in the power sector in the *BLUE Map Scenario* in 2050

Source: IEA (2010)

Within industry, CCS could contribute 33 per cent to overall CO₂ reduction activities by 2050, which would equal 1.75 Gt of CO₂/a (Fig. 1-7). Second only to energy efficiency measures,

this would be the most effective reduction measure, complemented by energy fuel and feed-stock switching as well as recycling and energy recovery.
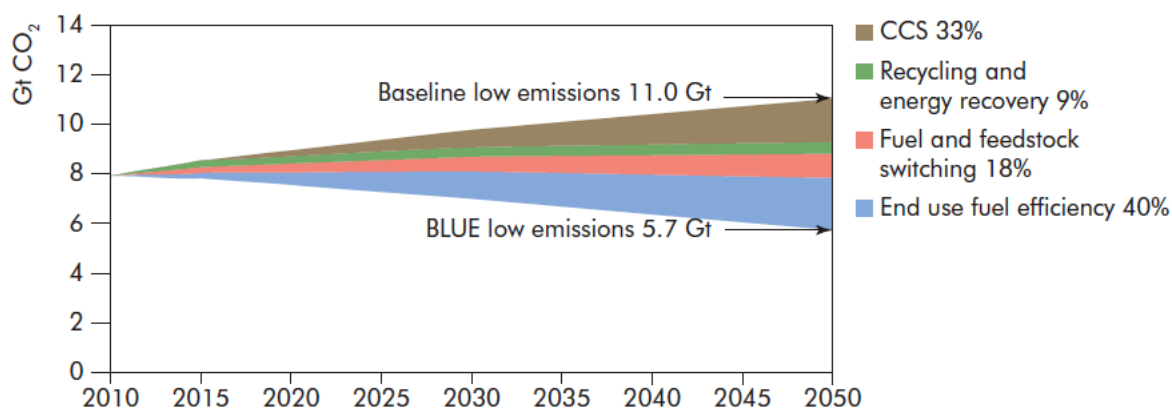
Fig. 1-7   Options for reducing direct CO_2 emissions from industry up to 2050

Source: IEA (2010)

The consequences of this scenario development are that:

- OECD countries reduce their CO_2 emissions by 77 per cent compared to 2005 levels, whilst non-OECD countries reduce their emissions by 25 per cent;

- By 2050, the share of coal use in power generation decreases from 44 per cent in the Baseline Scenario to 12 per cent in the BLUE Map Scenario;

- The contribution from natural gas decreases from 23 per cent to 15 per cent;

- More than 90 per cent of coal-based and around 30 per cent of gas-based electricity generation comes from power plants fitted with CCS;

- The total amount of annually captured CO_2 is 9.4 Gt/a and therefore 14.6 per cent higher than the avoided CO_2 (8.2 Gt/a). 21 per cent (2 Gt) is derived from industry, 57 per cent (5.4 Gt) from power plants and 21 per cent (2 Gt) from other transformation processes;

- In total, 1,011 GW of CCS-based power plants are expected to be installed by 2050 (in-cluding large-scale industrial CHP plants). This figure includes 550 GW of coal-fired, 298 GW of gas-fired and 49 GW of biomass- and waste-fired power plants (all of them newly built). 114 GW of coal-fired capacity is retrofitted with CCS;

- The share differs if one compares the source of captured CO_2 emissions: the major part (86 per cent) originates from coal, followed by 12 per cent from natural gas and 2 per cent from biomass;

- Combined, 79 Gt of CO_2 are being captured and stored between 2010 and 2050, of which coal-fired power plants account for 87 per cent (69 Gt), gas-fired 10 per cent (8.2 Gt) and biomass-fired 3 per cent (2.0 Gt).

1.3.3   The WEO-450 Scenario 2010

CCS is considered as a key element in the *WEO-450 Scenario*. As Fig. 1-8 shows, the con-tribution of CCS to worldwide CO_2 emission reductions amounts to 17 per cent by 2030 and

19 per cent by 2035, which differs from the *Current Policies Scenario*. The figure illustrates that there is an earlier deployment of CCS than that which is assumed in the *BLUE Map Scenario*, leading to a CO_2 emissions abatement of 2.6 Gt/a by 2030 and to 4 Gt/a by 2035 (compared to the *BLUE Map Scenario*, which requires about 1 Gt/a in 2030 and about 4 Gt/a in 2035). Possible reasons for this difference might be:

- The different approaches applied in the scenario development: whilst the Energy Technology Perspectives take a technological view, looking at technical development in more detail, the World Energy Outlook is demand driven, based on international energy and environmental policies and trying to optimise the economic aspect of future energy systems;

- The different reference value: as already mentioned, the WEO reduction targets refer to the 1990 level whilst the ETP takes 2005 as the base and therefore shrinks the required amount of CO_2 emission reduction.

As this scenario, unlike the other scenarios, runs only until 2035, it cannot be considered further since in the country analyses it is necessary to calculate the cumulated captured CO_2 emissions.
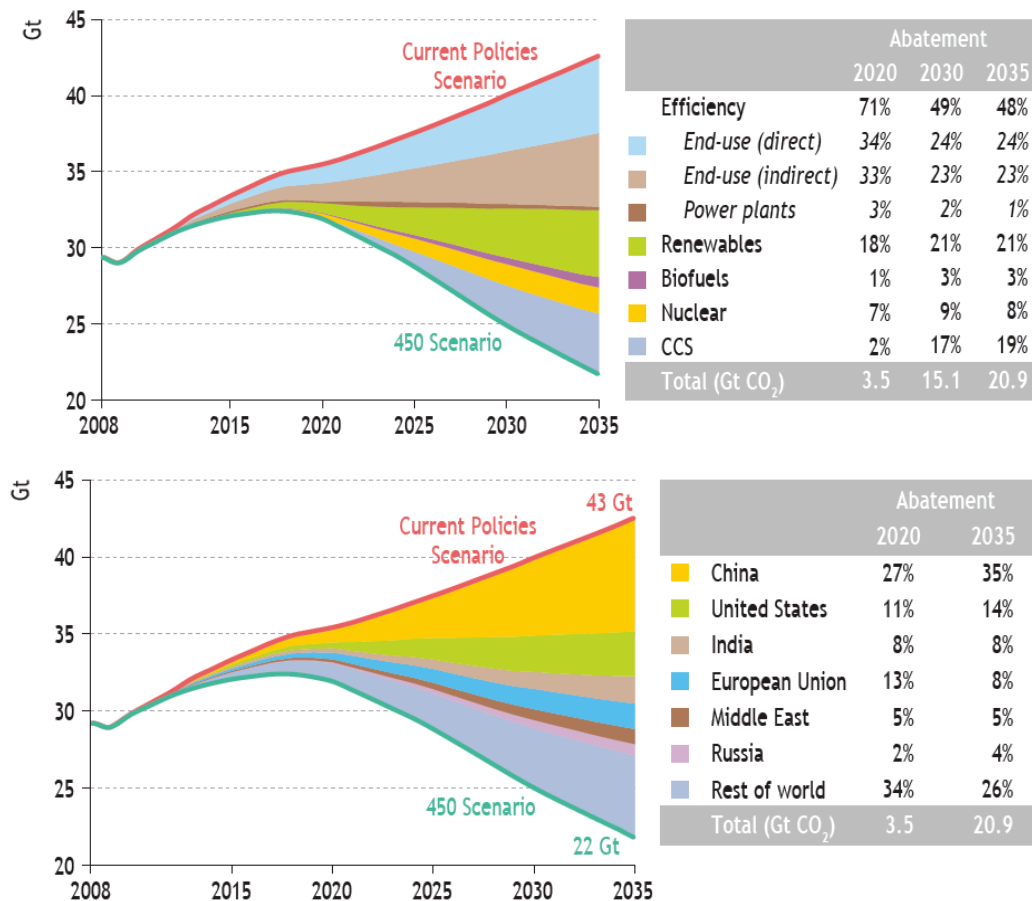
Fig. 1-8   Development of CO_2 emission savings by policy measures in the *WEO-450 Scenario* (top: worldwide; bottom: by region)

Source: IEA and OECD (2010)

1.4 Non-CCS-Based Electricity Generation in Global Low CO_2 Energy Scenarios

The *Energy [R]evolution Scenario 2010*

The Greenpeace/EREC-*Energy [R]evolution Scenario 2010* is based on the Reference Scenario published in the IEA World Energy Outlook 2009 (IEA and OECD 2009), which projects development up to 2030. Its key macroeconomic and energy indicators were extrapolated for the period between 2030 and 2050. Under BAU conditions, global CO_2 emissions would increase from 27.4 Gt of CO_2 in 2007 to 38.5 Gt of CO_2 by 2030 and to 44.3 Gt of CO_2 by 2050 (which is a total growth of 16.9 Gt, or 62 per cent). It is worth noting that in this study "China and India are expected to grow faster than other regions" (EREC and Greenpeace International 2010).

The aim of the *Energy [R]evolution Scenario* is to illustrate the efforts and actions required to achieve a worldwide reduction in CO_2 emissions down to a level of around 10 Gt by 2050, which would be necessary to keep the increase in global temperature below 2°C in 2100. As in the Reference Scenario, these efforts are broken down into the ten IEA world regions by applying a multi-region model. Besides the assumptions for macroeconomic figures, such as population development and economic growth, which are carried across from the Reference Scenario, the *Energy [R]evolution Scenario* is based on the following assumptions and principles:

- Using the cost curve approach to provide supply curves of carbon abatement for renewable energies and energy efficiency measures to show current and future potential and investments for each technology individually. They are based on cost projections provided by applying the learning curve approach;

- Assuming a worldwide CO_2 emissions trading system and including the (increasing) cost of CO_2 allowances in the calculation of electricity production costs;

- Implementing a Feed-in Tariff Support Mechanism (FTSM) which could enable the faster deployment of new renewable energy power plants in developing countries with financial support from industrialised nations. This instrument aims to bridge the current cost gap between renewable and coal- or gas-fired electricity generation;

- Sharing the national CO_2 reduction goals between industrialised and developing countries by applying the Greenhouse Development Rights (GDR) framework (Baer et al. 2008). This approach takes "inequality within countries into account and calculates national obligations on the basis of the estimated capacity and responsibility of individuals." It is the basis for developing national CO_2 reduction pathways, and Fig. 1-9 demonstrates this global obligation to move from the reference figures towards the targets of the *Energy [R]evolution Scenario*, divided into the largest regions required. Detailed figures for India and China are given in section 1.4.
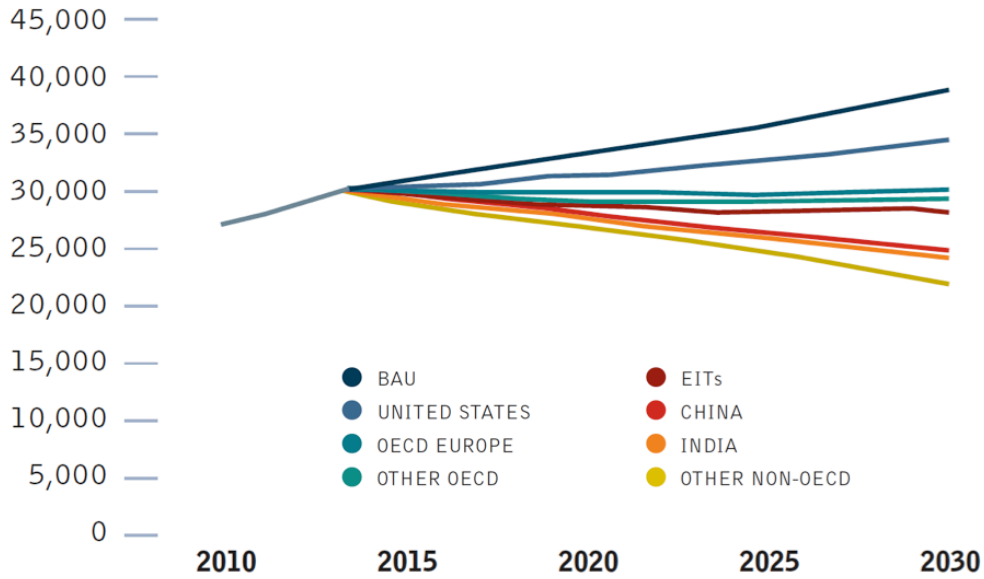
Fig. 1-9   Annual CO$_2$ emissions and reduction pathways allocated under the Greenhouse Development Rights system for different regions (up to 2030, in Mt)

Source: EREC and Greenpeace International (2010)

The resulting worldwide development of CO$_2$ emissions divided by sector is illustrated in Fig. 1-10. In the *Energy [R]evolution Scenario,* CO$_2$ emissions decrease from 27,408 Mt in 2007 to 10,202 Mt by 2050. This means a reduction of the annual per capita emissions from 4.1 to 1.1 tonnes. The main contributors to this reduction are efficiency gains and a high take-up of renewables.
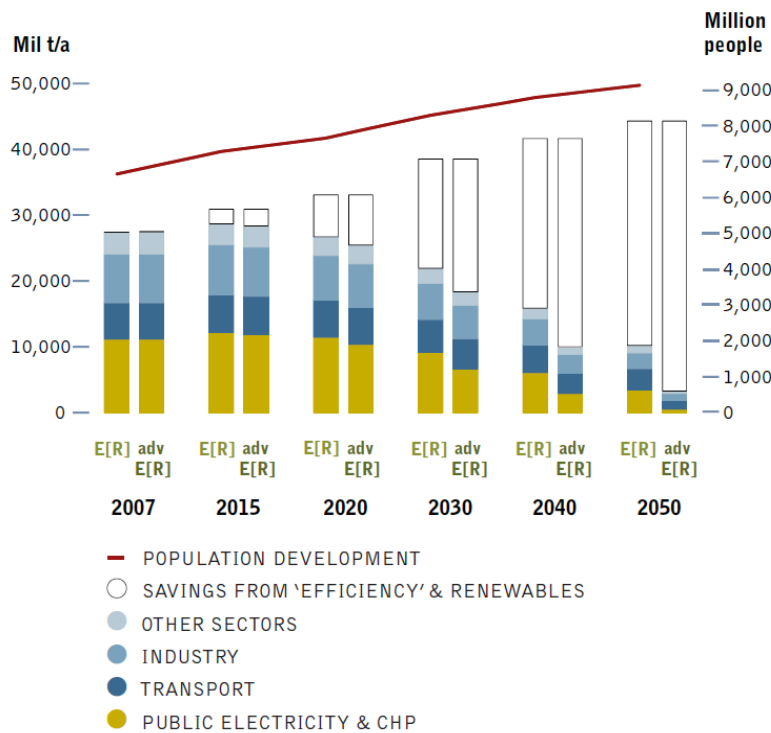
Fig. 1-10   Development of CO$_2$ emissions divided by sector under the *Energy [R]evolution Scenario* and the *Advanced Energy [R]evolution Scenario*

Source: EREC and Greenpeace International (2010)

By looking only at the power plant sector, Fig. 1-11 illustrates the share of different technologies in the electricity generation structure (including "efficiency" as a reduction compared to the Reference Scenario) for both the *Energy [R]evolution Scenario* and the *Advanced Energy [R]evolution Scenario* (which is not considered in the presented study). The development of the power plant sector within the *Energy [R]evolution Scenario* is characterised by a phase-out of nuclear energy and a significant reduction in the number of coal-fired power plants (hard coal, labelled as coal, and lignite). By 2050, 79 per cent of the electricity generated worldwide will come from renewable energy sources, 10 per cent from coal and 10 per cent from highly efficient natural gas power plants. The coal-fired power plants still in use in 2050 (611 GW) will mainly comprise those which have been built recently, or which are being built now and will be still in operation in the middle of the century.
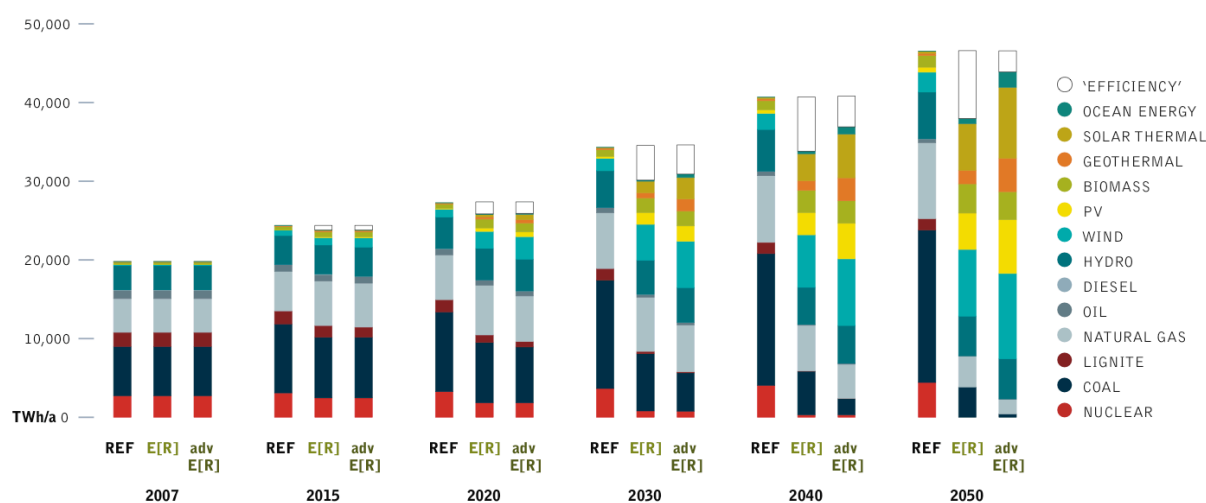
Fig. 1-11   Global development of electricity generation structure under three scenarios (*Reference*, *Energy [R]evolution* and *Advanced Energy [R]evolution*)

Source: EREC and Greenpeace International (2010)

As mentioned above, the *Energy [R]evolution Scenario* explicitly excludes CCS since it is not seen to be necessary for reaching even ambitious long-term GHG reduction goals by 2050. Greenpeace and EREC argue that CCS power plants are not included in their analyses since CCS would "probably not become commercially viable as a possible effective mitigation option until 2030." If it was to be viable earlier, it would not be a solution due to its high overall cost, which would "serve as a major barrier to its deployment" (EREC and Greenpeace International 2010).

1.5   National Energy Scenarios

In this section, there is a review of what energy scenarios are available for the countries under investigation in this study. From the considered scenarios, only the *Energy [R]evolution Scenario* (excluding CCS) and the *BLUE Map Scenario* (including CCS) consider trends on a regional and national level to some degree of detail. Whilst the first one adopts the IEA approach and considers ten world regions and single countries (therein India, China, South Africa), the latter investigates India, China, OECD Europe and the United States in detail. The *WEO-450 Scenario* also considers individual regions and states, but only provides qualitative statements on the role of CCS.

1.5.1   Regional Development in the Energy [R]evolution Scenario 2010

As mentioned above, in the *Energy [R]evolution Scenario* the Greenhouse Development Rights (GDR) framework is applied to develop national CO_2 reduction pathways. The GDR framework "calculates the share of global climate obligation for each country," so it can "be used to calculate (against a baseline) the reductions that each country needs to achieve to meet an international target" (EREC and Greenpeace International 2010). Applying the global obligation, which is required to move from the Baseline Scenario (*WEO 2009 Reference Scenario*) to the overall emission target set in the *Energy [R]evolution Scenario*, yields reduction curves proportionate to each country's share. These curves are illustrated in Fig. 1-12 for China and India.
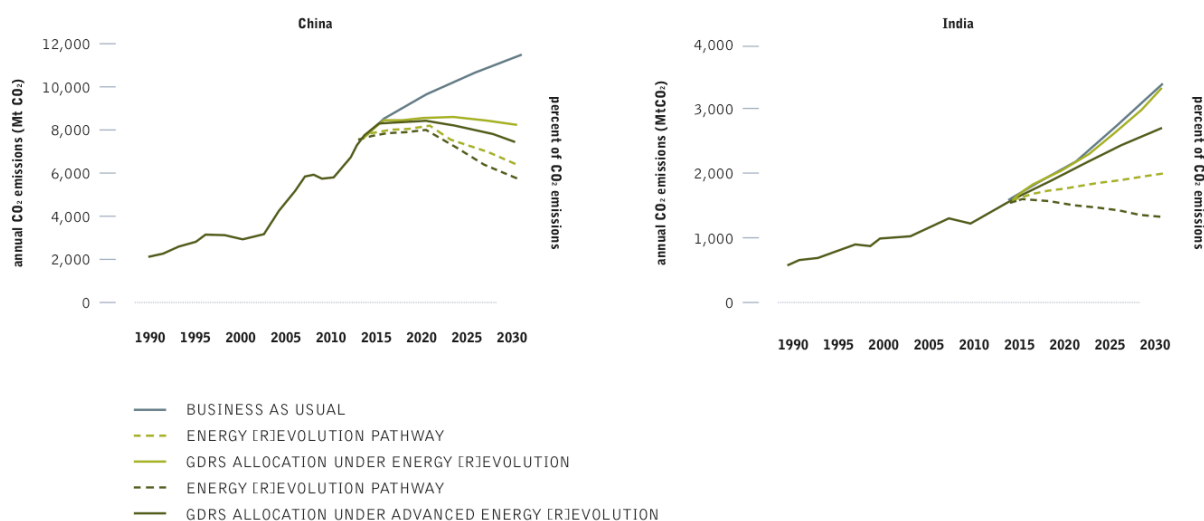
Fig. 1-12   Annual CO_2 emissions and reduction pathways allocated under the Greenhouse Development Rights system for China and India

Source: EREC and Greenpeace International (2010)

The curves illustrate that in these countries "the allocation of permits is greater than the estimated emissions [within the *Energy [R]evolution Scenarios*], indicating that other countries will need to support a reduction from the level indicated by the allocation (solid lines) and projected emissions (dashed lines)." Furthermore, the analysis within the *Energy [R]evolution Scenario* shows that these country-specific obligations can be met without using CCS or nuclear energy in the long term.

1.5.2   Regional Development in the ETP-BLUE Map Scenario 2010

Fig. 1-13 shows that for both China and India nearly the same share of CCS on the total CO_2 emissions abatement as that attributed globally is assumed. But in absolute figures, the amount of CO_2 captured in China would be double that captured in India. For *China*, the *BLUE Map Scenario* identifies a figure of 18 per cent of CO_2 emissions reduction by 2050 (2.09 Gt/a) which could be provided by CCS (10 per cent originates from power generation and 8 per cent from industry and transformation). For *India*, a share of 17 per cent by 2050 (9 per cent from power generation and 8 per cent from industry and transformation) is identified, which adds up to 0.85 Gt/a (compare Tab. 1-3).
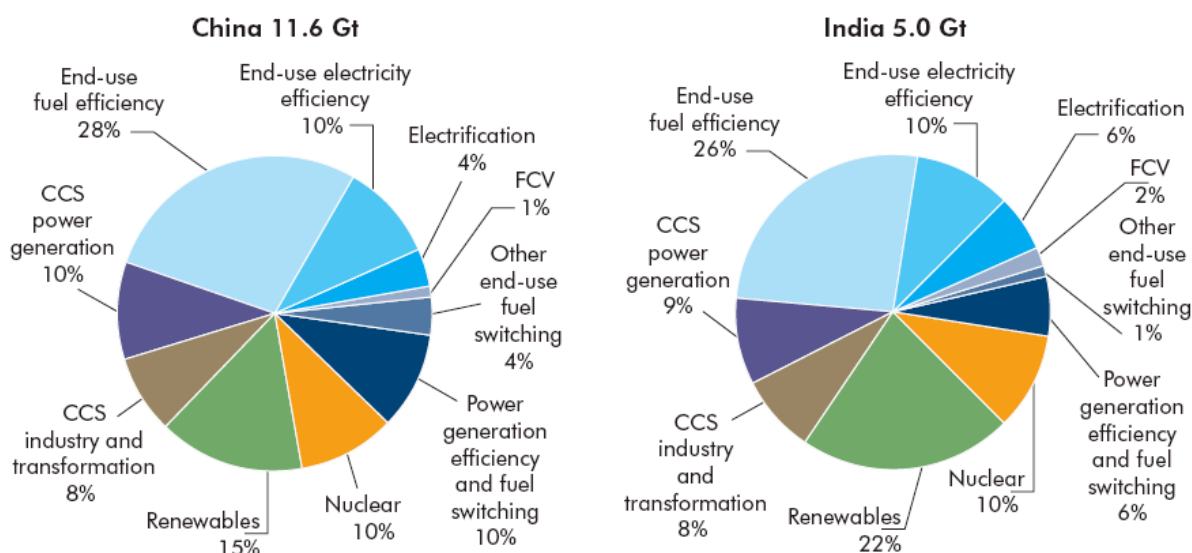
Fig. 1-13   Contribution of technologies to CO_2 emissions abatement under the *BLUE Map Scenario* for China and India in 2050

Source: IEA (2010)

Tab. 1-3   Contribution of CCS to CO_2 emissions abatement under the *BLUE Map Scenario* for China and India in 2050

Country	Total CO₂ reduction	Share of CCS		Share of CCS for power and industry			
				Power		Industry	
	Gt/a	Gt/a	%	Gt/a	%	Gt/a	%
China	11.6	2.09	18	1.16	10	0.93	8
India	5	0.85	17	0.45	9	0.4	8
Total	16.6	2.94		1.61		1.33	

Source: Authors' composition based on IEA (2010)

It is expected that the majority of worldwide CCS activities in 2050 will be located in *China* and *India.* As Fig. 1-14 illustrates, by 2050 nearly 300 GW from 1,100 GW of installed CCS-based power plant capacity worldwide will be based in these two countries, providing 2 Gt of separated[1] CO_2 emissions (around 36 per cent of globally separated CO_2 emissions). This contradicts the statistics given per country, where 1.61 Gt of CO_2/a is calculated for the energy sector (Tab. 1-3). It should be noted that the storage figures given in Fig. 1-14 show the amount of CO_2 stored in the year in question as Mt/a, and not as stated as Mt cumulated.

Unfortunately, the *BLUE Map Scenario* lacks the detailed data needed for the analyses presented in the country reports:

- Instead of illustrating the development of CCS- and non-CCS-based power generation capacities between 2000 and 2050, only the figures for 2050 (Baseline as well as *BLUE Map Scenario*) are given. This means that these scenarios can only be used for compari-

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[1]   It should be noted that "separated" CO_2 emissions are larger than "reduced" CO_2 emissions due to the energy penalty of the capture process that causes additional CO_2 emissions.

son purposes focusing on 2050, but not for assessing the cumulative CO_2 emissions that must be stored until 2050;

- In general, it is not clear whether these figures include the additional CO_2 emissions that occur due to the penalty load required by CCS or whether avoided emissions equal separated emissions.
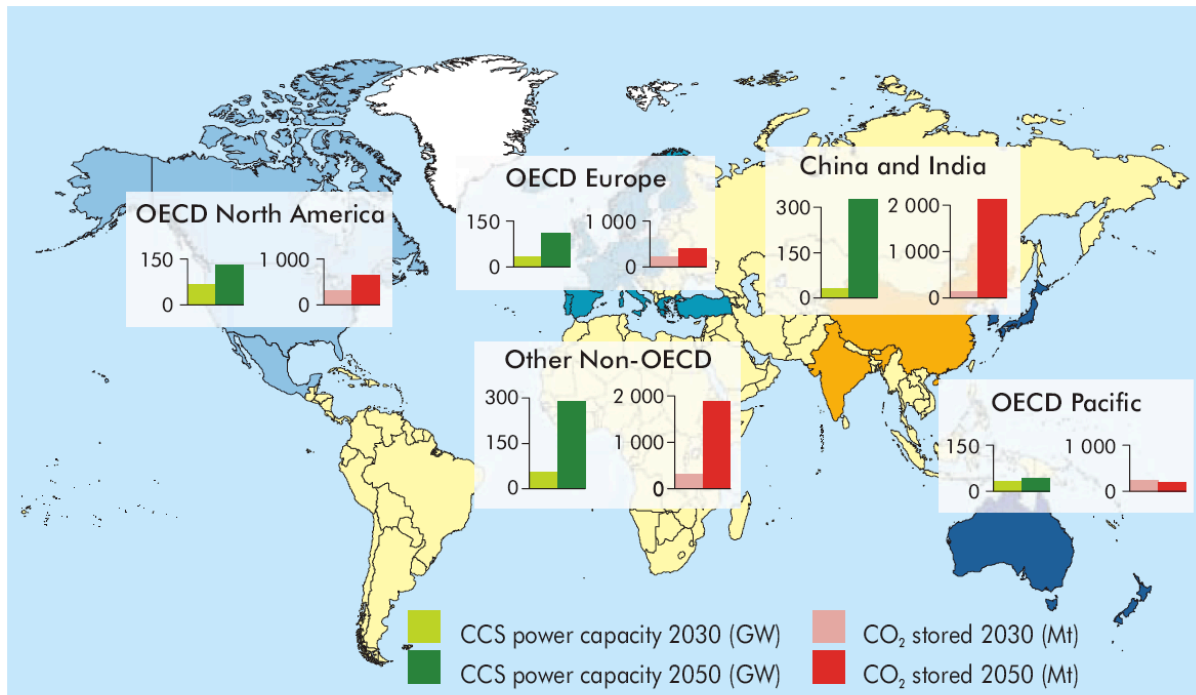
The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Fig. 1-14   Regional deployment of CCS in power generation under the BLUE Map Scenario (the storage figures show the amount of CO_2 stored in the considered year as Mt/a, not cumulated as Mt)

Source: IEA (2010)

1.5.3   Regional Development in the WEO-450 Scenario 2010

The *WEO-450 Scenario* provides only qualitative statements on the role of CCS for China, India and South Africa (IEA and OECD 2010):

- *China*: It is expected that, in the longer term, CCS development in China will play a key role in the global deployment of this technology;

- *India*: CCS is expected to play a powerful role in moving towards the *450 Scenario*;

- *South Africa*: Since South Africa's CO_2 emissions are expected to decrease by 53 per cent by as early as 2035, compared to 2008 emissions, a widespread deployment of CCS technologies is assumed. "In 2035, CCS would account for 48 per cent of South African abatement, compared with the *New Policies Scenario*, up from only 6 per cent in 2020. This very substantial share is because, with very rich coal resources and a CO_2 price of USD 90 per tonne in other major economies, the application of CCS to coal-fired generation makes better economic sense for South Africa than a move to other sources of power."

1.6   Summary

In this study, two main conditions must be fulfilled for an existing energy scenario to be used for country-level analysis:

1. A long-term development up to 2050 has been considered.

2. Data on the possible CCS deployment per decade are available at country level.

Tab. 1-4 illustrates the results of the assessments of the scenarios considered. It reveals that no scenario framework exists that fulfils the requirements outlined above. The only scenario where all required figures are both calculated and stated (*Energy [R]evolution scenario*) does not consider CCS. Therefore, in the country-specific sections, their own CCS-based scenarios will be developed, based on existing scenarios that have not included CCS so far.

Tab. 1-4   Analysed scenarios and criteria for exclusion of further treatment

Scenario	Time frame	Stated decades	Regional development		
			China	India	South Africa
CCS-based electricity generation scenarios as part of global low CO$_2$ energy scenarios					
The Bellona Scenario	2050	2050	---	---	---
ETP-BLUE Map Scenario 2010	2050	2050	**Only figures for 2050**		---
WEO-450 Scenario 2010	**2035**	2020, 2030, 2035	**Only qualitative**		
Non-CCS-based electricity generation scenarios as part of global low CO$_2$ energy scenario					
Energy [R]evolution Scenario	2050	2010–2050	X	X	X

Cells marked bold lead to the exclusion of further treatment in the country-specific analyses

Bellona Scenario: (Bellona Foundation 2008); ETP-BLUE Map Scenario: (IEA 2010); WEO-450 Scenario: (IEA and OECD 2010); Energy [R]evolution Scenario: (EREC and Greenpeace International 2010)

Source: Authors' composition

2 CO$_2$ Capture: Technologies, State of Development and Fields of Use

2.1 Introduction

Section 2.2 assesses technology options and the state of development in the field of CO$_2$ capture processes, including post-combustion, pre-combustion and oxyfuel capture technologies. There follows an evaluation of different fields of use for CO$_2$ capture. This encompasses new fossil-fired power plants, retrofitting of operating power plants and industrial processes, such as in the steel and iron industry, cement industry, chemical industry, fuel production and biomass utilisation.

2.2 Technology Options and State of Development

CO$_2$ capture processes can be subdivided into three technological groups: post-combustion, pre-combustion and oxyfuel processes (see Fig. 2-1). Fig. 2-2 illustrates ongoing research and development (R&D) for all three CO$_2$ capture routes.
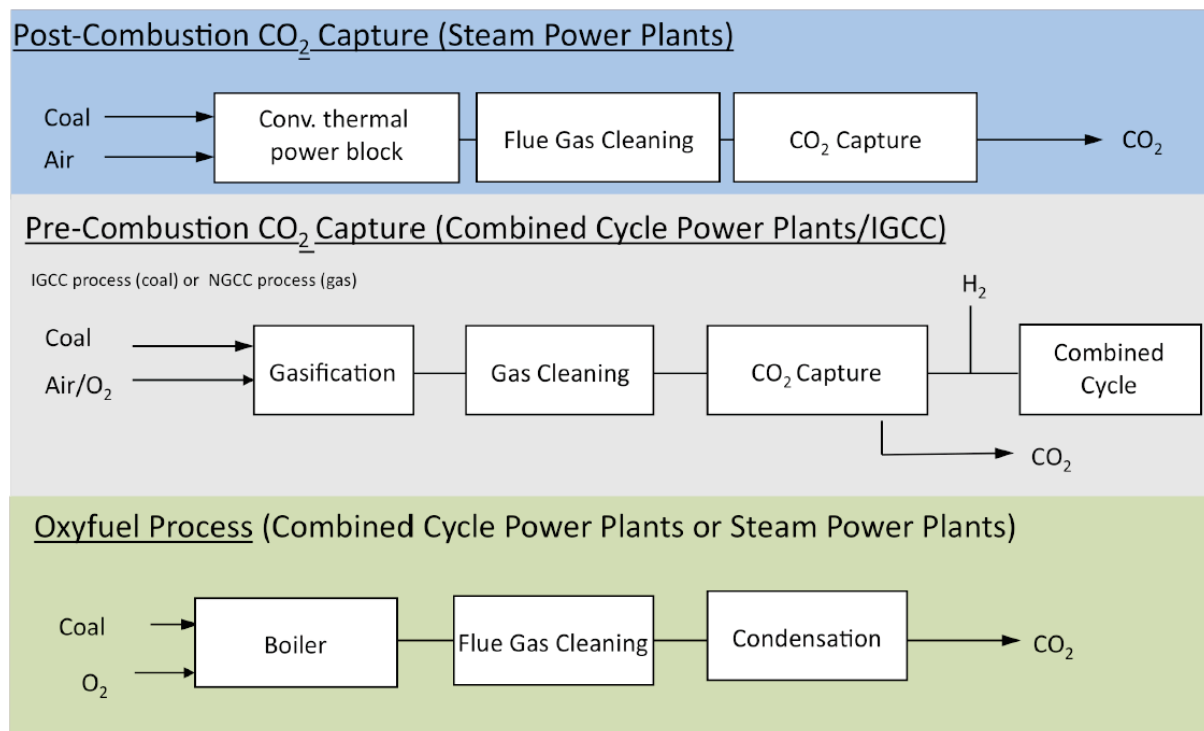
Fig. 2-1   Overview of various technological routes to CO$_2$ capture
Source: Ewers and Renzenbrink (2005)

2.2.1 Post-Combustion Process

CO$_2$ is captured from the flue gas of fossil-fired plants. The flue gas of conventional power plant processes has a CO$_2$ concentration of less than 3 to 15 per cent, because combustion of the fuel takes place with air, which is almost 80 per cent nitrogen. The low CO$_2$ concentration makes the economic capture of the greenhouse gas challenging, since a huge volume of gas needs to be treated, requiring large quantities of chemicals and energy. Nevertheless,

compared with other capture processes, post-combustion processes have the highest short- to medium-term achievable potential for CO_2 reduction. This is due to the fact that they are also suitable for being retrofitted onto existing power plants, which generate around two thirds of CO_2 emissions in the electricity sector (Figueroa et al. 2008). Demonstration plants are likely to be available by 2015, enabling the technology to be used on a large scale beginning sometime between 2020 and 2030. In addition, post-combustion processes are increasing in importance because a broad market launch of integrated gasification combined cycle (IGCC) power plants with pre-combustion processes have been curbed by a sharp increase in the investment costs for large-scale plants (Herzog et al. 2009).

Chemical absorption processes based on amines are the most developed solvents for post-combustion CO_2 capture processes, because similar scrubbing processes are already in use in other branches of industry. Some of the leading suppliers include Mitsubishi Heavy Industries (MHI; Japan), Cansolv (Canada), Fluor (USA), HTC Purenergy (Canada) and Aker Clean Carbon (Norway). Monoethanolamine (MEA) is one of the preferred amine solutions. However, MEA is a relatively powerful solution that bonds strongly with CO_2, causing its regeneration to involve high energy use. For this reason, ongoing R&D focuses on optimising amine solvents or the development of alternative solvents. Approaches for optimising amine solvents are hindered amines and blended solvents. The former is a modification of the molecular geometry of amines, aiming at increasing the reactivity of amines and weakening the bond between amines and CO_2 to reduce the energy requirements involved in CO_2 capture. Blending amines with other solvents also serves the purpose of optimising capture efficiency and enhancing the reaction rate.

Besides absorption, alternative post-combustion pathways such as adsorption, membrane processes and biological capture processes are being tested and developed in R&D projects. In *adsorption processes*, the CO_2 is not absorbed by the solvent but is attached to its surface. There is no chemical reaction between the CO_2 and the solvent. At present, work is being carried out on adsorption processes that use zeolitic or metal-organic substances to bond the CO_2. The former have a high CO_2 selectivity but a low capture capacity. The latter have a high adsorption capacity, but it is not certain how resistant they are to impurities in the flue gas.

Membrane processes are an alternative medium- to long-term option. Membranes are semi-permeable separating layers used to separate mixtures of substances, such as flue gas. They are already used commercially in a range of industries, but their use in CO_2 capture is still at a relatively early stage of development. Membranes have the advantage that impurities are removed by separating the flue gas prior to the capture process, reducing the consumption of the solvent. However, existing membrane technologies have a low level of technological maturity and are not yet an economical option. Therefore, current R&D activities shall enhance the economic efficiency of membranes and improve their selectivity and permeability. In Germany, the Forschungszentrum Jülich is working on the development of porous and ceramic membranes and on suitable methods for the production of membranes.

Biological capture processes are expected to be available on a large scale in the medium to long term. They use natural organisms, such as algae or enzymes, to bond the CO_2. Algae-based capture processes are currently being pursued with great interest in the USA, since CO_2 is converted into biomass which can be utilised as energy. German energy suppliers

such as RWE, E.On and Vattenfall Europe are also working on R&D projects in this field. In July 2010, Vattenfall Europe started a project which will analyse which species of algae are most suited for breeding from captured CO_2 produced in a lignite-fired co-generation power plant in Senftenberg (Brandenburg). Algae cultures can be bred in either open ponds or closed reactors. The CO_2 is transformed into air by photosynthesis. The algae reproduce and can be processed into related products such as biodiesel. In enzyme-based processes, the CO_2 is bound by enzymes in a biological reactor and transformed into bicarbonate ions. The bicarbonate can then be processed into limestone, amongst other things. The Canadian company CO_2 Solutions is currently developing and testing bacteria for the production of suitable enzymes in cooperation with Babcock and Wilcox.
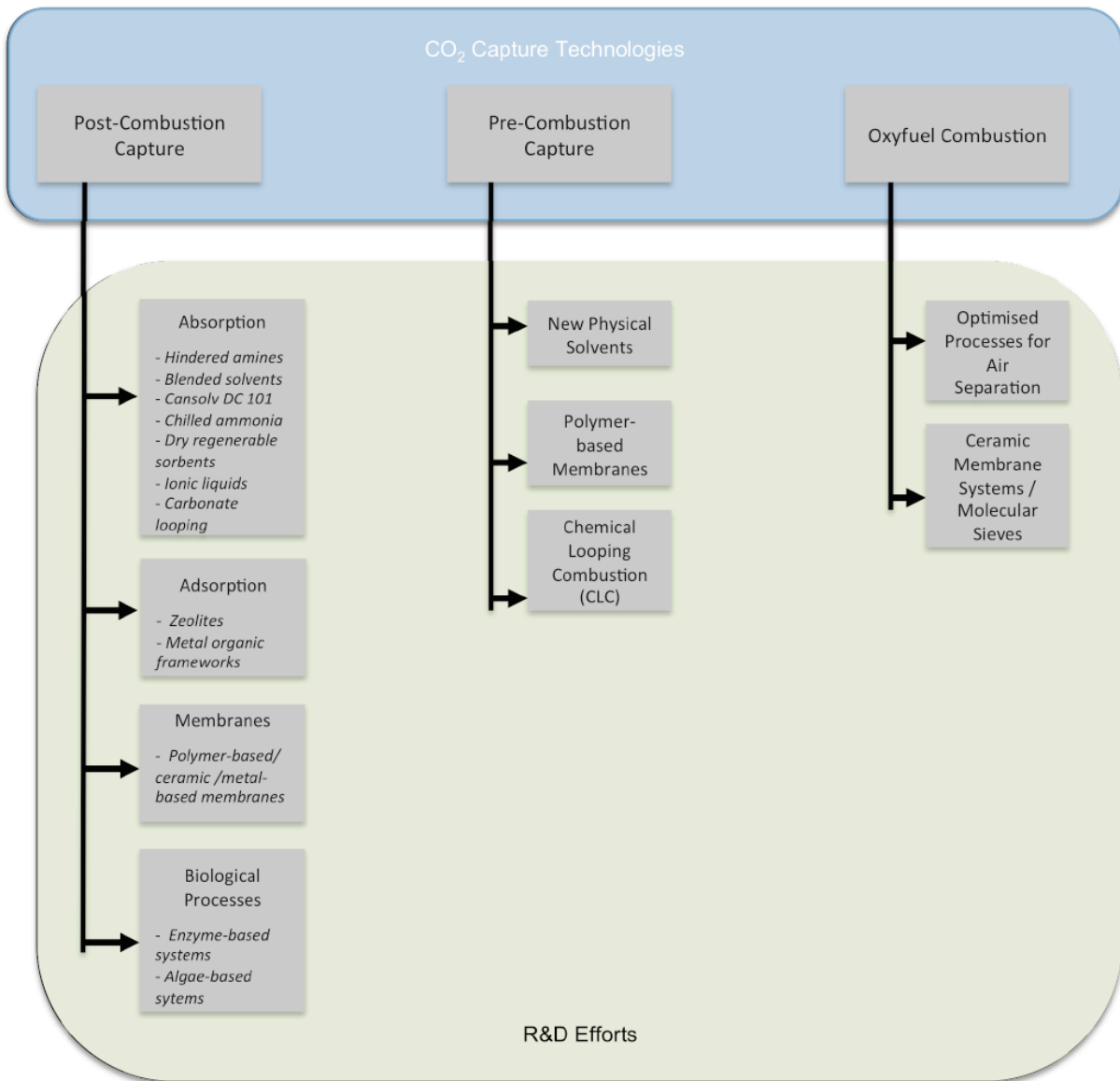
Fig. 2-2   International R&D activities on CO_2 capture

Source: Authors' composition

2.2.2   Pre-Combustion Process

In this process, the feedstock is transformed by gasification into a synthesis gas consisting mainly of carbon monoxide (CO), hydrogen (H_2) and CO_2. The proportion of CO content in

the synthesis gas is reduced in a shift reactor, creating a gas with a considerably higher CO_2 concentration than in the flue gas from conventional power plants. The CO_2 can be separated from the gas stream through physical absorption with considerably less energy consumption than in post-combustion processes due to the higher CO_2 concentration in the syngas. Despite their comparatively high capture efficiency, pre-combustion processes have been a lower priority for R&D recently. This is explained by the fact that the deployment of IGCC power plant technologies has not yet extended beyond individual demonstration plants, which is mainly due to the high investment costs involved. In addition, developing countries are concentrating primarily on conventional and mature combustion processes in the construction of new coal-fired power plants.

Current R&D activities in the field of pre-combustion deal primarily with the development of new physical solvents, such as lithium silicate, or alternative processes, such as membrane systems or chemical looping combustion (CLC). The latter uses metal oxides or limestone-based carriers to oxidise the fuel. Direct contact between the fuel and the air supplied for combustion is therefore avoided. The resulting combustion exhaust gases consist mainly of CO_2 and water, making it easy to separate the CO_2 once the water has been condensed out. CLC is currently being pursued by European market players in particular, such as Alstom and the Swedish Chalmers University.

2.2.3   Oxyfuel Process

In the oxyfuel process, virtually pure oxygen (over 95 per cent) substitutes air for the combustion of fuel. In this way, the CO_2 concentration in the flue gas can be increased to 80 per cent, enabling CO_2 to be captured by simply condensing it out. Oxyfuel processes are regarded as a promising alternative to post- and pre-combustion processes, but remain at an early stage of development. So far, virtually no reliable economic feasibility studies have been conducted.

The world's first oxyfuel pilot plant was commissioned in Germany at the Schwarze Pumpe site in the Brandenburg town of Spremberg by Vattenfall Europe in September 2008. The cost of the plant amounts to around EUR 70 million (Vattenfall 2009). In addition, Vattenfall Europe conducted feasibility studies for retrofitting one of six 500 MW generating units by installing two boilers, one equipped with oxyfuel technology and one with post-combustion technology. However, this project was cancelled in late 2012.

A focal point of current R&D work on oxyfuel technology is the exploration of energy-efficient methods for producing the required oxygen. Although cryogenic air separation processes are currently being used for this purpose, they are very energy- and cost-intensive. They comprise around 33 per cent of the investment costs and 67 per cent of the power demand of an oxyfuel plant (ENCAP 2009). Alternative options for producing oxygen are ceramic membrane systems and molecular sieves or the adsorption of oxygen. In the latter process, which is also denoted as ceramic autothermal recovery (CAR), air is fed at high temperatures to a fixed bed vessel with pellets made of the perovskite calcium titanium oxide ($Ca\ TiO_3$). Oxygen is adsorbed and stored at the surface of the perovskite.

2.3   Fields of Use

2.3.1   New Fossil-Fired Power Plants

Power plants are currently being discussed as the prioritised field of use for CCS. The World Energy Outlook 2009 of the International Energy Agency (2009) projects that CCS at power plants could mitigate approximately 1,410 million tonnes of CO_2 by 2030, which is equivalent to 10 per cent of the CO_2 mitigation required by this time in order to limit the concentration of CO_2 in the atmosphere to 450 ppm. This makes CCS at power plants a significant, but not the most important, mitigation option because energy efficiency (7,880 million tonnes) and renewable energies (27,741 million tonnes) contribute much larger values (IEA and OECD 2009).

The IEA estimates the mitigation potential of efficiency increases at power plants at 735 million tonnes of CO_2. In previous years, improvements in thermal efficiency, for example, through increases in steam pressure or temperature, have been the most important measures for mitigating CO_2 emissions from fossil-fired power stations. Such adjustments have resulted in successive improvements in the efficiency of power plants. Current designs of power plants fired with lignite or hard coal show that they could achieve efficiencies of 43 and 46 per cent, respectively. Gas-fired combined cycle gas turbine (CCGT) plants are capable of operating at efficiencies of approximately 58 per cent. By 2020, it is estimated that efficiencies will reach 47.5 per cent (lignite-fired plants), 49.5 per cent (hard coal-fired plants) or 60 per cent (CCGT) (Viebahn et al. 2010).

At present, pulverised coal combustion (PCC) plants represent more than 90 per cent of installed coal-fired capacities for power generation worldwide. The coal is ground (pulverised) to a fine powder which is blown with part of the combustion air into the boiler plant. Combustion takes place at temperatures ranging from 1,300 to 1,700°C, depending largely on coal rank. Steam is generated, driving a steam generator and a turbine (IEA Clean Coal Centre 2010). The thermal efficiency of PCC plants is mainly a function of steam temperature and pressure, with the former being the more important of the two parameters. Over the temperature range of 500 to 800°C, efficiencies vary almost linearly with steam temperature. Over the last three decades, steam temperatures have increased by about 60°C and are expected to grow by at least another 50°C in the coming 30 years (Graus et al. 2008).

PCC plants are distinguishable by their applied steam pressure and are grouped into three categories: subcritical, supercritical and ultra supercritical. Available definitions of these categories make different assumptions for steam temperature, steam pressure and achievable thermal efficiencies. Below, and in Tab. 2-1, the definitions from MIT (2007), Graus et al. (2008) and Nalbandian (2009) are summarised, reflecting the assumed ranges for each parameter:

- *Subcritical:* The majority of globally existing PCC plants, especially in developing or emerging economies, are subcritical units. Subcritical operation refers to steam pressures below 220 bar and steam temperatures around 535 to 550°C. Thermal efficiencies of subcritical plants vary from 33 to 39 per cent, depending on coal quality, operation, design parameters and location.

- *Supercritical:* Supercritical PCC plants first came into operation in the 1960s. Early supercritical units were operated with steam pressures below 220 bar and temperatures of approximately 540°C. Today, supercritical plants are widely deployed and are highly reliable. Current state-of-the-art plants use steam pressures ranging from 220 to 250 bar and temperatures from 540 to 580°C. Thermal efficiencies range from 38 to 42 per cent.

Tab. 2-1   Parameters for different categories of pulverised coal combustion technologies

PCC plant type	Steam temperature	Steam pressure	Efficiency
	°C	bar	%
Subcritical	535–550	<220	33–39
Supercritical	540–580	220–250	38–42
Ultra supercritical	565–580	>250	42–47

Source: Various

- *Ultra supercritical:* In order to achieve further efficiency improvements, the power industry continues to move towards higher steam pressures and temperatures. Operating steam cycle conditions beyond temperatures of 565 to 580°C and pressures higher than 250 bar qualify as ultra supercritical, increasing efficiency to between 42 and 47 per cent. One of the first ultra supercritical units was the hard coal-fired unit 3 at Nordjyllandsvaerket in Denmark, using steam at a pressure of 290 bar and a temperature of 580°C. The plant has an operating efficiency of 47 per cent. In Germany, RWE is constructing BoA plants 2 and 3 ("Braunkohlekraftwerk mit optimierter Anlagentechnik") in Neurath (North Rhine-Westphalia, NRW) with gross capacities of 1,100 MW and efficiencies of more than 43 per cent. BoA1 in Niederaußem (NRW), commissioned in 2003, has a gross capacity of 3,801 MW and shall also achieve an efficiency level of 43 per cent.

- In Europe and Japan, some ultra supercritical plants applying steam at 320 bar and 600 to 610°C are in operation. Current R&D projects aim to raise the steam temperature beyond 700°C, thereby achieving efficiencies in the range of 52 to 55 per cent. However, these plant designs are not expected before 2010 to 2015.

Due to limitations related to thermodynamic process parameters and boiler materials, the potential for further efficiency improvements of power plants is limited. Therefore, it is widely recognised that process optimisations are not sufficient to meet ambitious long-term CO_2 mitigation targets. This insight has moved CO_2 capture and storage technologies to the top of the international climate policy agenda in recent years. However, as mentioned in the previous section, CCS processes are still at the development and demonstration stage. An increasing number of voices do not expect the large-scale application of the integrated CCS process chain before 2025 or 2030 (Greenpeace 2008; MIT 2007; ZEP 2008). Fig. 2-3 shows a timeline of each step of the CCS process chain. The greatest level of uncertainty currently surrounds the storage stage, as estimates of international storage capacities vary significantly. Detailed assessments of individual storage formations are needed in order to quantify their actual capacity.
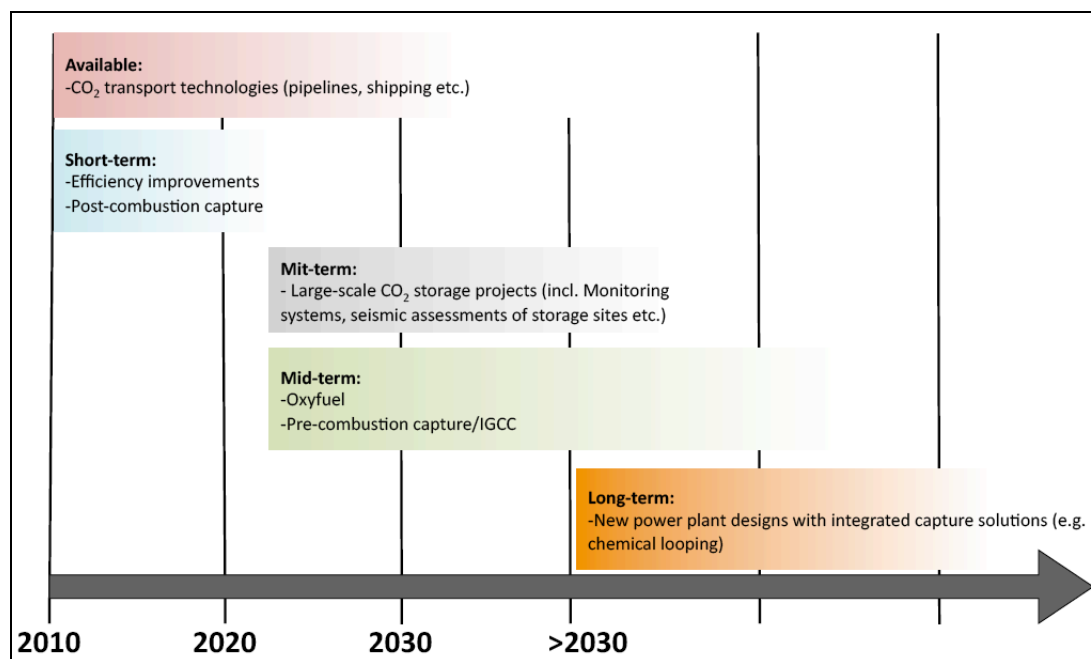
Fig. 2-3   Temporal availability of CCS

Source: Authors' illustration

The timeframe for the availability of CCS strongly affects the technology's mitigation potential, as it needs to coincide with the demise of a country's existing coal-fired power plants. In many countries, the existing power plant fleet will reach the end of its operational life before the earliest likelihood of CCS becoming available in around 2020 and, therefore, will be replaced by plants without CCS. This means that it is essential that new power plants are designed to be capture-ready in order to enable retrofits of CO_2 capture equipment (see section 2.3.2). This is also the case in developing countries such as the China – India – South Africa (CISA) nations used in this study, which have rapid growth rates in their fossil-fired power plant fleets. Fig. 2-4 shows the ages of existing coal-fired power plants globally. More than 500 GW of installed coal-fired generating capacities are less than ten (about 300 GW) or 20 years old (more than 200 GW). Assuming an average lifespan of 40 years, these plants will operate for another 20 or 30 years. They are not designed as capture-ready and, therefore, are rather unlikely to be retrofitted with CCS.

Capturing CO_2 at power plants causes substantial losses in the electrical efficiency of fossil-fired power plants. Amongst the different capture routes, post-combustion incurs the highest efficiency penalties because of the high energy intensity resulting from low CO_2 concentrations (3 to 15 per cent) and the strong bonds between the solvent and the CO_2. Fuel consumption per kWh of a new supercritical pulverised coal power plant increases by 24 to 40 per cent. Natural gas-based units and IGCC plants applying pre-combustion systems indicate lower but still significant energy penalties of 11 to 22 per cent or 14 to 25 per cent, respectively. The increased fuel requirement results in an increase in most other environmental emissions generated per kWh in comparison to new state-of-the-art plants without CO_2 capture (Viebahn et al. 2010). In addition, CO_2 capture leads to a rise in the amount of solid waste at coal-fired plants and an increased consumption of chemicals, such as ammonia and limestone used by pulverised coal plants for nitrogen oxide and sulphur emissions control (IPCC 2005).
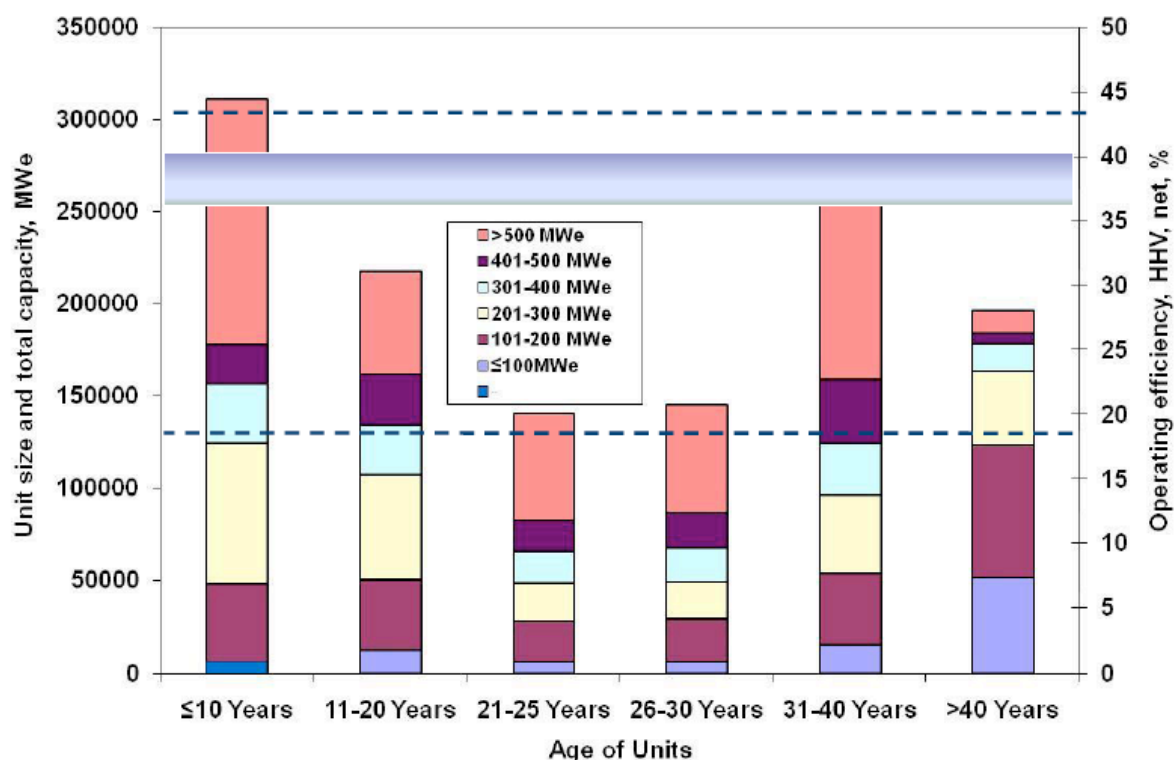
Fig. 2-4   Size, age and operating efficiency of coal-fired power plants installed worldwide

Source: Bhattacharya (2009)

Due to their energy intensity, CO_2 capture processes are the most costly component of the CCS process chain, representing approximately 63 per cent of the overall CCS costs (Fischedick et al. 2008). Post-combustion processes increase the costs of electricity genera-tion of a coal-fired power plant by approximately 40 to 70 per cent. Power generation costs of an IGCC plant with pre-combustion capture grow by about 20 to 55 per cent. This is mainly due to the lower CO_2 concentrations in the gas stream and the lower energy intensity of pre-combustion capture technologies (IPCC 2005). However, estimates of CO_2 capture costs suggest great uncertainty as plant investment costs have escalated in recent years due to the high costs of resources such as steel. Plant cost indices report cost increases of 35 to 100 per cent (Davison and Thambimuthu 2009). Furthermore, prices of fossil resources such as coal or natural gas have been highly volatile in recent years due to the unpredictable economy.

2.3.2   Retrofitting of CO_2 Capture at Operating Fossil-Fired Power Plants

Retrofitting of operating fossil-fired power plants occurs when they are supplemented at a later date by a further known component, or one that is yet to be developed, in order to fulfil an additional task without seriously restricting the existing function of the plant. Power plants which "can include CO_2 capture when the necessary regulatory or economic drivers are in place" (IEAGHG 2007) can be denoted as capture-ready plants. Capture-ready plants will avoid the risks of stranded assets or carbon lock-in. Plants that are not capture-ready either incur higher costs and efficiency losses when retrofitted with CO_2 capture technologies or retrofitting cannot be carried out due to a lack of space at the plant site.

Requirements of CCS Retrofits

So far, there is no universally understood definition of the term "capture ready." The Greenhouse Gas Programme of the International Energy Agency (IEAGHG 2007) has published a detailed study which analyses the requirements for retrofitting different carbon capture technologies to existing coal-fired power plants. The most essential general requirements are:

- *Provision of space:* Sufficient space needs to be reserved for the CO_2 capture plant at the site of the existing plant. For example, a post-combustion capture installation for a 540 to 600 MW_{el} coal-fired power plant requires nearly 24,000 m^2 (including the CO_2 compression plant), which is equivalent to an increase in space requirements of about 17 per cent compared to a plant without CO_2 capture (Lucquiaud and Gibbins 2009). Therefore, any assessment of a plant for capture readiness should include an evaluation of the plant elements that would be required for a retrofit, their position in the plant layout and their physical size.

- *Identification of transport routes:* This requires potential CO_2 storage sites and their capacities and distances from the power plants concerned to be identified. The next stage would be to identify potential transport routes. If pipelines are planned, potential obstacles such as securing rights of way and also an understanding of public opinion must be evaluated. In the event of transportation by ship, the feasibility, safety and acceptability of onshore buffer storage and ship loading and unloading facilities must be assessed.

- *Storage sites:* The requirements for identifying and qualifying storage sites must be defined by policy-makers. According to the IEA, it is conceivable on the one hand to simply prove the existence of a storage reservoir with a sufficiently large capacity; on the other hand, it could be necessary to carry out a detailed geological analysis and to earmark the land for a particular storage capacity at an early stage to avoid the intended area being used for other purposes.

- *Pre-investments:* A multitude of pre-investments are listed and economically assessed for the different capture routes. The IEA provides member countries of the Greenhouse Gas Programme with a tool to calculate and assess pre-investments.

General Impacts of CCS Retrofits

Regardless of the chosen capture routes, the following general impacts of retrofits can be determined:

- *Efficiency:* The efficiency of "capture ready" plants is generally lower than the potential efficiency of new plants with CO_2 capture. A study by the Wuppertal Institute of Climate, Environment and Energy assumed an additional efficiency loss of 1 to 2 percentage points with retrofits, having consulted with energy suppliers (WI 2009).

- *Increased investment costs:* Retrofitting leads to increased investment costs. However, it is possible for these to be offset over a shorter period than the total lifetime of the power plant. CO_2 retrofitting is, therefore, only practical if the plant's remaining service life is long enough.

- *Retrofit phase:* During the retrofit phase, the power plants have to be shut down temporarily. As a result, they cannot generate any revenue during the refit.

- *Additional space requirements:* Space has to be available not only on the premises of the power plant, but also within the plant to be able to integrate the CO_2 capture plants or to make any necessary alterations. Estimates assume 50 per cent more space is required for natural gas combined cycle power plants and up to 200 per cent for conventional coal-fired power plants (Fischedick et al. 2006).

Technical Requirements of CO_2 Capture Retrofits

Retrofitting of post-combustion, pre-combustion and oxyfuel CO_2 capture processes involves different requirements which are summarised in Tab. 2-2.

Post-combustion capture technologies are best suited for retrofits as they are more advanced than other capture technology options. Additional aggregates needed for CO_2 capture are units for CO_2 scrubbing and CO_2 compression. Furthermore, the steam cycle needs to be made "capture friendly" in order to be able to supply any steam required for the thermal regeneration of the capture solvent.

Tab. 2-2   Measures to be carried out for various CO_2 capture processes

Process	Measures
Post-combustion	Installation of a CO_2 gas scrubber
	Installation of a CO_2 liquefaction plant
	Optimisation of the steam cycle
	Connections for heat extraction to regenerate the solvent
	Optimisation of the cooling system
	Provisions for heat recovery in CO_2 capture and liquefaction
	Plants to remove the liquefied CO_2
	Optimisation of the flue gas desulphurisation plant to minimise the SO_2 content in the flue gas
	Extension and addition of balance of plant systems
	Installation of a CO_2 pipeline system for CO_2 transportation
	Provisions for increased auxiliary power demand
	Expansion of cooling capacity
Pre-combustion	Installation of a natural gas reformer
	Installation of a water gas shift reactor
	Additional water/steam injection for the water gas shift reaction
	Installation of a CO_2 gas scrubber before the gas turbine combustor
	Installation of gas turbines suited for combusting hydrogen-rich gases
	Installation of a CO_2 liquefaction plant
	Installation of a CO_2 pipeline system for CO_2 transportation
Oxyfuel	Installation of an air separation plant
	Installation of a CO_2 liquefaction plant
	Expansion of the planned auxiliary power generation and distribution system
	Increase of the cooling capacity to enable the water to be condensed out of the exhaust gas
	Installation of a flue gas circulation system and a flue gas dryer
	Installation of a CO_2 pipeline system for CO_2 transportation

Source: Author's own composition

The significant amount of heat (around 110 to 120°C) required for solvent regeneration is most effectively provided by condensing steam extracted from the power cycle (Lucquiaud et

al. 2009). Nearly 50 per cent of the steam leaving the intermediate pressure (IP) turbine is needed for this purpose. Another essential requirement for pre-combustion capture retrofitting is the modification of the flue gas desulphurisation (FGD) unit, enabling it to achieve high levels of sulphur removal to meet the high level of gas purity required for the amine scrubbing system. In order to adjust the power plant for the additional requirements of the capture equipment, some extension and addition of the balance of plant systems is needed.

When retrofitting an integrated gasification combined cycle (IGCC) plant with *pre-combustion capture technology*, several new plant components have to be added and a number of existing energy systems need to be reconfigured. Coal gasification produces a syngas consisting of carbon monoxide (CO), carbon dioxide (CO_2) and hydrogen (H_2). If coal is oxidised with air instead of pure oxygen, the synthesis gas is also rich in nitrogen oxides (NO_x). Pre-combustion CO_2 capture processes call for a highly concentrated CO_2 stream, requiring a water gas shift reactor which reduces the share of CO in the syngas whilst increasing the proportions of H_2 and CO_2. The reaction requires additional water/steam injection into the process, which may influence the overall thermodynamics. If the plant uses a quench gasifier, however, no further injection is needed (IEAGHG 2007).

The recovery of CO_2 from the syngas requires existing equipment for acid gas removal to be modified as pre-combustion CO_2 capture is either conducted via heating or by a reduction of pressure. The CO_2 capture unit has to be linked with a CO_2 compression plant, which needs to be connected to CO_2 transport facilities.

The CO_2-free syngas which is introduced to the gas turbine has a lower calorific value than the syngas in its original composition. As a consequence, the gas turbine either has to be derated or the gasifier needs to be expanded in order to ensure the required flow of fuel to the gas turbine. Furthermore, the modified syngas consists almost exclusively of hydrogen, which brings significant changes to the combustion properties of the gas (particularly higher flame temperatures and higher flame speed). The gas turbines need to be adjusted to accommodate these requirements. However, turbine designs capable of combusting hydrogen-rich gases are still at the development stage. Leading technology providers, power utility companies and research institutes, such as Siemens, E.On and RWTH Aachen University, are currently collaborating in the four-year project "Low Emission Gas Turbine Technology for Hydrogen-Rich Syngas" under the 7th EU Framework Programme.

Besides gas turbine modifications, steam flows and requirements within the process will be significantly changed, requiring adjustments of the heat recovery steam generator (HRSG) and the steam turbine.

In comparison to the pre-combustion capture option, the retrofitting of *oxyfuel technologies* requires fewer plant modifications as the steam generator and steam cycle for air-firing and oxyfuel-firing do not differ (Tigges et al. 2008). The steam turbine generator and auxiliaries are the same as those of a conventional air-fired pulverised coal power plant.

Additional requirements for oxy-fuelling are an air separation unit and a CO_2 compression plant. For both plant types, sufficient space at the plant site needs to be reserved. Both air separation and CO_2 compression units will significantly increase the internal electricity consumption of the power plant and, therefore, require additional capacity from the auxiliary power distribution system of a power station. Furthermore, oxygen production and CO_2 com-

pression lead to an overall increase in the required cooling capacity by 15 to 20 per cent, necessitating further modifications in the plant design. The CO_2 compression unit needs to be linked to a pipeline system for transferring the captured CO_2 to the storage site. The pipeline material needs to be resistant to corrosion from oxygen or sulphur dioxide (SO_2) residues in the CO_2.

Another major distinguishing feature of an oxyfuel plant compared to a conventional air-fired plant is its two-stage flue gas circulation system. Approximately two thirds of the flue gas needs to be moved back to the boiler plant in two streams. Recirculation of flue gas is necessary to provide a sufficient mass flow of gas for cooling the flame and to ensure sufficient heat capacity and convective heat transfer in the boiler (Tigges et al. 2008). The first flue gas stream serves as the transport medium for the pulverised fuel; the second stream is recycled to burners and the furnace. Before the flue gas can be recycled, it needs to be dried so that a flue gas dryer can be added.

2.3.3 Industrial Processes

There is a strong focus on the energy sector within the current debate on CCS. However, beyond this key sector, industries with large point sources of CO_2 are important potential fields of use for CO_2 capture technologies. In 2006, direct CO_2 emissions (encompassing fuel combustion and process-related emissions from within the industry sector) totalled 7.2 Gt of indirect CO_2 emissions, reflecting CO_2 discharges from electricity produced for industry which totalled 3.4 Gt (IEA 2009a). Fig. 2-5 and Fig. 2-6 illustrate the distribution of direct industrial emissions globally among sectors or regions/countries respectively. Iron and steel, cement and chemicals represent the largest sectoral shares of direct industrial CO_2 emissions; by region, China (34 per cent) is clearly the largest contributor of emissions. India's emissions are equivalent to about 5 per cent of direct industrial CO_2 emissions globally; South Africa is not among the major emitting countries.
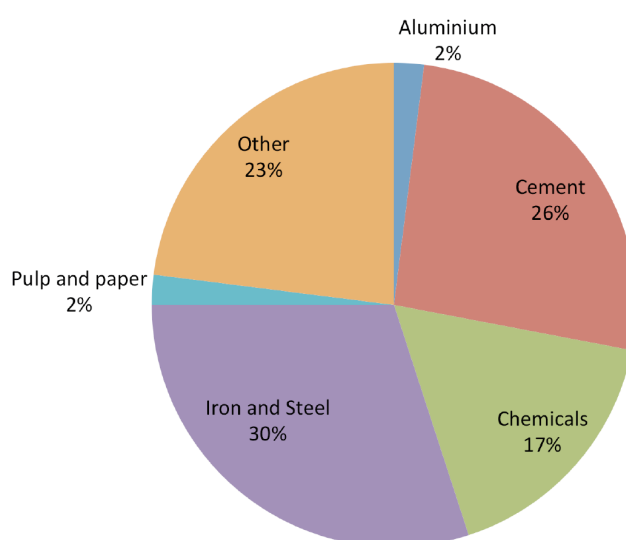
Fig. 2-5   Direct CO_2 emissions in industry by sector
Source: IEA (2009a)
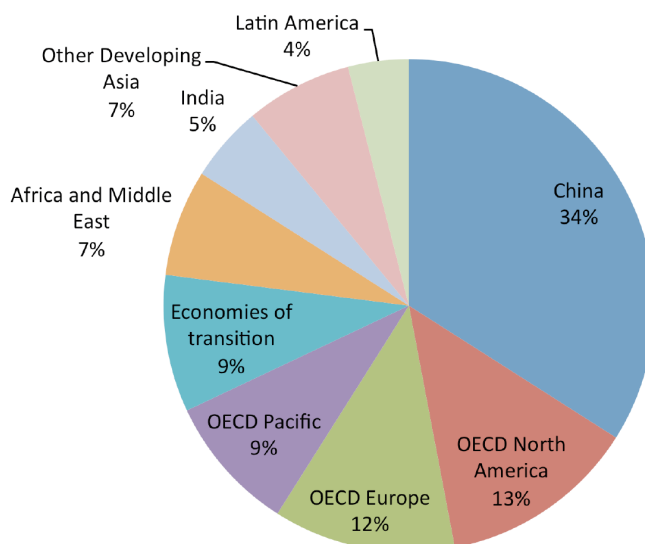
Fig. 2-6   Direct CO_2 emissions in industry by region/country

Source: IEA (2009a)

In the sections below, technical possibilities and the potential for applying CO_2 capture in the most CO_2-intensive industries, as well as early low-cost options, are presented.

2.3.3.1 Steel and Iron Industry

The global steel industry has shown unprecedented growth in recent years, reaching an overall production volume of 1,344 Mt in 2007. Whilst production was largely steady between 1975 and 2000, it escalated by 58 per cent between 2000 and 2007. China's rapid economic development was the main driver of this trend, with Chinese steel production representing about 36 per cent of the global production volume (IEA 2009a). The iron and steel industry is the world's largest single industrial source of CO_2. In 2006, its direct CO_2 discharge totalled 2.2 Gt. The International Energy Agency (IEA) estimates the industry's annual CO_2 saving potential at approximately 20 per cent if the best available technologies were applied, tapping the technical potential for energy efficiency improvements. The replacement of small-scale blast furnaces is the single most important mitigation opportunity. Better use of residual gases and waste heat is also important (IEA 2009a). However, due to the limited overall efficiency potential, additional mitigation technologies such as CCS might be needed to substantially reduce the industry's environmental footprint.

As iron and steel can be produced using very different processes, the industry has a complex technical structure. Blast furnaces have remained the dominant technology route, despite a significant growth in gas- and coal-based direct reduced iron (DRI). Blast furnaces are often part of integrated steel plants, which comprise several interconnected production units such as coke ovens, sinter plants and palletising plants. Within such an integrated production complex, blast furnaces generate the largest stream of CO_2 and therefore offer the most economical opportunity for CO_2 capture (Rootzén et al. 2009).

The IEA (2008) identifies two approaches for capturing CO_2 from coal-fired blast furnaces:

- *Oxy-fuelling to generate a pure CO_2 off-gas*: Instead of enriched air, blast furnaces use oxygen. In combination with recycled top gases, the emission stream would indicate a sufficiently high CO_2 concentration to capture CO_2 with physical absorbents. Physical absorption is significantly less energy intensive than chemical absorption. However, oxygen-fired blast furnaces are not yet technically proven.

- *Chemical absorption:* In general, post-combustion chemical absorption would be a feasible method for capturing CO_2 from blast furnaces. However, it would require substantial investment as the waste heat generated during iron and steel production is not sufficient to cover the heat demand of chemical absorption processes. Only about 50 per cent of the necessary heat could be recovered from integrated iron and steel plants. The remaining 50 per cent would have to be supplied by a separate combined heat and power (CHP) plant. Chemical absorption using waste heat and blast furnace gas reforming is currently being investigated in Japan, Korea and China.

R&D initiatives for reducing the carbon intensity of the iron and steel industry have been launched in Europe, North America, Japan, Korea, Australia and Brazil. The European Union (EU) is funding the Ultra-Low CO_2 Steelmaking Programme (ULCOS). The project is being conducted through a consortium of 48 partners including all major European steel companies, energy and engineering partners, research institutes and universities. ULCOS is aiming to reduce the specific CO_2 emissions of a modern blast furnace by 50 per cent. CO_2 capture was identified as one possible mitigation path for achieving this purpose.

Top gas recycling-blast furnaces (TGR-BF) are a promising technology prospect for CO_2 capture. In a TGR-BF, CO_2 in the top gas of the blast furnace is removed so that the useful gas components – CO and H_2 – can be recycled back into the furnace. This would reduce the amount of coke needed in the furnace. Additionally, oxygen could be injected into the furnace instead of air; unwanted nitrogen (N_2) would be removed, facilitating CO_2 capture (Zuo and Hirsch 2008). The IPCC estimates that 70 per cent of the CO_2 emitted from an integrated steel plant could be recovered if TGR-BF with CO_2 capture were to be introduced (IPCC 2005).

In 2007, the Swedish mining company LKAB tested different CCS configurations at an experimental top gas-recycling blast furnace (see Fig. 2-7). In combination with carbon capture, the trials achieved a total CO_2 mitigation of 76 per cent (Zuo and Hirsch 2008). Experts estimate that carbon capture at blast furnaces in combination with transportation and storage could cost approximately USD 40 to 50/t of CO_2 (IEA 2008). CCS within gas-based direct reduced iron (DRI) would be significantly less costly, leading to abatement costs of USD 20 to 25/t of CO_2. However, as DRI units are concentrated in relatively few countries and are on a rather small scale, the discussion focuses on CO_2 capture at blast furnaces.
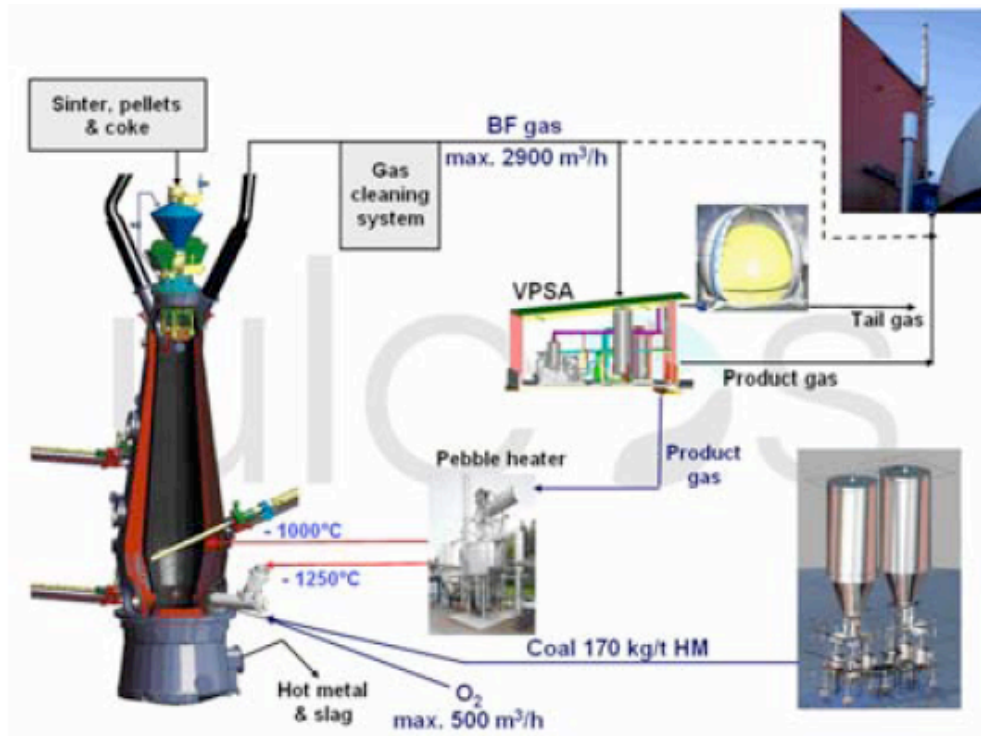
Fig. 2-7   LKAB's top gas-recycling blast furnace with CO_2 removal plant (VPSA)
Source: Zuo and Hirsch (2008)

2.3.3.2 Cement Industry

The cement industry is currently responsible for 1.9 Gt, or 26 per cent, of the world's total direct industrial CO_2 emissions. Around 0.8 Gt are emitted from fuel combustion, whilst 1.1 Gt are process emissions (IEA 2009a). Global cement production has experienced a steady growth over many years, reaching about 2.5 Gt in 2006. The average growth rate was 5.5 per cent per year during the period 1990 to 2006, and the average rate has accelerated to 8.7 per cent annually since 2002 (IEA 2008). The main growth has taken place in China, which accounts for nearly 50 per cent of the world's cement production. India is the second largest producer, but representing only 6 per cent of the global cement production (IEA 2009a).

Cement is produced from a feedstock of limestone, clay and sand, providing lime, silica, alumina and iron. In the first step, the raw material is ground and homogenised. Afterwards, the raw materials are mixed and delivered to a clinker kiln. In modern cement plants, precalciners are used to preheat the feedstock and calcine the raw material. Inside the kiln, the raw material is gradually heated and burned at a peak temperature of approximately 1,450°C. Calcination takes place at around 900°C, and CO_2 is released from calcium carbonate. As the temperature rises, calcium oxide agglomerates with silica, alumina and ferrous oxide, forming pellets called clinker (Rootzén et al. 2009). The clinker is ground and mixed with additives, such as gypsum and other minerals, to be converted into cement.

Clinker production is by far the most energy-intensive step of cement production, accounting for more than 70 per cent of the total energy consumed (Rootzén et al. 2009). As a consequence, an overwhelming percentage of the direct emissions from cement production derive

from clinker burning. Two types of clinker kilns – wet and dry – can be distinguished, depending on the water content of the raw material feedstock. Water evaporation makes the wet process more energy intensive than the dry process which, therefore, dominates modern cement production. Whilst wet cement kiln technologies consume between 5.9 and 6.7 GJ per tonne of clinker, the energy consumption of dry processes ranges from 2.9 to 4.6 GJ per tonne of clinker (IEA 2009a). It seems unlikely that the fuel efficiency of current dry kiln designs can be raised to much higher levels. Hence, additional mitigation measures are needed to substantially reduce direct emissions of the cement industry (IEA 2009a).

Fuel is fed to two devices in modern cement plants: the precalciner and the clinker kiln. The resulting flue gas has a relatively high CO_2 concentration of about 25 per cent compared to 14 per cent for a coal-fired power plant. CO_2 can be captured both at the precalciner and the clinker kiln. Similar to a power plant, post-combustion capture would not affect the core of the cement production process but recover CO_2 after the combustion process. A CO_2 capture plant, a compressor to increase CO_2 pressure for transport via a pipeline, a plant to provide steam for the regeneration of the CO_2 as well as equipment for flue gas desulphurisation and scrubbing of NO_x would have to be added. According to the IEA Greenhouse Gas Programme, post-combustion capture processes could recover about 85 per cent of the CO_2 produced in cement plants. 95 per cent of capture is considered to be feasible without significantly affecting the cost per tonne of captured CO_2. Using chemical absorption systems, the costs of CCS are estimated at USD 75 to 100 per tonne of captured CO_2, increasing capital costs by 40 to 90 per cent (IEAGHG 2008).

Oxy-fuelling can be applied both to the precalciner and the clinker kiln, but if applied only to the precalciner, the impact on the clinkerisation process could be minimised. However, process redesign might be needed, involving substantial capital costs. Oxy-combustion in the precalciner has the potential of avoiding 61 per cent of the CO_2 produced at the cement plant. However, net CO_2 mitigation would be only 52 per cent as oxy-fuelling causes a significant increase in auxiliary power consumption for O_2 production, CO_2 compression and purification. If oxy-combustion was applied to both the precalciner and the cement kiln, more than 90 per cent of the CO_2 could be avoided. Generating costs of USD 40 per tonne of CO_2 avoided, oxy-fuelling is much less expensive than post-combustion CO_2 capture (IEA 2008).

2.3.3.3 Refineries

The refining sector accounts for about 4 per cent of global CO_2 emissions, totalling nearly 1 Gt per year (Gale 2005). Refineries are different from other industrial large-point CO_2 sources in that they include multiple emission sources, often dispersed over a large area, as they involve several different process operations. The most important processes are distillation, reforming, hydrogenation and cracking.

Potential CO_2 mitigation options include the construction of co-generation plants for covering internal heat and power demand, the reduction of flaring, the use of alternative energy sources and CO_2 capture and storage (Van Straelen et al. 2010). CO_2 capture can be applied to process heaters and steam boilers, which are the two largest single emission sources within refinery plants. Process heaters alone account for 44 per cent of the CO_2 emissions from fluid catalytic cracking (FCC) refineries and 55 per cent of the emissions from hydrocracking refineries (IEA 2008). The total mitigation potential of applying CCS at process

heaters and steam boilers is 65 per cent of a refinery's overall emissions (Rootzén et al. 2009). Furthermore, CO_2 may be captured at internal co-generation plants. CO_2 can be either captured through chemical absorption (post-combustion capture) or by designing heaters and boilers for oxyfuel operation. Applying post-combustion capture to a refinery heater is highly energy intensive, also in comparison to fossil-fired power plants, as the flue gas needs to be pushed through the network and due to the pressure imposed by the packed column absorbers and the flue gas pre-treatment to reduce NO_x and SO_2 concentrations.

A study for a UK refinery and petrochemical complex concludes that post-combustion capture requires 6.2 GJ per tonne of captured CO_2 and investment costs of USD 238 per tonne of CO_2. Fig. 2-8 illustrates the cost structure for a refinery complex with CO_2 capture (Simmonds et al. 2003).
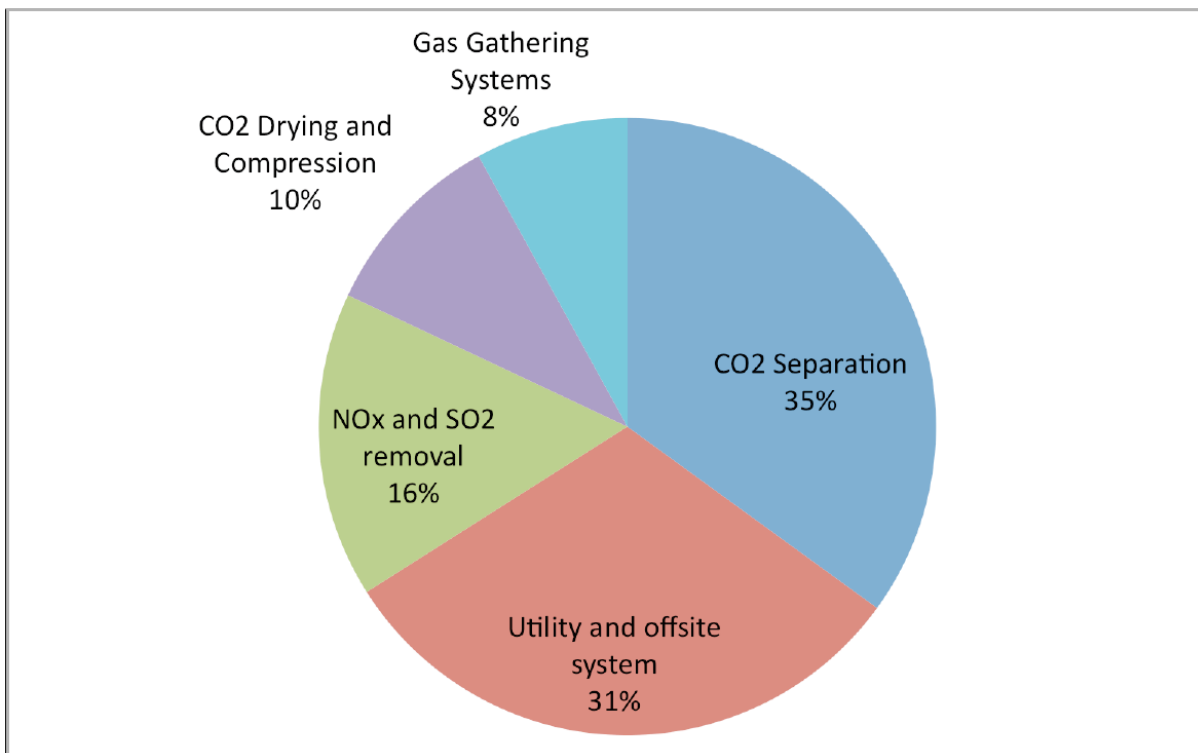
Fig. 2-8   Investment cost structure for a refinery complex with CO_2 capture

Source: Based on Simmonds et al. (2003)

The overall cost per tonne of CO_2 avoided is estimated at USD 50 to 60 (Simmonds et al. 2003), based on relatively low costs of energy, steel and engineering services. A later study by van Straelen et al. (2010) estimates the costs of capturing CO_2 from different process steps through post-combustion capture at EUR 90 to 120 per tonne of captured CO_2. If CO_2 was captured at numerous smaller sources, for example small boilers or small furnaces, which are scattered over the refinery site, then costs would be higher as many kilometres of additional ducting would be required to collect the CO_2.

Another study focuses on oxy-fuelling for a refinery power station boiler, using heavy oil and gas (Wilkinson et al. 2001). Electricity requirements for the air separation unit and CO_2 capture amount to 1.5 GJ per tonne of CO_2. Investment costs would be around USD 50 per tonne of CO_2.

2.3.3.4 Chemical and Petrochemical Industry

The chemical industry accounts for approximately 17 per cent of direct industrial CO_2 emissions. It is the largest industrial energy user, accounting for approximately 10 per cent of total worldwide final energy demand. The bulk of the industry's energy demand is provided by three groups of products including petrochemicals (steam cracking of naphtha, aromatic processes, production of methanol and olefins), inorganic chemicals (carbon black, soda ash, industrial gases, chlorine) and fertilisers (ammonia production) (IEA 2008).

In the petrochemical industry, most carbon is stored in synthetic organic products. This carbon is only available for capture when these products are combusted, either in waste incinerators or for energy recovery in other products. The most important sources of CO_2 in the petrochemical industry are steam boilers and an increasing number of CHP plants. Technologies being applied for CO_2 capture at large-scale CHP plants are similar to CO_2 capture processes for other power plants. For steam cracking with high-temperature boilers, the only feasible option is chemical absorption, since the residual gas is a mixture of methane and hydrogen and has a low CO_2 concentration per unit of energy used.

High-purity CO_2 is generated from the production of ethylene oxide from ethylene and the production of ammonia. The latter constitutes an early opportunity for industrial CCS as CO_2 capture is an integrated process step of ammonia production. CO_2 capture is separated from hydrogen at an early stage by using solvent absorption. A significant share of the recovered CO_2 is used for the production of urea. The remaining CO_2 is relatively low cost CCS as only CO_2 compression, transportation and storage are required as additional steps.

2.3.4 Fuel Production

2.3.4.1 Coal to Liquids

The production of liquid fuels (for example, diesel or kerosene) from coal through so-called coal-to-liquid (CTL) plants has gained new prominence in recent years. Countries with vast coal reserves, such as the United States, China or India, consider an extension of coal utilisation to fuel production as a way to alleviate energy security concerns. Distinction can be made between indirect and direct coal liquefaction processes. In indirect CTL processes, coal is gasified into synthesis gas consisting of carbon monoxide, hydrogen and various impurities, such as sulphur compounds or CO_2. The syngas is then liquefied via Fischer-Tropsch synthesis involving iron or cobalt catalysts. Fischer-Tropsch synthesis generates a broad range of hydrocarbons, including high-quality synthetic diesel or jet fuels. Globally, about 24 indirect CTL facilities were at the planning stage in mid 2009. The total initial capacity of all planned indirect coal liquefaction plants added up to 747,900 barrels per day, which was equivalent to approximately 72 per cent of the total 2006 gasoline and diesel demand of Germany's transport sector (Vallentin 2009).

Direct coal liquefaction processes convert coal into a slurry and, by applying high temperatures and pressure, liquefy the feedstock in either a one- or two-stage process. Subsequently, gaseous products are separated and liquid hydrocarbons are distilled to light, middle and heavy oils. Direct coal liquefaction receives less attention than the indirect process route, with China being the only country seriously considering the commercialisation of this tech-

nology. An important reason for the international preference of indirect coal liquefaction is its greater technical maturity. Furthermore, indirect CTL processes imply synergies with carbon capture technologies. CTL technologies are highly carbon intensive; hence, their deployment in a carbon-constrained environment strongly depends on the feasibility and economic viability of CCS.

Before being injected into the Fischer-Tropsch plant, the synthesis gas needs to be essentially free of impurities such as sulphur compounds or CO_2 as they can poison the highly sensitive Fischer-Tropsch catalysts. The impurities accumulate on the surface of the catalysts and reduce their activity. Thus, the removal of CO_2 is desirable to maximise the synthesis of coal-derived liquids and to extend the lifetime of the catalyst. The Fischer-Tropsch process requires a CO_2 capture rate of about 90 per cent. Hence, CO_2 capture is an integrated element of indirect coal liquefaction processes and does not cause additional costs. However, direct coal liquefaction offers no direct opportunity for carbon capture.
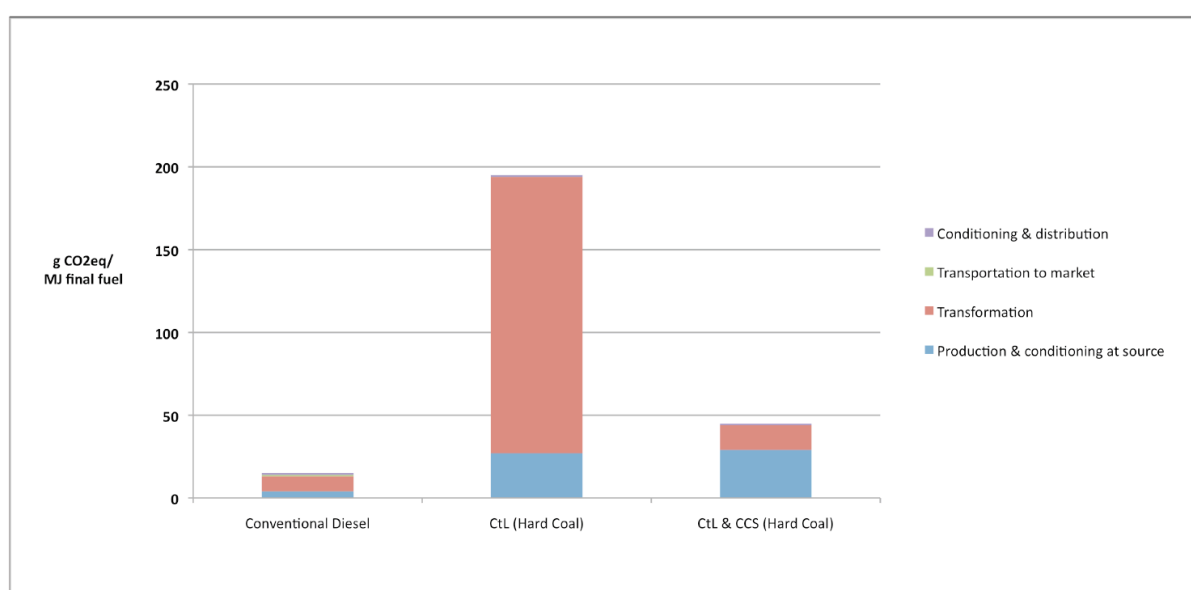
Fig. 2-9   Well-to-tank emissions of indirect coal liquefaction (with and without CCS) in comparison to conventional diesel

Source: Based on CONCAWE et al. (2007)

Without CCS, the well-to-tank (WTT) emissions of indirect CTL plants are about nine times as high as those of conventional diesel. Nearly 80 per cent of the emissions from indirect coal liquefaction are caused by coal transformation, including a credit for co-producing electricity in an IGCC process from heat, which is a by-product of indirect coal liquefaction. Excluding the IGCC credit, the CTL's WTT emissions would be eleven times as high as the WTT cycle of conventional diesel. Applying CCS may significantly reduce the WTT emissions of indirect coal liquefaction, but even with a 90 per cent capture rate, coal-derived diesel remains significantly more GHG-intensive than petroleum-based diesel (Fig. 2-9).

2.3.4.2 CCS and Biomass

CCS in combination with biomass-fired plants (bio-energy with carbon capture and storage/BECCS) has emerged as a new topic in the international CCS debate. This option is being considered, especially with regard to low carbon stabilisation scenarios, as biomass

CCS plants would be capable of producing negative net CO_2 emissions and, therefore, function as a CO_2 sink. Bellona, a Norwegian NGO with a strong focus on CCS, projects that the share of "carbon negative energy" will reach 18 per cent of the overall reduction targets to be fulfilled by 2050 (Bellona Foundation 2008). In recent scenarios, BECCS has been identified as being critical to achieving a greenhouse gas concentration of 400 ppm CO_2 equivalent. The costs of BECCS are strongly determined by the international biomass potential (Bauer et al. 2009; Edenhofer et al. 2010; Knopf et al. 2009).

BECCS can be applied in different sectors and plant configurations (biomass-only plants or co-firing with coal). CCS could be added to plants for the production of biofuels, such as ethanol (fermentation), methanol or Fischer-Tropsch synfuels (both via gasification), or power plants, including combustion or gasification-based units. In ethanol plants, CO_2 can be most easily captured from the fermentation process. The CO_2 produced during fermentation is rather pure and it would be relatively easy and inexpensive to capture the gas. Afterwards, the water needs to be removed and CO_2 has to be compressed to generate pressure. According to Lindfeldt et al. (2009), the amount of CO_2 captured and stored after fermentation totals 12 tonnes of CO_2 per TJ of biomass input if the efficiency of the ethanol production process is 33 per cent. Biomass production and transportation cause 3 tonnes of CO_2 per TJ of biomass, and distribution of the produced ethanol leads to 0.4 tonnes of CO_2 per TJ of biomass input. Consequently, each TJ of biomass that is used for ethanol production with low efficiency results in negative carbon dioxide emissions of 8.6 tonnes of CO_2 (Lindfeldt and Westermark 2009).

Co-firing of biomass and coal in combination with CCS can be used for electricity generation, fuel production (for example, Fischer-Tropsch synfuels) or the co-generation of several products. However, co-firing brings with it several technical challenges mainly due to the feedstock features of biomass. On the one hand, biomass contains significantly higher shares of volatile matter and has a higher reactivity than coal, reducing the amount of oxygen/air needed for gasification. Biomass reduces the production of undesirable by-products, such as ash, sulphur compounds or tar, which require costly cleaning procedures. On the other hand, the high moisture content and low heating value of biomass limits the range of compatible gasifier designs and coal ranks. Low-quality coal, such as lignite with its high moisture content, is not suited for co-firing operations with biomass (Vallentin 2009). Furthermore, the lower energy density of biomass causes a drop of gasifier efficiency as the combustion fraction rises in comparison to coal. The higher degree of combustion also affects the syngas composition and the CO_2 content in the syngas (Meerman et al. 2009).

The IEA (IEAGHG 2009a) has presented a detailed comparison of the costs of electricity generation of different types of 500 MW_{el} coal-fired power plants with 10 per cent biomass co-firing both with and without CO_2 capture. The plant types considered in this comparison are pulverised coal units and different fluidised bed power plants (circulating fluidised bed/CFB vs. bubbling fluidised bed/BFB). Furthermore, the study compares the electricity generation costs of different plant capacities (250 MW_{el} versus 75 MW_{el}) and plants which are fully biomass-fired or co-firing.

Fig. 2-10 shows the electricity generation costs of the aforementioned plant configurations with and without CO_2 capture. In general, it becomes clear that the generation costs of the 100 per cent biomass-fired facilities are more than twice as high as the generation costs of

coal-fired power plants with biomass co-firing. This is mainly due to the high costs of the bi-omass feedstock, which is approximately three times more expensive than the coal in terms of energy. In all cases, adding CO_2 capture technologies substantially increases electricity generation costs. For the co-firing plants, costs grow by 54 to 58 per cent; electricity generating costs of the considered biomass-fired plants grow by 80 to 84 per cent.
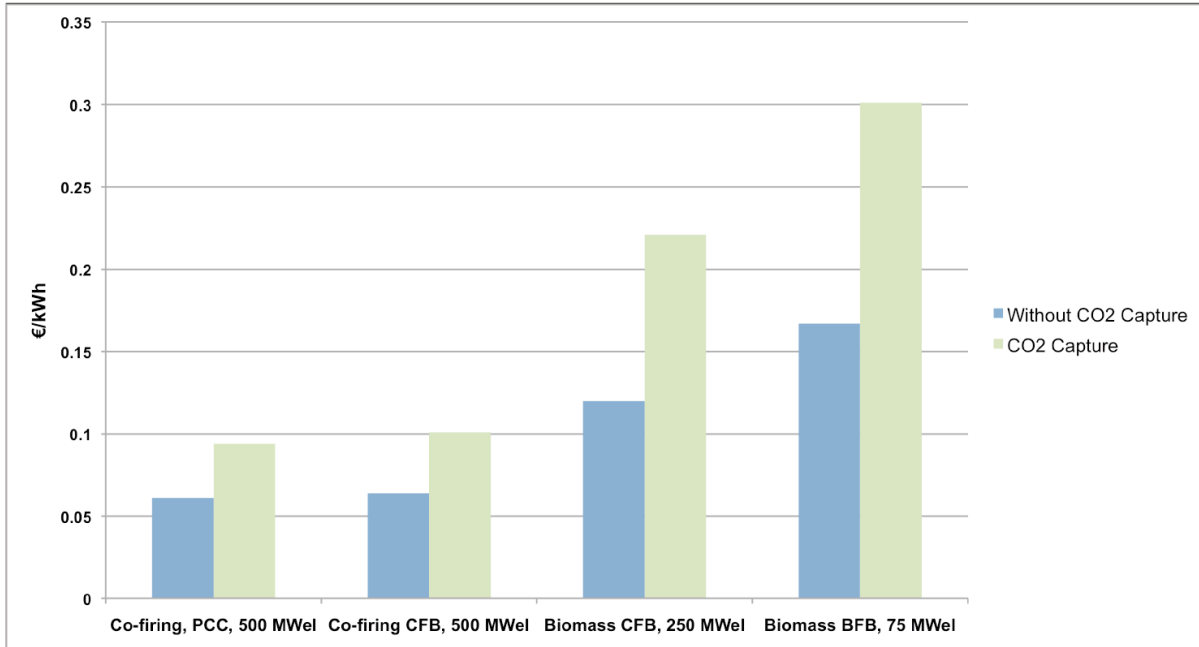
Fig. 2-10   Electricity generation costs of co-firing and fully biomass-fired power plants both with and without CCS

Source: IEA GHG (2009a)

3 CO_2 Transport: Technical, Financial and Infrastructural Challenges

3.1 Introduction

This section describes the journey between the CO_2 capture process and the potential injection sites, either for CO_2 enhanced oil recovery (EOR) or for geological sequestration. Costs and the amount of CO_2 transported per year increase by distance, thus short routes and an intelligent infrastructure are most favourable.

In section 3.2, the technical aspects of the different means of transport are presented as well as financial and infrastructural issues. Examples of existing CO_2 pipelines are given in section 3.3. The following section describes worldwide transport studies and models for CO_2 (section 3.4) to show how a transport system for CO_2 could be implemented. The final section, 3.5, examines risks and uncertainties associated with the possible transport schemes.

3.2 General Description of CO_2 Transport Issues

To conduct successful CCS projects, the captured CO_2 has to be transferred from the emission source to potential sinks. Transport is possible both onshore and offshore through pipelines; onshore by truck or train or offshore by ship. In order to be transported, the greenhouse gas is compressed to a supercritical fluid (>8 MPa in pipelines) or a liquid (typically at a low pressure of 0.7 MPa to 2 MPa). In this section, these different transport possibilities are described and the advantages and disadvantages of each are assessed. In each section, a differentiation is made between transport capacity, costs and environmental impacts. The underlying problem with all transport options is that they require energy, which causes additional emissions such as CO_2, SO_x or NO_x.

3.2.1 Truck and Train Transport

A possible way to transfer CO_2 onshore without constructing a pipeline would be by truck or freight train.

Transport Capacity

The amount of CO_2 that can be transported via truck or train is very limited compared to a continuous pipeline. A container on a truck can be filled with 20 tonnes of CO_2 (Coleman 2009), whereas an entire train could be loaded with 1,300 to 3,000 tonnes of CO_2 (Fischedick et al. 2008). Both methods are only suitable for small-scale applications, for example for demonstration or pilot plants or during the construction phase of a pipeline system. One example is the CO_2Sink project in Ketzin, Germany, where trucks deliver pure CO_2 for storage (Möller 2009).

Costs

The costs per km of transport are very high for truck and train transport. This is mainly due to the very low transport capacity (compare Tab. 3-2).

Environmental Impacts

Transportation of CO_2 by truck needs fuel. Burning this fuel releases greenhouse gas emissions into the atmosphere and is contradictory to the aim of sequestering CO_2 underground. Additionally, SO_x and NO_x emissions occur. The freight train option, if this uses electricity and non-renewable sources, also increases the amount of CO_2.

In a future scenario, where CCS has been adopted on a large scale, bringing with it the movement of millions of tonnes of CO_2 via truck or train, congestion and noise levels would catapult. (Coleman 2009) estimates that the equivalent of a truck lane circling the globe 38 times would be required to transport just 1 Gt of CO_2. This would have a prohibitive impact on the environment, landscape and population and so this means of transport must be restricted to early applications at low capacities.

3.2.2 Transport by Ship

Shipping CO_2 from source to sink is flexible, and could be made available rapidly and much sooner than a pipeline. However, shipping may have to be combined with other forms of transport if onshore CO_2 emissions are being transported to offshore sites. The journey from the source to the harbour could be via truck, train, boats on inland waterways or by onshore pipeline. From the harbour to the sinks, offshore vessels could transfer greenhouse gas where an injection facility is needed.

Shipping CO_2 is new but lessons can be learned from transporting liquefied natural or petroleum gas (LNG, LPG). These products are transported commercially on a large scale by marine tankers (IPCC 2005). Recently, a technical association of businesses agreed to work on the design and risk assessment of tankers for shipping CO_2 (Schulze 2010). The tankers developed will have similarities with LPG carriers and offshore shuttle tankers.

Transport Capacity

For CO_2 transportation offshore by ship, a loading and unloading infrastructure is needed at the harbour and possibly a site for intermediate storage (Chiyoda Corporation 2011). Seagoing tankers can transport around 24,000 tonnes of CO_2 (MAERSK 2010). The Chiyoda Corporation (2011) assumes a transport capacity per ship of 1 million tonnes of CO_2 per year.

Costs

The cost of transporting CO_2 by ship comprises tanker costs, harbour fees, fuel costs, costs for loading and unloading processes as well as intermediate storage and condensation plants. It includes additional costs for liquefaction compared to compression. The total costs amount to between USD 20 and 30 per tonne of CO_2 for transporting within the North Sea with volumes of more than 2 Mt/a (Möller 2009). Fig. 3-1 indicates costs of USD 8 to 28 per tonne of CO_2 (IPCC 2005). Chiyoda Corporation (2011) estimates that the cost of loading, shuttle and injection based on a distance of 400 to 800 km with four tankers in operation is USD 37 per tonne of CO_2.

Nevertheless the costs for shipping CO_2 are rather low in comparison to transport by truck or rail. When comparing with the pipeline alternative, this depends on the distance. From 0 to 500 km, pipeline transport is most efficient. Beyond 1,000 km, the break-even point is

reached and shipping appears to be cheaper than constructing, maintaining and using large-scale pipelines (IPCC 2005) (see Fig. 3-1).
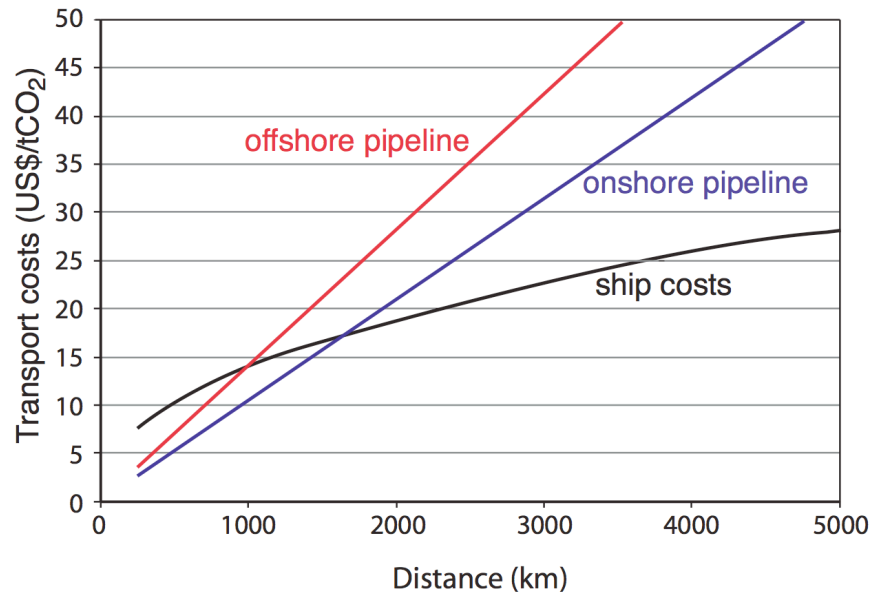
Fig. 3-1   Costs against distance for onshore pipelines, offshore pipelines and ship transport. The pipeline costs are given for a mass flow of 6 Mt of CO_2/a

Source: IPCC (2005)

Environmental Impacts

Shipping CO_2 needs heavy fuel, the production of which leads to ozone layer depletion (Koornneef et al. 2008). Additionally, photochemical oxidation and acidification resulting from SO_x emissions as well as acidification and eutrophication due to NO_x emissions occur. The greenhouse gas effectiveness of such an operation has to be analysed before the form of transport is chosen. Additionally, CO_2 might be lost during loading and unloading processes.

The large-scale movement of CO_2 using offshore tankers would considerably increase shipping traffic, which would heighten the risk of collisions. It could also lead to conflicts of use with existing shipping transport.

3.2.3   Movement by Pipeline

Pipelines can transport CO_2 as a highly compressed supercritical fluid with a pressure greater than 8 MPa and thus a high density of 1,100 kg/m^3. This is the most cost-effective and controllable way of transporting CO_2 for distances up to 1,000 km offshore and even longer distances onshore (compare the break-even point in Fig. 3-1 at approximately 1,700 km). (IPCC 2005)

Another advantage when compared to ships is their possible application both onshore and offshore. The experience gained from natural gas pipelines and some small CCS pipeline connections is explained in section 3.3.

Transport Capacity

The amount of CO_2 that can be transported by pipelines is very high compared to the other methods. It depends mainly on design features such as the diameter of the tube, the pressure applied and the temperature in the pipeline (dependent on the quantity of, and distance between, compressors). It is understood that a larger diameter, higher pressure or increased flow rate of CO_2 in the pipeline increases the mass transport of CO_2 per year (see Tab. 3-1). The design also includes the pipeline track. Populated areas should be avoided as well as valleys where leaked CO_2 could gather (because it is denser than air) and be dangerous. Detours that accommodate these guidelines would increase pipeline lengths and thus the transport time.

Costs

Transport investment costs are highest for the pipeline solution. Costs are dependent on pipeline diameters and whether their track runs onshore or offshore (see Tab. 3-1). However, the operational and maintenance costs are very low in comparison. The transport costs over 100 km and 40 years of operation time decrease in line with the diameter size. However, for larger diameters, the cost spectrum varies quite substantially. For offshore pipes, additional costs have to be factored in as construction, maintenance and monitoring are more expensive on the seabed. A cost reduction might be possible where routes can be shared with existing pipelines (for example, natural gas). The same track might be used, which cuts planning costs for a pipeline, and there may be greater acceptance among the local community. There needs to be some analysis of whether natural gas pipelines are compatible with CO_2 in order to establish whether they can be used to transport both. This is currently being tested at the Lacq gas processing plant in south-west France (Total 2012). Besides complex technical requirements, the conflict of use would be an issue. Natural gas is becoming increasingly important and many projects are underway to build additional natural gas pipelines and gas storage facilities, thus the functioning older ones will continue to be used. Additionally, more and more biogas is being introduced to the natural gas pipeline system and energy scenarios include gas produced from renewables. In the medium term, it may also be necessary to transport hydrogen through pipelines, which would create another potential conflict of use.

Tab. 3-1   Design of CO_2 pipelines with an initial pressure of 11 MPa and flow rate of 1.5 m/s

Diameter	Costs (onshore)	Capacity	Cost
m	Million USD/km	Mt of CO_2/a	USD/t of CO_2
0.3	0.3	2.9	0.25
0.4	0.4–0.9	5.1	0.2–0.44
0.75	0.8–1.0	18	0.11–0.13
1.0	1.0–2.3	35.9	0.07–0.16
1.6	1.9–6.2	81.8	0.06–0.19

The costs for transportation over 100 km within a period of 40 years are calculated

Source: Based on Göttlicher (2004)

Another important aspect is the construction material needed for the pipeline. If the transported CO_2 has a high purity, then conventional carbon steel is sufficient. However, if there is the possibility of water or water vapour content occurring during the transportation phase, then non-corrosive steel is needed, which increases costs. Because of the corrosion issue, companies tend to prefer to construct new pipelines for transporting CO_2 rather than relying on older gas pipes.

The calculation of installation costs also needs to reflect labour costs (Wildenborg et al. 2004). Besides investment costs, the budget should also take into account operational and maintenance costs as well as possible energy costs. Safety factors, such as detours in pipelines to avoid hazardous or populated areas, conflicts with local residents or reducing the danger of terrorist attacks or pipeline accidents, could delay pipeline construction and incur considerable additional costs.

(Hendriks 2010) calculates the investment costs as being EUR 0.6 to 1.0 million/km for an onshore pipeline with no complications and a 1 metre diameter. Offshore, this amount would increase to EUR 1.0 to 2.0 million/km. Existing projects have investment costs (for 1 m diameter) of EUR 0.5 million/km (the onshore Weyburn project) to 2.3 million EUR/km (offshore at Snøhvit). Tab. 3-1 shows the costs depending on the pipeline diameter. For a 1 m diameter, costs of USD 1 to 2.3 million/km are derived, which is comparable with the above-mentioned project costs.

For a single 900 MW power plant, a smaller diameter would be sufficient (0.2 to 0.5 m), which would reduce installation and operating costs. But if economies of scale are considered, pipelines with a larger diameter connecting various plants would be even more cost-effective (compare Tab. 3-1). The transport costs are given at EUR 4 to 8 per tonne of CO_2 for a distance between 200 and 300 km at the demonstration stage (Hendriks 2010). This is supposed to decrease to EUR 4 to 6 per tonne of CO_2 for the same distance on a commercial scale. The IPCC (2005) provides similar estimates of transport costs with a range of USD 1 to 8 per tonne of CO_2 per 250 km transport. Chrysostomidis et al. (2009) calculate the average costs for transporting CO_2 as being dependent on capacity utilisation with EUR 8 to 11 per tonne of CO_2. These figures are in line with the cost assessments of CO_2 transportation via pipeline by Massachusetts Institute of Technology (MIT 2007), the Global CCS Institute (2009) and McCoy (2008). On average, costs are around USD 2 per tonne of CO_2 for transportation over a distance of 100 km. This amount is used in the cost calculation for the three selected countries.

Environmental Impacts

The specific additional CO_2 emissions are most favourable, with pipelines at only 1 to 2 per cent per 1,000 km. For shipping, this doubles to 3 to 4 per cent per 1,000 km (IPCC 2005). The pipeline has to connect sources and sinks over hundreds of kilometres. This would impose a significant impact on land use and involve considerable construction projects, with potentially far-reaching local environmental consequences.

3.2.4   Comparison of Different Forms of Transport

Tab. 3-2 compares the different transport options in terms of capacity, costs and the additional CO_2 emissions. The transport capacity indicates the possible amount that could be

transported with one truck, freight train or ship tanker. Movement through pipelines is strongly dependent on the pipe's diameter (see Tab. 3-1). The additional CO_2 emissions referring to the same amount of gas being transported are included qualitatively. These range from high emissions for transportation by truck or train through to intermediate emissions for ships and down to low emissions for pipeline transport.

It can be concluded that pipelines are most suitable for large-scale CO_2 transportation. Ships could be more feasible under three circumstances at the initial phase of a project: if the total volume of CO_2 being transported is low, if pipeline investment is too costly or if the transport distance is more than approximately 1,000 km (Neele et al. 2011).

Tab. 3-2   Characteristics and suitability of different forms of transport for CO_2

Means of transport	Capacity	Costs	CO_2 emissions
	kt of CO_2	USD/t of CO_2 (100 km)	
Truck	0.02	10	High
Train	1–3	4	High
Ship	10–135	1.5	Intermediate
Pipeline	Dependent on diameter	0.4–3.2	Low

Source: Authors' compilation

For the cost calculation in this report, only pipeline transport is assumed. Based on Tab. 3-2, the average costs for transporting a tonne of CO_2 over a distance of 100 km are USD 2.

3.3   Existing CO_2 Pipeline Infrastructures

Pipeline transport is well established for natural gas, oil, condensate and water. These substances can be transported onshore and offshore up to 1,000 km. But there is some experience in CO_2 pipeline transport as well. This originates mainly from the USA, where high-pressure pipelines have been built since the seventies to transport carbon dioxide from natural sources to nearly-depleted oilfields in order to increase production (enhanced oil recovery). Five such projects are known for the USA, as well as one between the USA and Canada and one project in Turkey (Fischedick et al. 2008). In total, 50 Mt of CO_2/a are transported about a total length of 2,600 km. The transport costs amount to between USD 9 and 18 per tonne which is low compared to capture costs, which usually amount to between USD 40 and 60 per tonne.

3.4   Global CO_2 Transport Studies

This section gives an overview of some transport models and scenarios. CO_2Europipe is a partly EU-funded project under the 7th Framework Programme of the European Commission, which ran from April 2009 through to October 2011. It analysed and defined requirements for a possible large-scale pipeline infrastructure for CO_2 transport in north-western and central Europe. The project tried to address which CO_2 emissions could be transported in such a system; where the sources were situated and when they would occur. Three scenarios, based on onshore and offshore transport and EOR, were calculated (Neele et al. 2011). Haszeldine (2009) elaborated a possible CO_2 pipeline network in north-west Europe, and

Middleton and Bielicki (2009a, 2009b) developed a CCS infrastructure model based on California.

The IEA (2009b) calculated the potential global pipeline investments from 2010 to 2050 within its CCS model. Up to 2020, about USD 15 billion would have to be invested from which China and India would receive 20 per cent (USD 3 billion to build 17 to 20 pipelines between 2,100 to 2,700 km in length). Until 2050, the amount invested in China and India would increase to 33 per cent (USD 275 billion for 360 to 660 pipelines totalling 55,000 to 100,000 km in length) at a total of USD 550 to 1,000 billion in infrastructure investment (IEA 2009b). McKinsey (2008) argues that 400 Mt of CO_2/a would have to be transported by 2030. In order to achieve such challenging aims, the author identifies clusters where regional transport hubs would have to be installed and a pipeline network would have to be laid. Other methods, such as ship and truck, are also analysed.

3.5   Risks and Uncertainties with CO_2 Transport

As mentioned earlier, the avoidance of corrosion of materials is important to allow the safe passage of CO_2 in ships, tankers or pipelines. The quality of CO_2 is important when assessing risks since the amount of other substances such as H_2S, NO_x, SO_x or N_2 reduces its purity. Dry CO_2 does not corrode usual carbon-manganese steels and so water content is a crucial factor. The corrosion rate would be very small (0.01 mm/a). Effective steel has to be selected and regular monitoring would be needed. Besides material corrosion, there are other risks. Leakages could occur at the transfer stage between capture facility and pipeline or tanker. CO_2 may also escape at possible injection sites.

Another crucial issue in the transportation of CO_2 is public acceptance. There may be local resistance due to an absence of information or explanations, which can make it very difficult to obtain planning permission for a CO_2 pipeline from public authorities.

The potential harm to the local population must be kept to a minimum. Pipeline routes should not be installed through valleys because if there was a CO_2 leak there, it would gather because of its higher density than the air. Such an accumulation would be invisible, and therefore could go undetected, potentially leading to casualties because of a lack of oxygen.

4 CO₂ Storage: Types of Storage Formations, Mechanisms for CO₂ Storage and Methods for Assessing Storage Potentials

4.1 Introduction

An essential part of the CCS chain is the storage of CO_2 in the geological subsurface. Therefore, within this study, an in-depth review of the storage capacity in the three selected countries is provided. In order to examine the different perspectives of CO_2 storage capacity, general arguments, assumptions and methods are presented in this section.

Firstly, the characteristics of suitable geological formations for the injection and storage of CO_2 are described (section 4.2). The different types of formations are explained separately and the favourable conditions and negative impacts of different trapping mechanisms are shown. In section 4.3 there is an explanation of how CO_2 storage capacities are calculated for each of these formations and their classification in the different capacity concepts. Potential problems and constraints of CO_2 sequestration are discussed in section 4.4. Finally, the overall aim of the storage assessment for CISA is described (section 4.5). If storage projects are taking place in China, India or South Africa, these projects are described in their specific country report.

4.2 Characteristics of Geological Formations Suitable for CO₂ Storage

The storage of CO_2 in the subsurface is linked to geological formations. Some general requirements have to be fulfilled in order to declare a storage site as suitable. Formation types considered for CO_2 storage include oil and gas fields, deep saline aquifers, unminable coal seams and other possibilities such as basalt storage.

4.2.1 Types of Formations and Reservoir Requirements for CO₂ Storage

4.2.1.1 General Requirements for CO₂ Storage

Generally speaking, CO_2 storage needs pores into which the gas can be injected. This property is called *porosity* and is calculated by pore volume per total bulk volume. To inject and store CO_2 effectively, these pores have to interconnect to allow the fluid to disperse in the underground (*permeability*). Porosity and permeability are related and conditions for both have to be sufficient to obtain a high percentage of usable pore space. This can be expressed by the factor n/g (*net-to-gross ratio*). This is required for fast injection (high injectivity). In terms of estimating total storage capacity, the maximum allowable injection rate is not important. Instead, for regional or local injection projects, the *injection rate* may be the limiting factor. For this study it was not possible to cover this issue in the context of source-sink matching as there is a considerable lack of knowledge on injectivity at potential storage sites.

High levels of porosity and permeability are found in most sandstone reservoirs. Average values for efficient reservoirs are 20 per cent porosity and 300 mD of permeability. The depth essentially influences porosity and permeability, and these properties generally decrease with increasing depth.

Besides the required pore volume space, another essential aspect of safe CO_2 storage is the *caprock*. The porous storage area has to be sealed by an impermeable sediment layer of clay or salt with a substantial thickness. This reliable cap has to be able to resist the applied injection pressure at the bore well and also the general pressure increase created by CO_2 injection over the time it is operating as a storage site. Recently, experts have been favouring the multi-seal concept, meaning that not only one, but several confining layers are in place to secure the storage site (Birkholzer et al. 2009; DNV 2010). Consequently, even if the first cap layer is destabilised and CO_2 leaks beyond it, the second or third layer can contain the gas underground.

The described geological properties have another important impact on CO_2. As the overlaying sediment layers become thicker and thicker with increased depth, the temperature and pressure rise. On average, earth underground warms up by 25 to 30°C per km (geothermal gradient) and the pressure rises by 10 to 12 MPa per km (pressure gradient) (North 1985).

Pressure and temperature control the phase state of CO_2. The relationship can be seen in Fig. 4-1. At higher temperatures (>31.1°C) and high pressures (>7.3 MPa), CO_2 is compressed to the supercritical state. Beyond this *supercritical point*, the difference between the liquid and the gas phase vanishes. These conditions occur at a depth of around 800 m when average gradients are applied.
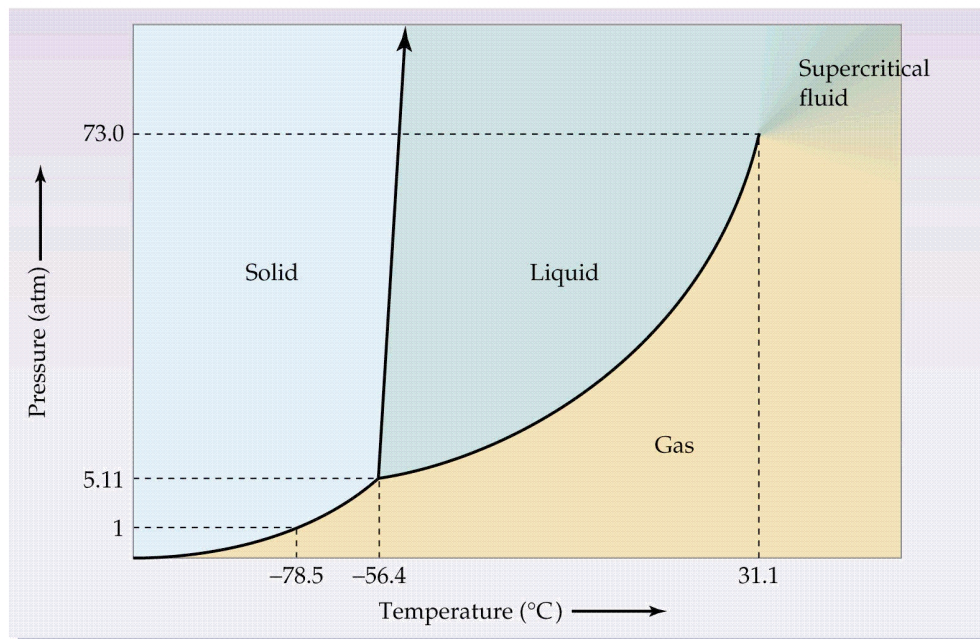
Fig. 4-1   Phase diagram for CO_2
Source: Piri et al. (2005)

The supercritical state is closely related to the density of CO_2. High pressure compresses the relative volume of a gas. Fig. 4-2 shows the reduction of volume with increased depth. At the supercritical point, around a depth of 800 m, it was reduced to a relative volume of 3.8 per cent and a CO_2 density of around 600 kg/m^3 is reached. This depth is considered as the minimum depth for CO_2 storage because the changes in volume and density until 2.5 km are only minor (2.7 per cent of the original size and a density of 700 kg/m^3). Vangkilde-Pedersen et al. (2009a) define 2.5 km as the maximum depth because of the considerable decrease in

permeability and porosity. The opportunity for CO_2 storage in aquifers and oil or gas fields lies, therefore, at between 800 and 2,500 m.
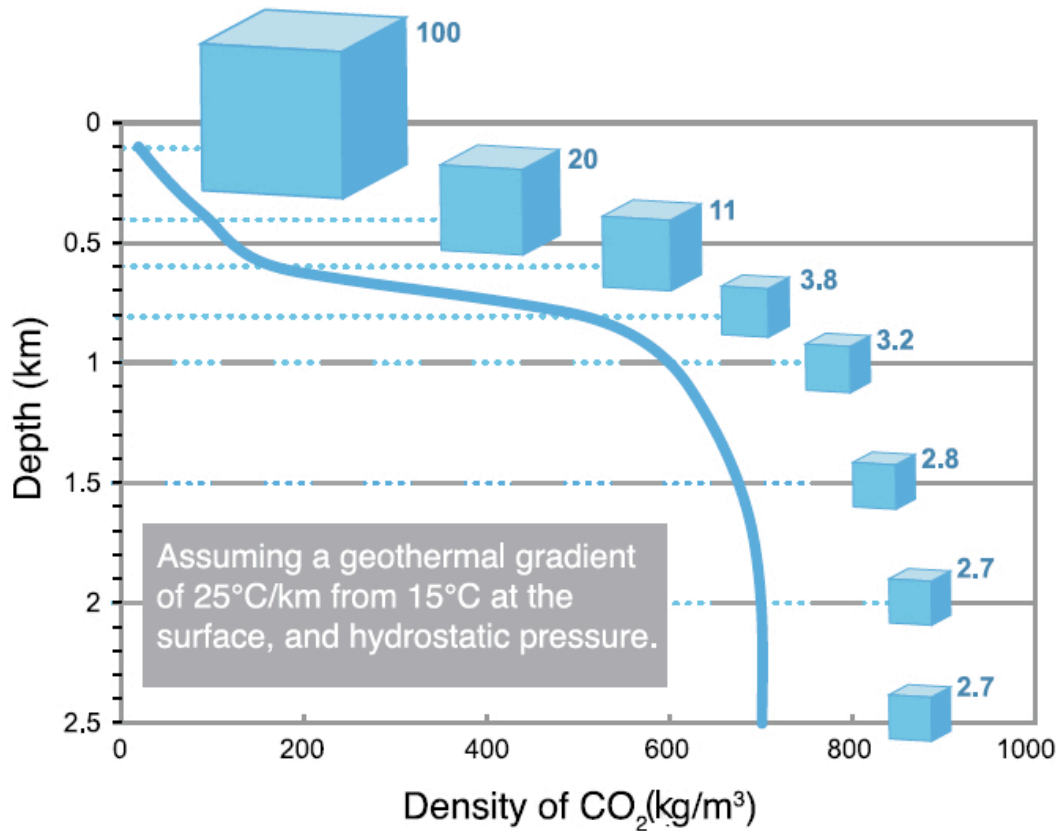
Fig. 4-2   Variation of CO_2 density with depth

Source: IPCC (2005)

In particular, the gain in volume leads to much more efficient storage operations because multiple amounts of CO_2 can be injected and stored. This positive effect is reached without additional energy input as the geological gradients deliver adequate conditions.

In coalfields (see section 4.2.1.4), the permeability threshold has already been reached at a depth of 1,300 to 1,500 m. Most of the methane production wells are shallower than 1,000 m (IPCC 2005). CO2CRC (2008) points out that the influence of supercritical CO_2 on the coal is very unclear and, therefore, for security reasons, injected CO_2 should remain in the gaseous phase, in other words, no deeper than 700 to 800 m. The density of this gaseous CO_2 would be less than the supercritical 600 to 700 kg/m^3, and would range from 2 kg/m^3 at the surface to 500 kg/m^3 at a depth of 700 m (see Fig. 4-2).

Several authors indicate that the coal situated in the groundwater protection zone has to be excluded from any plans for CO_2 storage (Bachu et al. 2007; Christensen and Holloway 2004; Hamelinck et al. 2001). Depending on water protection regulation and the depth of the potable water level, and if the previously defined maximum depth of 700 to 800 m is applied, the scope of appropriate depths is reduced considerably.

Tab. 4-1 gives an overview of the maximum and minimum values of variables for adequate CO_2 storage sites in aquifers and hydrocarbon fields. These figures vary for coal seams.

Tab. 4-1   Overview of the characteristic properties of suitable reservoir rocks for aquifers and gas/oil fields (minimum, maximum and optimum conditions)

Property		Unit	Minimum	Optimum	Maximum	Example *
Permeability	Cap rock	mD	As low as possible		1–10	
	Reservoir	mD	200	> 300	> 1,000	100–700
Porosity	Cap rock	%	-	< 10	10	
	Reservoir	%	10	20	30	18.7
Thickness	Cap rock	m	20	> 100	Infinite	Infinite
	Reservoir	m	20–50	100	300	200
CO_2 density		kg/m^3	500	700	750	650
Depth		m	800	1,200	2,500	200–3000

* = properties of a Lower Trias reservoir (UK), average values based on (Bentham 2006)

Source: Höller (2009)

4.2.1.2 Oil and Gas Fields

Depleted oil and natural gas fields are ideal for storing CO_2 underground. The carbon dioxide is injected where the former hydrocarbons were situated. The point of injection (for example, at the bottom or at the top of the structure) is chosen depending on the injection strategy and the geology of the site. If it is injected at the bottom, the differences in density cause the CO_2 plume to rise (similar to the formation of oil and natural gas) and it is collected underneath the roof. For millions of years, depleted oil and natural gas fields have shown the existence of suitable caprocks for hydrocarbons, which are equally assumed to be impermeable to CO_2. It should be pointed out, however, that CO_2 has different chemical properties to those of oil or natural gas, which could lead to problems. Above all, the formation of carbonic acid, caused by the dissolution of CO_2 in the prevailing water, creates an acidic and therefore corrosive environment. This could jeopardise the integrity of the caprock or wellbore cement (Ennis-King and Paterson 2007; Hunt 1995; Kharaka et al. 2006).

A big advantage of storing CO_2 in hydrocarbon fields is that plenty of data is available. The fields are well analysed and researched following decades of exploitation so the necessary geological information can be provided.

The trigger for starting the commercial application of CCS could take place through the expansion of *tertiary oil recovery* (enhanced oil recovery = EOR), which has already been applied for decades in the USA. There, a long CO_2 pipeline has been constructed which provides oil fields with fresh and pure natural CO_2. Dooley et al. (2010) assess that this pipeline network and existing CO_2-EOR operations do not help to boost the commercial deployment of CCS in the USA. Thus, new EOR projects include the potential value of sequestered CO_2 in the financial feasibility study of the projects (Nummedal 2008).

The first depletion phase of an oil field is induced by natural pressure, i.e. pressure in the reservoir is higher than that in the adjacent well bore. In the second production step, water is injected to increase the pressure difference between reservoir and well. The water displaces the oil. When this technique has lost its impact, CO_2-EOR is introduced and the recovery is enhanced with the greenhouse gas. On the one hand, CO_2 reduces the viscosity of oil and makes the recovery easier. On the other hand, it pushes the oil into the wellbore through

increased reservoir pressure. In comparison to usual EOR technologies, CO_2-EOR is more complex. Furthermore, it is a long-term technology with high costs.

The percentage of recovery of the original oil is extended from 10 to 30 per cent to 35 to 55 per cent through secondary recovery. Additionally, CO_2-EOR contributes between 5 and 15 per cent (Bellona Foundation 2005; SCCS 2009; van der Straaten et al. 1996). However, the CO_2 also blends with the oil and has to be separated from it afterwards. If CO_2 captured from emissions is to be used as a recovery aid, a small fraction of it may be stored underground. The Weyburn project produces between 5 and 10 barrels of oil for every tonne of CO_2 sequestered permanently underground (Nummedal 2008).

Thus, a life cycle assessment of the emission impact has to be taken into account. (Jaramillo et al. 2009) calculate that around 60 per cent of the injected CO_2 remains underground and that for every injected tonne of CO_2, approximately 3.7 to 4.7 tonnes of CO_2 are emitted into the atmosphere. These emissions include CO_2 released during production, transport, refinery and burning of the additionally produced hydrocarbons. EOR is therefore not an option for reducing emissions and is counter-productive to climate change initiatives (Luhmann 2009).

Another issue is scheduling. On the one hand, during EOR operations, efforts are made to achieve the highest possible oil output. For this reason, injection rates might be reduced to balance the internal reservoir pressure build-up. A continuous and safe CO_2 provision for several years at least is needed because stopping the operation could cause problems. On the other hand, CO_2 sequestration projects aim to inject the most amount of CO_2 at a continuous speed but an injection stop does not cause major problems (Nummedal 2008).

But nevertheless, EOR could help to implement a CO_2 pipeline system which could later be used for storage purposes. When EOR shuts down, the redundant field could be used afterwards for CO_2 injection and sequestration. But economic conditions such as oil recovery, oil market prices and infrastructure suitability, need to be favourable to achieve an adequate implementation. This is especially true offshore (SCCS 2009).

Enhanced gas recovery (EGR) is not as popular as the oil option. This is largely explained by three reasons. Firstly, the primary recovery step already produces 75 to 95 per cent of the original gas in place. Thus, additional recovery is not as important as for oil, and ranges from around 1 to 2 per cent of the original gas (Paterson 2003). Secondly, the gas mixes with CO_2 and the effect of enhanced recovery is not as obvious as for EOR. This gas mixture has a much higher CO_2 content than typical natural gas, and needs further refinery. Thirdly, EGR projects are still being investigated under laboratory conditions or in pilot projects, and this technology is not yet commercially available (IPCC 2005).

Unconventional Gas

Recently, prospective unconventional gas resources have fired imaginations with the possibility of a revolution in gas exploitation and its use as a domestic energy source, especially in the USA (Flavin and Kitasei 2010). The three possible gas sources are *trapped gas* from low-porosity rocks; *gas from shales* and *coalbed methane* recovery. Gas extraction from low-porosity sedimentary rocks is difficult and only becomes feasible if a high gas price exceeds the increased recovery costs. Technological advancements such as hydraulic fracturing and horizontal drilling help to recover trapped gas from shales. On the one hand, these techniques have considerable implications for the local environment as water laced with toxic

chemicals is injected for rock fracturing. These added chemicals create a huge toxic disposal problem and may contaminate water and other natural resources (NYSDEC 2009). On the other hand, horizontal drilling could reduce disruption to the land as it may cut the amount of vertical drilling required. In the USA, a shale "gold rush" is taking place (IHS CERA 2010). Coalbed methane recovery is explained in section 4.2.1.4.

Unconventional gas recovery is mentioned here as a considerable increase in gas production would increase the potential space for CO_2 injection. However, the production of trapped or shale gas destabilises the rock through fracturing, which diminishes the potential of suitable CO_2 storage sites. Additionally, greater quantities of domestic gas could partially replace coal as a leading energy source in upcoming economies such as India, China and South Africa. Instead of large coal-fired power plants, decentralised gas-fired plants could be constructed. Flavin and Kitasei (2010) argue that these countries may have extensive natural gas resources and could, by using these methods, reduce greenhouse gas emissions. This is underlined by the projections of IEA and OECD (2009). China is collaborating with the USA in enhancing unconventional gas recovery within the "US-China Shale Gas Resource Initiative". In spite of this, it remains rather uncertain whether these unconventional sources will boost global gas production, and the significance that this will have upon CCS implementation.

4.2.1.3 Deep Saline Aquifers

Unlike oil and gas fields, groundwater-saturated sediment formations, also referred to as deep saline aquifers, are relatively under-explored. Although there is a lack of reliable data, the injection of CO_2 into deep saline aquifers is generally considered to be the most attractive solution in terms of volume. The availability of suitable sedimentary basins is widespread and can be found in almost all parts of the world. Such basins are used for the underground storage of natural gas. Lessons learned from this technology could be applied to the storage of CO_2.

These formations contain water that has a very high salt content and is, therefore, undrinkable. A further property of potential storage formations is the very slow flowing movement of the groundwater (approximately just a few centimetres per year). Researchers assume that the injected CO_2 would remain safely underground in the long term due to dissolution and mineralisation. These effects are described in more detail in section 4.2.2.

Open and Closed Formations

An essential prerequisite for CO_2 storage in aquifers is the connection of the injection area to the rest of the formation. It can be compared with open and closed *structures* in open and closed *systems* (see Fig. 4-3).

The most straightforward type of a closed structure is a trap which can be likened to an upturned bucket or a subterranean hill. If CO_2 is injected into such a structure, it would remain inside, assuming the presence of a sufficient confining layer. Other possible structures are flat or trough-shaped (open or synclinal structures). If an open structure is used for CO_2 storage, the gas would not remain in the structure but would dissipate to other connected areas in the subsurface.

Open and closed structures in saline aquifers can be found in open or closed systems. In both cases, the injection of CO_2 is followed by compression and displacement of the pore

water. The compression increases the pressure in the system. If the system is closed, the maximum pressure increase of the aquifer system controls the amount of CO_2 to be injected because the pores are saturated with salt water and disruption of the cap and leakage has to be ruled out. If the system is open, this saline water can be displaced out of the structure and into other parts of the system. It is important that there are assurances that this displacement of highly saline water does not contaminate other environments. Catastrophes such as the salinisation of drinking water or the release of salt water to the surface must be prevented through safeguarding controls. Consequently, not only the risk of leaks of CO_2 emissions, but also that of saline water has to be taken into account.
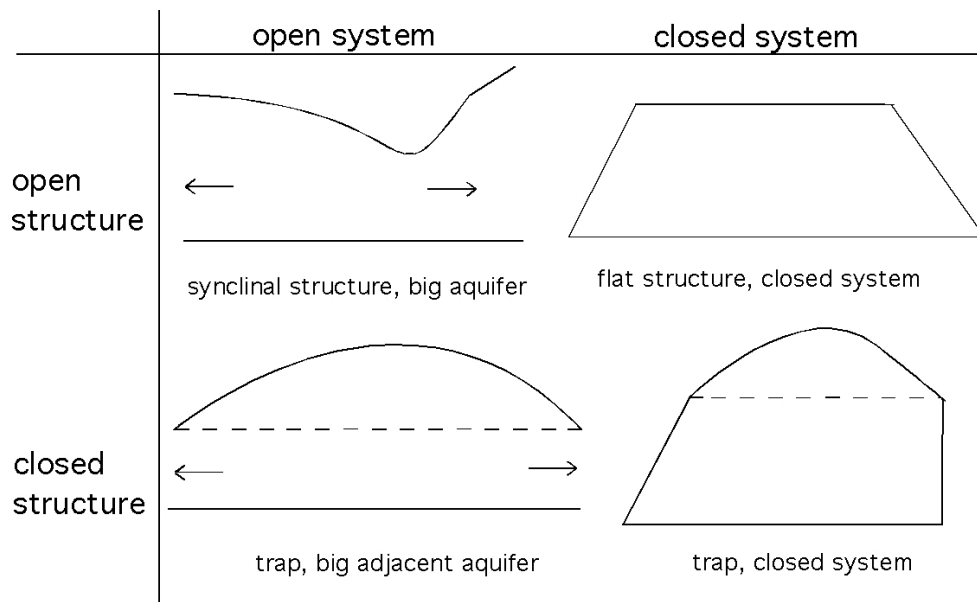
Fig. 4-3   Schematic examples of open and closed structures in open and closed aquifer systems
Source: Höller (2009)

4.2.1.4 Unminable Coal Seams

In many coalfields, coalbed methane (CBM) is present. This methane presents a danger to miners and the mining process as it is highly explosive. All over the world, explosions caused by methane emissions are a big problem in coal mining. Coalfield fires frequently occur and spontaneously combusting coalfields pose a severe threat to people and the economy. Additionally, there are heightened methane risks brought about by global warming. There have been cases of methane leaking to the surface close to coal mines. More detailed information on environmental issues concerning coal mining, especially in CISA, is provided in the country-specific sections on environmental impacts of CCS.

A very convenient way of reducing these risks is to recover the coalbed methane. Besides the safety benefits, it can be used for energy generation, and capturing the gas additionally reduces the emissions from coal mining. Recovery can be enhanced through the injection of CO_2 into deep uneconomic coal seams (*enhanced coalbed methane (ECBM)* recovery). In the long run, CO_2 storage is an opportunity here, in addition to depleted oil or natural gas fields and deep saline aquifers.

The storage of CO_2 in coalfields is based on the adsorption of CO_2 on the solid coal. Coal is a polymer-like substance and has a very large number of micro pores. Methane is present in

many pores, as mentioned above, but coal has a higher affinity to injected CO_2. At the same pressure (for example, 3 MPa), one gramme of dry coal adsorbs a volume of approximately 5 cm^3 of methane or 15 cm^3 of CO_2 (see Fig. 4-4). Due to this higher affinity, the methane is exchanged by CO_2 and can be produced *(ECBM)*. It has the potential to increase the recovery rate of methane from 50 to 90 per cent, and could lead to economically feasible exploitation (Hamelinck et al. 2001). For every methane molecule recovered, two to three molecules of carbon dioxide are accommodated (Gentzis 2000).

CO_2 has two effects on coal. On the one hand, it works as a "plasticiser", leading to a softening of the coal. On the other hand, CO_2 swells the coal and reduces its permeability (Day et al. 2010).

The depth of coalfields suitable for storing CO_2 is the source of some controversial discussion in the literature. One argument is that it is widely assumed that CO_2 storage is impossible in the depth area where coal mining has taken place and in groundwater protection zones. This can occur up to 600 to 1,200 m depth. For safety reasons, CO_2 storage should only be considered 100 m below the deepest mining operation (Holloway et al. 2009). The counter-argument is that coalfields below 1,300 to 1,500 m are declared as not viable for storing CO_2 because permeability is too low (< 1 mD) (Bachu et al. 2007). These depth restrictions would make it rather difficult to find adequate storage space. For comparison, most coalbed methane-producing wells are less than 1 km deep (IPCC 2005). Whether CO_2 storage or ECBM activities in traces of coal from depleted mines are safely available is also open to question. The abandoned coal mines accommodate many different wells, lodes and shafts so that a controlled sealing before injection is almost impossible. May (2003) points out that recovery in adjacent mines could still be in process, potentially raising other safety concerns. Additionally, crevasse formations often occur above the coal deposition.
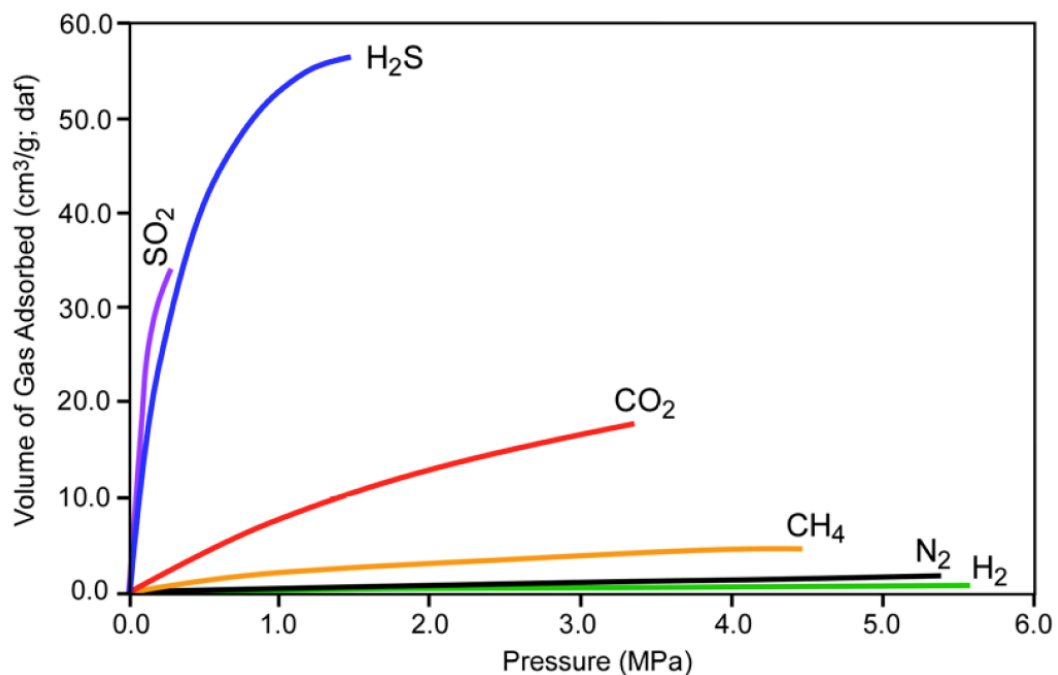

Fig. 4-4   Adsorption of various gases on "dry and ash free" coal (daf)

Source: Bachu et al. (2007)

Another limitation is the state of CO_2. It is considered as being unsafe if it is injected in the supercritical phase (CO2CRC 2008). Therefore the gaseous conditions of CO_2 should be maintained, which reduces the maximum depth range to 700 to 800 m (Holloway et al. 2009). It should also be appreciated that any CO_2 storage contaminates the coal, thereby precluding it from further exploitation meaning that this part of the energy resource is sterilised (Bachu et al. 2007).

Lignite occurrences are excluded from such possibilities since ECBM or CO_2 storage in these low-rank coals remain uncertain (Hendriks et al. 2004; Kumar and Mani 2007).

For these reasons, the option for storage in coal deposits has often been declared as unfeasible due to safety concerns and questions regarding storage efficiency (Shi and Durucan 2005). Nevertheless, many storage capacity estimates do include this deposition as a possibility and thus the methodology is described in section 4.3.4.

4.2.1.5 Other Possibilities

Underground Coal Gasification

Underground coal gasification (UCG) is another potential technology for CO_2 sequestration. The concept behind this process is to retain the coal resources underground so that it can be gasified there. Two wells are drilled into the coal for this purpose. One is reserved for the injection of oxidants such as air, oxygen, water vapour or mixtures of these substances. These are injected and heated to create syngas out of the solid coal. The second well is used to bring this product to the surface. The syngas does not have the purity of natural gas and it needs to be cleaned before it can be used for energy production. Clean CO_2 is formed as a by-product, ready for sequestration or CO_2-EOR application. Operations can be halted by injecting nitrogen (N_2) into the first well.

For CO_2 storage purposes, scientists argue that coal gasification turns the remaining coal into a rough equivalent of activated carbon with many internal pores (porosity from 2 to 30 per cent). This process should deliver enough space for CO_2 to be adsorbed, although there is no proof that this actually works (Kempka et al. 2009).

This technology might have major problems. It leaves the coal underground, but the gasification process reduces the mass, running the risk of huge subsidence. UCG causes (geo-) thermal and geochemical changes, which may influence the CO_2 storage potential. Properties such as pressure, temperature or the flow of fuel gas vary according to time and location. Severe groundwater contamination issues have been reported from UCG projects, including the possibility of organic contaminants in CO_2 and metals in acid groundwater becoming more soluble (BHEL 2006; Friedmann 2007). All these effects have to be analysed before injecting CO_2 back into coal seams or near to an active UCG production facility (Voosen 2010).

Basalts

Flood basalts form part of large igneous provinces, mostly in the oceans. Major continental formations are situated in the USA (Columbia River basalts), India (Deccan Volcanic Province), South Africa (Karroo basalts), Canada (Keeweenawan) and Brazil (Parana). Basalts typically have low porosity, low permeability and low pore space continuity. The thickness of

the uppermost section is often highly variable because the flood basalts have an inherent heterogeneous nature.

During solidification of the magma, different processes take place to form joints and porous and permeable flow tops of basaltic lava. These processes include variations in cooling rates and thermal contraction, degassing and interaction of the magma with water. These effects partially established the necessary characteristics for CO_2 sequestration (sufficiently high porosity and permeability), but also created properties such as joints which can lead to severe problems in CO_2 injection operations. The basalt formations are partly confined by seals to contain the CO_2 in the basalt. These are dense, low permeable basalts and sediment beds with a low permeability within the basalt.

The possible injection rate per well might be higher than a few million tonnes of CO_2 per year, although there is yet to be a detailed evaluation of their storage potential. Consequently, the IPCC (2005) states that still more research is needed and that basalts appear unlikely to be suitable for CO_2 storage. Nevertheless, recent studies have evaluated the potential of CO_2 storage in continental flood basalts in the US and Indian basalts (Kumar et al. 2008; McGrail et al. 2006, 2009; Schaef et al. 2010; Singh et al. 2006).

4.2.2   Storage Mechanisms

Once CO_2 has been injected into the subsurface, it can be kept there using a variety of techniques.

When it comes to storage in *saline aquifers*, the pore water is displaced by the injected carbon dioxide. CO_2 rises in this formation because it has a lower density than the surrounding salt water. As soon as it reaches a cap rock, it collects there in a structure (for example, trap) as a mobile phase. This mobile phase of CO_2 is similar to storage operations in *depleted oil or gas fields,* where the displacement issue is different. There, the space created by produced hydrocarbons may be filled with CO_2.

In both formation types, CO_2 is gradually dissolved in the salt water at the boundary surface to the water layer, and carbonic acid is formed. Eventually the entire mobile CO_2 phase should be dissolved. The mineralogical deposition of carbonates does not start until the water is CO_2-saturated and enough cations (such as calcium ions) are available. The Intergovernmental Panel on Climate Change (IPCC) special report on CCS (IPCC 2005) provides an overview of the trapping mechanisms and the planning stages for saline aquifers (see Fig. 4-5).

Mineralogical storage is also the trapping mechanism available for storage in *flood basalts*. There, it is supposed that the injected supercritical CO_2 dissolves sufficient ions from the rocks. These cationic ions can react with dissolved CO_2 to create carbonate minerals.

CO_2 storage in *coalbeds* is different to the described methods. There, trapping by adsorption is the essential mechanism.

In the following section, the trapping mechanisms and the different activation time periods (see Fig. 4-5) are described and summarised in Tab. 4-2.
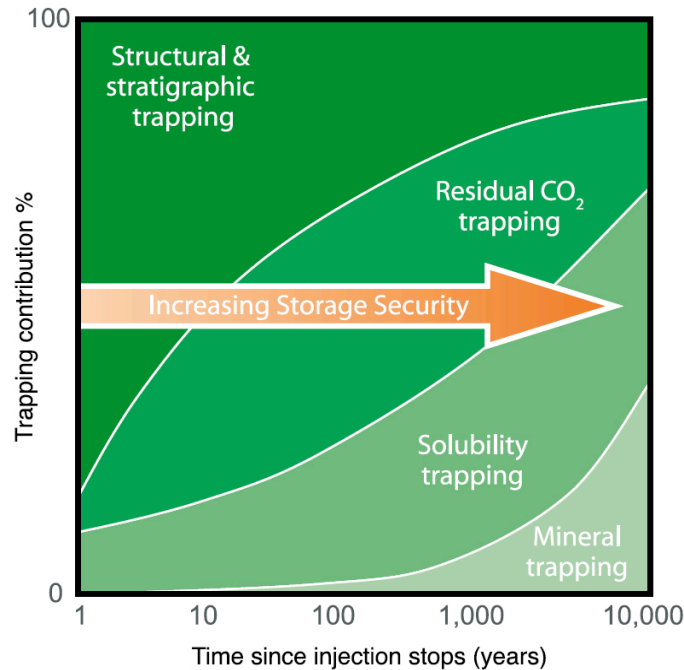
Fig. 4-5   Share of different trapping mechanisms after injection stops
Source: IPCC (2005)

4.2.2.1 Free-Phase Trapping

The contribution of free-phase trapping is at its highest at the beginning of the injection pro-
cess and decreases as time goes by and as other processes become more important. The
most convenient pore spaces are within structural and stratigraphic traps, where CO_2 accu-
mulates underneath a confining layer.

4.2.2.2 Capillary Trapping

Whilst the injected CO_2 moves as a plume through the subsurface, parts of it are retained in
the pores due to capillary forces. This amount of residual trapped CO_2 increases with the
length of the migration path and with the amount of pore space volume that is passed
through. The migration rate of the injected CO_2 is reservoir specific and depends on the
properties of the rock such as permeability and porosity, the brine density, the CO_2 itself and
the injection strategy. The formation water situated in the pores is exchanged by CO_2. This is
called residual trapping, and develops with age, from immediately after the injection has
stopped, lasting for an indeterminate period of time, and possibly over centuries (Bradshaw
et al. 2005).

4.2.2.3 Dissolution Trapping

The CO_2 fraction trapped in structures or stored in pores dissolves into the surrounding water
in the long term.

The dissolution process occurs in conjunction with residual trapping and is referred to as
solubility trapping in Fig. 4-5. The migrating CO_2 is dissolved in the formation water. The
amount of dissolution relies heavily on the conditions in the subsurface. A greater amount of
gas can be dissolved if the pressure is high and salinity is low. CO_2 dissolved in water forms

ionic species and produces a weak acid (slightly lower pH). The acid-rich salt water has a higher density than the CO_2-free saline water and descends. New saline water can rise to the boundary and dissolve additional CO_2.

Because of the time frame, this trapping mechanism does not increase the short-term storage potential, which is borne out by numerical simulations (Bielinski et al. 2008; Doughty et al. 2001; Pruess 2003). If a CCS operation of between 40 to 60 years is assumed, most of the injected CO_2 will be captured during this period in structural and stratigraphic traps (free-phase trapping). Effective dissolution starts only after decades of injection and could increase the pore space available for further injection.

A huge amount of CO_2 can be trapped by dissolution over a timescale of hundreds to thousands of years (Bradshaw et al. 2005). In the long term, it is believed that all free CO_2 will be dissolved due to the slow velocity of the injected CO_2 plume (cm/a) (Bradshaw et al. 2005; Gunter et al. 1993). The lateral movement is slow enough that the whole CO_2 would dissolve before exiting the formation. This also applies if no traps or caps impede the movement.

Gilfillan et al. (2009) describe solubility trapping as a major sink for CO_2 by providing examples of natural analogies. Regarding the long-term storage, dissolution removes up to 90 per cent of the CO_2 in the formation whereas mineral precipitation has only a minor impact (0 to 15 per cent). The occurrence of natural CO_2 deposits is explained by assuming a very slow dissolution process in the formation in question. In contrast, van der Meer (1996) models the contribution of dissolution to storage as being less efficient and states that only a small amount will be dissolved.

4.2.2.4 Mineral Trapping

Mineral trapping works over an even longer timescale and provides the highest level of storage security. The drawback is that it only starts to occur significantly centuries after injection has taken place (see Fig. 4-5).

In geochemical terms, mineral storage is based on CO_2-saturated pore water (dissolution trapping). The carbonate ionic species react via bicarbonate ions to carbonate minerals with calcium, magnesium and iron. These derive from silicate minerals in the rock matrix. Such reactions can take place in saline aquifers, oil and gas fields and in flood basalts, and result in the precipitation of carbonate minerals. CO_2 can be sequestered sustainably underground due to this geochemical trapping.

The main difference between sedimentary rock formations and basalts is the relatively fast reaction rate of mineralogical trapping in basalts. Firstly, the CO_2 is dissolved in the basaltic pore water. After that, a rapid reaction of CO_2-saturated pore water with major crystalline components of the basalts takes place and stable carbonates are formed. The associated mineralisation reactions in basalts have already been demonstrated under laboratory conditions in less than 1,000 days but need to be verified in nature (McGrail et al. 2006; Schaef et al. 2010). The researchers tested basalts from the USA, India and South Africa. All samples had different levels of reactivity, for example, the Karoo basalt of South Africa was highly reactive with the CO_2-H_2S mixture and least reactive with supercritical CO_2. But virtually all the basalts showed some type of reaction under the presence of CO_2, suggesting that they could permanently store the gas as carbonate minerals. Prasad et al. (2009) tried to optimise

the reaction rate under laboratory conditions to maximise the amount of sequestered CO_2. The careful adjustment of process conditions such as altering the particle size, reservoir temperature or CO_2 pressure could enhance the trapped amount. It would be very difficult to guarantee such conditions in nature and many investigations still have to be carried out to prove the suitability of basalt storage. BGS (2010) mentions a different method of storing CO_2 in basalts. Using its approach, the gas would be injected through the basalt using high pressure, possibly causing it to partially react with the rock. However, much of the injected CO_2 would be emitted at the other end of the formation, leading to obvious problems concerning emission control and safety.

One pilot study designed to make new discoveries about the environmentally safe and irreversible long-term storage of CO_2 in Deccan basalt is being conducted by an international consortium led by the National Geophysical Research Institute in Hyderabad (Kumar et al. 2008).

Sediment basins are much more widespread, and thus have a higher storage potential, but deliver only insufficient calcium, magnesium or iron ions for mineral trapping. The supercritical CO_2 remains much longer in the formation, mixing very slowly with the pore water and so leakage is possible.

4.2.2.5 Adsorption Trapping

This trapping mechanism is restricted to CO_2 storage in coal seams and after underground coal gasification. When the gas comes into contact with the surface of the coal, it is adsorbed and, where present, coalbed methane is displaced. In order to achieve an economic output through coalbed methane recovery, this process has to be quick (Bachu et al. 2007). Absorption and structural rearrangement of the coal also controls the speed of the initial adsorption (CO2CRC 2008).

CO_2 adsorption is most successful where large quantities of micro pores are available. This process has been successfully demonstrated in a laboratory setting, but must be tested in natural environments through an extensive testing process to show its viability for large-scale CCS deployment.

Tab. 4-2   Overview of trapping mechanisms

	Free-phase	Capillary	Dissolution	Mineral	Adsorption
Oil and gas fields	x	x	x	x	
Deep saline aquifers	x	x	x	x	
Coalbeds/UCG	x				x
Flood basalts	x		x	x	
Time	Initially fast, decreasing in long term	Increasing with migration path	Medium to long term	Long term (centuries), faster in basalts	Short term
Dependent on	Porosity, permeability	Permeability	Lateral movement, water conditions (pressure, salinity)	Cations, CO_2-saturated pore water, CO_2 pressure, temperature	Available coal micro pores, bounded CH_4

Source: Authors' compilation

4.3 Methods for Assessing the Capacity of CO_2 Storage Formations

This section provides an overview of different methods for assessing CO_2 storage capacity, which is crucial to understanding the available estimates and the huge variations between them (Bradshaw et al. 2007). First of all, various concepts for capacity categorisation are explained. This is followed by a description of the calculation methods for different formation types such as oil and gas fields, deep saline aquifers and unminable coal seams.

4.3.1 Capacity Concepts

Against the backdrop of carbon dioxide sequestration activities becoming more prevalent, different concepts for describing available underground capacity are reviewed. There are two key aspects here: one is to consider the dimensions of the assessment, adopting either a top-down or a bottom-up approach, whilst the other is to specify the estimated CO_2 storage capacities. This is widely achieved using the so-called pyramid concept, where the estimates are sorted according to viability.

4.3.1.1 Top-Down and Bottom-Up Approaches

There are two different approaches to investigating the spatial aspects of CO_2 storage: the *top-down* approach derives from the total size of a region or federal state and uses generalised values and assumptions to estimate capacity. This differs from the *bottom-up* method, in which site-by-site level data is collected in order to assess volume, properties and storage characteristics. Applying these factors gives a site-specific capacity estimation which can be scaled upwards to calculate a figure for the entire region. If reliable measurements are available, the bottom-up approach can deliver a much more detailed capacity perspective.

Depending on the formation type, different geological information is available. The exploration and production industry has collected significant data for oil and gas fields. Here, a bottom-up approach is possible and widely applied to estimate storage capacity. Data about deep saline aquifers has only been sparsely collected and therefore in most cases general values are used to derive storage capacity using a top-down approach. Nonetheless, regional or formation-specific assessments do exist. Coal seams are somewhere in between: the coal industry has significant data about reserves, but this is limited to commercially exploitable areas. For CO_2 storage, only uneconomic seams are considered and thus data is limited because the capacity depends on the quality of the coal and the specific adsorption capacity (CO2CRC 2008). This is the reason for the top-down approach usually being applied to coal seams.

4.3.1.2 The Pyramid Concept

Besides the spatial view of storage capacities, there needs to be an evaluation of the reliability of estimations. When the available capacity estimates for the same region are compared, the variation is enormous (Bradshaw et al. 2007). The differences can be partly explained by applying a concept which sorts the different results into categories. A commonly used concept is the "techno-economic resource-reserve pyramid for CO_2 storage capacity" proposed by the Carbon Sequestration Leadership Forum (CSLF) (Bachu et al. 2007). It provides a good overview of different capacities. Essentially, the pyramid consists of four categories:

theoretical, effective, matched and practical capacity. Fig. 4-6 shows a modified version of that pyramid. The whole pyramid represents the *theoretical capacity.* This represents the maximum volume that can be filled with CO_2. This capacity includes uneconomic and unrealistic volumes. Geologically, the most important capacity is the *effective capacity*. It is a subset of the theoretical one applying physical, geological and engineering cut-off limits on capacity. The matched capacity is derived through a source-sink matching of big CO_2 sources with potential sinks. The *practical storage capacity* incorporates technical, legal and economic barriers.
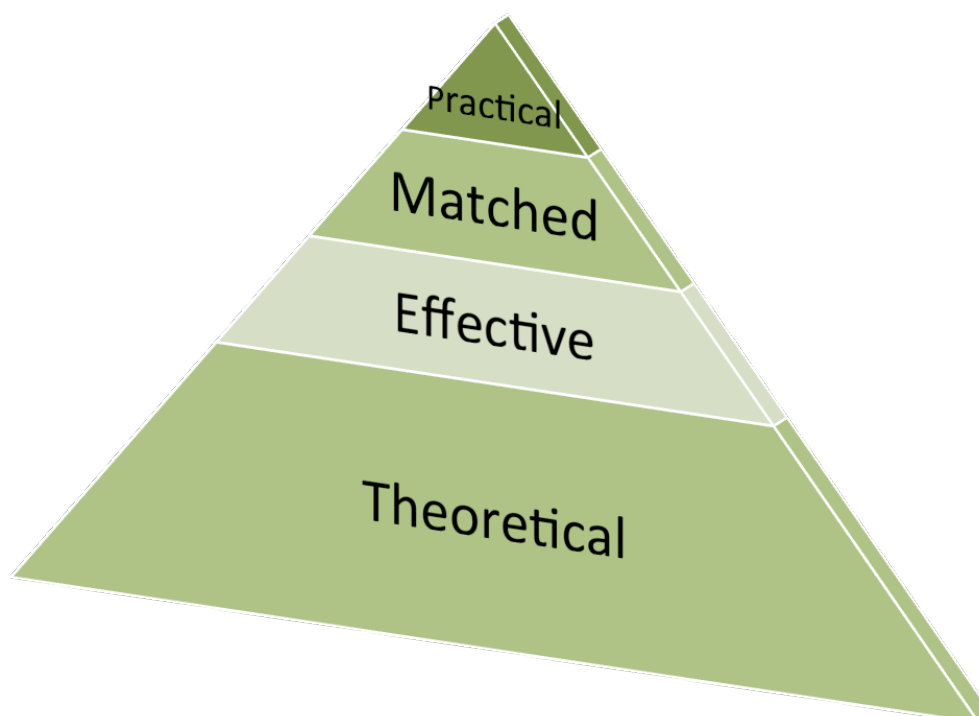
Fig. 4-6   Modified version of the storage potential pyramid suggested by CSLF

Source: Authors' illustration based on Bachu et al. (2007)

This section presents the methodologies for obtaining the *effective capacity,* although it was not possible to apply these equations to all countries in this study. If the required data was unavailable, the *theoretical capacity* was derived. To demonstrate the wide range of options for storage, scenarios are developed for either *effective* or *theoretical capacity*. Based on these scenarios, the country-specific sections deal with the infrastructural challenges involved in achieving broad source-sink matching. In the case of *effective* capacities, a *matched* capacity, as shown in Fig. 4-6, is derived. If only theoretical storage capacity estimates are available, a *theoretically matched* capacity is calculated.

4.3.2   Oil and Gas Fields

The storage capacity for oil and gas fields is mostly calculated from depleted fields. Additionally, enhanced oil or gas recovery may contribute to storage capacity via increased recovery.

The capacity to store CO_2 in depleted oil and gas fields is calculated from the amount of hydrocarbons produced (and remaining reserves) or from the original reserve number (original oil or gas in place) modified by a recovery factor. This results in the *volume of gas or oil* at

standard temperature (15°C) and pressure (1,000 hPa) at the surface (STP): $V_{gas}(STP)$ or $V_{oil}(STP)$. A factor is needed to take the shift of density from reservoir conditions to the surface into account. This coefficient is called the *gas expansion factor B_g* for storage in depleted gas fields and the *formation volume factor FVF* for oil fields. Additionally, the density of CO_2 at reservoir conditions is applied to convert from a volume to a mass of CO_2 to be stored. This leads to Equations 4-1 for gas fields and 4-2 for oil fields.

$$m_{CO_2,theoretical} = V_{gas}(STP) \cdot \rho_{CO_2} \cdot B_g \qquad\qquad \text{4-1}$$

$$m_{CO_2,theoretical} = V_{oil}(STP) \cdot \rho_{CO_2} \cdot FVF \qquad\qquad \text{4-2}$$

where

$m_{CO2,theoretical}$	= theoretical storage capacity $[m_{CO2,theoretical}]$ = kg;
$V_{gas}(STP)$	= volume of ultimately recoverable gas at the surface (standard temperature and pressure (STP)), $[V_{gas}(STP)]$ = m^3;
$V_{oil}(STP)$	= volume of ultimately recoverable oil at the surface, $[V_{oil}(STP)]$ = m^3;
ρ_{CO2}	= density of CO_2 at reservoir conditions, $[\rho_{CO2}]$ = kg/m^3;
B_g	= gas expansion factor from reservoir conditions to STP, $[B_g]$ = -;
FVF	= formation volume factor, $[FVF]$ = -.

It should be added that this storage capacity in gas and oil fields has to be considered as theoretical as it assumes that 100 per cent of the oil or gas formerly there can be replaced by carbon dioxide. As (hydro-)geological processes take place during and after the depletion of a field, this is a rather optimistic assumption. The CSLF has defined an efficiency factor for hydrocarbon fields (Bachu et al. 2007). This factor is derived from water migration into the field, surface subsidence and the heterogeneity of the geological structure. These effects could lead to a diminution of pore space and thus makes it more realistic to apply an efficiency factor on the estimated theoretical capacity. Hendriks et al. (2004) and the IEA GHG (2009) suggest a sweep efficiency of 75 per cent. This can be considered as the average efficiency provided by Holloway et al. (2006) at 65 to 90 per cent. If the intention is to obtain an efficient CO_2 storage capacity in hydrocarbon fields, such an efficiency of around 75 per cent should be applied.

Economically, there is another potential way to remove (at least part of) the CO_2. CO_2 may be used within increased oil or gas recovery (EOR/EGR), when the production rate of the hydrocarbons decreases. If this is undertaken, the storage capacity in oil or gas fields is increased by the amount of additionally recovered hydrocarbons, although the CO_2 already stored during hydrocarbon production has to be included in this calculation.

4.3.3 Deep Saline Aquifers

The general formula for effective CO_2 storage capacity estimation in saline aquifers is based on the top-down approach (compare Vangkilde-Pedersen et al. (2009b)):

$$m_{CO_2,theoretical} = V_b \cdot n/g \cdot \phi \cdot traps\% \cdot \rho_{CO_2} \qquad\qquad \text{4-3}$$

where

m_{CO2}	= storage capacity, theoretical or effective, $[m_{CO2}]$ = kg;
V_b	= volume of the potential storage site, $[V_b]$ = m^3;
Φ	= porosity, $[\Phi]$ = %;
n/g	= net-to-gross ratio, usable space of a rock, i.e. the percentage of porous and permeable rock in comparison to the total bulk volume of the aquifer, $[n/g]$ = %;
$traps\%$	= amount of traps of total volume, $[traps\%]$ = %;
ρ_{CO2}	= density of CO_2, $[\rho_{CO2}]$ = kg/m^3.

Firstly, the volume is estimated from the entire sediment area and the average aquifer thickness potentially available for CO_2 sequestration. The net-to-gross ratio helps to limit this volume to the usable part of the total bulk volume. Most of the scientists dealing with CCS agree that storage in deep saline aquifers has to be limited to closed structures because this increases the safety of the operation, facilitates monitoring and could enhance societal acceptance. This factor is expressed by $traps\%$. Additionally, the density of CO_2 in reservoir conditions is included in the equation to derive the gravimetric theoretical storage capacity. This unrealistically high capacity assumes that the entire usable pore space (which is water saturated in aquifers) can be filled with CO_2. This is not possible and thus an efficiency factor E has been created to reduce this theoretical capacity towards a more realistic one:

$$m_{CO_{2,effective}} = m_{CO_{2,theoretical}} \cdot E \qquad \text{4-4}$$

where

E	= efficiency factor, $[E]$ = %.

This efficiency factor is the focus of broad discussions within the international CCS scientist community. Storage capacity estimates range from between 0.01 per cent and 40 per cent, depending on the research (Höller 2009). These strong deviations are largely explained by the assumed volume projections. The variations in other parameters, which may modify this substantial range, should also be taken into account. The most conservative approach is introduced by van der Meer and Egberts (2008). These Dutch scientists regard every geological system as finite or confined. If this assumption is true, formation water cannot be displaced out of the system and storage capacity is controlled by water and rock compressibility (c_p+c_w) and maximum pressure increase in the system (Δp) (compare Wildenborg et al. 2004). The conservative efficiency is derived from a multiplication of total compressibility and maximum pressure increase by

$$E = (c_p + c_w) \cdot \Delta p \qquad (7.4)$$

If a total compressibility of 10^{-3}/MPa and a pressure of 1 to 10 MPa is inserted, efficiency values of 0.1 to 1 per cent are derived.

This approach is underlined by Ehlig-Economides and Economides (2010) who give a possible range of 0.01 to 1 per cent and IEA GHG (2009c) who calculate an exemplary efficiency of 0.59 per cent for closed systems.

These values below 1 per cent are estimated from the allowable pressure increase in the total system and so refer to the entire volume. This does not overcome the limitation that storage of CO_2 takes place only in traps, but for capacity calculation, the percentage of traps does not play a role. Thus *traps%* is set to 1.

Besides the calculation of CO_2 capacity in closed systems, there are models to estimate capacity in open systems as well. This is not described further within this study because of the lack of information and uncertainties surrounding the security of the displaced fluids when CO_2 is injected; this has persuaded the authors to gravitate towards the conservative efficiency option.

It should be stated that the differences between efficiency factors mentioned above are partially explained by differing approaches, which puts this into some perspective. If an efficiency factor of 0.1 per cent, referring to the *total usable pore volume* (i.e. the affected space in Fig. 4-7), is compared to an efficiency factor of 20 per cent, for example, referring to the *trap volume* (i.e. the available space to the spill point in Fig. 4-7), the difference is not as significant as it appears. If the percentage of traps is 5 per cent (i.e. 5 per cent of the affected space is the available space in Fig. 4-7), the difference between these two scenarios is "just" factor 10 (instead of factor 200). But even a capacity in saline aquifers ten times higher is very notable and could have significant political implications.
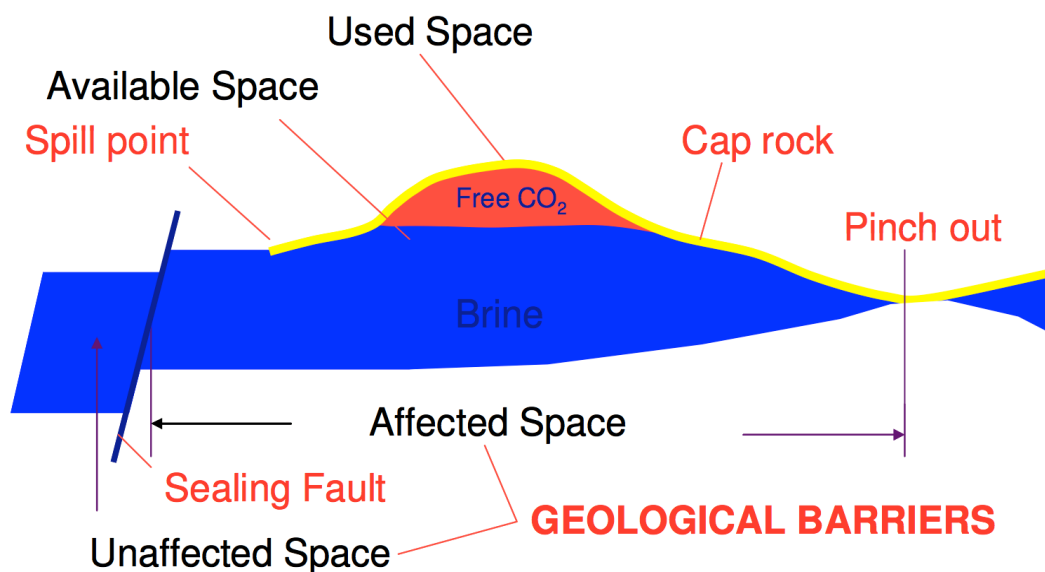
Fig. 4-7   Conceptual model of geological CO_2 storage

Source: van der Meer and Yavuz (2009)

As explained in section 4.3.1.1, an estimation of capacity would be much more detailed if the necessary data to derive the parameters of Equation 4-3 were measured at a site-specific level. As this is not possible for the countries selected for this study, assumptions have to be made and a general assessment of the parameters is needed.

Specific Storage Density

Different authors have estimated a specific storage density for CO_2 storage in deep saline aquifers. Wildenborg et al. (2004) calculated it at 0.2 Mt CO_2/km^2 for European conditions, which is used by Holloway et al. (2008) to show a possible storage capacity for India. Within

GeoCapacity, Vangkilde-Pedersen et al. (2009b) assumed a specific storage density of 0.08 Mt of CO_2/km^2 to 0.12 Mt of CO_2/km^2. When considering Germany, a density of 0.12 Mt of CO_2/km^2 is assumed (May et al. 2005). Globally, (Koide et al. 1992) used 0.492 Mt of CO_2/km^2, which has been downscaled to 0.00492 Mt CO_2/km^2 by an efficiency factor of 1 per cent.

4.3.4   Unminable Coal Seams

Like the calculation for deep saline aquifers (Equations 4-3 and 4-4), the effective CO_2 storage capacity in coal seams can be described by the general formula based on a top-down approach (after Bachu (2008); Hendriks et al. (2004)). It assumes homogeneous deposits and is based on the bulk volume of coal (*A*•*h*) and coal density ρ_{coal}. This is multiplied by the density of gaseous CO_2 at the surface (1.873 kg/m^3). As indicated in section 4.2.1.4, it is assumed that CO_2 is injected shallower than the supercritical phase state of 700 to 800 m, where a pressure of 7.3 MPa prevails. The appropriate volume of gas adsorbed (*GC*), i.e. the sorption capacity, can be seen qualitatively in Fig. 4-4. In terms of quantity, the gas content is given at 4 to 20 m^3 CO_2/t coal (Hendriks et al. 2004). This shows also the higher affinity of coal for gaseous CO_2 than for methane. (Hendriks et al. 2004) complements this by pointing out that the exchange ratio of CO_2 and CH_4 has to be included in Equation 4-5, too. It is assumed that one molecule of CH_4 is substituted with two molecules of CO_2 and thus the capacity would double.

$$m_{CO_{2,effective}} = \rho_{CO_2} \cdot A \cdot h \cdot \rho_{coal} \cdot GC \cdot E \qquad \qquad \text{4-5}$$

where

$m_{CO2,effective}$	= effective storage capacity, $[m_{CO2,effective}]$ = kg;
ρ_{CO2}	= density of CO_2 at standard circumstances, $[\rho_{CO2}]$ = kg/m^3;
A	= surface area of coal basins, $[A]$ = m^2;
h	= cumulative thickness of the coal, $[h]$ = m;
ρ_{coal}	= bulk coal density, $[\rho_{coal}]$ = t/m^3;
GC	= gas content (or specific sorption capacity), $[GC]$ = m^3 gas/t coal;
$E=R_f$•C	= efficiency factor based on recovery R_f and completion factor C, $[E]$ = -.

Regarding storage in coal seams, the efficiency factor *E* is crucial. It can be divided into the *recovery factor* and the *completion factor* (Bachu et al. 2007). The recovery factor represents the fraction of coalbed methane that can be exploited. This recovery can be increased by producing large quantities of water to create a beneficial drop in pressure. As coal has more affinity to CO_2 than to CH_4, CO_2 injection additionally increases the recovery factor (ECBM). The completion factor covers the part of the coal seam that is available for any ECBM or CO_2 storage operation. Hendriks et al. (2004) estimate this factor at a conservative 0.1, meaning that only 10 per cent of the total coal area could be used. If taken together with a conservative recovery factor of 40 per cent, the efficiency is considerable lower (4 per cent) than the assessment by Frailey (2008), where a range for *E* of 28 to 40 per cent is provided.

Wildenborg et al. (2004) calculate the amount that can be stored in coalfields through the recovery of coalbed methane. The "producible gas in place" and the exchange ratio of CO_2 for methane determine the storage capacity.

4.3.5   Other Possibilities

Underground Coal Gasification

Additionally, underground coal gasification technology with connected storage of carbon dioxide could increase the estimates. Different authors anticipate plenty of potential for this use of coal in the future (Courtney 2008; Friedmann 2007; Kempka et al. 2009), but it remains very uncertain whether this will become a reality. Also, there is no reliable method of estimating the true potential. Thus UCG will not be included in CO_2 storage capacity calculations in this study.

Basalt

Some authors are looking at CO_2 sequestration in continental *flood basalts* (Kumar et al. 2008; McGrail et al. 2006; Schaef et al. 2010; Singh et al. 2006). In India and South Africa, considerable amounts of magmatic basalt deposits can be found onshore. The calculation of India's storage capacity in basalt traps using a volumetric approach was carried out by Singh et al. (2006). The calculation by McGrail et al. (2006) for the Columbian River is more comprehensible and is based on the specific basaltic storage density. It is assumed that the area of the Columbian River basalts with 164,000 km^2 obtains a capacity of 20 to 100 Gt of CO_2 and so a density of 0.12 to 0.6 Mt of CO_2/km can be derived. This density range will be applied on the area of the Deccan Basalt formation and the Karroo basalts in the respective sections to achieve a first, very broad estimate of the storage capacity in these basalts.

4.4   Problems and Constraints of CO_2 Storage

CCS could be a means of fighting climate change. But there are several difficulties and issues particularly relating to the storage of CO_2 that must be resolved before this technology could be implemented on a large scale. These obstacles include the potential risk of leakage, not just of CO_2, but also the prevailing salt water (section 4.4.1), possible seismic activity resulting from stored CO_2 (section 4.4.2) and the question of whether the total storage capacity or the limited allowable injection rate during operations is the real limiting factor of CO_2 storage (section 4.4.3).

4.4.1   Leakage

The sole purpose of CCS is to reduce the level of CO_2 emissions in the atmosphere. This implies that CO_2 storage operations have to be reliable and secure, meaning that the injected gas must remain underground. The IPCC (2005) refers to a maximum acceptable leakage rate of 0.01 per cent per year. This would lead to 99 per cent of CO_2 being retained in the formation after one hundred years. Ha-Duong and Loisel (2009), representing various stakeholder perspectives, argue that "zero is the only acceptable leakage rate for geologically stored CO_2." The logic of both arguments can be understood when the spatial scale is included. Locally, zero emissions must be the goal. Globally, 0.01 per cent leakage may still be allowable when weighed against benefits it would bring to climate change.

If all CO_2 was to stay underground, there might be other implications. If injection into water-saturated aquifers takes place, then there are only two possibilities regarding saline water. On the one hand, CO_2 injection increases the reservoir pressure and pushes water at the margins out of the structure or system. If monitoring is limited to the CO_2 plume, it is not clear what controls the migration of salt water underground. This water could contaminate drinking water or the surface during the decades of CO_2 injection at a site. This leakage of water has to be taken very seriously and risks should be assessed as part of the legislative implementation process (IPCC 2005). Potential migration paths of CO_2 underground are shown and described in Fig. 4-8.

On the other hand, the saline water may be produced to increase the available pore space for CO_2 storage and to control the pressure in the formation (for the sake of pressure remediation). This idea is increasingly being discussed within the scientific community (Bradshaw 2010; Hughes 2010). The water produced may then be desalinised, used or deposited into rivers, into the ocean or into a different aquifer. The remaining saltwater, water or salt create another waste disposal problem.
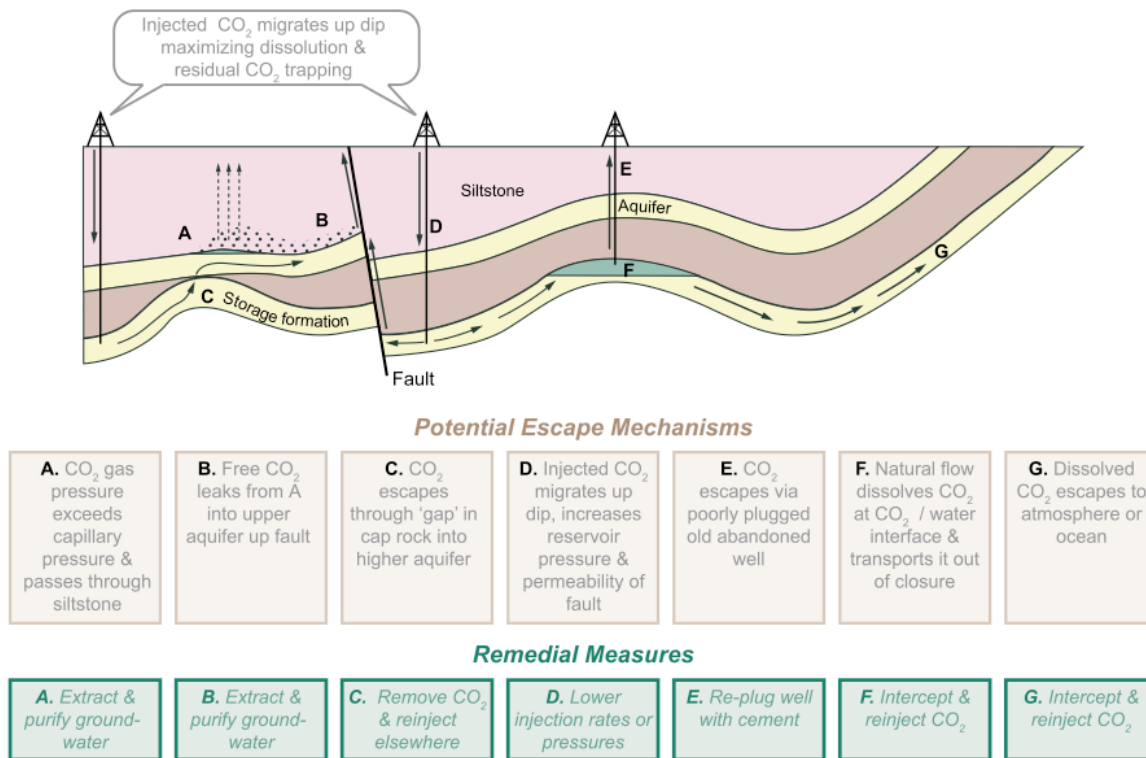
Fig. 4-8   Potential escape and leakage routes for CO_2 injected into saline formations
Source: IPCC 2005

4.4.2   Seismicity

Induced geological risks include seismicity (earthquakes), volcanic and magmatic activity, hydrothermal activity, hydrological and hydrogeological responses to geological changes and large scale erosion (Bhandari 2006). Regarding events in CISA, India and China in particular have suffered recently from hazardous seismicity with many casualties (earthquakes in Eastern Sichuan (China) in 2007 and India in 2001). It is a contentious issue whether safe and secure storage operations can take place in these regions. Therefore the safety risks must

be analysed in order to determine how, and to what extent, earthquakes or other geological risks influence CO_2 sequestration sites. As part of the selection process of appropriate storage areas, this issue must be taken into account (see Beck et al. (2007); Shackley and Verma (2008) for the situation in India).

The BGS (2010) points out that seismicity could lead to problems in CO_2 storage operations, but that it is hard to analyse. There are large oil and gas fields in seismically active areas and thus CO_2 could be stored there as well. The occurrence of huge earthquakes does increase the risk of leakage, though it does not necessarily mean that the stored CO_2 will be ruptured. CTEMPO (2010) adds that extreme seismic events affect the surface more than what lies beneath it. It concludes that seismicity is not really a limiting factor for the storage of CO_2.

Beside natural geological hazards, the drilling of wells or CO_2 injection may trigger seismicity locally. This has occurred when there has been well drilling for the disposal of hazardous waste or for oil fields (Sminchak and Gupta 2002). However, if the site is carefully selected and the installation, operation and monitoring is done properly, then seismicity could be prevented. Such seismicity is most likely where there are existing fractures and faults and if the pressure being applied is too high, causing hydraulic fracturing (Bachu 2008b). Thus, the stress conditions in the subsurface have to be analysed beforehand. Mineral precipitation may reduce permeability and create a build-up of pressure underground if CO_2 is injected. This effect could create seismic activity (Sminchak and Gupta 2002). The processes involved are shown in Fig. 4-9.
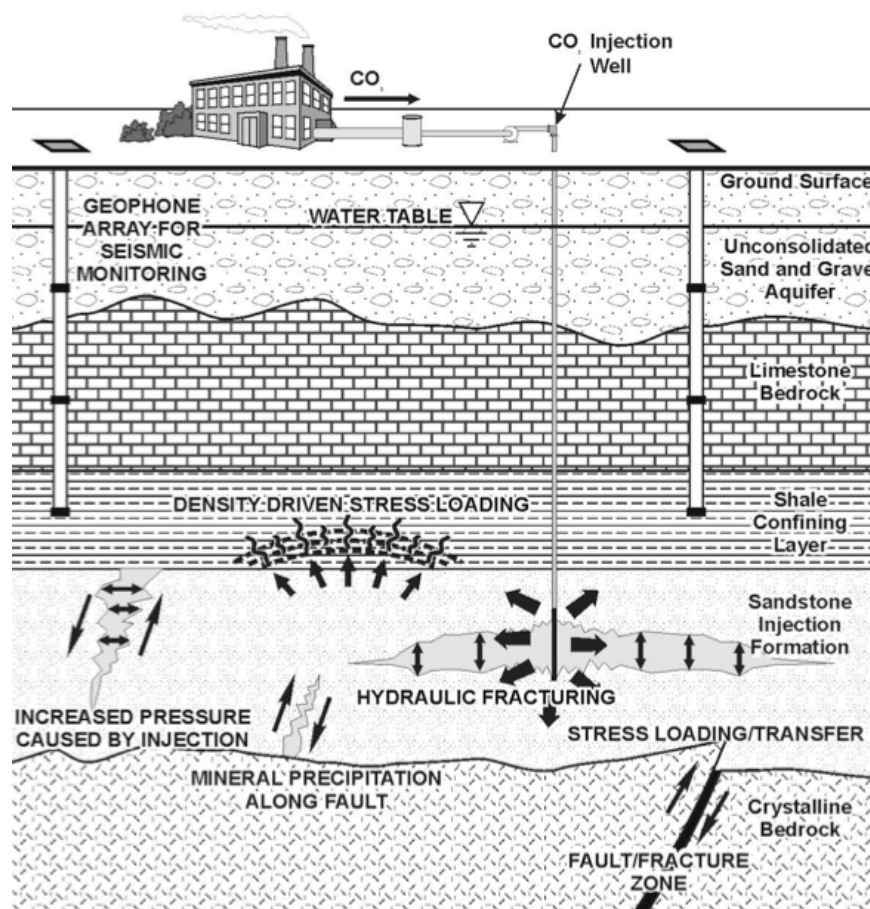

Fig. 4-9   Processes involved in seismic activity induced by underground injection of CO_2

Source: Sminchak and Gupta (2002)

Knowledge gained from experience in understanding factors that induce seismicity from geo-thermal energy generation, underground mining and hydrocarbon production can be applied to CO_2 storage operations. National, regional and especially site-specific circumstances have to be included in the risk assessment of any storage operation. In the case of India, there needs to be research into the relationship between storage capacity and seismic events. This is not yet available (Goel 2010).

4.4.3   Injection Rate Constraints

If the total capacity is not considered as a limiting factor, then the timeframe of the injection rate might be. CCS could contribute significantly to CO_2 reduction targets if a large quantity of this gas was stored safely each year. This presupposes that sufficient storage sites are available and that, from a technological point of view, there is no strict limit on injecting CO_2 into the available structures at the necessary time. The first assumption may well be true, but it is rather uncertain as to whether there are enough good storage sites that could be investi-gated, accredited and prepared in time. Adequate monitoring also has to be assured. This will definitely vary from country to country, but is still not easy to achieve in any country.

The second assumption is also confronted by major difficulties. At just one potential storage site, the operator has had to design the necessary injection strategy and the required number of wells for achieving the injection rate target. Modern storage projects inject scarcely more than 1 Mt of CO_2/a. 70 CCS projects in the world today inject a total of 40 Mt of CO_2/a (Beck et al. 2007). But it should be added that these projects are still at the R&D stage. When it comes to the commercial application of this technique, adequate storage sites should be big enough to store the emissions of a 1,600 MW power plant with total emissions of up to 400 Mt in 40 years (ZEP 2008). This would indicate that up to 10 Mt of CO_2 have to be injected per year and per project. Field experiments and reservoir modelling have to show whether this is possible, bearing in mind the numerous variations in rock characteristics. Among other effects, the pressure build-up at the wells and the pressure regime in the subsurface have to be kept under control. The maximum allowable pressure increase must maintain a faultless seal to ensure a safe long-term operation. This might be supplemented by saline water pro-duction as a pressure remediation option, which has already been discussed in section 4.4.1.

4.5   Aim of Storage Assessment in this Study

Given that the underground storage of CO_2 is crucial to the whole CCS process chain, the sections above have shown that there are lots of challenges to be considered when calculat-ing the storage capacity. The formations available for CO_2 storage must fulfil several geolog-ical quality properties. These are:

- A minimal available space in the structure;

- A sealing cap rock;

- Sufficiently high porosity and permeability.

The quality of the storage formation depends on the usable volume within the formation. To assess the theoretical capacity, a detailed and site-specific data investigation is needed, which is very difficult to achieve, especially for the studied countries.

Nevertheless, an air capacity assessment is required for orientation purposes by potential investors and political decision-makers. Considering the general aim of the present study, the storage assessment plays an essential role in determining how relevant CCS could become for China, India and South Africa in the future.

Therefore, the objectives of the analysis are to:

- Systematically analyse and compare existing capacity estimates for the CISA countries with regard to their assumptions, the methodologies applied, the chosen parameters and the data sources;

- Present a range of theoretical capacities;

- Develop three storage scenarios of effective capacities for each country;

- Match the effective capacities of these scenarios with the cumulated amount of CO_2 to be captured by 2050, derived from different development pathways of the national energy and industry sector.

Finally, the results of the capacity calculation matched between the CO_2 sources and geological CO_2 storage sites yield a range within which CCS might be able to contribute to a reduction of CO_2 emissions into the atmosphere.

It should be pointed out that, rather than basing the analysis on new geological data, it uses findings given in the literature. This process is accompanied by both expert interviews and internal reviews conducted by experts in the individual countries. Furthermore, due to a lack of practical experience of injecting CO_2 in China, India and South Africa, such general estimates can only be rough generalisations and need to be supplemented by evidence from detailed investigations into individual storage structures.

5 Supplementary Technology Assessment of CCS

5.1 Assessment of Reserves

The aim of the reserve assessment is to develop an understanding of the domestic supply potential of coal. For this purpose, reserves are analysed with respect to their changes in recent decades. These data are further disaggregated into regional supply potential and differentiated according to quality, at least to the greatest extent possible.

Past and present production history is given with detailed data, either of regional production volumes or of company production. A third topic covers coal price developments. Local prices are compared with international price developments. Finally, based on price projections of the International Energy Agency, price scenarios are developed for coal import prices up to 2035.

5.2 Economic Assessment

The aim of the economic assessment as part of the supplementary technology assessment of CCS is to conduct a comparative analysis of the long-term development of levelised cost of electricity (LCOE) and the costs of CO_2 mitigation for coal-fired power plants with and without CCS in the selected countries. The plant types considered are supercritical, pulverised coal (PC) power plants. The analysis is built upon three main methodological principles:

Firstly, it integrates three pathways for the development of coal-fired power plant capacities in India, China and South Africa up to 2050. They are based on the coal development pathways E1–E3, which are provided for each of the considered countries.

Secondly, the economic assessment uses data from available studies as well as the knowledge of numerous experts, who were interviewed during the course of this project, to define and quantify important cost parameters, such as capital costs and operation and maintenance costs. Whenever possible, country-specific conditions and data have been taken into account. This is particularly true for plant capital costs. Plant parameters, such as plant efficiency and the number of annual full load hours, were synchronised with corresponding assumptions in other parts of this study.

Thirdly, the economic assessment uses experience curves and learning rates to project the cost development of supercritical PC plants with and without CCS. An experience curve describes how unit costs decline with cumulative production. The progress of cost reduction is expressed by the progress ratio (PR) and the corresponding learning rate (LR). LR and PR used in this study are derived from a report of the IEAGHG Programme (IEAGHG 2006).

5.3 Life Cycle Assessment

For the ecological evaluation of selected system configurations, the method of life cycle assessment (LCA) according to ISO 14 040/14.044 is often used[2]. "LCA addresses the environmental aspects and potential environmental impacts (for example, use of resources and

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[2]   ISO 14 040:2006: Environmental management – Life cycle assessment – Principles and framework; ISO 14 044:2006: Environmental management – Life cycle assessment – Requirements and guidelines

environmental consequences of releases) throughout a product's life cycle from raw material acquisition through production, use, end-of-life treatment, recycling and final disposal" (ISO 14 040).

The *first step* of a life cycle assessment, the "goal and scope definition", is to address the system's boundaries, its level of detail, the subject of the LCA study as well as its intended purpose (Fig. 5-1).
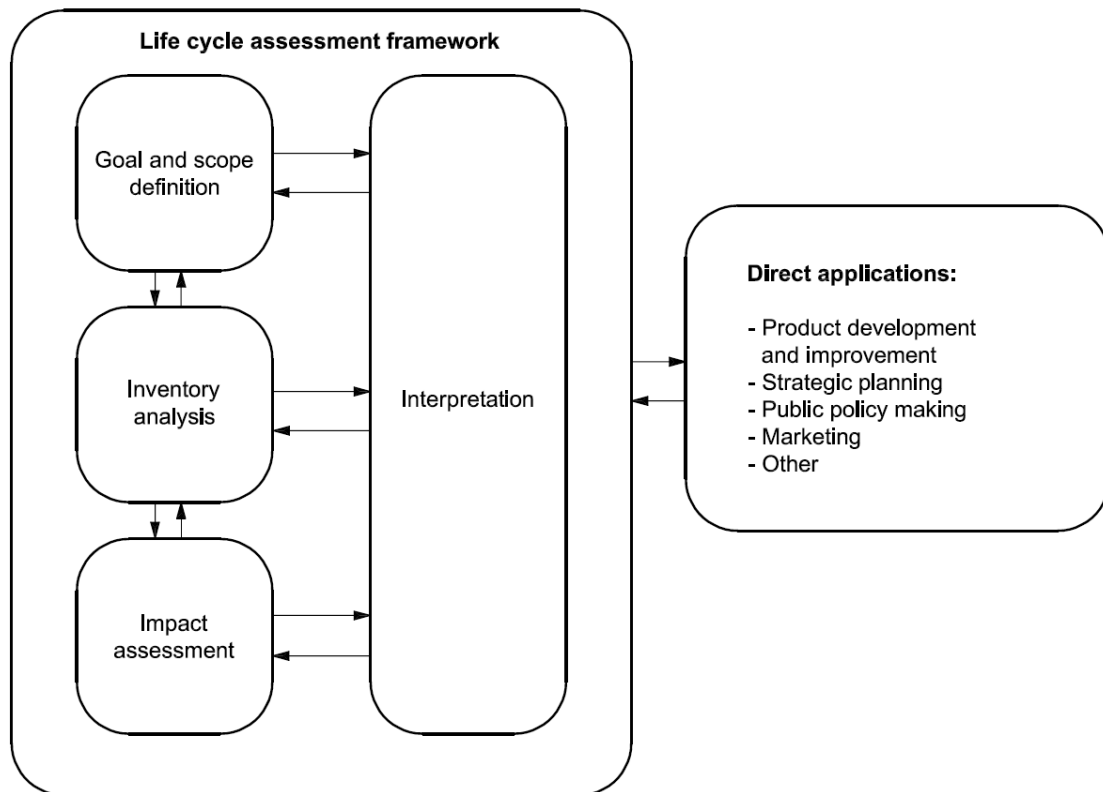

Fig. 5-1   Stages of a life cycle assessment according to ISO 14 040/14 044
Source: ISO 14 040

The *second step* of an LCA compares the material and energy flows that enter a system, are converted there and leave it in a different form (input/output balance, "life cycle inventory analysis"). A product LCA thus examines all the material and energy flows caused by a single product, beginning with the extraction and processing of the raw materials and following the process through manufacturing and use to the product's eventual disposal (the "cradle-to-grave" approach).

The *third step* is to calculate the environmental impact of the assessed flows. During this "life cycle impact assessment" it is necessary to "weigh up, aggregate, or generalise flows of different materials in different environmental media with different environmental impacts" (Schmidt 1997). Such impact categories are, for example, the global warming potential, the acidification potential or the resource consumption. By applying the results to a functional unit (for example, 1 kWh electricity output at the power plant's stack), different production processes and the best technology can be selected with regard to an impact category.

In the *final step*, the "life cycle interpretation", the results are discussed and serve as a basis for recommendations and political consultation.

5.4   Stakeholder Analysis

Stakeholders are key players in implementing and deploying new and innovative technologies. Hence, analysing the position of key stakeholders regarding the prospects of CCS in India, China and South Africa is an important element of the supplementary assessment of CCS technology. The overall aim of the analysis is to reflect the current state of the CCS debate in the three countries and to draw up a map of key stakeholders.

The analysis is mainly based on research interviews with experts from the national governments, science, industry and societal organisations. The interviews were guided by a questionnaire containing open questions, giving interviewees the opportunity to freely unfold their positions and to identify parameters affecting the prospects of CCS in the respective country. If necessary, the questionnaire is supplemented with questions tailored to the individual expertise of each respondent. The project team has conducted a total of 49 interviews with CCS and energy experts from all three countries. For India and China, the qualitative assessment is complemented and concluded with a standard survey in order to reflect the respondents' views on general issues related to CCS. However, the survey by no means claims to be representative due to the small number of participants. In India and China, 22 experts each participated in the survey.

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