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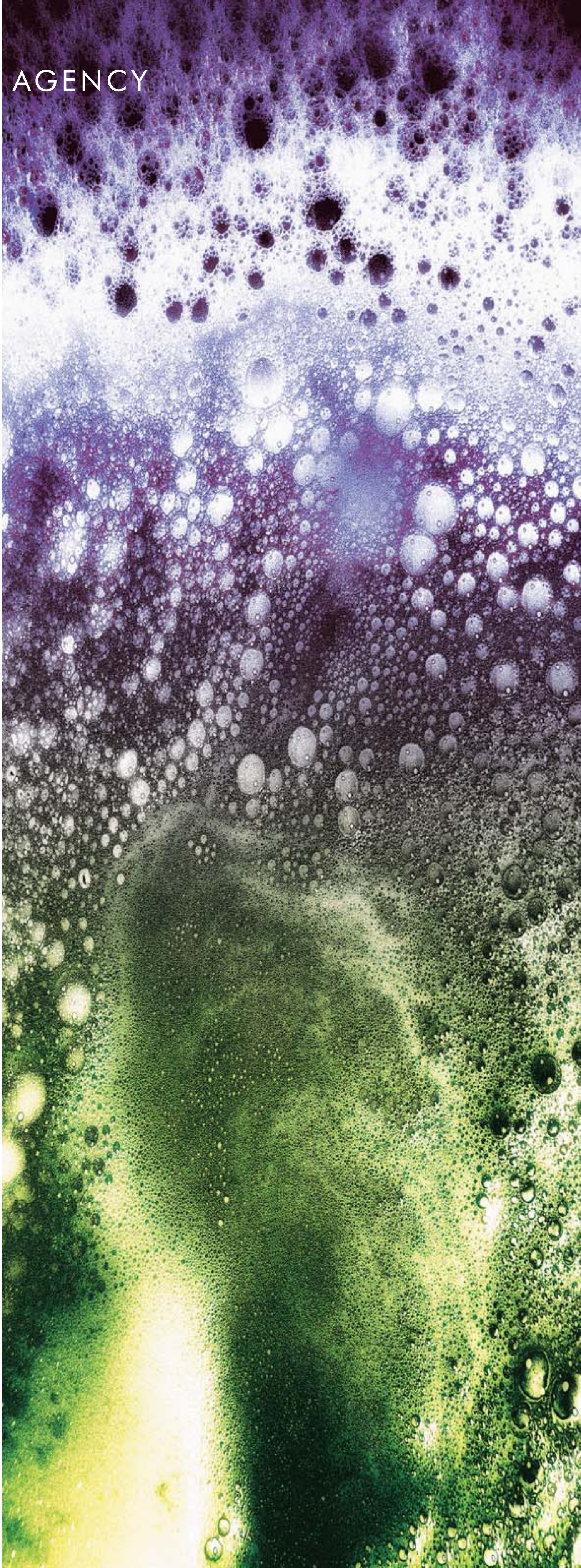
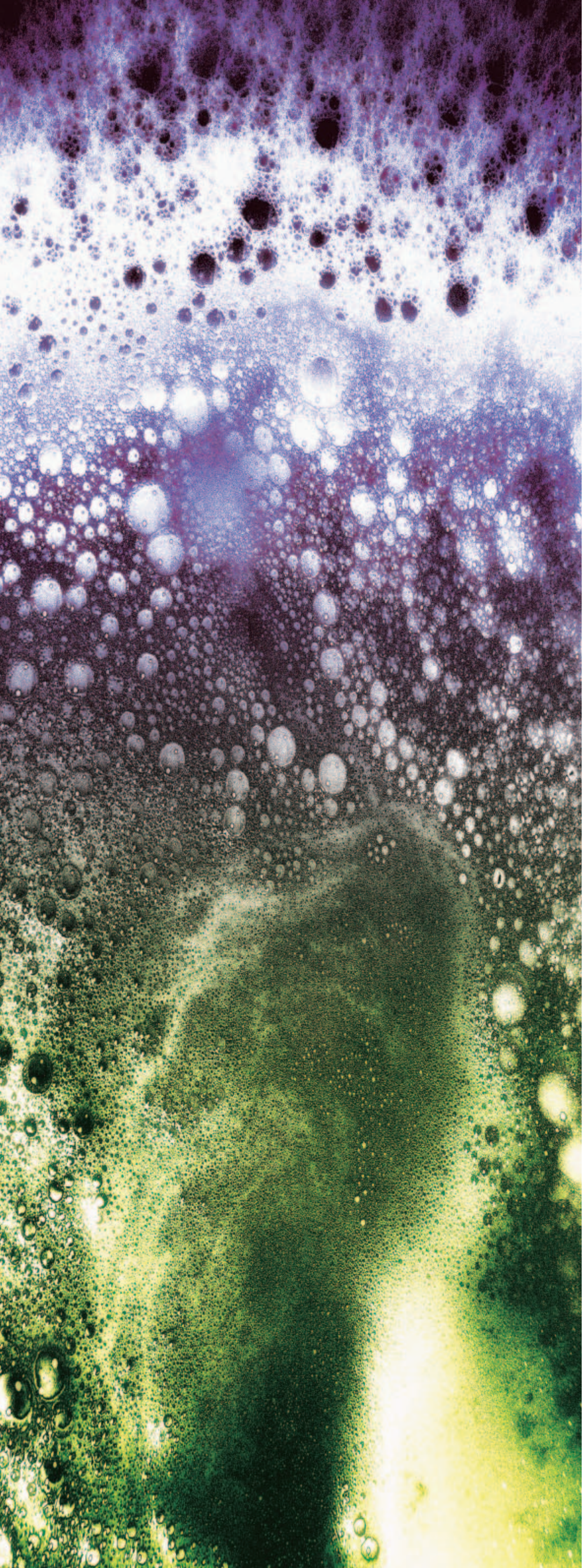


Energy
Technology
Analysis

CO_2 CAPTURE AND STORAGE

A key carbon abatement option

OECD



CO_2 CAPTURE AND STORAGE

A key carbon abatement option

Oil, coal and natural gas will remain the world's dominant sources of energy over the next decades, with resulting carbon dioxide emissions set to increase to unsustainable levels. However, technologies that help reduce CO_2 emissions from fossil fuels can reverse this trend. CO_2 capture and storage (CCS) is particularly promising. CCS takes CO_2 from large stationary sources and stores it in deep geological layers to prevent its release into the atmosphere.

At their Gleneagles summit in 2005, G8 leaders asked the IEA to advise on alternative energy scenarios and strategies aimed at a "clean clever and competitive energy future", and to work on accelerating the development and commercialisation of CCS.

CO_2 Capture and Storage: A Key Carbon Abatement Option responds to the G8 request. The study documents progress toward the development of CCS:

- Capture, transportation and storage technologies and their costs
- Storage capacity estimates
- Regional assessment of CCS potential
- Legal and regulatory frameworks
- Public awareness and outreach strategies
- Financial mechanisms and international mechanisms

The IEA study discusses also the role of CCS in ambitious new energy scenarios that aim for substantial emissions reduction. This publication elaborates the potential of CCS in coal-fuelled electricity generation and estimates for capture in the industry and fuel transformation sectors. Finally, it assesses the infrastructure needed to process and transport large volumes of CO_2.

With an updated roadmap of CCS development needs in the near and long term, this publication equips decision makers in the public and private sector with essential information that is needed for accelerating its demonstration and deployment in a sustainable manner.

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INTERNATIONAL ENERGY AGENCY

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-eight of the OECD thirty member countries. The basic aims of the IEA are:

- To maintain and improve systems for coping with oil supply disruptions.
- To promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations.
- To operate a permanent information system on the international oil market.
- To improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use.
- To promote international collaboration on energy technology.
- To assist in the integration of environmental and energy policies.

The IEA member countries are: Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Republic of Korea, Luxembourg, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States. The European Commission also participates in the work of the IEA.

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

The OECD is a unique forum where the governments of thirty democracies work together to address the economic, social and environmental challenges of globalisation. The OECD is also at the forefront of efforts to understand and to help governments respond to new developments and concerns, such as corporate governance, the information economy and the challenges of an ageing population. The Organisation provides a setting where governments can compare policy experiences, seek answers to common problems, identify good practice and work to co-ordinate domestic and international policies.

The OECD member countries are: Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Republic of Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States.
The European Commission takes part in the work of the OECD.

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FOREWORD

Recent IEA analysis confirms that, without policy changes, CO_2-intensive coal and other fossil fuels will play a growing role in meeting our future energy needs. The successful deployment of CO_2 capture and storage (CCS) will allow countries to continue using these resources while simultaneously achieving deep reductions in greenhouse gas emissions. Of course CCS is not a magic bullet, but it can be an important part of a broad portfolio of options, which include energy efficiency, renewables and nuclear energy, for improving energy security and tackling climate change. The energy challenges we face are great; all of these technologies have a role to play in achieving a more sustainable future.

The 2004 IEA publication *Prospects for CO_2 Capture and Storage provided* the first detailed global assessment of the role of CCS in climate change mitigation, and included our best attempts to analyse the cost, performance and policy implications of this important technology. Since that publication, there has been an explosion of interest in CCS at every level, resulting in international treaty amendments, new policies and regulations related to CCS, major national and regional demonstration projects, and private sector research and deployment of various aspects of the technology. As a result, today we have better information about the cost and performance of CCS—including the individual components: CO_2 capture, transport and storage. We have used this improved data to analyse the contribution of CCS in future climate change mitigation scenarios.

While these developments are to be commended, there remain significant challenges if CCS is to be successfully commercialised. These include the lack of appropriate long-term policy frameworks and sufficient financial incentives to justify investment, particularly for the critical early demonstration projects. This publication takes a look at the many approaches for CCS commercialisation that are currently being tested in a number of different countries, and makes recommendations for a roadmap that attempts to address the technical, financing and legal/regulatory challenges.

I am delighted that the IEA continues to play a leading role in promoting the development and deployment of CO_2 capture and storage, and hope that this latest publication helps to foster the rapid uptake of this key CO_2 abatement option.

Nobuo Tanaka
Executive Director

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EXECUTIVE SUMMARY

Introduction

Climate change is a major challenge. Secure, reliable and affordable energy supplies are needed for economic growth, but increases in the associated carbon dioxide (CO_2) emissions are the cause of major concern.

About 69% of all CO_2 emissions, and 60% of all greenhouse gas emissions, are energy-related. Recent IEA analysis in *Energy Technology Perspectives 2008* (ETP) projects that the CO_2 emissions attributable to the energy sector will increase by 130% by 2050 in the absence of new policies or supply constraints, largely as a result of increased fossil fuel usage. The 2007 Intergovernmental Panel on Climate Change (IPCC) *4th Assessment Report* indicates that such a rise in emissions could lead to a temperature increase in the range of 4-7°C, with major impacts on the environment and human activity. It is widely agreed that a halving of energy-related CO_2 emissions is needed by 2050 to limit the expected temperature increase to less than 3 degrees. To achieve this will take an energy technology revolution involving increased energy efficiency, increased renewable energies and nuclear power, and the decarbonisation of power generation from fossil fuels.

The only technology available to mitigate greenhouse gas (GHG) emissions from large-scale fossil fuel usage is CO_2 capture and storage (CCS). The ETP scenarios demonstrate that CCS will need to contribute nearly one-fifth of the necessary emissions reductions to reduce global GHG emissions by 50% by 2050 at a reasonable cost. CCS is therefore essential to the achievement of deep emission cuts.

Most of the major world economies recognise this, and have CCS technology development programmes designed to achieve commercial deployment. In fact, at the 2008 Hokkaido Toyako summit, the G8 countries endorsed the IEA's recommendation that 20 large-scale CCS demonstration projects need to be committed by 2010, with a view to beginning broad deployment by 2020. Ministers specifically asked for an assessment by the IEA in 2010 of the implementation of these recommendations, as well as an assessment of progress towards accelerated deployment and commercialisation.

Current spending and activity levels are nowhere near enough to achieve these deployment goals. CCS technology demonstration has been held back for a number of reasons. In particular, CCS technology costs have increased significantly in the last 5 years. In the absence of suitable financial mechanisms to support CCS, including significant public and private funding for near-term demonstrations and longer-term integration of CCS into GHG regulatory and incentive schemes, high costs have precluded the initiation of large-scale CCS projects.

The regulatory framework necessary to support CCS projects also needs to be further developed. Despite important progress, especially in relation to international marine protection treaties, no country has yet developed the comprehensive, detailed legal and regulatory framework that is necessary effectively to govern the use of CCS. CCS is also poorly understood by the general public. As a result, there is a general lack of public support for CCS as compared to several other GHG mitigation options.

This report attempts to address some of these issues by collecting the best global information about the cost and performance of CO_2 capture, transport and storage technologies throughout the CCS project chain. Chapters 1-4 contain this information, and use it to conduct a scenario analysis of the role of CCS in climate change mitigation. Chapter 5 discusses the financial incentive mechanisms that governments can use to provide both short- and long-term incentives for CCS. This chapter also contains an expansion and update of the 2007 IEA publication *Legal Aspects of CO_2 Storage: Updates and Recommendations* and examines the current state of public awareness and acceptance of the relevant technologies. Chapter 6 includes a review of the status of CCS policies, research and demonstration programmes, and CO_2 storage prospects for several regions and countries. Chapter 7 concludes with a proposed CCS roadmap that includes the necessary technical, political, financial and international collaboration activities to enable CCS to make the contribution it needs to make to global GHG mitigation in the coming decades.

General Findings

Given appropriate emission reduction incentives, CCS offers a viable and competitive route to mitigate CO_2 emissions. In a scenario that aims at emissions stabilisation based on options with costs up to USD 50/t CO_2 (ACT Map[1]), 5.1 Gigatonnes (Gt) per year of CO_2 would be captured and stored by 2050, which is 14% of the total needed for global temperature stabilisation. In the ETP BLUE Map scenario, which cuts global CO_2 emissions in half and which considers emission abatement options with a cost of up to USD 200/t CO_2, CCS accounts for 19% of total emissions reductions in 2050. In this scenario, 10.4 Gt of CO_2 per year would be captured and stored in 2050. Without CCS, the annual cost for emissions halving in 2050 is USD 1.28 trillion per year higher than in the BLUE Map scenario. This is an increase of about 71%. About half of all CCS would be in power generation and half would be in industrial processes (cement, iron and steel and chemicals) and the fuel transformation sector.

Overall, on the basis of current economics, the financial consequences of CCS range from a potential benefit of USD 50/t CO_2 mitigated (through the use of CO_2 for enhanced oil recovery) to a potential cost of USD 100/t CO_2 mitigated.

CO_2 capture leads to an increase in capital and operating expenses, combined with a decrease in plant energy efficiency. In terms of cost per tonne of CO_2 captured, costs are USD 40-55/t for coal-fired plants, and USD 50-90 for gas-fired plants. In terms of cost per tonne of CO_2 abated, the figures for coal-fired plants in 2010 are around USD 60-75, dropping to USD 50-65/t CO_2 in 2030; and for gas-fired plants, USD 60-110 in 2010, dropping to USD 55-90 in 2030.

CO_2 Transport and Storage

CO_2 transportation costs depend on the volumes that need to be transported and the distances involved. Regional "hub and spoke" network structures would be the most efficient way of connecting many emitting nodes to large storage sites. However, putting in place a safe, efficient CO_2 transportation system will raise very significant cost and infrastructure challenges.

1. In ETP, the ACT scenarios envisage bringing global CO_2 emissions in 2050 back to 2005 levels, while the BLUE scenarios envisage halving those emissions.

With the recent development of a more robust methodology for storage capacity estimates, governments urgently need to conduct detailed evaluations of their national CO_2 storage capacity, working in partnership with bordering nations who share the same storage space. In the medium term, depleted oil and gas reserves, unmineable coal seams, and deep saline formations are the best options for CO_2 storage. Deep saline formations appear to offer the potential to store several hundreds of years' worth of CO_2 emissions. This must be validated, and site selection criteria must be developed and shared internationally to identify the most appropriate storage sites. Wider international collaboration and consensus are critically needed to ensure the viability, availability and permanence of CO_2 storage.

CCS Demonstration

The next 10 years will be critical for CCS development. By 2020, the implementation of at least 20 full-scale CCS projects in a variety of power and industrial sector settings, including coal-fired power plant retrofits, will considerably reduce the uncertainties related to the cost and reliability of CCS technologies. Several industrial-size demonstration CCS projects have been announced in Europe, North America and Australia, along with cooperative programmes in non-OECD countries. But many of these projects appear to be making slow progress. If these demonstration projects do not materialise in the near future, it will be impossible for CCS to make a meaningful contribution to GHG mitigation efforts by 2030.

CCS and clean coal technologies should be developed in tandem. As a first priority, R&D should focus on improving fossil plant efficiency, along with research on the integrity of storage methods. Better CO_2 capture technologies also need to be developed and to be integrated with power plant designs. Governments should also ensure that new power plants either include CCS or are CCS ready, with engineering designs that provide for later carbon capture retrofit, together with identified routes to CO_2 storage sites.

Demonstration projects should leverage and expand on existing CO_2-Enhanced Oil Recovery (EOR) activities, as they can generate revenues to offset costs. Over 200 additional billion barrels of oil can be recovered using enhanced oil recovery. This will provide a CO_2 storage potential of 70-100 Gt at low or even negative cost. However, there is a shrinking window of opportunity for most oil fields to apply CO_2-EOR and the oil and gas sectors should cooperate to maximise these opportunities. The development of CO_2-EOR can also jump-start the transport infrastructure required for full CCS deployment in some regions.

Financial and Regulatory Incentives

Investment in CCS will only occur if there are suitable financial incentives and/or regulatory mandates. Various financial and regulatory options exist for encouraging CCS. The most appropriate approach will vary from country to country. It is clear that market-based solutions alone will be insufficient to finance critical early demonstration projects. Governments must lead by providing sufficient direct financing or financial incentives for CCS demonstration. Private sector finance is also critical. In the area of financing CO_2 transport, governments can help to encourage the development of the enabling infrastructure, and can help optimise the linkage of major emission nodes and storage sites. In addition, the medium- and longer-term viability of CCS, particularly in developing nations, will be enhanced by inclusion of CCS in the Kyoto Protocol Clean Development Mechanism. Finally, the financial and insurance industry must be engaged to develop tailored products to address long-term liability issues.

Development of Legal and Regulatory Frameworks

Governments are making important progress toward the establishment of legal and regulatory frameworks governing CCS, including the recently proposed European Union framework. But much additional work is needed to fill important gaps. Significant national and sub-national effort is needed to address CO_2 transport, CO_2 storage site selection and monitoring requirements, liability for CO_2 leakage, and property rights, among other things. International marine environment protection instruments have led the way in clarifying the legal status of offshore CO_2 storage, and the permitting approaches and technical guidance being developed by the London Protocol provide important precedents that other regional and national authorities can adapt in their own contexts.

Public Awareness and Acceptance

The current level of public awareness of the potential for CCS to be an important GHG mitigation solution is generally low, and public opinion tends to be indifferent or unfavourable as a result. In many countries, public acceptance of CCS will be closely linked to the development of regulatory frameworks to manage risks to public health and safety. Governments in some countries have begun strong public education efforts. But little is known about successful strategies that can be learned from these early efforts. Governments need to share lessons internationally from these programmes, and adapt their future awareness efforts in the light of these conclusions.

International Co-operation

Given the scale of investment required for CCS RD&D, and the projected growth of fossil-fuel usage in non-OECD countries, international co-operation is clearly needed to accelerate CCS deployment. In particular, more must be done to develop a co-ordinated, complementary set of early CCS demonstration projects around the world, using different technologies and geologic settings for CO_2 storage. This will serve to maximise the benefit from initial investments and target gaps in knowledge. Organisations such as the IEA (and its Implementing Agreements) and the Carbon Sequestration Leadership Forum have created networks to share best practices and lessons learned relating to CCS technologies, site selection, monitoring and verification, and the development of legal and regulatory frameworks. However, these networks must be expanded to include broader and more meaningful participation from emerging economies and the Middle East if CCS is to achieve its full global potential as a CO_2 abatement solution.

CCS Roadmaps

International co-operation can be enhanced through the development and implementation of a global CCS roadmap. Building on the CCS roadmaps in ETP 2008 and other roadmap activities on a national and international level, we have deepened the analysis to include a more extensive set of short, medium and long term milestones needed for CCS to achieve global commercialisation by 2030. The way forward for CCS urgently needs to be co-ordinated amongst major stakeholders. The G8/IEA/CSLF *Near-Term Opportunities for CCS* recommendations are a first step in that direction. The roadmap developed for this publication outlines one potential way forward to further enhance dialogue amongst government and industry stakeholders which would aim to lead to the implementation of a more co-ordinated global strategy on CCS.

1. INTRODUCTION

The availability of secure, reliable and affordable energy is fundamental to economic stability and development. Energy security, the threat of disruptive climate change and growing energy demand all pose major challenges to energy policy decision-makers.

This publication deals with one potentially very significant means of reducing CO_2 emissions at a time of rapidly growing energy needs, namely carbon capture and storage (CCS). It provides an analysis of the status and future prospects for CCS. It outlines the barriers to the implementation of the technologies used in CCS and the measures that may be needed to overcome those barriers. It explores how the implementation of CCS can change our energy future. The IEA anticipates that the qualitative and quantitative insights provided by this study will help governments and industries that are considering CO_2 emissions mitigation strategies to better understand the legal and regulatory, technological, and financial aspects of CCS, its potential as an abatement option, and the near- and long-term actions required to bring the technology to full-scale implementation.

There is an increasingly urgent need to mitigate greenhouse gas (GHG) emissions, including those related to energy production and consumption. Approximately 69% of all CO_2 emissions are energy related, and about 60% of all GHG emissions can be attributed to energy supply and energy use (IPCC, 2007). The IEA *World Energy Outlook 2007* (IEA, 2007a) projects that, without changes in current and already planned policies, global energy-related CO_2 emissions will be 57% higher in 2030 than in 2005, with oil demand increasing by 40%. In 2030, fossil fuels would remain the dominant source of energy. The bulk of the additional CO_2 emissions and increased demand for energy, 84% of which will come from using fossil fuels, will come from developing countries.

The United Nations Intergovernmental Panel on Climate Change (IPCC) has concluded that 50% to 80% cuts in global CO_2 emissions by 2050 compared to the 2000 level will be needed to limit the long-term global mean temperature rise to 2.0°C to 2.4°C (IPCC, 2007; see Table 1.1). Higher emissions will result in higher temperature rises and more significant climate change. The Stern review (Stern, 2007) has concluded that the benefits of limiting temperature rises to two degrees would outweigh the costs of doing so, although other analyses result in varying conclusions depending on the economic assumptions (such as the discounting factors) on which the calculations are based (Nordhaus, 2007).

Table 1.1 *The Relation between Emissions and Climate Change According to the IPCC 2007 Assessment Report*

Temperature increase	All GHGs	CO_2	CO_2 emissions 2050 (% of 2000 emissions)
(°C)	(ppm CO_2 equivalent)	(ppm CO_2)	(%)
2.0 – 2.4	445 – 490	350 – 400	-85 to -50
2.4 – 2.8	490 – 535	400 – 440	-60 to -30
2.8 – 3.2	535 – 590	440 – 485	-30 to +5
3.2 – 4.0	590 – 710	485 – 570	+10 to +60

Source: IPCC, 2007.

The Political Context

At the IEA Ministerial Meeting in May 2007, Ministers concluded: "We need to respond to the twin energy-related challenges we confront: ensuring secure, affordable energy for more of the world's population, and managing in a sustainable manner the environmental consequences of producing, transforming and using that energy" (IEA, 2007b). They committed to reinforcing their efforts to "accelerate the development and deployment of new technologies", and called on the IEA "to continue to work towards identifying truly sustainable scenarios and on identifying least-cost policy solutions for combating energy-related climate change".

Leaders of the Group of Eight (G8) countries[2] have agreed on the need to "act with resolve and urgency now to meet our shared and multiple objectives of reducing greenhouse gas emissions, improving the global environment, enhancing energy security and cutting air pollution in conjunction with our vigorous efforts to reduce poverty" (FCO, 2005). This was reinforced at the June 2007 summit in Heiligendamm, Germany: "In setting a global goal for emissions reductions in the process we have agreed today involving all major emitters, we will consider seriously the decisions made by the European Union, Canada and Japan which include at least a halving of global emissions by 2050" (Federal Press Office, 2007, page 15). At the 2008 Hokkaido Toyako Summit, the G8 leaders called for an international initiative to be established with the support of the IEA to develop roadmaps for innovative technologies and for greater technological co-operation, based upon existing and new partnerships, including in the development of CCS and other advanced energy technologies. They also committed their support for the launching of 20 large-scale CCS demonstration projects by 2010, taking into account various national circumstances, with a view to beginning the broad deployment of CCS by 2020.

The Purpose and Scope of this Study

This study provides an initial IEA response to the G8 leaders' commitment to the development of CCS. It builds on the IEA publication *Prospects for CO_2 Capture and Storage (IEA, 2004),* and publication *Legal Aspects of CO_2 Storage: Updates and Recommendations* (IEA, 2007c). It updates these publications based on the latest economic projections, technology insights, and policy developments, and provides new, detailed regional and country level CCS overviews.

The study:

- provides an overview of the prospects, costs and research and development (R&D) challenges of technologies used in CCS for the capture, transportation and storage of CO_2;
- outlines the current legal and regulatory frameworks, and financial policies, related to CCS;
- analyses the prospects for CCS on the basis of the IEA Energy Technology Perspectives model (IEA, 2008);
- reviews regional prospects and progress towards CCS implementation, and projects CO_2 abatement potentials at different levels of CO_2 reduction incentive; and
- describes a roadmap of actions required to fast-track the deployment of CCS, and identifies additional measures that will be needed if CCS is to be deployed as part of a CO_2 mitigation strategy.

2. The G8 member countries are Canada, France, Germany, Italy, Japan, Russia, the United Kingdom and the United States.

There have been significant changes in the cost structure of the technologies in all parts of the CCS chain since *Prospects for CO_2 Capture and Storage* (IEA, 2004) was published. This study sheds new light on the economic potential for CCS over the next 20 to 40 years and assesses the prospects for CCS technologies against a range of assumptions about energy resources, regional and sectoral shifts in global energy demand, and changes in energy technology portfolios. It compares CCS with other emission mitigation strategies and identifies the key issues and uncertainties that will need to be considered in relation to CCS and its use as a CO_2 emission mitigation tool.

The Structure of the Publication

Chapter 2 describes the ETP scenarios. In the Baseline scenario, it is assumed that no significant changes are made to the energy policies in place or planned today. In the ACT and BLUE scenarios, technological developments are accelerated by policies designed to drive progressively larger CO_2 emission reductions.

Chapters 3 and 4 describe the progress of technologies and recent findings related to CO_2 capture, transport and storage. Chapter 5 presents an overview of the legal and regulatory frameworks surrounding CCS and examines issues related to financing and to public awareness. Chapter 6 presents a regional overview of CCS policies, R&D activities, and CO_2 storage projections. Chapter 7 provides a roadmap including the near- and long-term steps required for the wide-scale implementation of CCS, highlighting the need for greater international collaboration.

2. SCENARIOS FOR CO_2 CAPTURE AND STORAGE

KEY FINDINGS

- In the Baseline scenario, CO_2 emissions are projected to triple from 20.6 Gt in 1990 to 62 Gt in 2050.
- In the ACT Map scenario, which envisages a USD 50/t CO_2 emission reduction incentive, global emissions stabilise at around 27 Gt CO_2 per year by 2050, more than halving Baseline scenario emissions. CO_2 emission capture and storage would increase to 5.1 Gt per year in 2050, and CCS would represent 14% of the total CO_2 abated. In the BLUE Map scenario, with an incentive of USD 200/t CO_2 saved, CCS would increase to 10.4 Gt in 2050, saving 19% of the total CO_2 abated.
- 54% of all CCS in the BLUE Map scenario is applied in the electricity generation sector, the remaining 46% in the industry and fuel transformation sectors.
- CCS contributes 21% of the CO_2 emission reductions in electricity generation in 2050 in the ACT Map scenario and 26% in the BLUE Map scenario. It contributes 17% of the CO_2 emission reductions in the industry sector in the ACT Map scenario, and 37% of the reductions in the BLUE Map scenario.
- In the ACT Map scenario, 18% of total electricity generation in 2050 would be from plants equipped with CCS. This share increases to 27% in the BLUE Map scenario.
- Retrofitting of coal plants with CCS plays a significant role in the ACT Map scenario. At the BLUE Map scenario price of USD 200/t CO_2, there is sufficient economic incentive to accelerate the replacement of inefficient power plants with new plants equipped with CCS. In the BLUE Map scenario, 350 GW of coal-fired power-plant capacity is closed down before the end of its technical life span. Of the 700 GW coal plant running in 2050, 80% would be new capacity equipped with CCS and 20% CCS retrofits.
- Achieving a 50% reduction in CO_2 emissions by 2050 without using CCS would result in an increase of the annual cost by USD 1.28 trillion, an increase of 71%.
- In the ACT Map scenario, more than 40% of all CO_2 capture takes place in IEA member countries in 2030; by 2050, this share declines to less than 25% if CO_2 policies are introduced worldwide. Due to their anticipated energy demand growth and other factors, major emerging economies represent a significant critical potential for the application of CCS in the longer term.
- CO_2-enhanced oil recovery (EOR) may provide some limited early opportunities for CCS. Longer term, the best prospects for CO_2 storage lie in deep saline formations.

The Scenarios in this Study

This study is based on the scenarios underlying the IEA *Energy Technology Perspectives 2008* (IEA, 2008) publication. In terms of projections of economic growth, fuel prices and other macroeconomic drivers, these scenarios are consistent with the Reference scenario and the 450 ppm case published in *World Energy Outlook 2007* (IEA, 2007a).

The Baseline scenario reflects developments that are expected on the basis of the energy and climate policies that have been implemented and are planned to date. It is consistent with the *World Energy Outlook 2007* Reference scenario for the period 2005 to 2030. The *World Energy Outlook* trends have been extrapolated for the period 2030 to 2050 using the new *Energy Technology Perspectives* (ETP) model. The pattern of economic growth changes after 2030, as population growth slows and developing country economies begin to mature.

The implications of two policy objectives have been analysed. The ACT scenarios envisage bringing global energy-related CO_2 emissions in 2050 back to 2005 levels. The BLUE scenarios envisage reducing 2050 CO_2 emissions by 50% as compared with 2005 levels. The BLUE scenarios are consistent with a global rise in temperatures of 2-3°C, but only if the reduction in energy-related CO_2 emissions is combined with deep cuts in other greenhouse gas emissions. Both scenarios also aim for reduced dependence on oil and gas.

The ACT and BLUE scenarios are based on the same macro-economic assumptions as the Baseline scenario. In all scenarios, average world economic growth is a robust 3.3% per year between 2005 and 2050, resulting in economic activity in 2050 being four times that in 2005. The underlying demand for energy services is also the same in all scenarios, *i.e.* the analysis does not consider actions for reducing the demand for energy services (such as by reducing indoor room temperatures or restricting personal travel activity).

The ACT and BLUE scenarios enable the exploration of the technological options that will need to be exploited if the ambitious CO_2 reductions implicit in the scenarios are to be achieved. The analysis does not reflect on the likelihood of these things happening, or on the climate policy instruments that might best help achieve these objectives. The scenarios assume an optimistic view of technology development. However, it is clear that these objectives can only be met if the whole world participates.

In total, five variants have been analysed for the electricity generation sector in the ACT and BLUE scenarios, as follows:

- Map: these scenarios are relatively optimistic for all technologies;
- a high nuclear variant (hiNUC) which assumes 2 000 GW nuclear capacity rather than the 1 250 GW assumed in the Map variant;
- a no-carbon capture and storage (no CCS) variant;
- a low renewables variant (loREN) which makes less optimistic cost reduction assumptions for renewable power generation technologies; and
- a low end-use efficiency gains variant (loEFF) which assumes a 0.3% lower annual energy efficiency improvement than the Map scenarios.

The ACT Map and BLUE Map scenarios contain relatively optimistic assumptions for all key technology areas. The BLUE Map scenario is more speculative than the ACT Map scenario insofar as it assumes technology that is not available today. It also requires the rapid development and widespread uptake of such technologies. Without affordable new energy technologies, the objectives of the BLUE Map scenario will be unachievable.

These scenarios are not predictions. They are internally consistent analyses of the least-cost pathways that may be available to meet energy policy objectives, given a certain set of optimistic technology assumptions. This work can help policy makers identify technology portfolios and flexible strategies that may help deliver the outcomes they are seeking. The scenarios are the basis for roadmaps that can help establish appropriate mechanisms and plans for further international technology co-operation.

The results of the ACT and the BLUE scenarios assume the successful implementation of a wide range of policies and measures to overcome barriers to the adoption of appropriate technologies. Both the public and the private sectors have major roles to play in creating and disseminating new energy technologies. The increased uptake of cleaner and more efficient energy technologies envisaged in the ACT and the BLUE scenarios will need to be driven by:

- **Increased support for the research and development (R&D)** of energy technologies that face technical challenges and need to reduce costs before they become commercially viable.
- **Demonstration programmes** for energy technologies that need to prove they can work on a commercial scale under relevant operating conditions.
- **Deployment programmes** for energy technologies that are not yet cost-competitive, but whose costs could be reduced through learning-by-doing. These programmes would be expected to be phased out as individual technologies become cost-competitive.
- **CO_2 reduction incentives** to encourage the adoption of low-carbon technologies. Such incentives could take the form of regulation, pricing incentives, tax breaks, voluntary programmes, subsidies or trading schemes. The ACT scenarios assume that policies and measures are put in place that would lead to the adoption of low-carbon technologies with a cost of up to USD 50/t CO_2 saved from 2030 in all countries, including developing countries. In the BLUE scenarios the level of incentive is assumed to continue to rise from 2030 onwards, reaching a level of USD 200/t CO_2 saved in 2040 and beyond.
- **Policy instruments to overcome other commercialisation barriers** that are not primarily economic. These include enabling standards and other regulations, labelling schemes, information campaigns and energy auditing. These measures can play an important role in increasing the uptake of energy-efficient technologies in the building and transport sectors, as well as in non-energy intensive industry sectors where energy costs are low compared to other production costs.

Energy prices in each of the ACT and BLUE scenarios respond to changes in demand and supply. In the Baseline scenario, oil prices increase from USD 62 per barrel in 2030 to USD 65 per barrel in 2050 (in real present dollar terms). This price trajectory is consistent with the *World Energy Outlook 2007* Reference scenario (IEA, 2007a). At these prices, substitutes for conventional oil (such as tar sands) as well as transport fuels produced from gas and coal will begin to play a larger role. If the necessary investments in oil and gas production do not materialise, prices will be considerably higher (IEA, 2007a). The interactions between the availability of energy resources, the energy technology used, the demand for energy services and energy prices are captured in the energy system model used for this analysis (see IEA, 2008 Annex B). While lower oil and gas demand in the ACT and BLUE scenarios will result in price reductions, the precise impact on prices is uncertain.

The ACT scenarios were originally presented in *Energy Technology Perspectives 2006* (IEA, 2006). However, the ETP 2008 scenarios on which this study is based incorporate a number of important changes to the 2006 scenarios:

- Economic growth projections have been revised upwards.
- Equipment costs have been revised upwards, due to a combination of business cycles, strong demand growth in Asia, resource scarcity, lack of skilled labour and a deteriorating dollar exchange rate. Typically, costs have risen by a factor of two.
- Energy feedstock prices have undergone a substantial increase.
- Long-term cost projections for certain key technologies have also been revised upwards.

It remains to be seen if these factors will be sustained over the coming decades, or if they will change. However, one significant consequence of this analysis is that the CO_2 incentive level for emissions stabilisation in the ACT scenarios has been raised from USD 25/t CO_2 to USD 50/t CO_2. Short- and medium-term deployment costs have risen significantly for most technologies and this has made substantive energy transition even more challenging than it appeared even two years ago.

Results

In the ACT Map scenario, end-use efficiency provides the most emission reductions (44%), with electricity end-use efficiency accounting for 35% of the total end-use efficiency gains (Figure 2.1). In the BLUE Map scenario, end-use efficiency accounts for a smaller percentage (36%) of a larger overall reduction, with electricity generation accounting for 38% of the reduction attributable to end-use efficiency. CCS in industry, fuel transformation and electricity generation accounts for 14% of the emissions reduction in the ACT Map scenario and 19% in the BLUE Map scenario, leading to the capture of 5.1 Gt to 10.4 Gt of CO_2. Renewables account for 16% to 21% of the total emissions reduction. About a quarter of the renewables contribution in the BLUE Map scenario comes from biofuels, with most of the remainder from the use of renewables in the power sector. It should be noted that the percentages in Figure 2.1 underestimate the importance of nuclear and hydropower for CO_2-free energy, as both options already play an important role in Baseline.

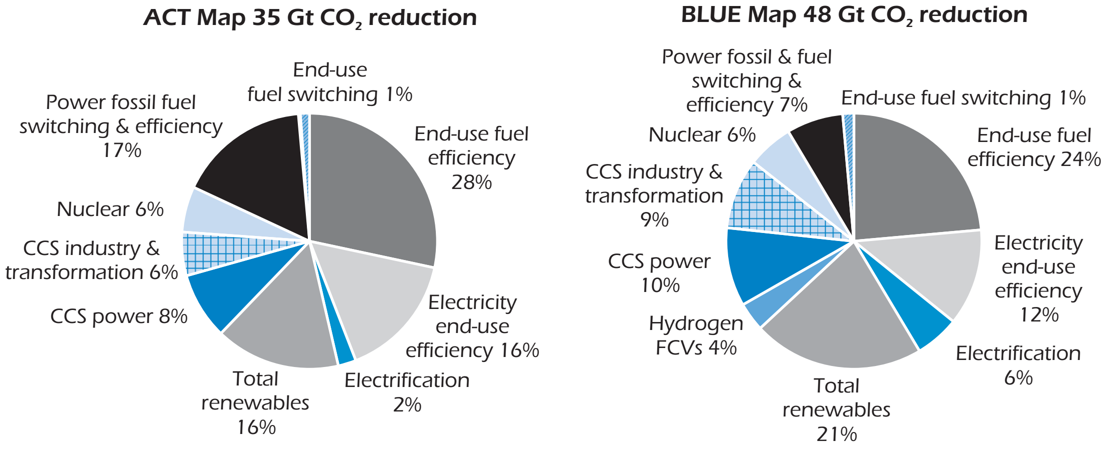
The growth of CCS between the ACT Map and the BLUE Map scenarios accounts for 32% of the additional emissions reduction in the BLUE Map. The level of CO_2 reduction using future advanced technologies is approximately 10% to 20% lower than the total amount of CO_2 captured, because CCS uses significant additional energy. In the BLUE Map scenario, 54% of the CO_2 capture takes place in the power sector (Figure 2.2). The remainder takes place in the fuel-transformation sector (refineries, synfuel production, blast furnaces) and in manufacturing industries, for example in cement kilns, ammonia plants and industrial combined heat and power (CHP) units.

In the power sector, the retrofit of power plants with CO_2 capture plays an important role in the ACT Map scenario. Retrofitting plays a smaller part in the BLUE Map scenario, where CCS is incorporated into new generation capacity earlier. In the ACT Map scenario, 239 GW of coal-fired capacity is retrofitted with CCS by 2050 and 379 GW of new capacity is equipped with CCS. The new plants are largely integrated gasification combined-cycle (IGCC) based. In the BLUE Map scenario, only 157 GW of coal-fired capacity is retrofitted with CCS and 543 GW of

Figure 2.1 Reduction in CO_2 Emissions from the Baseline Scenario in the ACT Map and BLUE Map Scenarios by Technology Area, 2050

Key point

End-use efficiency and power-generation options account for the bulk of emissions reductions.



Note: CCS share accounts for the loss in energy efficiency.

Source: IEA, 2008.

new capacity with CCS is installed. Retrofit of power plants built before 2005 is not significant in either scenario because the efficiency of these plants is too low. Only 10% of all coal fired electricity generation capacity today (about 120 GW) achieves the 40% net efficiency that would make it suitable for retrofitting CCS.

In the ACT Map scenario, 280 GW of new gas-fired capacity is equipped with CCS. This increases to 817 GW in the BLUE Map scenario. These figures include industrial large-scale combined heat and power (CHP) generation units. In addition, black liquor gasifiers are equipped with CCS in both scenarios and CCS is increasingly applied to industrial processes (*e.g.* cement kilns and iron production processes) and in the fuel-transformation sector (*e.g.* hydrogen production for refineries). CCS is especially important for some industries such as steel and cement because it is the only way to achieve deep emission cuts.

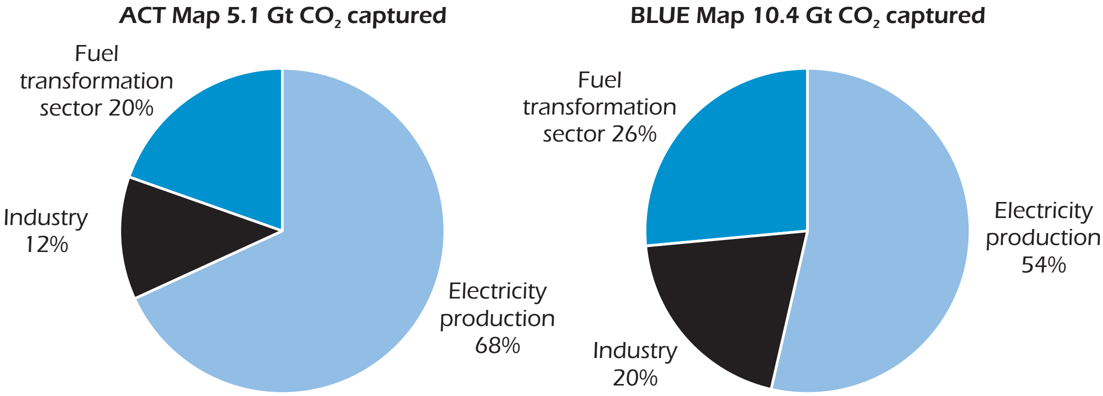
In the Baseline scenario, which assumes a negligible price for CO_2, CCS is mainly limited to enhanced oil recovery (EOR) and fuel-transformation applications. Figure 2.3 shows the growth in emission reductions from CCS in the ACT Map scenario, which assumes an incentive of USD 50/t CO_2. CCS achieves a saving of 5.1 Gt CO_2 per year in 2050, of which 68% is from the electricity sector. Retrofits represent nearly 40% of this amount. Gas processing and synthetic-fuel production represent 17%, and industry CCS 5% of the total reduction. The cumulative storage volume between 2010 and 2050 is less than 100 Gt, representing only a small fraction of the capacity available.

Achieving a reduction of 1.4 Gt CO_2 from CCS in the power sector by 2030 will be challenging as it will require utilising CCS to be used at 300 coal fired power plants of 500 MW each (150 GW). At present, about 100 GW of coal fired capacity is built each year. Achieving 150 GW of CCS use by 2030 will only be possible if steps are taken to fast-track research and development, to validate the technology, and to develop large-scale regional CO_2 transport infrastructures. As the CCS curve flattens after 2040, the 2050 targets are not strictly dependent on the absolute level of CCS use in 2030. The main issue is a substantial phase-in of the large-scale deployment of CCS in the next two decades. A major international collaboration effort will be required to meet this challenge, as described in (for more detail on this topic, see Chapter 7.)

Figure 2.2 Use of CO_2 Capture and Storage in the ACT Map and BLUE Map Scenarios

Key point

CO_2 capture and storage can play an important role outside the power sector.

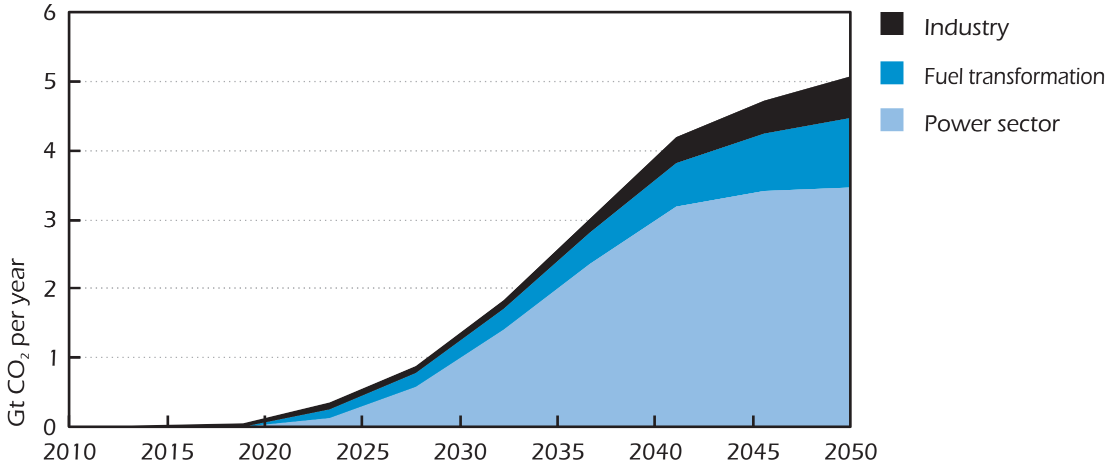


Source: IEA, 2008 (ETP Model).

Figure 2.3 Growth of CO_2 Capture and Storage in the ACT Map Scenario

Key point

The main growth in CCS is between 2020 and 2040. 5.1 Gt CO_2 per year would be captured and stored by 2050, mainly from the power sector, but also from industry and synthetic fuel production.



Source: IEA, 2008 (ETP Model).

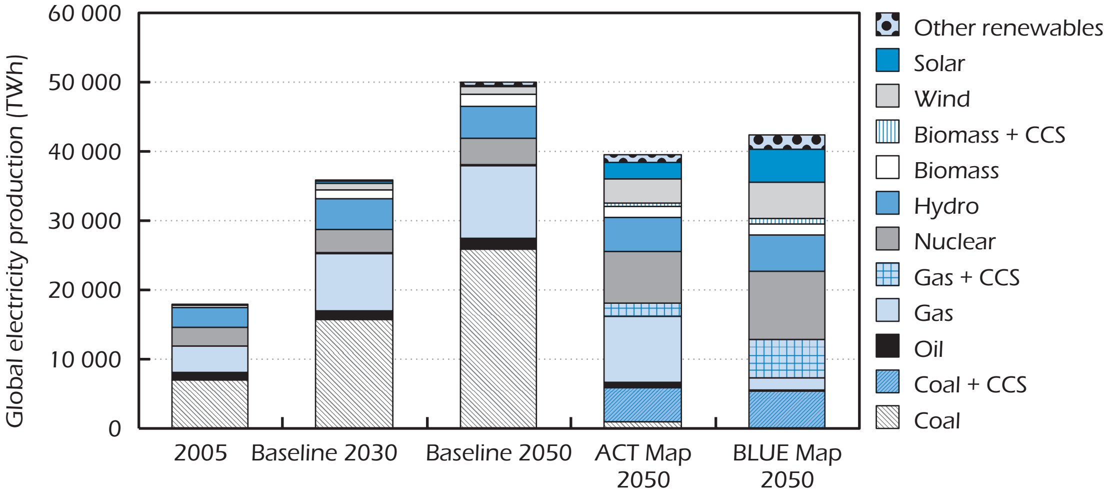
CO_2 Capture in Electricity Generation

In the Baseline scenario, global electricity production increases by 179% between 2005 and 2050 (Figure 2.4). In 2050, coal-based generation is forecast to be 252% higher than in 2005, accounting for 52% of all power generation. Gas-fired power generation increases from a share of 20% today to 23% in 2050. Nuclear decreases to 8%, hydro decreases to 10%, and wind increases to account for 2.5% of all power generation.

Figure 2.4 Global Electricity Production by Fuel and Scenario, 2005, 2030 and 2050: Baseline, ACT Map and BLUE Map Scenarios

Key point

There is a major shift from fossil fuels to carbon-free alternatives in the ACT Map and BLUE Map scenarios.



Source: IEA, 2008 (ETP Model).

Electricity production is currently responsible for 32% of total global fossil-fuel use and 41% of energy-related CO_2 emissions. Table 2.1 shows the potential for efficiency improvements in electricity generation. Improving the efficiency of electricity production offers a significant opportunity to reduce the world's dependence on fossil fuels, and to help combat climate change and improve energy security. This is also a key enabling step for CCS, as capture and storage only makes sense for highly efficient plants.

In the ACT Map scenario, significant savings in electricity demand in the buildings and industry sectors reduce the level of growth in power generation capacity. Nonetheless, electricity demand more than doubles by 2050. Demand in the BLUE Map scenario is 7% higher than in the ACT Map scenario in 2050, largely due to increased demand for electricity for heat pumps and plug-in vehicles.

The CO_2 emission reduction incentives and other measures introduced in the ACT Map scenario significantly change the electricity generation mix relative to the Baseline scenario (Table 2.2), resulting in increases in nuclear and renewable power and reductions in fossil-fuelled power. The share of gas-based power generation increases by 8% in the ACT Map scenario compared to the Baseline in 2050, but decreases by 17% in the BLUE scenario in which virtually all coal-fired production and 40% of all gas-fired production is from plants equipped with CCS.

Table 2.1 Technical Fuel Savings and CO_2 Reduction Potentials from Improving the Efficiency of Electricity Production

	Coal (Mtoe/yr)	Oil (Mtoe/yr)	Gas (Mtoe/yr)	All fossil fuels (Mtoe/yr)
OECD	134 - 213	12 - 24	60 - 81	205 - 320
G8	112 - 177	10 - 17	93 - 115	213 - 311
Plus Five	189 - 244	7 - 12	7 - 10	20 - 27
World	**356 - 504**	**36 - 64**	**105 - 134**	**494 - 702**
	(Gt CO_2/yr)	**(Gt CO_2/yr)**	**(Gt CO_2/yr)**	**(Gt CO_2/yr)**
OECD	0.53 - 0.85	0.04 - 0.08	0.14 - 0.19	0.71 - 1.12
G8	0.44 - 0.71	0.03 - 0.06	0.22 - 0.27	0.69 - 1.03
Plus Five	0.73 - 0.95	0.03 - 0.04	0.02 - 0.02	0.77 - 1.01
World	**1.40 - 1.98**	**0.11 - 0.20**	**0.25 - 0.31**	**1.75 - 2.50**

Note: Compared to the 2005 reference year.

The power sector is the most important potential contributor to global emission reductions in both low-carbon scenarios. The power sector is virtually decarbonised in the BLUE Map scenario.

In the ACT Map scenario, electricity demand is reduced by 21% due to end-use efficiency measures and reductions in transmission and distribution losses. This results in reductions of more than 6 Gt CO_2 by 2050 compared to the Baseline scenario. Emissions reductions increase to almost 7 Gt CO_2 in the BLUE Map scenario. However, electricity demand is higher in the latter scenario because of a switch from fossil fuels to electricity in buildings, industry and transportation. Compared to the Baseline scenario, electricity demand is 15% lower.

In the ACT Map scenario, a reduction of 13.9 Gt of CO_2 is achieved as a result of supply-side changes in power generation. This increases to 18 Gt CO_2 in the BLUE Map scenario. Figure 2.5 provides a breakdown of the relative importance of the supply-side measures.

The efficiencies of fossil-fuel power plants increase substantially in both the ACT Map and the BLUE Map scenarios, to the extent that coal-fired plants with CCS in these scenarios are on average more efficient than coal-fired plants without CCS in the Baseline scenario (Figure 2.6). IGCC and ultra-supercritical steam cycles (USCSC) play a role in these scenarios.

The use of CHP triples in the Baseline scenario between 2005 and 2050. Its share in power generation rises from 9% to 10%. In the ACT Map and the BLUE Map scenarios, its share rises to 17% and 14% respectively. In the IEA energy accounting system, the benefits of CHP show up as an efficiency gain for electricity generation.

Most electricity generated by coal-fired power plants in the ACT Map and BLUE Map scenarios, and half of the gas-fired power generation in the BLUE Map scenario, comes from plants equipped with CCS. Retrofitting of coal plants with CCS plays a significant role in the ACT Map scenario; and at the price of USD 200/t CO_2 envisaged in the BLUE Map scenario, there is sufficient economic incentive to accelerate the replacement of inefficient power plants before they reach the end of their life span.

Table 2.2 Global Electricity Production by Type for Baseline, ACT Map and BLUE Map Scenarios and Sensitivity Analyses, 2050

	2005	Baseline 2050	ACT Map	ACT noCCS	ACT hiNUC	ACT loREN	ACT loEFF	BLUE Map	BLUE noCCS	BLUE hiNUC	BLUE loREN	BLUE loEFF	BLUE hiOil & Gas price	BLUE OECD
Production (TWh/yr)														
Nuclear	2 771	3 896	7 336	7 336	15 865	7 336	7 336	9 857	9 857	15 877	9 857	9 857	9 857	6 809
Oil	1 186	897	882	832	864	885	954	133	123	150	210	332	113	905
Coal	7 334	25 825	949	2 531	566	1 277	1 879	0	353	0	0	0	0	14 666
Coal + CCS	0	3	4 872	0	2 732	5 915	6 460	5 468	0	4 208	7 392	7 461	6 509	1 006
Gas	3 585	10 590	9 480	12 696	7 619	10 953	12 410	1 751	4 260	1 570	1 747	2 073	1 358	5 974
Gas + CCS	0	83	1 962	0	1 850	2 024	2 005	5 458	0	4 926	6 711	6 820	3 765	3 062
Hydro	2 922	4 900	5 037	5 020	4 985	4 663	5 045	5 260	5 504	5 203	5 114	5 385	5 505	4 929
Bio/waste	231	1 696	1 578	2 124	1 609	1 487	1 640	1 617	3 918	1 606	1 448	1 689	1 842	1 540
Bio + CCS	0	0	402	0	401	406	404	835	0	678	1 103	1 077	864	363
Geothermal	52	348	934	937	731	909	934	1 059	1 059	1 059	1 059	1 059	1 059	746
Wind	111	1 515	3 607	4 654	2 680	2 735	4 169	5 174	6 743	4 402	3 988	5 951	6 395	2 811
Tidal	1	10	111	111	111	35	111	413	2 389	419	165	806	755	110
Solar	3	167	2 319	2 565	1 487	648	2 673	4 754	5 297	4 220	2 314	4 987	5 278	1 858
Hydrogen	0	4	1	0	0	1	1	559	517	472	664	649	720	239
Total	**18 196**	**49 934**	**39 471**	**38 807**	**41 501**	**39 274**	**46 022**	**42 340**	**40 021**	**44 791**	**41 773**	**48 146**	**44 021**	**45 018**

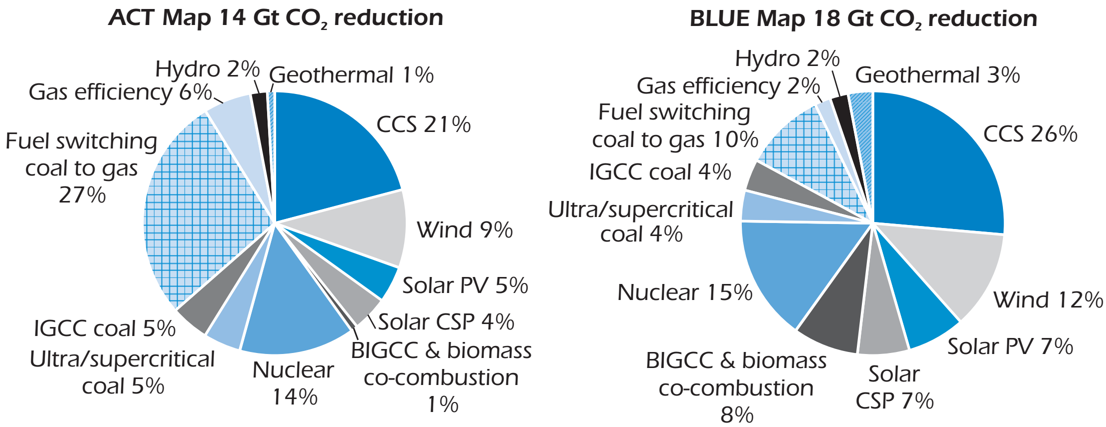
Table 2.2 Global Electricity Production by Type for Baseline, ACT Map and BLUE Map Scenarios and Sensitivity Analyses, 2050 (continued)

	2005	Baseline 2050	ACT Map	ACT noCCS	ACT hiNUC	ACT loREN	ACT loEFF	BLUE Map	BLUE noCCS	BLUE hiNUC	BLUE loREN	BLUE loEFF	BLUE hiOil & Gas price	BLUE OECD
Share (%)														
Nuclear	15	8	19	19	38	19	16	23	25	35	24	20	22	15
Oil	7	2	2	2	2	2	2	0	0	0	1	1	0	2
Coal	40	52	2	7	1	3	4	0	1	0	0	0	0	33
Coal + CCS	0	0	12	0	7	15	14	13	0	9	18	15	15	2
Gas	20	21	24	33	18	28	27	4	11	4	4	4	3	13
Gas + CCS	0	0	5	0	4	5	4	13	0	11	16	14	9	7
Hydro	16	10	13	13	12	12	11	12	14	12	12	11	13	11
Bio/waste	1	3	4	5	4	4	4	4	10	4	3	4	4	3
Bio + CCS	0	0	1	0	1	1	1	2	0	2	3	2	2	1
Geothermal	0	1	2	2	2	2	2	3	3	2	3	2	2	2
Wind	1	3	9	12	6	7	9	12	17	10	10	12	15	6
Tidal	0	0	0	0	0	0	0	1	6	1	0	2	2	0
Solar	0	0	6	7	4	2	6	11	13	9	6	10	12	4
Hydrogen	0	0	0	0	0	0	0	1	1	1	2	1	2	1
Total	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
CO_2 in 2050 ($Gt\ CO_2/yr$)	27	62	27	31.3	25.6	27.6	29.3	14	20.4	13.4	14.2	15	13.3	41.6
Incremental cost in 2050 (trln. USD/yr)				0.215	-0.07	0.03	0.115		1.28	-0.12	0.04	0.20	-0.14	NA
Marginal cost to meet target (USD/t CO_2)			50	76	41	54	64	200	394	182	206	230	179	

Figure 2.5 Reduction in CO_2 Emissions from the Baseline Scenario in the Power Sector in the ACT Map and BLUE Map Scenarios in 2050, by Technology Area

Key point

A mix of nuclear, renewables and CCS plays an important role in reducing emissions in the power sector.



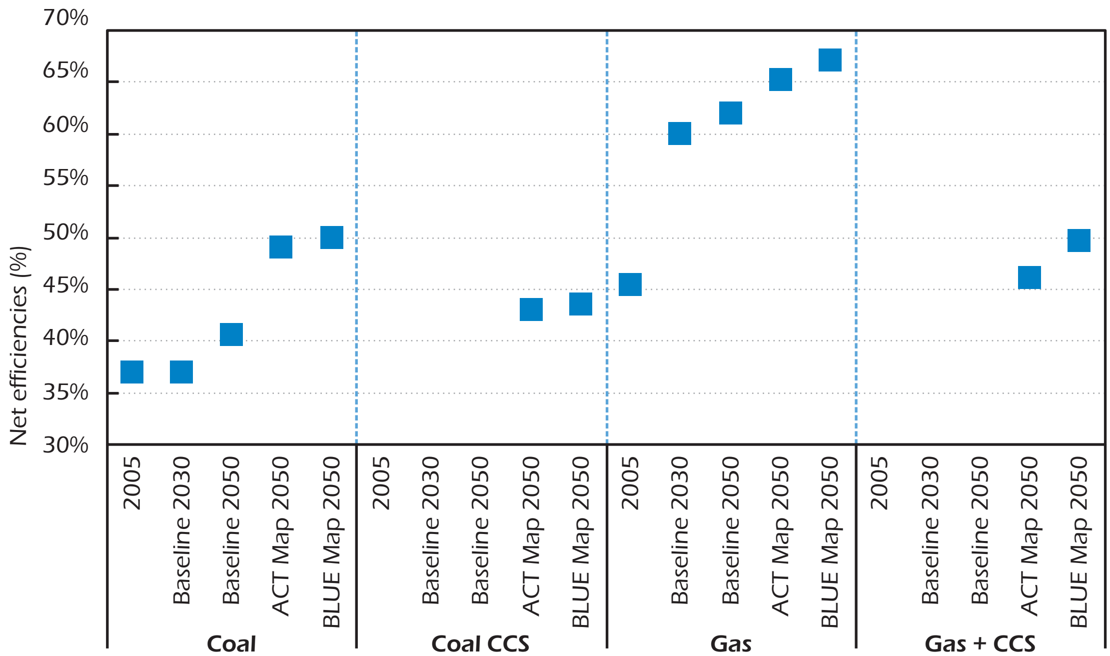
Note: Excludes the impact of end-use efficiency and electrification.

Source: IEA, 2008.

Figure 2.6 Net Efficiencies of Fossil-Fuelled Power Plants

Key point

Efficiencies of power plants increase in the ACT Map and BLUE Map scenarios, but the switch to CCS significantly reduces efficiency gains.



Note: Data refer to average stock efficiency. Gas includes CHP credits following IEA accounting rules (which implies about 85% efficiency for large natural gas combined-cycle (NGCC) CHP plants).

Source: IEA, 2008.

In the BLUE Map scenario, 350 GW of coal-fired power-plant capacity is closed down early. 80% of the 700 GW of coal plant in 2050 consists of new capacity that is equipped with CCS, the remaining 20% being old plants retrofitted with CCS.

The growth of CCS in the BLUE Map scenario compared to the ACT Map scenario is largely attributable to installing CCS at gas and biomass plants. As biomass contains carbon captured from the atmosphere, the capture and storage of that carbon results in a net removal of CO_2 from the atmosphere. This can offset emissions elsewhere. However this option is costly: biomass transportation costs limit plant size whereas CCS benefits from economies of scale (see Box 2.2).

Table 2.3 shows electricity generation from power plants fitted with CCS in the ACT Map and BLUE Map scenarios. In the ACT Map scenario, total generation nearly triples between 2030 and 2050, rising to 7 237 TWh in 2050. A mix of IGCC and steam cycle coal fired plants with CCS produce 46% of all power from CCS plant in 2030. This rises to 67% in 2050. Retrofitted CCS includes post-combustion chemical absorption and some oxyfueling. The share of oxyfueling rises over time for gas- and for coal fired power plants. There are, however, significant technical uncertainties on the cost and performance of IGCC compared to oxyfuel and steam cycles with post-combustion capture. Different cost assumptions may result in different shares.

In the BLUE Map scenario, the use of CCS in power generation in 2030 is about 20% higher than in the ACT Map scenario. The gap grows over time and amounts to 63% by 2050. In 2050, 23% of coal fired power plants are retrofitted. CCS from gas fired power plants grows significantly. As a result, CCS fitted coal fired power plants produce a smaller proportion (46%) of the total CCS power generation in 2050 than in the ACT Map scenario. This accounts for 57% of the CO_2 captured through CCS.

Table 2.2 provides an overview of components of the electricity generation sector for all five ACT and all five BLUE scenarios. These variants show that total electricity generation, and the generation mix, depend on the assumptions that are made in different scenarios. This suggests that there is some room to choose among CO_2 free electricity generation options.

Among the BLUE variants, the one without CCS (noCCS) has the highest CO_2 emissions. In this variant, the share of coal-fired generation drops by 10%. The share of gas also declines. Total electricity demand is 7% lower and the share of renewables increases. CO_2 emissions increase not only in electricity generation, but also in industry and fuel-transformation sectors. As a consequence, it is not possible to achieve the target of halving CO_2 emissions required by the BLUE scenarios even with a CO_2 incentive of USD 200/t. This indicates the importance of CCS for the achievement of climate objectives.

In the high-nuclear (hiNUC) BLUE variant where nuclear generation is doubled to 2 000 GW in 2050, almost all of the nuclear capacity is used. This is largely at the expense of coal with CCS, but the share of combustible renewables also declines by 3%. Total global emissions in this variant are 0.5 Gt CO_2 lower in2050 than in the BLUE Map scenario. This variant would require the construction of 50 GW of nuclear power on average every year between now and 2050. This is twice the highest recorded construction rate in the past.

In the low-renewables (loREN) BLUE variant, the share of renewables is reduced by 5%, which is compensated by more CCS and, to a lesser extent, reduced electricity use.

Table 2.3 Electricity Generation from Power Plants Fitted with CCS by Technology and Fuel for the ACT Map and BLUE Map Scenarios

		ACT		BLUE	
		2030 (TWh/yr)	2050 (TWh/yr)	2030 (TWh/yr)	2050 (TWh/yr)
Coal	Retrofit post – combustion capture	197	1 880	95	1 241
	Coal IGCC	676	2 083	165	426
	Pulverised coal + oxyfueling	425	908	616	3 801
	Conv. pulverised coal	0	0	0	0
	Total coal	1 299	4 872	875	5 468
Gas	NGCC + chemical looping	0	0	89	612
	NGCC + flue gas removal	88	27	483	282
	NGCC + oxyfueling	0	0	353	1 741
	Industrial NGCC (CHP) + CCS	1 130	1 935	1 251	2 823
	Total gas	1 218	1 962	2 177	5 458
Biomass	Retrofit	0	0	0	377
	BIGCC	0	0	0	0
	Black liquor gasifiers	297	402	368	458
	Total biomass	297	402	368	835
Total		**2 814**	**7 237**	**3 420**	**11 761**

Source: IEA, 2008 (ETP Model).

Another way to look at these scenario variants is to assume a constant level of CO_2 reduction and to compare the impact on the marginal and total annual incremental policy costs. In this analysis, the impact on incremental cost is based on the difference in emissions between the Map cases and the variants, multiplied by the marginal abatement cost (USD 50/t CO_2 and USD 200/t CO_2 for the ACT and the BLUE scenarios respectively).

The highest additional cost occurs in the BLUE noCCS variant, where the annual cost in 2050 is USD 1.28 trillion higher than in the BLUE Map scenario (Table 2.4). This is an increase of about 71%. This shows again the critical importance of CCS for deep emission reductions. The impact on the marginal costs, as calculated by the ETP model, is also highest in this case, where they nearly double to USD 394/t CO_2. Making more nuclear power available results in a USD 9/t CO_2 reduction in marginal costs in the ACT Map scenario (-18%) and a USD 18/t CO_2 reduction in the BLUE Map scenario (-9%).

Despite the increasing shares of coal and gas in electricity generation in the Baseline scenario, the CO_2 intensity of electricity generation declines marginally between 2005 and 2050 (Figure 2.7). This is a result of improvements in generation efficiency that more than outweigh the impact of the input mix becoming more CO_2 intensive. In the ACT Map scenario, CO_2 emissions per kWh are 76% lower than in the Baseline scenario. Electricity generation becomes largely decarbonised in the BLUE Map scenario, with CO_2 emissions per kWh being reduced by as much as 86%. The difference in the carbon intensity of electricity production between OECD and non-OECD countries narrows in both the ACT Map and the BLUE Map scenarios.

Box 2.1 Electricity Prices in the Scenario Variants

The five power-sector variants result in important variations in electricity prices. Table 2.4 provides an overview of how the average prices of 15 regions for the period 2030 to 2050 compare with the Baseline scenario prices for the same period. The price range is also indicated for the 15 regions.

Table 2.4 Annual Average Electricity Price Increases for the ACT and BLUE Scenarios for the Period 2030-2050, Relative to the Baseline Scenario

	Average increase 2030 – 2050 (%)	Increase range for world Regions (%)	Change compared to MAP (% points)
ACT Map	58	26 – 116	
ACT noCCS	58	19 – 122	0
ACT hiNUC	47	10 – 119	-5
ACT loREN	61	21 – 119	3
ACT loEFF	64	23 – 124	6
BLUE Map	90	65 – 163	
BLUE noCCS	106	55 – 211	16
BLUE hiNUC	81	37 – 162	-9
BLUE loREN	94	46 – 180	4
BLUE loEFF	108	52 – 186	18

Note: Electricity production costs exclude transmission and distribution.

Source: IEA, 2008.

The results show that price increases compared to the Baseline scenario are higher in the BLUE scenarios than in the ACT scenarios. From 2030 to 2050, prices approximately double in the BLUE scenarios compared to the Baseline. Variations between the scenarios are also more significant in the BLUE than in the ACT scenarios. The availability of CCS technologies and low-cost renewables in the BLUE Map scenario results in prices that are lower by 16% to 18% than if these options are constrained. The availability of the full range of options is important to reduce overall costs. The range of price increases varies widely across different regions as a result of differences in emission mitigation potentials and needs.

Box 2.2 Biomass with CO_2 Capture and Storage

Biomass is a CO_2 neutral fuel as it only releases back into the atmosphere the CO_2 which it had previously captured from the atmosphere as it grew. However, biomass has a high carbon content and, when it is burned, it emits more CO_2 per unit of energy than coal. As a fuel, solid biomass is similar in many ways to coal, and the combustion technologies are therefore similar. This means that CCS strategies that are being developed for coal could also be applied to biomass. The combination of biomass with CCS would result in a net *removal of CO_2 from the atmosphere. This makes biomass with CCS a potentially important option if a very rapid reduction of CO_2 emissions is needed.*

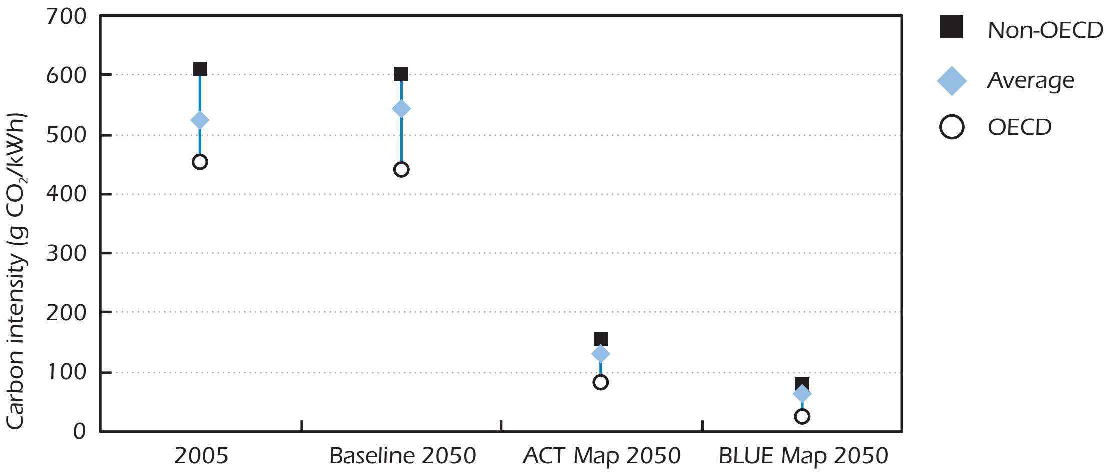
The cost per tonne of CO_2 removal through CCS, however, depends on the plant size. Typically, it is estimated that the cost per tonne of CO_2 removed doubles for each order of magnitude reduction in the size of plant. Biomass plants will usually be smaller than coal fired power plants because of feedstock availability and transport limitations.

Biomass can also be co-combusted in coal fired plants. Co-combusted biomass benefits from the scale effects of coal in terms of higher efficiency and lower cost. If CCS is applied to such a process, the cost of applying CCS to the biomass component would be significantly lower than applying CCS to biomass combustion alone. Other options to which CCS might be applied include black liquor boilers or gasifiers in chemical pulp production and bagasse boilers in sugar cane processing. Trials are planned for ethanol plants with CCS in the Netherlands.

Figure 2.7 CO_2 Intensity of Electricity Production by Scenario

Key point

In the ACT scenarios, global CO_2 intensity of power generation is a quarter of the Baseline level in 2050, while the power sector is virtually decarbonised in the BLUE scenarios.



Source: IEA, 2008.

CO_2 Capture in Industry and Fuel Transformation

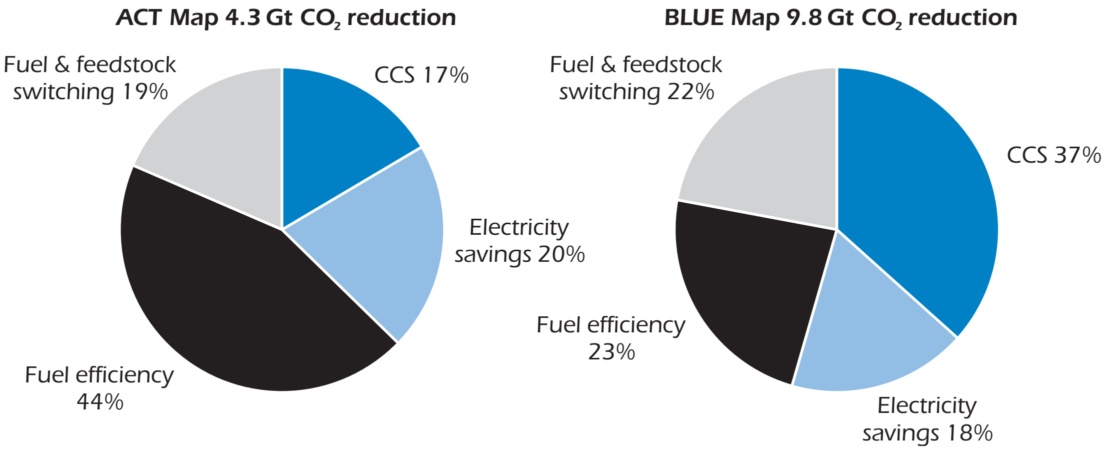
In the Baseline scenario, industrial CO_2 emissions[3] increase by 134% between 2005 and 2050, reaching 23.2 Gt CO_2 in 2050. More than half (13.5 Gt) are direct emissions; the remainder are indirect emissions in power generation. In the ACT Map scenario, direct emissions are reduced to 10.9 Gt CO_2. In the BLUE Map scenario they are reduced to 5.2 Gt CO_2, *i.e.* 61% below the Baseline level and 22% below the 2005 level in 2050. Total fuel and electricity savings account for 42% of the emissions reduction in the BLUE Map scenario (Figure 2.8).

3. The industrial emissions include the upstream emissions from electricity and heat generation and coal use in coke ovens and blast furnaces, and process emissions from cement and steel making.

Figure 2.8 Industrial CO_2 Emission Reductions in the ACT Map and BLUE Map Scenarios in 2050, Compared to the Baseline Scenario

Key point

CCS accounts for 17% of total industry sector emissions reductions in the ACT Map scenario and 37% in the BLUE Map scenario.



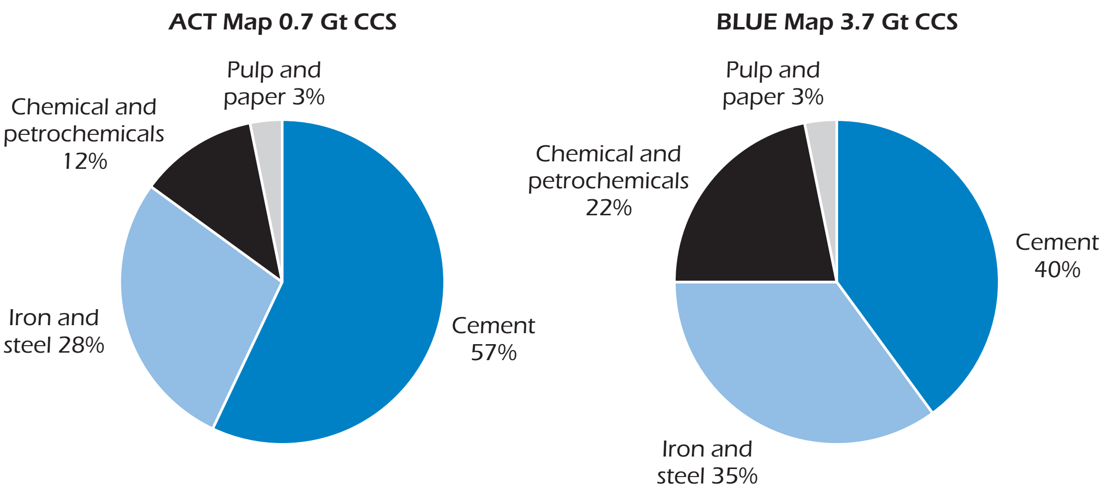
Note: Includes savings from coke ovens, blast furnaces and steam crackers, and CO_2 emission reductions in power generation due to reduced electricity demand in industry.

Source: IEA, 2008.

Figure 2.9 Breakdown of industrial CO_2 Emission Reductions by Sector in the ACT Map and BLUE Map Scenarios in 2050

Key point

There are important opportunities for reducing CO_2 emissions through the use of CCS in iron and cement manufacturing.



Note: Includes CCS for blast furnaces that are in the fuel transformation sector in the IEA energy statistics.

Source: IEA, 2008 (ETP Model).

The main difference between ACT Map and BLUE Map scenarios in terms of emissions reduction is the growth in CCS use. In the BLUE Map scenario, CCS plays a pivotal role and accounts for 37% of the total industrial emissions reduction.

In the ACT Map and BLUE Map scenarios, CCS is used with iron-making processes, cement kilns, ammonia production, large CHP units and black liquor gasifiers in pulp production, as shown in Figure 2.9. In the ACT Map scenario, the cement sector represents more than half of the total CO_2 captured. In the BLUE Map scenario, cement and iron and steel have similar shares and together represent 75% of the total CO_2 captured. Cogeneration units in the chemical and petrochemical industry are equipped with CCS, and part of this capture is allocated to this sector (pro rata to electricity and heat production). The same applies to black liquor boilers in pulp making.

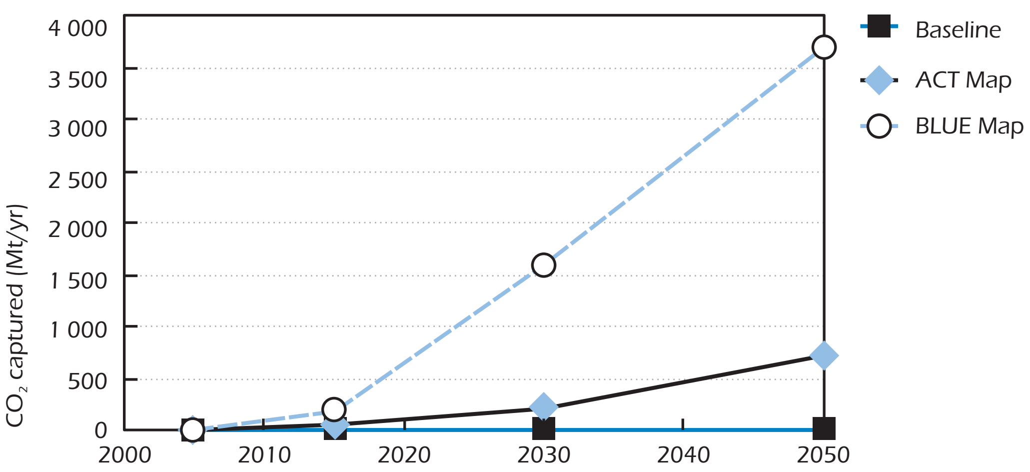
In the scenarios, in the iron and steel sector, CO_2 is captured from blast furnaces, smelt reduction and direct reduced iron (DRI) production plants. Capture in the cement sector is from rotary kilns for clinker production. Capture in the chemicals and petrochemicals sectors is mainly in ammonia production and in CHP units (for which only part of CCS use is allocated to the industry, proportional to the heat production in total useful energy production). While capture from ammonia and DRI plants is a straightforward process, capture from cement kilns and blast furnaces is a relatively new technology that will require major process adjustments. The future role of CCS in these areas is less certain than capture from ammonia plants. However, CCS is one of few options available substantially to reduce CO_2 emissions from steel and cement making. Further analysis and process development will be needed to verify the viability of these options and to enhance understanding of them.

In the BLUE Map scenario, CCS from ammonia plants starts in 2015 (Figure 2.10). This represents an early application opportunity of the technology since capture from such processes is already operational, CO_2 purity from the process is high, and only CO_2 transportation and storage would be required. This therefore represents a relatively low-cost CCS option. CCS is not applicable

Figure 2.10 Development of Industrial CCS over Time in the Different Scenarios 2005-2050

Key point

CCS grows very rapidly in the BLUE Map scenario, with 1.6 Gt capture from industrial sources in 2030.



Source: IEA, 2008 (ETP Model).

to all ammonia plants. About half of all generated and captured CO_2 is nowadays used for urea fertiliser production. Some plants also have a different configuration where no pure CO_2 is captured, and not all plants are close to suitable storage sites. Therefore the total global potential is at present less than 100 Mt CCS per year.

CCS in industry is in the BLUE Map scenario is very significant by 2030, given the early low-cost opportunities in this sector. However, beyond 2030 although CCS in industry continues to rise significantly, this is outstripped by the growth in CCS in electricity generation.

CCS can also be applied in refineries and in the production of synfuels (hydrogen and oil product synfuels). Hydrogen production (for refineries, transportation fuels and for decentralised CHP units, notably fuel cells) accounts for about half of the total CCS in fuel transformation in 2050. About 500 Mtoe hydrogen is needed in BLUE Map in 2050, but part of the hydrogen for transport fuel applications is produced from decentralised units or from electricity and nuclear fission, where CCS does not apply.

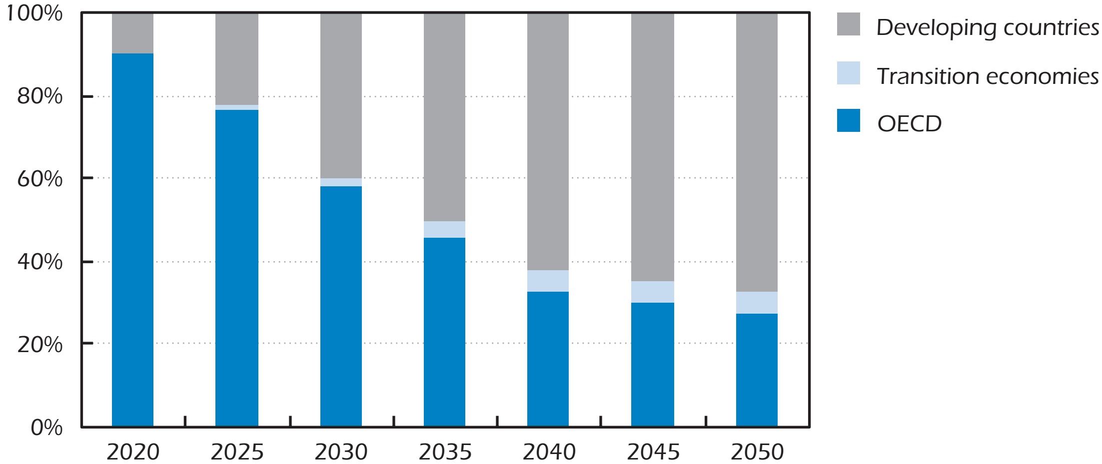
Regional Use of CCS

Figure 2.11 shows CO_2 capture by region under the ACT Map scenario. The distribution for the BLUE Map scenario is very similar. Up to 2030, more than half of total capture takes place in OECD countries. After 2035, emerging economies account for more than half of total CCS use. This pattern can be explained by the assumption of the delayed introduction of CO_2 policies in developing countries and the need for technology transfer. However, in the long run, developing countries account for the bulk of the economic activity and for two thirds of the CO_2 emissions in the Baseline scenario. Therefore, their potential to apply CCS is much higher. The high share of capture in developing countries in this scenario suggests that if CCS is not applied in developing

Figure 2.11 Global CO_2 Capture by Region, ACT Map Scenario

Key point

Up to 2030, capture is predominantly applied in OECD countries. After 2030, capture in developing countries dominates.



Source: IEA, 2008 (ETP Model).

countries, the total quantity captured worldwide will be much lower. This indicates the importance of international co-operation to maximise the impact of CCS as an abatement option.

CO_2 Storage

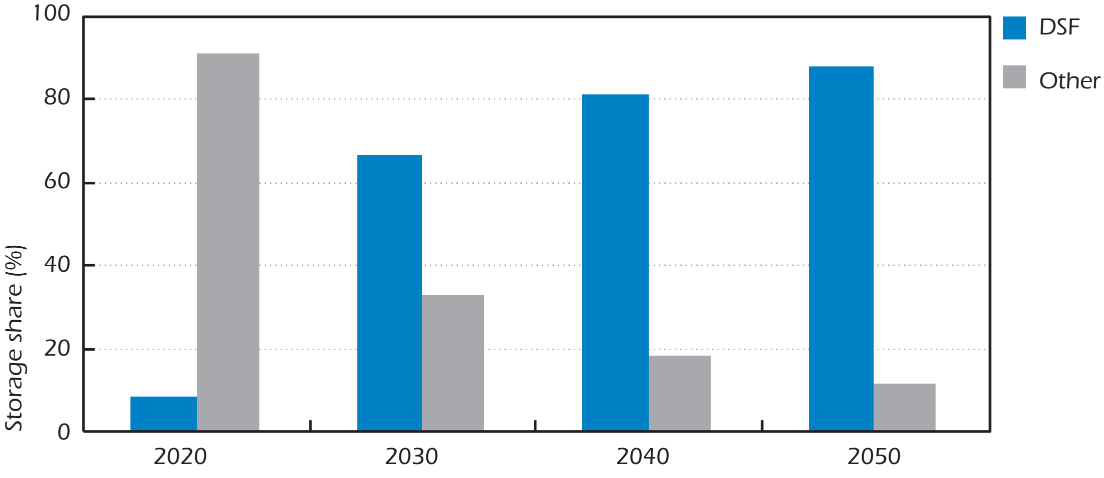
The use of CO_2 for enhanced oil recovery (CO_2-EOR) has been applied on a limited scale for the past 25 years. Opportunities are likely to increase gradually over the next 15 years as production in certain basins such as the North Sea and the Gulf of Mexico matures. In practice, CO_2-EOR use is likely to be limited: many oil and gas fields are in remote regions which are far from sources where CO_2 could be captured. In such cases, the cost of bringing CO_2 to the site must be compared to the cost of alternative EOR technologies. The model results regarding CO_2 use for EOR are subject to significant uncertainties. A proper assessment of the potential would require detailed field-by-field data, which is beyond the scope of the ETP model analysis. Nonetheless, the model suggests suggest that CO_2-EOR opportunities are not critical for the feasibility of CCS strategies.

Figure 2.12 shows results for CO_2 storage under the ACT Map scenario. Storage is initially mainly associated with EOR. By 2025, it is roughly evenly divided between aquifers and depleted oil and gas fields, including enhanced oil and gas recovery (EOR and Carbon Sequestration and Enhanced Gas Recovery - CSEGR). By 2030, storage in deep saline formations (DSF) will dominate. Total cumulative storage over the period 2000 to 2050 amounts to 80 Gt, a small share of the total global storage potential. In a least-cost optimisation model such as ETP, one might expect that CO_2 use for enhanced fossil fuel production would be chosen first. Currently, only 3% of world oil production is based on EOR and 0.3% is associated with CO_2-EOR. The remaining 97% is based on primary and secondary production technologies.

Figure 2.12 CO_2 Storage in the ACT Map Scenario

Key point

By 2050, most of the CO_2 storage will be in deep saline formations (DSF).



Note: Other CO_2 applications include CO_2 enhanced recovery and storage in depleted oil and gas fields.

Source: IEA, 2008 (ETP Model).

3. CO_2 CAPTURE TECHNOLOGIES

KEY FINDINGS

- Carbon dioxide capture and storage (CCS) can be applied to fossil fuelled power plants, in industrial processes and in the fuel production and transformation sectors.
- Three main technology options exist for CO_2 capture: post-combustion, pre-combustion, and oxyfueling (or denitrogenation).
- CO_2 capture and pressurisation requires energy, it reduces overall energy efficiency and it adds cost. Typical efficiency losses today are 6 to 12 percentage points, which translate into extra fuel consumption dependent upon the efficiency of the plant. The best technology for individual CCS applications depends on the power plant and its fuel characteristics. Post combustion capture based on chemical absorption is the technology of choice for current coal- and gas fired power plants. Pre-combustion capture based on physical absorption would be the preferred option for coal fired integrated gasification combined cycle (IGCC) plants.
- Reducing CO_2 capture costs through new process designs and the improvement of existing designs is critical for the large-scale deployment of CCS.
- Rapid progress has been made in reducing the energy used in chemical absorption. Further improvements are foreseen. Chemical absorption is likely to remain viable in the future.
- Additional costs of pre-combustion capture for IGCC plants are less than for post-combustion capture, but IGCC generation is more expensive than conventional steam cycle generation. Only five coal fired 250 MW IGCC plants are in operation worldwide.
- Power plant construction costs have significantly increased in the last five years. Capture and storage from coal fired power plants will typically cost USD 50 per tonne CO_2 mitigated, once the technology has matured. Today's costs are about twice as high as this. Total electricity generation costs including CCS are about 75% to 100% higher than for conventional steam cycles without CCS. This may reduce to 30% to 50% in the longer term.
- Biomass generation with CCS would remove CO_2 from the atmosphere. While low-cost niches exist, dedicated biomass plants with CCS will generally result in costs twice the level of coal fired power plants with CCS.
- A number of industrial processes offer interesting opportunities for CCS. However, iron making and cement making processes will need to be redesigned to accommodate CCS, and widespread adoption of CCS in these industries is likely to take decades. There is an urgent need for research, development and demonstration.
- CO_2 capture from natural gas separation, ethanol production and fertiliser production can provide near-term opportunities with lower costs than capture from power plants. Production of hydrogen and other fuel transformation processes offer interesting opportunities for CCS today.

CO_2 Emissions and Capture Opportunities

Stationary CO_2 sources associated with fossil-fuel energy use produce the bulk of the world's CO_2 emissions. Table 3.1 shows the world CO_2 emissions by sector category. Electricity and heat production, industry and transport account for over 80% of total emissions.

Rates of growth vary sector by sector. Emissions from the fuel transformation sector grew fastest between 2000 and 2005 but from a relatively small base. Emissions from electricity and heat production rose by almost 20% over that period and showed the largest growth in absolute terms.

Electricity and heat plants and other fuel transformation activities account for 40% of total global CO_2 emissions. These sectors are prime candidates for CO_2 capture given both the size of the emission sources and the new capacity that will need to be commissioned in coming years to meet increased electricity demand in developing economies.

Table 3.1 Evolution of Global CO_2 Emissions by Sector, 2000-2005

CO_2 emissions by sector	**Emissions** 2000 Gt CO_2	**Emissions** 2005 Gt CO_2	**2000-2005** % Change
Electricity and heat production	8	9.6	19.6
Industry	6.3	6.8	7.1
Transport	5	5.2	3.8
Residential	1.9	2.2	18.2
Fuel transformation	0.7	0.9	43.1
Commercial	0.7	0.9	33.9
Agriculture	0.6	0.7	7.1
Total	**23.2**	**26.3**	**13.4**

Source: IEA, 2007.

Industrial production (including iron and steel, chemicals and petrochemicals, non-metallic minerals, and pulp and papers) accounts for 26% of total global emissions. Like electricity and heat production and fuel transformation, these emissions come predominantly from large stationary sources. This suggests that this sector may also offer significant potential for CCS (IEA, 2007).

The transport sector accounts for 20% of CO_2 emissions, mostly from road vehicles. Capture of CO_2 from non-stationary sources is complex and prohibitively costly. But transport emissions could be reduced, possibly significantly, if electricity or hydrogen for the transport sector was to be generated from renewable sources or from fossil fuels with CO_2 capture and storage.

The residential, service and agriculture sectors account for less than 20% of energy-related CO_2 emissions. Given the dispersed nature of the emissions from fuel combustion in these sectors, as with transport, CCS could only realistically make a contribution to CO_2 reductions if there were to be a switch to electricity or hydrogen as an energy vector.

CO_2 Capture in Electricity and Heat Generation

There are three main technology options for CO_2 capture in the generation of electricity and heat: post-combustion capture through chemical absorption, pre-combustion capture, and oxyfuelling (or denitrogenation) (Figure 3.1).

In the post-combustion process, CO_2 is captured from flue gases that contain 4% to 8% of CO_2 by volume for natural gas-fired power plants, and 12% to 15% by volume for coal-fired power plants. The CO_2 is captured typically through the use of solvents and subsequent solvent regeneration, sometimes in combination with membrane separation. The basic technology (using amine-based solvents) has been used on an industrial scale for decades, but the challenge is to recover the CO_2 with a minimum energy penalty and at an acceptable cost.

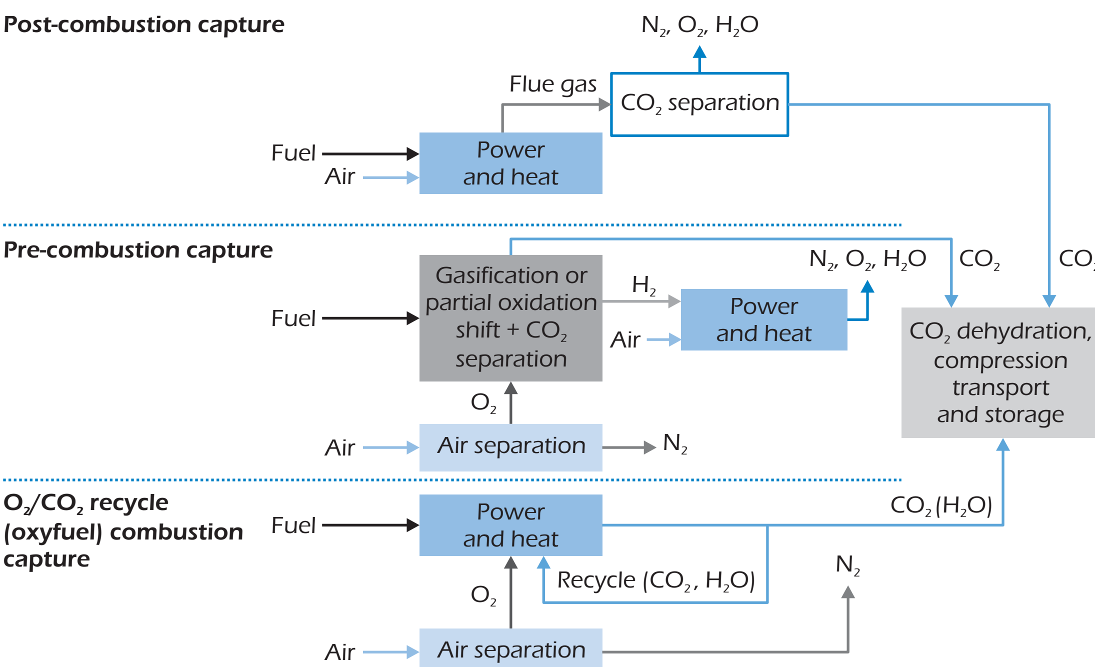
Pre-combustion capture processes can also be used in coal- or natural gas-based plant. The fuel is reacted first with oxygen and/or steam and then further processed in a shift reactor to produce a mixture of hydrogen and CO_2. The CO_2 is captured from a high-pressure gas mixture (up to 70 bars) that contains between 15% and 40% CO_2. The hydrogen is used to generate electricity and heat in a combined-cycle gas turbine.

The oxy-combustion process involves the removal of nitrogen from the air in the oxidant stream using an air separation unit (ASU) or, potentially in the future, membranes. The fossil fuel is then combusted with near-pure oxygen using recycled flue gas to control the combustion temperature.

Figure 3.1 CO_2 Capture Processes

Key point

There are three main processes for CO_2 capture: post-combustion, pre-combustion and oxyfueling.



Source: IPCC, 2005.

Table 3.2 provides an overview of current CO_2 capture options and their potential. The most promising of these are described in more detail in the following sections. In all three main technology options, membranes, chemical and physical absorption, cryogenic separation methods and solid sorbents have a potential role to play. Biotechnology may also play a role on the longer term, provided the biomass production rate can be accelerated. Most attention is for the time being focused on solvents and membrane separation.

Table 3.2 CO_2 Capture Toolbox: Current and Future Technologies

Capture method	Post-combustion decarbonisation CO_2/N_2		Pre-combustion decarbonisation CO_2/H_2		Oxyfuel conversion O_2/N_2	
Principles of separation	**Current**	**Future**	**Current**	**Future**	**Current**	**Future**
Membranes	Polymeric	Ceramic facilitated transport Carbon molecular sieve	Polymeric	Ceramic Palladium Reactors Contactors	Polymeric	Ion-transport facilitated transport
Solvents / Absorption	Chemical solvents	Improved process design Improved solvents Novel contacting equipment	Chemical solvents Physical solvents	Improved process design Improved solvents Novel contacting equipment	NA	Bio-mimetic solvents
Cryogenic	Liquefaction	Hybrid process Anti-sublimation	Liquefaction	Hybrid process	Distillation	Improved distillation
Solid Sorbents	Zeolites Activated carbon	Carbonates Carbon based solvents	Zeolites Activated carbon Alumina	Dolomites Hydrotalcites Zirconates	Zeolites Activated carbon	Carbonates Hydrotalcites Silicates
Biotechnology		Algae production		High pressure		Bio-mimetic

Sources: ZEP, 2006; Feron, 2006.

Post-Combustion Capture

CO_2 is already captured in a wide range of industrial manufacturing processes, refining and gas processing. The same capture technologies can also be applied to power plants. In the 1980s, CO_2 capture from gas-fired boiler flue gases was applied commercially in the United States in order to produce CO_2 for enhanced oil recovery (EOR) projects (Chapel, *et al.,* 1999). These processes were commercially viable at a price between USD 19/t CO_2 and USD 38/t CO_2. But when oil prices collapsed in the 90s, the plants were closed.

Most existing CO_2 capture systems are based on chemical absorption in combination with heat induced CO_2 recovery (using solvents such as MonoEthanolAmine (MEA)). Table 3.3 lists the range of solvents being studied.

Table 3.3 Commercial CO_2 Scrubbing Solvents Used in Industry

	Solvent name	Solvent type	Process conditions
Physical solvents	Rectisol	Methanol	-10/-70°C, >2 MPa
	Purisol	n-2-methyl-2-pyrolidone	-20/+40°C, >2 MPa
	Selexol	Dimethyl ethers of polyethyleneglycol	-40°C, 2-3 MPa
	Fluor solvent	Propylene carbonate	Below ambient temperatures, 3.1-6.9 MPa
Chemical solvents	MEA	2,5n momoethanolamine and inhibitors	40°C, ambient-intermediate pressures
	Amine guard	5n monoethanolamine and inhibitors	40°C, ambient-intermediate pressures
	Econamine	6n diglycolamine	80-120°C, 6.3 MPa
	ADIP	2-4n diisopropanolamine 2n methyldiethanolamine	35-40°C, >0.1 MPa
	MDEA	2n methyldiethanolamine	
	Flexsorb, KS-1, KS-2, KS-3	Hindered amine	
	Benfield and versions	Potassium carbonate and catalysts. Lurgi & Catacarb processes with arsenic trioxide	70-120°C, 2.2-7 MPa
Physical/chemical solvents	Sulfinol-D, Sulfinol-M	Mixture of DIPA or MDEA, water and tertahydrothiopene (DIPAM) or diethylamine	>0.5 MPa
	Amisol	Mixture of methanol and MEA, DEA, diisopropylamine (DIPAM) or diethylamine	5/40°C, >1 MPa

Sources: Gupta and Thambimuthu, 2003; IPCC, 2005.

In chemical absorption strong bonds are created between the solvent and CO_2. The breaking of these bonds requires large amounts of energy. New chemical absorbents such as sterically hindered amines are being examined where the bonding between the solvent and CO_2 is less strong. Steam consumption for the latest chemical absorption systems is on average about 1.5 tonnes of low-pressure steam per tonne of CO_2 recovered (3.2 GJ/t) for a boiler system with 90% recovery, and slightly higher for higher recovery rates (Mimura, *et al.,* 2002). The recovery energy needed declines from 3.4 GJ/t to 2.9 GJ/t as CO_2 concentrations increase from 3% to 14% (the lowest and highest concentrations commonly found in natural gas turbine and coal-fired steam cycles).

Table 3.4 shows past and expected trends in post-combustion capture process performance (Feron, 2006). Between 1995 and 2005, the energy efficiency of the process improved by about one third. Future developments are expected to reduce energy needs by about one third again, from the equivalent of 0.306 kWh/kg CO_2 in 2005 to 0.196 kWh/kg CO_2 in 2015. For a gas fired combined cycle with 60% efficiency, this translates into an efficiency drop of 10 percentage points today, which may be reduced to 7 percentage points by 2015. For coal fired plants the percentage efficiency loss would be much higher, because approximately twice as much CO_2 must be captured per unit of electricity produced.

Table 3.4 Expected Trends of Chemical Absorption Capture Process Performance

Year	1995	2005	2015
Thermal energy	4.2 GJ/t CO_2	3.2 GJ/t CO_2	2.0 GJ/t CO_2
Power equivalent factor used	0.292 kWh/kg CO_2 (0.25)	0.178 kWh/kg CO_2 (0.20)	0.083 kWh/kg CO_2 (0.15)
Power for capture	0.040 kWh/kg CO_2	0.020 kWh/kg CO_2	0.010 kWh/kg CO_2
CO_2 compressor	0.114 kWh/kg CO_2	0.108 kWh/kg CO_2	0.103 kWh/kg CO_2
Total	**0.446 kWh/kg CO_2**	**0.306 kWh/kg CO_2**	**0.196 kWh/kg CO_2**

Note: The Power equivalent factor used refers to the electric efficiency at which the thermal energy needed for capturing CO_2 could be used for power generation. There is considerable debate about these trends in the scientific community, and the trends shown here depend on some step-changes in the technology.

Source: Feron, 2006.

In physical absorption there is a much weaker bonding between the CO_2 and the solvent than in chemical absorption. Bonding takes place at high pressure and the CO_2 is released again when the pressure is reduced. Energy is needed to drive the compressors for gas pressurisation. The amount of energy per tonne of CO_2 captured is inversely proportional to the CO_2 concentration in the gas, *i.e.* twice as much energy is needed if the CO_2 is half as concentrated. Chemical absorption is the preferred method at low CO_2 concentrations (below 15%) because the energy required is not particularly sensitive to low concentrations. Physical absorption is the preferred method at CO_2 concentrations higher than 15%, such as in pre-combustion capture.

New processes for post-combustion capture include (Bailey and Feron, 2005):

- novel solvents that would require lower energy for solvent regeneration (*e.g.* ammonia, promoted aqueous potassium carbonate, ionic acids);
- novel process designs such as split flow systems (IEA GHG, 2004);
- membranes, including polymer gel, ceramic, and membrane contactors (Box 3.1).

Preliminary assessments of amino-acid salts show the potential to reduce capture costs by 50% for pulverised coal (PC) and 40% for natural gas combined-cycle (NGCC) plant (Feron, 2006).

Box 3.1 The Importance of Improved Air Separation Technologies

The efficiency of oxyfueled power plants and their associated CO_2 capture systems depends heavily on the energy required for oxygen production. At present, large-scale oxygen production is based on cryogenic air separation with plants reaching capacities of up to 3 000 t of oxygen per day. Improvements in efficiency have achieved energy reductions to around 0.3 kWh per normal m^3 of low-pressure oxygen (210 kWh/t oxygen or 0.77 GJ/t oxygen). A further reduction to 0.28 kWh per normal m^3 is projected for 2010 (representing a 6.7% energy efficiency improvement).

More complex processes at higher pressures may reduce power consumption further and result in capital cost savings (Castle, 2002). Vacuum pressure swing adsorption is an alternative for medium-size plants producing 250-350 t of oxygen per day. A typical 250 MW IGCC needs 2 000 t of oxygen per day.

Ion transport membrane systems, based on inorganic oxide ceramic materials, could also be used to provide oxygen for IGCCs. What is not clear is whether this technology, which is still under development, will be economical when scaled-up for use in power plants (Smith and Klosek, 2001). If membrane systems do succeed, the energy requirement for air separation may be reduced to 147 kWh/t oxygen (Stein and Foster, 2001). This would represent a 51% energy efficiency improvement compared to the current cryogenic oxygen separation technology.

For an oxygen-blown IGCC, this would imply an electric efficiency improvement of 1 to 2 percentage points. At the same time, the costs of oxygen production are reduced by 35% and the investment costs for IGCC reduced by USD 75/kW. These figures suggest that new air separation systems would enhance the prospects of oxygen based CO_2 capture strategies significantly.

Pre-Combustion Capture

Pre-combustion capture technologies are used commercially in various industrial applications such as the production of hydrogen and ammonia from hydrocarbon feedstocks. If the carbon is removed as CO_2, the resulting hydrogen can be used in a wide range of applications (Figure 3.2).

Where coal is the feedstock, it needs first to be gasified to produce syngas. Both natural gas and syngas must be shift reformed to generate a mixture of hydrogen and CO_2. Then either the CO_2 is removed using physical sorbents or the hydrogen is removed using membranes.

All the components of the process have been tested at pilot plant scale. Critical elements that need further development are the coal gasifiers and, where the hydrogen is used for electricity generation, the hydrogen turbines. Further work is also needed to demonstrate the components in integrated systems (Figure 3.3).

Oxyfueling

The oxyfuel process involves the combustion of hydrocarbons in almost pure oxygen, obtained from an air separation unit (ASU). This results in CO_2 concentrations of 70-85%. Because of different combustion characteristics a different approach to air combustion is required, such as water recycling, or CO_2 recycling.

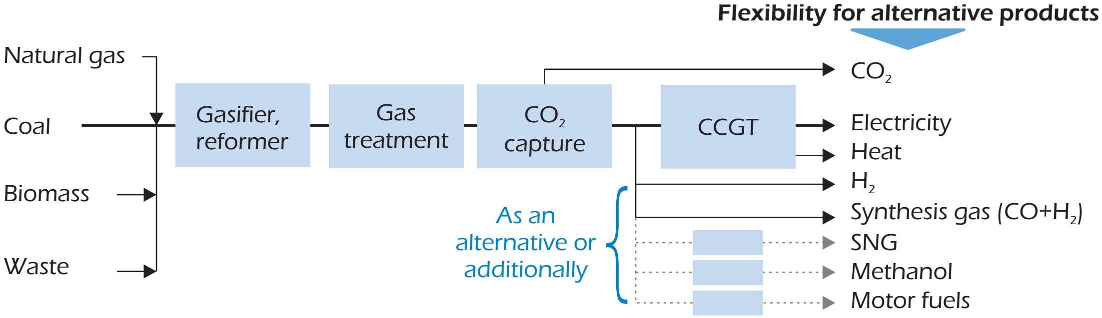
Chemical Looping

This concept can be considered a variant of oxyfueling. In this process, calcium compounds or metal compounds are used to carry oxygen and heat between successive reaction loops. The concept is being examined and developed on a pilot scale in the United States, and shows promise for demonstration by 2020. If successful, it may improve the efficiency of IGCC units by 2% to 3%.

Figure 3.2 Pre-Combustion Capture Options

Key point

Pre-combustion processes can be applied to different feedstocks and different outputs.

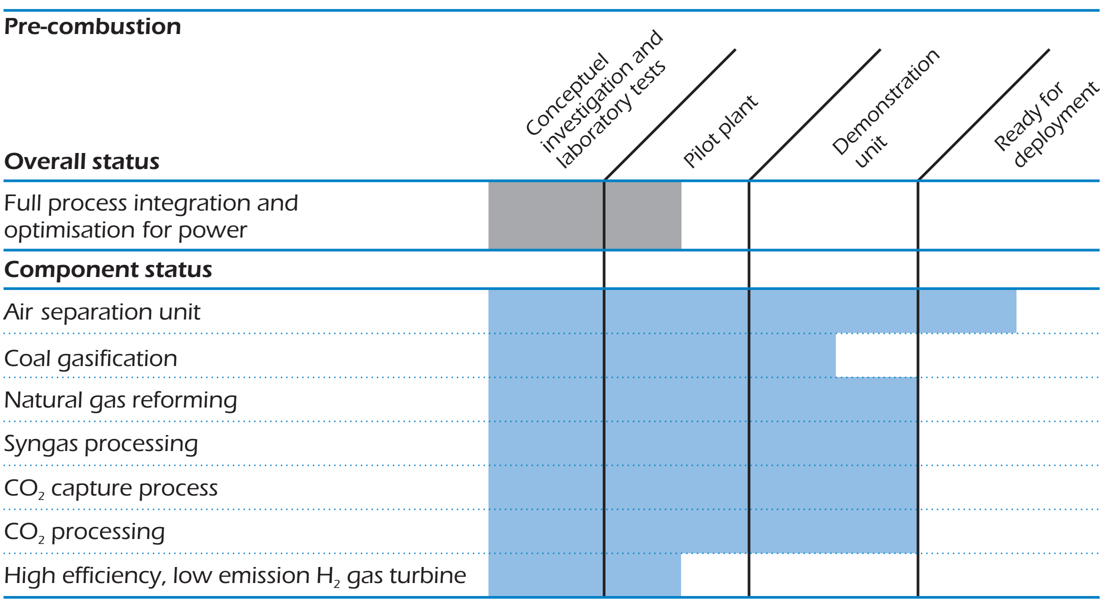


Source: ZEP, 2006.

Figure 3.3 Maturity of Pre-Combustion Technology Components

Key point

High-efficiency and low emission H_2 gas turbines and process integration and optimisation are still at the pilot scale.

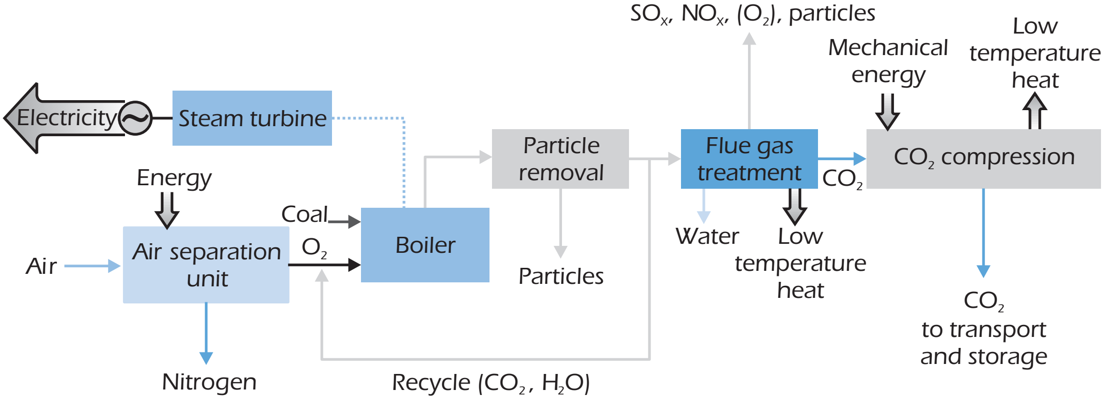


Source: ZEP, 2006.

Figure 3.4 Oxyfueling in Coal-Fired Boilers with O_2/CO_2 Recycle Combustion

Key point

Oxyfueling involves the combustion of hydrocarbons in almost pure oxygen.



Source: Vattenfall.

CO_2 Capture in the Electricity Sector

Coal fired electricity generation accounted for 72% of all CO_2 emissions in the electricity generation sector in 2005. Gas-fired plants accounted for 20% of emissions. The remainder were oil-fired plants. The discussion below focuses on coal- and gas-fuelled plants, being the dominant types.

Emissions from a total of about 1 000 coal-fired power plants globally were 7.9 Gt CO_2 in 2007. This is about 27% of total global CO_2 emissions. The largest plant emitted 41 Mt CO_2 and the 100 largest plants emit on average 21 Mt CO_2 per year (CARMA, 2008).

The world average efficiency of the coal-fired power generation stock is below 35%. The average efficiency of gas fueled plants is similar. These efficiencies are significantly below those of new plants using the latest technologies.

Efficiencies, electricity output and CO_2 emissions of typical recently built coal and gas-fired power plants are summarised in Table 3.5. PC plant and IGCC plant using the Shell gasifier technology have similar net efficiencies (43% to 44% lower heating value (LHV)) and CO_2 emissions (740 kg/MWh to 760 kg/MWh). Natural gas-fired combined cycle plants have a net efficiency close to 55% and 50% lower CO_2 emissions per MWh.

As Table 3.5 shows, coal-fired and gas-fired plants produce very different amounts of CO_2 per unit of electricity generated. For a coal-fuelled plant, emissions are in the range of 743 kg/MWh to 833 kg/MWh. This is more than twice the average emission level of gas fueled plant, at 379 kg/MWh. The flue gases from a gas-fired power plant contain between 3% and 4% of CO_2, and those from a conventional coal-fired power plant contain between 13% and 14% of CO_2.

The higher emission intensity of coal based processes means that the capture cost per tonne of CO_2 is lower than for gas based plant. However, the cost of CCS per unit of electricity generated is similar for coal- and gas based processes because more than twice as much CO_2 must be captured for coal.

Table 3.5 Typical New Built Power Plant Efficiency and CO_2 Emissions

Fuel	Power generation technology	Gross efficiency % LHV	Auxiliary consumption % fuel energy	Net efficiency % LHV	CO_2 emissions kg/MWh
Coal	Pulverised coal	48.2	4.2	44	743
	IGCC (Shell)	50.5	7.4	43.1	43.1
	IGCC (GE)	45.4	7.4	38.0	833
Gas	Gas turbine combined cycle	57.3	1.7	55.6	379

Note: As in most IEA and European statistics, all efficiency values are based on LHV or net calorific value (NCV); in the United States, statistics are generally reported using the higher heating value (HHV) or gross calorific value. The difference between the two values for a fuel is the latent heat of evaporation of the water contained in the combustion products (i.e. the energy needed to transform the water product of the combustion reaction into steam). The differences of about 4% to 5% for bituminous coal and 10% for natural gas correspond to about 2 and 5 percentage points lower efficiency respectively for a bituminous coal- and a gas-fired combined cycle plant when HHV rather than LHV is used (i.e. a coal-fired power plant with an HHV efficiency of 38% would have a LHV efficiency of 40%). The difference between the gross and net efficiencies is the auxiliary consumption (% fuel energy).

Source: Davison, 2007.

In many parts of the world, coal-based power is considerably cheaper than gas-based power, especially where coal is an indigenous fuel and gas is imported. Given the higher share of coal in total emissions, and given the higher emissions per unit of electricity generated in coal-based plants, attention to date has primarily focused on capture and storage for coal-based plants, and less on gas-based plants. In addition, gas-based plants have limited potential for improving efficiency. It is also unlikely that pre-combustion capture systems based on natural gas will show a markedly better performance than post-combustion chemical absorption technologies.

CCS technologies for coal based plants must be considered in combination with appropriate coal conversion technologies. A number of advanced coal power generation technologies are under development with different possibilities for CO_2 capture and storage.

Advanced Coal Technologies

Advanced coal technologies (often confused with clean coal technologies) will play an important role in minimising the environmental impact of future coal use by reducing dust, sulphur oxides (SO_x) and oxides of nitrogen (NO_x) emissions. At the same time, these technologies have the potential to deliver improved thermal efficiency and hence to reduce CO_2 emissions per unit of electricity generated.

Air combustion of pulverised coal in a sub-critical steam cycle has been the mainstay of coal-based electricity generation worldwide for almost a hundred years. The efficiency of the PC units in use today depend on the quality of the coal, ambient conditions and the back-end cooling which is employed. At present, the highest efficiency plant operates in Denmark at over 44% (HHV, net).

This section briefly reviews the current status and current and future performance of these advanced coal technologies, some of which are mature and others of which are still at the stage of R&D or demonstration.

The important coal technologies that are either available or in development include:

- Supercritical (SC) and Ultra-Supercritical (USC) PC Combustion;

- Integrated Gasification Combined Cycle (IGCC);
- Oxyfiring in PC Units.

A number of other designs exist, but seem of lesser importance. These will not be discussed in more detail, but they include:

- Circulating Fluidised Bed Combustion (CFBC);
- Pressurised Fluidised Bed Combustion (PFBC);
- Integrated Gasification-fuel Cell Combined Cycle (IGFC);
- Advanced Pressurised Fluidised Bed Combustion (APFBC).

Supercritical (SC) and Ultra-Supercritical (USC) PC Combustion

The efficiency of a steam cycle is a function of the steam pressure and of the superheat and reheat temperatures. Typical sub-critical steam cycle operating parameters are 163 bar pressure and a temperature of 538°C for both superheat and reheat. Steam cycle operating parameters in supercritical (SC) mode typically are 245 bar pressure and a temperature in excess of 550°C for both superheat and reheat steam. In ultra-supercritical (USC) mode, the temperature is around 600°C or higher at present.

SC conditions have become the norm for new plants in industrialised countries. SC plant as a proportion of total worldwide coal-fired capacity is expected to increase significantly since many SC plants are being built in China and India.

Considerable development efforts are underway in Europe (the AD700 and COMTES700 programmes) and in the United States (the Advanced Boiler Materials programme) to increase both the pressure and the temperature of steam to 375 bar and up to 700°C. If successful, this will raise the efficiency of the new USC units to over 46% (HHV) by 2020. In combination with thermodynamically optimised cycles (such as the so-called Master cycle), the efficiencies for advanced pulverised coal plants could be raised to over 50%, or even to 55% for plants with seawater cooling (Blum, *et al.,* 2007).

Box 3.2 Materials Science Challenges for Clean Coal

Pulverised Coal Combustion

Increasing temperatures to 720°C to 760°C and pressures to 350 to 380 bar will require new materials for coal fired power plant. Higher strength ferritic steels are needed for waterwalls, and higher strength austenitic steels and nickel-based super alloys are needed for the pressure parts that are exposed to the highest steam temperatures. In the steam turbine, the high pressure/intermediate-pressure rotors, rotating blades, bolting, and inner cylinder are exposed to the highest temperatures. These components will probably need to be constructed from super alloys. Further temperature and pressure increases will move beyond the capabilities of iron-based alloys to nickel-based super alloys for most components.

To achieve the required long-term creep strength and fatigue resistance these materials must remain stable at the microstructural level for more than 40 000 hours of operation and at metal temperatures that can be 50°C above the prevailing steam temperature of *some components. The coefficients of thermal expansion must be compatible in components that are joined to other components. In addition, they must be resistant to sulfide and chloride attack on the fire side and to oxidation on the steam side. It will be difficult to find materials that meet all these criteria, so effective coating and/or cladding technologies will also need to be developed.*

Oxyfueling

Oxyfired pulverised coal combustion plants do not yet exist on a commercial scale, although several such new plant constructions have recently been announced in the United States and elsewhere. There is as yet also limited experience of the ways in which oxyfueling retrofits might impact on boiler materials or the operation of plant as a whole.

Research is currently focused on developing ion-transport membranes operating at 800°C to 900°C to produce oxygen from compressed air. Ceramic materials face brittleness, sealing and relatively low permeability barriers. Mixed-matrix membranes, utilising a polymer base coupled with a material that can increase the solubility or diffusivity properties of the composite, such as carbon nanotubes or metal-organic frameworks, are also being investigated. However, so far they do not work well.

The materials challenges in respect of oxyfuel combustion are similar to those of ultra-supercritical combustion, with even higher metal temperatures inside the boiler. The corrosiveness of the fire-side environment will be different in oxyfired systems, and the materials resistance will have to be confirmed or alternative protection strategies developed.

IGCC

Over 1.5 GW of coal-fired IGCC is currently in operation. The materials challenges associated with gasification involve the reliability of the gasifier itself as well as the separation technologies for oxygen production and synthesis gas processing. The most significant materials reliability challenges arise in slagging systems where operating temperatures can range from 1 350°C to 1 600°C and construction materials are exposed to both flowing slag and corrosive gases. Current materials are insufficiently robust to sustain target system on-line availabilities.

There are also issues with the corrosion and wear of feed injector systems and with the excessive wear of components in feedstock preparation. Better equipment is also needed to measure process conditions.

Gas turbines in IGCCs will need greater fuel flexibility and the capability to operate at temperatures in excess of 1 400°C. Moisture in hydrogen rich gases poses special materials challenges.

Within the hot section of the turbines, construction materials will need to be resistant to oxidation, heat corrosion, creep, fatigue, and wear at temperatures in excess of 1 400°C for long periods of operation (30 000 hours is the current target). Current generation nickel- and cobalt-based super alloys cannot withstand sustained metal temperatures greater than *approximately 1 100°C, so that internal cooling as well as thermal-barrier and oxidation-resistant coatings will be needed to meet the required turbine performance. Silicides, nitrides and metal alloys all have the potential to meet the temperature requirements but all face environmental stability challenges.*

Computational methods for modelling complete materials chemistry, microstructure and processing strategies will be critical to accelerating the development of these next-generation materials.

Source: Powell and Morreale, 2008.

Integrated Gasification Combined Cycle (IGCC)

As the name suggests, IGCC combines coal gasification with a combined cycle power plant. In the gasifier, coal is gasified with air or oxygen to produce fuel gas that, after cleaning, is burned in a gas turbine to produce electricity. Exhaust gas from the gas turbine passes through a heat recovery boiler generating steam, which drives a steam turbine to generate extra electricity. The efficiency of an IGCC depends upon several factors including the extent of gasification, the gas turbine inlet temperature, the gasification medium (air or oxygen and/or steam), the mode of feeding (dry or slurry feed) and the amount of electricity generated in the gas turbine proportionate to that produced in the steam turbine.

Gasifiers can be entrained flow gasifiers, fluidised bed-type gasifiers, or fixed bed gasifiers. For electricity generation, entrained-flow gasifiers are most suitable because they operate at temperatures above ash fusion temperatures which allow full gasification of the coal. Fluidised bed-type gasifiers are more suitable for low-rank coals as they operate at lower, below ash fusion, temperatures. Fluid-bed gasifiers are still at the early demonstration phase.

Commercial gasification technologies, from highest to lowest capacity installed, include (MIT, 2007):

- the Lurgi-Sasol dry ash, moving bed, non-slagging gasifier;
- the GE (Texaco) slagging, entrained flow, slurry feed, single stage;
- the Shell slagging, entrained flow, dry feed, single stage; and
- the Conoco-Phillips (Dow Chemical) slagging, entrained flow, slurry feed, two stages.

Only five IGCC plants have been built so far for coal-based electricity generation, amounting to over 1.5 GW capacity in total (about 0.1% of the total coal-fired plant stock in operation). The most efficient plant (Buggenum in the Netherlands) is 42% efficient. All of the plants use entrained-flow gasifiers for complete coal conversion. Plant availability is generally relatively low, but this is expected to improve over time with greater operating experience. Because regular maintenance is required, particularly of the gasifiers, future plants should be equipped with two or three gasifiers so that operation can be maintained during maintenance periods. This of course entails higher capital cost.

Oxyfiring in PC or Circulating Fluid Bed Combustion (CFBC) Units

The increasing efficiency of SC units and the fuel-flexibility of CFBC designs have made the oxyfiring of coal in these units a significant focus for R&D. The use of oxygen instead of air significantly reduces the mass flow rate of flue gas and NOx emissions. To control the temperature, part of the flue gas must be re-circulated. The concentration of CO_2 in the flue gas is around 70-85%. This gas can be compressed and is ready for transport and storage without energy intensive separation. Worldwide R&D is significant; two demonstration plants at 30 MW scale are being built in Australia (Callide A in Queensland) and Germany (Schwarze Pumpe in Spremberg). Other demonstration units are being considered elsewhere. Oxyfiring has in principle good potential for retrofit with PC and CFBC units, as the steam cycle is less affected. However, the impact of higher flame temperatures and different combustion conditions on the boiler life and heat transfer is not yet well understood and needs to be evaluated in more detail.

Retrofitting Existing Power Plants

All the designs that have been discussed so far relate to new build investments. Some studies suggest it might be possible to retrofit existing power plant with CO_2 capture. However, given the efficiency penalty of CO_2 capture, such retrofit makes only sense for existing power plant with high efficiencies. As a rule of thumb, to retrofit plant with less than 40% net electric efficiency (HHV) (*i.e.,* around 90% of the existing worldwide stock) is unlikely to be economic. This implies that only recently built coal fired power plants are suitable for retrofit. CCS may also be part of an extensive repowering effort of old plants, where the efficiency is increased. But retrofitting is likely to be even more expensive than fitting CCS to new built plants.

For gas fired power plants, efficiency needs to be above 55% for retrofitting to be economic. A case study of a new gas-fired power plant at Karstø in Norway has compared two capture systems. The first was an integrated system where steam was extracted from the power plant; the second was a back-end capture system with its own steam supply. The integrated system resulted in an efficiency loss of 11 percentage points (from 58% to 47%). The stand-alone system resulted in an efficiency loss of 14.3 percentage points (from 58% to 43.7%). The impact of this efficiency penalty would depend on local gas prices and CO_2 prices. However, power plant investment costs would be virtually the same at EUR 675 per kW. These figures suggest that retrofitting high efficiency gas-fired power plants is a feasible option if gas prices are sufficiently low (Elvestad, 2003). That now seems unlikely.

Pulverised coal-fired plants could also be retrofitted with CCS, with oxyfueling appearing to offer the best potential (Singh, *et al.,* 2003). Total primary energy use for an ASU, low temperature flash for purifying CO_2 from 95% to 98%, and CO_2 separation and pressurisation to 150 bar would amount to 3.1 GJ natural gas/t CO_2. The electricity used for CO_2 capture (air separation, CO_2 purification and CO_2 pressurisation) would amount to 35% of the electricity produced in a plant without CO_2 capture.

Assuming 40% electric efficiency for the original power plant, 0.72 GJ gas would be needed per GJ of electricity produced, resulting in a reduction of 74% in CO_2 emissions. Capital costs would amount to USD 120/t CO_2 captured (for a 400 MW coal-fired power plant where 2.7 Mt CO_2 per year is captured). Half of the capital costs would be accounted for by the ASU. Assuming an annuity of 15%, CO_2 capture costs would amount to USD 27/t CO_2 captured, or USD 33/t CO_2 avoided.

Lower costs could be achieved for new build oxyfueling plant, for example by designing the process so that the CO_2 recycle flow can be reduced significantly. Better process integration could also reduce electricity losses by 6% (Jordal, *et al.,* 2004).

Box 3.3 Oxy-Fuel Retrofit Projects

Oxy-Fuel: a Potentially Low-Cost Retrofit Option

The oxy-fuel process is a promising enabling technology for CCS from coal-fired power plants. It is especially relevant as it may be used to retrofit existing steam cycle plants. Two projects are in an advanced stage of development in Europe and in Australia.

Vattenfall has announced a retrofit/reconfiguration of the coal plant at the Schwarze Pumpe facility in Germany. The new oxy-fuel burner unit will use residues from lignite briquette production to produce heat which will be integrated into the existing steam system through a set of heat exchangers. The facility will have a 30 MW thermal capacity (i.e. about 10 MW electric capacity). The CO_2 will be captured and stored underground. The facility is scheduled to become operational in 2008.

The Callide A unit in Queensland, proposed by CS Energy, involves the retrofit of an existing PC plant. The project, which is a joint Australian and Japanese venture, has been proposed in the framework of the Australian Low Emission Technology Fund. It will focus on oxyfueling, with a plan to add CO_2 storage at a later stage. The existing plant has 30 MW net electric capacity; the new plant will have 25 MW net electric capacity. The existing boiler can be used. New elements include the ASU, the gas treatment unit, and gas recycling units (including heat exchangers) and the project as a whole is intended to result in the capture of 90% of the CO_2 in the flue gas. The project cost is AUD 115 million (USD 100 million), including investment and operating costs for 5 years. It does not account for the loss of capacity (due to a decline of the net efficiency from 42% to 35% on a LHV basis, including CO_2 pressurisation to 100 bar). The project is scheduled to be operational in 2009, with storage demonstration from 2010 (Spero, 2005).

Tests will be done with various coal types, and various gas qualities. One critical issue to be studied is the control of the off-gas and recycle gas temperatures in order to avoid sulphur condensation which would result in corrosion. Compression of the enriched CO_2 off-gas also needs attention, as the gas contains 11% nitrogen and 0.2% sulphur.

The oxyfueling plant will generate 0.269 t CO_2 per GJ of electricity produced. About 0.70 GJ electricity is needed per tonne of CO_2 captured (including CO_2 pressurisation to 100 bar). Given electricity production cost of USD 0.04/kWh and a 10% discount rate, the cost of this option would amount to USD 17/t CO_2 captured. This excludes transportation and storage, so the total cost would be around USD 25/t CO_2 to USD 30/t CO_2 captured and stored. Given the loss in electric efficiency this would translate into USD 35/t CO_2 to USD 40/t CO_2 mitigated.

Oxyfueling competes with post-combustion capture as a retrofit option. Oxyfueling has an advantage over post-combustion capture in that it would also reduce SO_x and NO_x emissions dramatically. The efficiencies would be similar for both types of designs.

Capture-Ready and Storage-Ready Plants

There is currently a need for significant new electricity production capacity worldwide and many new plants are in development and planning. Coal-fired power plants have a very long lifespan. In the absence of any material incentive to offset the additional costs of fitting CCS to new plant, plants built in the coming years will likely need to be retrofitted with CCS if emissions reduction becomes a priority. This is especially an issue for developing countries that do not yet have well-defined CO_2 reduction targets.

The concept of "capture-ready" (and storage-ready) plant attempts to address the issue of newly built power plants that cannot incorporate CO_2 capture equipment in their initial operation phase due to regulations and/or economics. Such plant can be retrofitted with CO_2 capture once the regulatory/financial drivers are in place. The IEA Greenhouse Gas R&D Programme (IEA GHG) has proposed a definition for capture readiness and its implication on project economics (IEA GHG, 2007). A CO_2 capture-ready power plant:

- Can include CO_2 capture when the necessary regulatory or economic drivers are in place. The aim of building plants that are capture-ready is to reduce the risk of stranded assets and 'carbon lock-in'. Developers of capture-ready plants should take responsibility for ensuring that all known factors in their control that would prevent the installation and operation of CO_2 capture technologies have been identified and eliminated.
- Has analysed options for CO_2 capture retrofit and potential pre-investments.
- Has sufficient space and access for the additional facilities included in its design.
- Has identified routes to a CO_2 storage site, including the geological characterisation of potential sites with their capacity and distance to the emission nodes. If a main CO_2 pipeline exists within the vicinity of the plant, the study should evaluate the possibility of building a pipeline that would connect to the main trunk.
- Has provided sufficient information to the competent authorities involved in permitting power units, so that they can judge whether the developer has met these criteria.

The IEA GHG study also included a cost analysis of investing in capture-ready plants.

For IGCCs, it might be possible to reserve space for future expansion with CO_2 capture equipment. The initial design would accommodate the space for a shift reactor, Selexol units, a larger ASU, expanded coal handling facilities and larger vessels. In addition, CO_2 capture would involve changes in the gas turbine since the gas composition would change. A case study suggests that an initial design that considers later retrofit would reduce subsequent capture investment costs from USD 438/kW to USD 305/kW. However, initial investment costs would be USD 59/kW higher (Rutkowski and Schoff, 2003) reducing the net investment cost by about 17%.

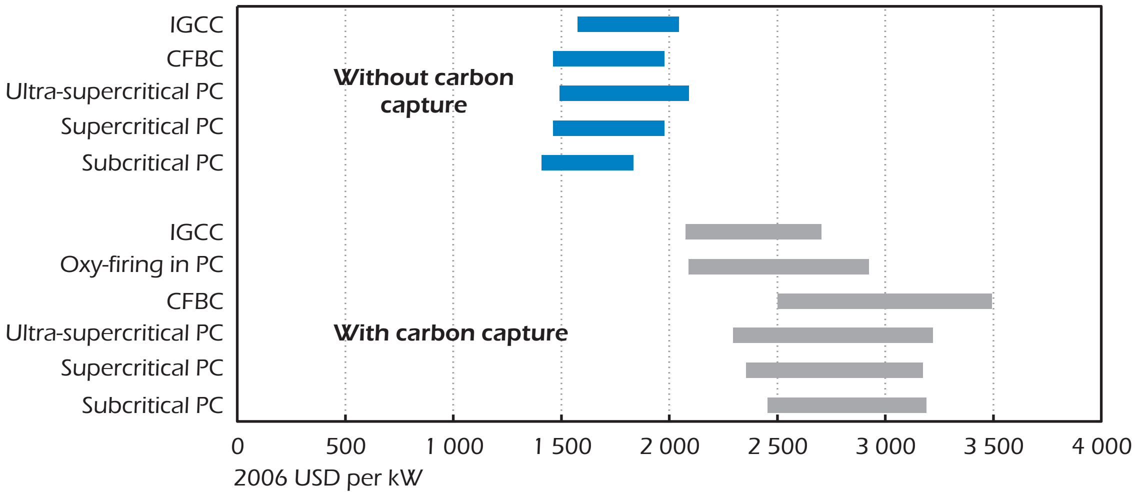
Cost of Power Plants with CO_2 Capture

The cost of capturing CO_2 depends on the type of power plant used, its overall efficiency and the energy requirements of the capture process. CAPEX (and OPEX) for CO_2-capture plants can vary within wide bounds depending on where the boundary is drawn (*e.g.* utility systems, cooling water), whether the development takes place on a brown-field or green-field site, and on the financing parameters. Figure 3.5 shows the investment cost for different types of coal fired power plants with and without CCS. The additional investment cost for capture ranges from USD 600/kW to USD 1 700/kW. The cost increase is 50% to 100% of the plant cost without CO_2 capture.

Figure 3.5: 2010 Coal-Fired Power Plant Investment Costs

Key point

Investment costs forecast involve significant variability.



Source: IEA, 2008.

The costs of capture consist of three main components:

- the loss of electric efficiency, which means more gross power capacity is needed for the same output;
- the cost of additional capture equipment; and
- the cost of additional fuel.

The relative importance of these three components depends on the fuel price and the relevant power plant and capture technologies (Figure 3.6).

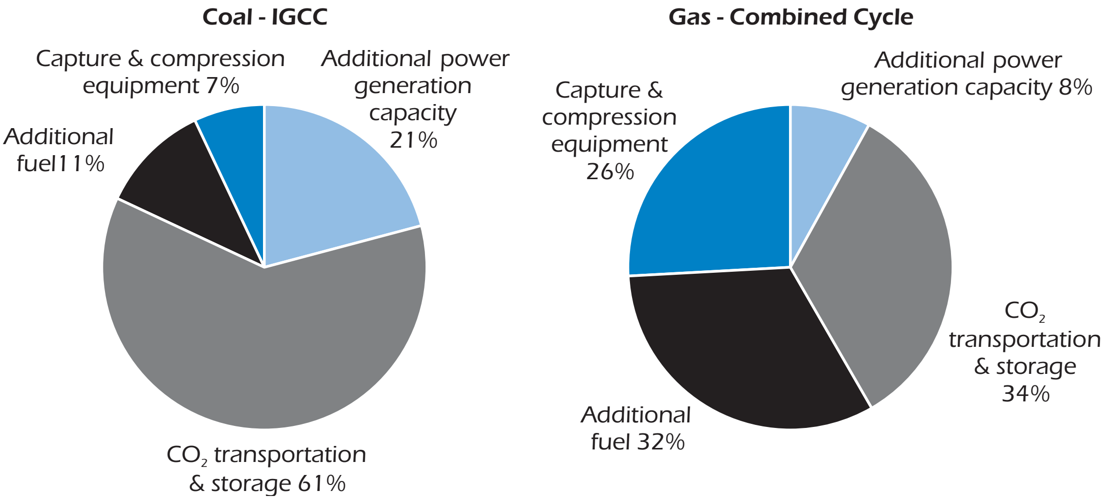
The cost of building a new power plant has more than doubled between 2000 and the first quarter of 2008 according to the most recent IHS/CERA *Power Capital Costs Index* (PCCI) (IHS/CERA, 2008). The majority of this cost increase has occurred since 2005, with the index rising 69% since then (Figure 3.7). These cost increases do not affect all power plant types to the same extent. Capital intensive types of plant such as coal (without or with CCS), nuclear and renewables such as wind are especially affected (IHS/CERA, 2008).

The price of coal fired power plant has increased in cost by 78% since 2000. Strong international demand for boilers, the most expensive component of power plants, has particularly influenced cost increases. But the cost of power houses and steam turbines, the next two important cost components, and pressure pipelines and expansion joints has increased as well. This cost increase is related to bottlenecks in materials processing, component supply and construction capacity. A 1 230 MW coal-fired power plant requires 0.1 M m³ of concrete and over 30 000 tonnes of steel (EPSA, 2008). But these basic materials costs represent less than 2% of the plant construction cost and cost increases in these areas are far less significant than those resulting from engineering and production capacity bottlenecks.

Figure 3.6 Capture Cost Components of Coal and Gas CO_2 Capture

Key point

IGCC and NGCC power plants with CCS have different cost structures.



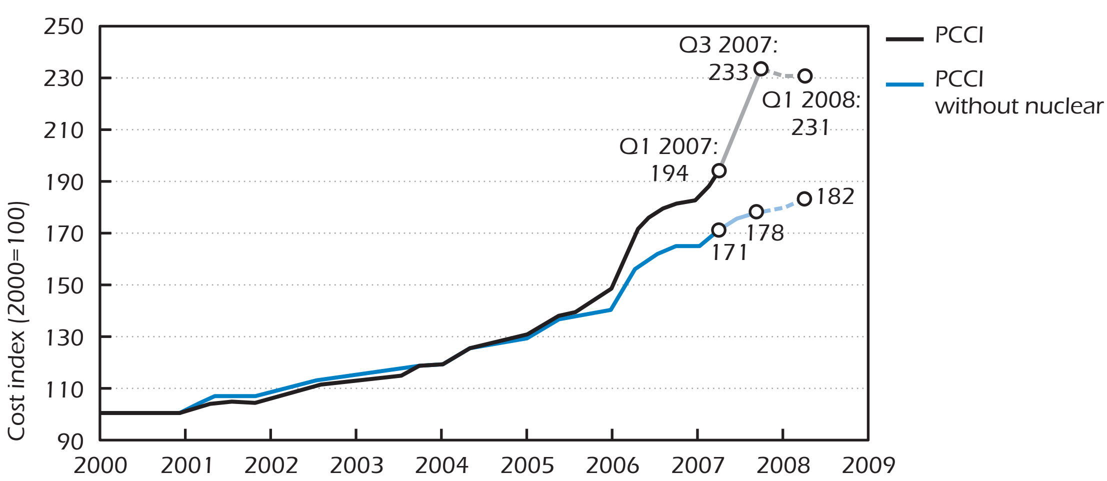
Note: 12% annuity, annual operating and maintenance costs 4% of investment. Coal USD 2/GJ; gas USD 8/GJ.

Source: IEA, 2008.

Figure 3.7 Power Plant Construction Cost Indices

Key point

Investment costs for new plants have increased rapidly in recent years.



Source: IHS/CERA, 2008.

Power plant cost increases have occurred for all plant types, although the cost increase was highest for nuclear and lowest for gas. The fundamentals that have driven costs upward for the past eight years include supply constraints, increasing wages, rising materials costs and stricter environmental regulations (*e.g.* in the case of coal in the United States).

The cost increase has not been the same in all parts of the world. China and India have only seen modest price increases. China's equipment manufacturers are still improving economies of scale and productivity, and moving into other parts of Asia. Other companies are also starting production in emerging economies such as India.

It should be noted that the IHS/CERA index refers to dollar nominated US plants. Because the raw materials are commodities that are bought and sold on a global market, the devaluation of the USD against foreign currencies makes construction even more expensive for US companies or in countries with currencies that are pegged to the dollar.

The important question is which share of this cost increase will be structural. Given that the bulk of the cost increase is related to a very tight market, there is no fundamental reason to assume that prices will remain high. Demand for coal-fired power remains roughly constant in the BLUE Map scenario. Therefore, the market for boilers should ease. Steam turbines are also needed for nuclear plants and gas-fired combined cycles.

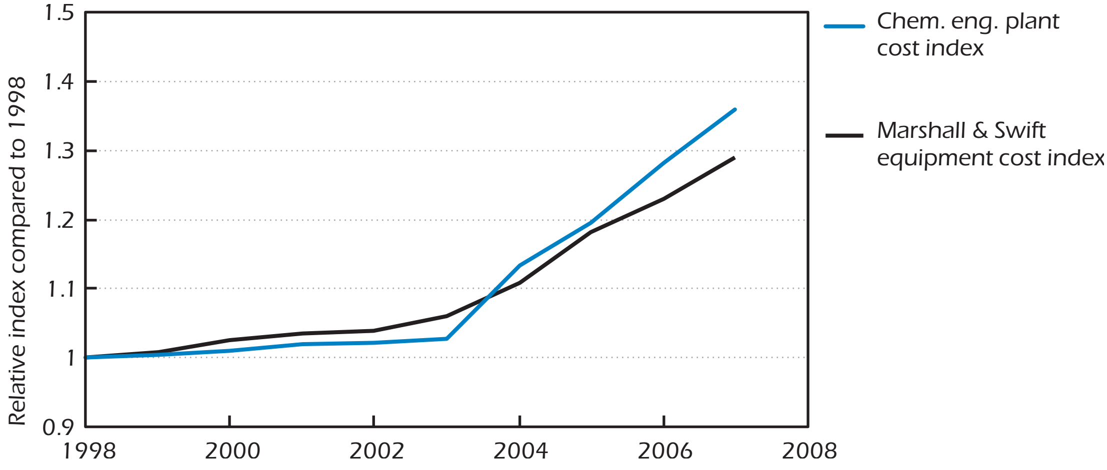
Similar increases have occurred for other types of equipment (Figure 3.8). Higher steel prices and lack of skilled staff are widely quoted as main drivers of price across the energy sector. Higher demand and the increased market power of equipment suppliers also play a role. It is not clear how these costs will develop in the future, but they play an important role not only for the power plant itself but for capture and storage equipment as well. If half of the capture costs are equipment costs, total capture costs will rise by 50% if power plant costs double. The cost of pipelines and injection wells are subject to similar cost increases.

Higher fuel costs also affect capture costs, as additional fuel use is a significant cost component, especially for gas fired plants.

Figure 3.8 Construction Cost Indices

Key point

Compressors, pipelines and drilling equipment costs have increased rapidly in recent years.



Source: Holt, 2007.

Evaluating the Cost of CCS: Different Methods Yield Different Results

Production costs include three components: capital expenditure (CAPEX) (production facility, CO_2 capture, CO_2 compression, infrastructure), operational and maintenance expenditure (OPEX), and fuel costs. The cost of production of an electricity unit is determined as:

*Cost (production) = [(CAPEX * Annuity factor) + OPEX + Fuel Cost] / delivered energy*

CO_2 capture and compression increases energy use, which results in additional emissions that must be taken into account when evaluating the impact and the cost-efficiency of CCS (Freund, 2003). The terms CO_2 capture cost and CO_2 avoidance cost are used for these two different evaluation methods. For power plants, capture cost can be translated into avoidance cost based on the equation:

$$Cost\ (avoided) = Cost\ (captured) \times CE/[eff_{new} / eff_{old} - 1 + CE]$$

Where eff_{new} and eff_{old} are respectively the efficiencies of the power plants with and without CO_2 capture, and CE is the fraction that is captured. For example, if eff_{new} and eff_{old} are respectively 31% and 43% and CE is 0.90, the cost ratio (avoided/captured) is 1.45. The ratio will decrease to 1.20 to 1.25 for more energy efficient emerging CCS technologies.

Expressing CCS costs in terms of the cost/tonne of CO_2 avoided allows those costs to be directly compared with other CO_2 abatement measures in terms of the cost of the environmental effects that have been achieved. For a full economic analysis of technology options, however, it is necessary to compare technologies in terms of their costs per unit of CO_2-free electricity produced. This entails making additional assumptions about, for example, power plant capital costs, discount rates, and plant lifespan.

The relative cost of individual technologies per unit of output (*e.g.* per kWh of CO_2-free electricity produced) may not be the same if comparisons are based on costs per tonne of CO_2 captured or CO_2 avoided. For example, the cost per tonne of CO_2 captured or avoided will be lower for a coal-fired power plant than for a gas-fired power plant, although the electricity supply cost may be lower for the gas-fired power plant with CO_2 capture than for the coal-fired plant with CO_2 capture. All three cost parameters (USD per kWh of CO_2-free electricity, USD per tonne of CO_2 avoided, USD per tonne of CO_2 captured) are used throughout this book.

CCS for a coal-fired power plant will reduce emissions significantly compared to the same power plant without CO_2 capture. However, comparing an identical plant with and without CO_2 capture may not adequately reflect the real emission impact in the case of a new build investment decision. A coal-fired power plant with CCS does not reduce emissions compared to a hydropower or nuclear plant. The choice of a reference process is therefore crucial for estimating CO_2 avoidance costs.

In a marginal costing approach, the reference plant is the plant with the highest supply costs in the base case without CO_2 policies, *i.e.* the plant that determines the product price in an ideal market. The emissions of this plant may be high or low, depending on the energy resource endowment and the economic structure of a region. The CO_2 avoidance cost of the same CCS technology could therefore be completely different for two regions. For many OECD countries, a gas-fired combined cycle power plant would be the marginal producer with which a coal-fired power plant with CO_2 capture should be compared. This reduces the CO_2 benefits by a half or by two-thirds.

Table 3.6 provides an overview of the cost and efficiencies of the main CCS power plant technologies. The costs for CCS have been calculated in comparison to a similar plant without

CCS. The additional costs for CCS are today about USD 0.03/kWh to USD 0.04/kWh for coal fired plants and about USD 0.03/kWh for gas fired plants. These costs are projected to drop by one third, to around USD 0.03/kWh for coal-fired plants and USD 0.02/kWh for gas-fired plants. Costs are higher for smaller scale biomass plants.

Box 3.4 CO_2 Compression Energy Needs

For transport and underground storage, CO_2 needs to be compressed. The pressurisation energy needed depends on the transportation distance and the pressure of the underground reservoir (which depends on its depth). Typically pressurisation needs around 0.22 GJ to 0.5 GJ of electricity per tonne of CO_2, reducing plant efficiency by between 4 and 5 percentage points. Lower efficiency losses are only possible by increasing power plant efficiency considerably above 40%.

The values in Table 3.6 translate into USD 40 to USD 55 per tonne of CO_2 captured for coal-fired plants and USD 50 to USD 90 for gas-fired plants. In terms of cost per tonne of CO_2 avoided, these are around USD 60 to USD 75 in 2010 dropping to USD 50 to USD 65 in 2030 for coal, and USD 60 to USD 110 in 2010 dropping to USD 55 to USD 90 in 2030 for gas-fired plants. Costs for biomass are only slightly higher than for coal.

Table 3.6 Power Plants: Cost with CO_2 Capture

Technology	Start	Investment costs		Efficiency	Eff. loss	Capture rate	Electricity cost	Reference plant
		with capture (USD/kW)	without capture (USD/kW)	LHV (%)	LHV (%)	(%)	(USD/ MWh)	(USD/ MWh)
Coal, steam cycle, CA	2010	2 250-3 200	1 500-2 200	38	9	85	74-83	39
	2030	1 850-2 500	1 300-2 000	44	8	85	59-68	27-29
Coal, steam cycle, oxyfueling	2020	2 500-3 100	1 900-2 400	37	10	90	77-87	41-44
	2030	2 100-2 600	1 500-2 100	44	8	90	60-69	28-31
Coal, IGCC, Selexol	2010	2 300-2 800	1 600-2 300	35	9	85	76-86	40-41
	2030	1 800-2 400	1 300-2 000	48	6	85	58-65	26
Biomass, IGCC	2025	2 600-3 000	1 900-2 400	26	8	85	110-130	64-73
Gas, CC, CA	2010	1 000-1 200	660-750	49	8	85	59-88	33-59
	2030	800-1 000	550-650	56	7	85	49-75	30-53
Gas, CC, oxyfuelling	2020	1 250-1 400	700-850	48	10	95	51-79	30-53

Note: Based on a 12% annuity and annual operating and maintenance cost at 4% of investment cost. CO_2 transportation and storage cost USD 20/t CO_2 in 2010, declining to USD 15/t by 2030 (USD 0.015/kWh to USD 0.02/kWh of coal and USD 0.008/kWh to USD 0.01/kWh of gas). Gas price USD 4/GJ to USD 8/GJ; Coal price USD 1.5/GJ to USD 2.5/GJ.

Source: Remme, 2007.

It should be noted that about half of the cost increase for coal fired plants can be attributed to CO_2 transportation and storage.[4] This cost component will depend on the local circumstances and the scale of the infrastructure. The costs do not take account of any EOR benefits. If CO_2 is used for EOR and two barrels (bbl) of oil is produced per tonne of CO_2 (a conservative estimate), the credit for enhanced oil recovery amounts to USD 100/t CO_2, if the oil is valued at USD 50/bbl.

CO_2 Capture in Industry

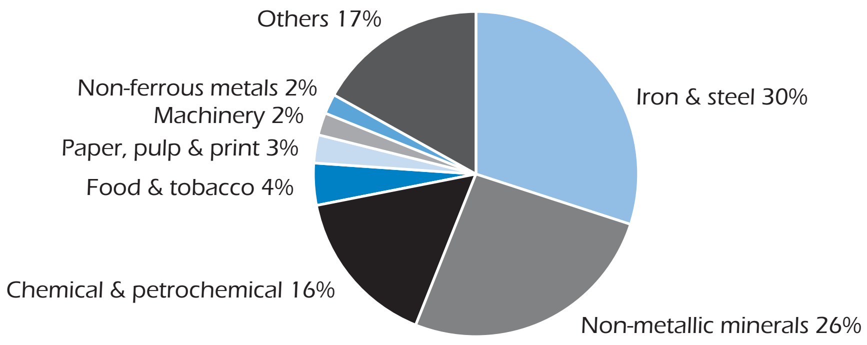
Industry accounted for nearly one-third of the world's primary energy use and approximately 22% of the world's energy and process CO_2 emissions in 2005. Total direct and indirect CO_2 emissions from industry were 9.9 Gt in 2005, equivalent to 37% of total global CO_2 emissions.[5] Direct emissions were 6.7 Gt. Iron and steel, non-metallic minerals (mainly cement production), and chemicals and petrochemicals were responsible for 72% of direct industrial CO_2 emissions (Figure 3.9). These data exclude upstream CO_2 emissions from the production of electricity (which are allocated to the electricity sector in IEA statistics) and downstream emissions from the incineration of synthetic organic products. The G8+5 countries account for 70% of industrial direct CO_2 emissions.

CO_2 can be captured in a number of production processes in the manufacturing industry with lower costs than in the electricity generation sector. However, high concentration industrial sources represent a limited share of the sector's total emissions (3% to 4%, or about 200 Mt CO_2 per year). They include the production of ethylene oxide, ammonia and direct

Figure 3.9 Industrial Direct CO_2 Emissions by Sector, 2005

Key point

Iron and steel, non-metallic minerals, and chemicals and petrochemicals account for 72% of direct industrial CO_2 emissions.



Note: Includes coke ovens, blast furnaces and process CO_2 emissions from cement and steel production. Excludes emissions in power supply; assumes 75% carbon storage for all petrochemical feedstocks.

Source: IEA, 2008.

4. With a 70/30 split of cost between capture and transportation/storage, a 40 % capture and a 100 % storage cost increase lead to a 50 % cost increase from the latter.

5. This includes coke ovens and blast furnaces that are reported as part of the transformation sector in IEA statistics. It also includes CO_2 emissions from electricity generation and process emissions.

reduced iron (DRI). These higher concentration sources would represent good early opportunities for the demonstration of CCS.

Several manufacturing processes such as blast furnaces and cement kilns emit more highly concentrated CO_2 than coal-fired power plants. But single production units tend to be smaller point sources than power plants, which increases the capital cost of CO_2 capture per unit of output. CO_2 capture in these processes would generally require the use of costly and energy-intensive CO_2 chemical absorption or process re-design to increase CO_2 concentrations, such as through pre-combustion CO_2 removal or the use of oxygen in the post-combustion phase.

Iron and Steel

The 2005 production of pig iron and steel was 785 and 1 129 Mt per year respectively (IISI, 2006). Of the 9.9 Gt CO_2 direct and indirect emissions from industry, the iron and steel sector accounted for 27% or 2.6 Gt (equivalent to 10% of worldwide emissions).

There are three approaches to CO_2 capture from blast furnaces:

- oxyfueling to generate a pure CO_2 off-gas;
- using waste heat for chemical absorption; and
- substituting coke and coal with hydrogen or electricity.

None of these approaches will capture all of the CO_2 from steel plants since substantial amounts are emitted from non-core processes, *e.g.* coke ovens, sinter plants, basic oxygen furnaces and rolling mills. However, CO_2 reductions in the core process could amount to 75% of the total emissions. Capturing the remaining non-core CO_2 could only be achieved at a considerably higher, prohibitive, cost.

Blast furnaces emit 1.0 t to 1.5 t of CO_2 per tonne of iron produced. This can be removed by re-designing the blast furnace to use oxygen and removing the CO_2 with physical absorbents. Post-combustion capture using chemical absorbents is not suitable for CO_2 capture in the iron and steel industry as insufficient waste heat is available. Only about half of the necessary heat could be recovered from coke ovens, sinter plants, blast furnace slag, and converter slag and slabs, and separate combined heat and power (CHP) units would be needed to achieve this. Integrated oxyfueling is therefore preferred.

The cost of CCS for blast furnaces is uncertain. Capture costs are estimated at EUR 20/t CO_2 to EUR 25/t CO_2, although changes in furnace productivity can have a significant impact on the process economics (Borlée, 2007).

The potential for CO_2 emission reductions in iron and steel production is large (up to 1.5 Gt per year). A number of initiatives have been taken to reduce emissions: the International Iron and Steel Institute has an initiative (the CO_2 Breakthrough Programme) to reduce, eliminate or capture emissions. R&D programmes have been launched in Europe, North America, Japan, Korea, Australia and Brazil. The European Union (EU)-funded and Arcelor-led Ultra-Low CO_2 Steelmaking (ULCOS) programme, which is part of the EU-Research Fund for Coal and Steel, aims to develop a new blast furnace process which would operate with low CO_2 emissions in part by drastically reducing the consumption of carbon containing input materials. Another component of the project is a large-scale pilot demonstration unit with a new CO_2 reduced iron-making process. The target is a 50% reduction of specific CO_2 emissions compared to a modern blast furnace.

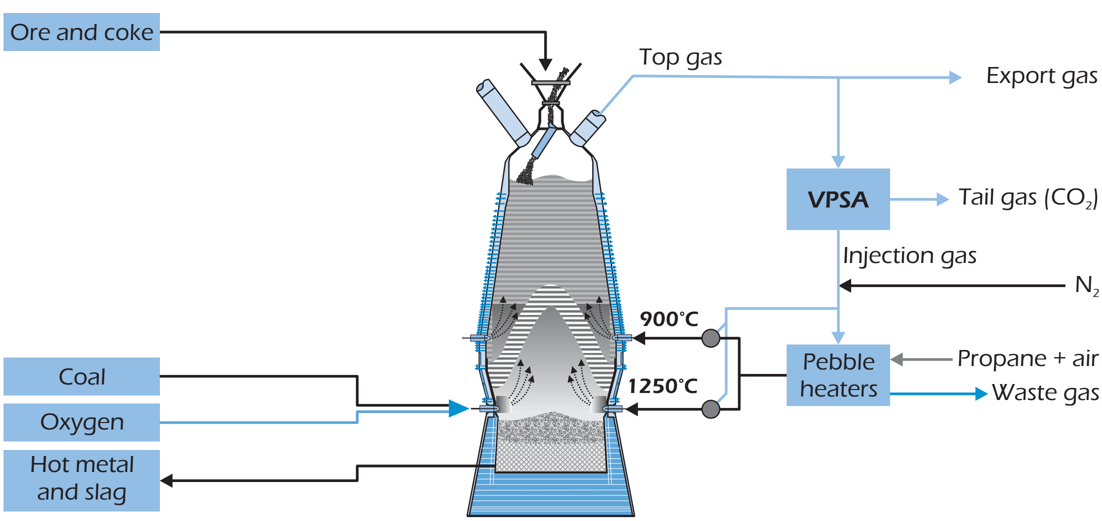
Technologies under evaluation include a new carbon-based smelting reduction process, new types of reactors, the use of biomass, and CO_2 capture.

CCS, used together with oxygen injection, could result in a reduction of 85% to 95% of the CO_2 emissions attributable to the core production processes. The ULCOS project is undertaking new engineering studies of CCS in iron production. The LKAB experimental blast furnace in Sweden started testing various CCS configurations for a small-scale blast furnace in 2007 (with a capacity of only one to two tonnes of iron per hour), with the aim of running a demonstration plant in the period 2015 20. The gas flow through the reactor is one of the things that need to be optimised and issues regarding gas cleaning remain to be solved. CCS using physical absorbents is likely to be more cost-effective than CCS using chemical absorbents. But blast-furnace gas-reforming and chemical absorption using waste heat is being investigated in Japan, Korea and China.

Figure 3.10 Gas Recycled Blast Furnace

Key point

The Top gas recycled blast furnace has a potential to reduce CO_2 emissions by 50% when combined with CCS.



Source: ULCOS/Jitsuhara, 2007.

If blast furnaces were re-designed to use oxygen instead of enriched air and to recycle top gases, their emissions would be sufficiently rich in CO_2 to enable it to be captured with physical absorbents. However, the oxygen-injection blast furnace is not yet proven. Smelt reduction is also an enabling technology for CCS, provided the process uses oxygen. The FINEX technology, developed by Siemens and POSCO, a Korean steelmaking company, is currently being tested in a 1.5 Mt demonstration plant in Korea. Part of the CO_2 is removed from the recirculation gas of this plant and vented because of lack of suitable storage sites. With some process re-design all the CO_2 could be captured, with no efficiency penalty compared to the same plant without CCS. The coal use of such a facility is lower than for existing blast furnaces. Other comparable processes such as HiSmelt are currently being demonstrated and could also be equipped with CCS.

Current expert estimates suggest that CCS for blast furnaces would cost around USD 40/t CO_2 to USD 50/t CO_2 in capture, transport and storage costs, excluding any furnace productivity changes that could have a significant positive or negative impact on the process economics (Borlée, 2007). The marginal investment costs would be higher for retrofits than for new builds.

Gas based direct reduced iron (DRI) production would allow CCS at a relatively low cost, below USD 25/t CO_2. But DRI facilities are concentrated in relatively few countries and are comparatively small scale. As a result, this approach has so far received only limited attention. With the expected rapid growth in DRI production in the Middle East and elsewhere, especially in the BLUE Map scenario, the potential for CO_2 capture could amount to 400 Mt per year by 2050. Overall, CCS in iron and steel production could save around 0.5 Gt CO_2 to 1.5 Gt CO_2 per year by 2050, which is 10% to 15% of total reduction attributable to CCS in the IEA scenarios. However, this will not only depend on technology development, but also on a global level playing field, for example an approach based on sectoral agreements.

Cement Industry

In 2005 around 2.3 Gt of cement was produced worldwide. China accounted for more than 46% of this (USGS, 2006). Cement production accounts for about 22% (1.5 Gt in 2005) of the industry sector's total direct CO_2 emissions. Two thirds of this (0.94 Gt per year in 2005) is generated by the decomposition of limestone into cement clinker and CO_2. The remaining one third is from fuel combustion.

The calcination of limestone in cement kilns results in relatively high concentrations of CO_2 in the off gas (25% to 35%). This CO_2 can be captured in any of three ways:

- back-end chemical absorption;
- oxyfueling; or
- chemical looping using calcium oxide.

The amount of CO_2 that is generated per tonne of cement clinker produced depends on the energy source. In an efficient kiln burning coal, approximately 800 kg of CO_2 is produced per tonne of clinker. About 95% of this CO_2 could be captured through chemical absorption. The process would need some 1.5 GJ/t clinker in the form of heat and around 0.2 GJ electricity per tonne of clinker produced for CO_2 compression. This raises the fuel and electricity needed for clinker production by about 50%.

Using chemical absorption systems, the cost of CCS would be approximately USD 50 to USD 75 per tonne of clinker, or USD 75 to USD 100 per tonne of CO_2 captured. This cost comprises 40% capital cost, 30% cost for the heat, and 30% for transportation and storage. So while the use of CCS in cement kilns is technically feasible, it would raise production costs overall by 40% to 90% (IEA GHG, 2008).

Using oxygen instead of air in cement kilns would result in a pure CO_2 off-gas, although process re-design might be needed to avoid excessive equipment wear. Different process designs using oxyfueling might halve the cost, but these are still at the conceptual stage. More analysis is needed, especially as the overall savings are potentially significant. The main reason for these savings is that the productivity of such kilns would be much higher than for conventional rotary kilns.

Chemical looping is a process where the CO_2 is captured using pure CaO. This generates pure $CaCO_3$, from which the CO_2 can be released through heating. So far a major obstacle is the stability of the $CaO/CaCO_3$ particles, which can only withstand a limited number of cycles. The feasibility of this option remains at this stage speculative.

In summary, the use of CCS in cement kilns is technically feasible but it would raise production costs by 40% to 90% (Table 3.7; IEA GHG, 2008).

Table 3.7 Global Technology Prospects for CO_2 Capture and Storage for Cement Kilns

CCS	2008-2015	2015-2030	2030-2050
Technology stage	R&D	R&D demonstration	Demonstration commercial
Investment costs (USD/t CO_2)	500	250-350	150-200
Emission reduction (%)	95	95	95
CO_2 reduction (Gt CO_2/yr)	0	0-0.25	0.4-1.4

Source: IEA, 2008.

Chemical and Petrochemical Industry

The chemical and petrochemical sectors produced 1 086 Mt CO_2 in 2005, from a total energy use of 34 EJ. The energy use attributable to this sector has increased by 2.2% per year on average since 1970 and now represents 28% of total global industrial energy use (IEA, 2008). Nine processes account for two thirds of this:

- Petrochemicals:
  - steam cracking of naphtha, ethane and other feedstocks to produce ethylene, propylene, butadiene and aromatics;
  - aromatic processes;
  - methanol; and
  - olefins and aromatic processing.
- Inorganic chemicals:
  - chlorine and sodium-hydroxide production;
  - carbon black;
  - soda ash; and
  - industrial gases.
- Fertilisers:
  - ammonia production.

In the petrochemical industry most carbon is stored in the 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 production processes.

The main sources of CO_2 in the petrochemical industry are steam boilers and an increasing number of CHP plants. The technology for CO_2 capture from large-scale CHP plants is similar to that of other power plants. In steam cracking, where high-temperature furnaces are used, 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 obtained from two processes:

- The production of ethylene oxide from ethylene (13% of the 100 Mt per year of ethylene produced). This generates limited amounts of pure CO_2.
- The production of ammonia.

In 2005, 145 Mt of ammonia was produced worldwide. In most ammonia plants, CO_2 is separated from hydrogen at an early stage generally using solvent absorption. The efficiency and CO_2 emission intensity of ammonia plants depends on the plant's age and size. The International Fertiliser Industry Association has conducted a benchmarking study to compare the energy efficiency of ammonia plants built in the last four decades. Emissions varied between 1.5 tonne CO_2 and 3.1 tonne CO_2 per tonne of ammonia produced. A significant share of the separated CO_2 is used to produce urea, a popular type of nitrogen fertiliser: 0.88 tonnes of CO_2 are required to produce one tonne of urea. Given worldwide urea production volumes, about 180 Mt CO_2 would remain to be recovered from ammonia plants. This would enable relatively low-cost CCS as only compression and transportation would be required. The amount of CO_2 available would increase if market demand was to switch from urea to other forms of nitrogen fertiliser. The main reason for the popularity of urea is the ready availability of CO_2 at the fertiliser plant. If there were financial incentives to store the CO_2, producers would switch from urea to other nitrogen fertilisers and more CO_2 could be captured.

Pulp and Paper

The worldwide production of paper and paperboard and chemical wood pulp amounted to 355 Mt and 165 Mt respectively in 2004 (IEA, 2007). The emissions per tonne of paper produced vary widely, depending on the energy source used, ranging from 0.14 tonne CO_2 to 0.7 tonne CO_2 per tonne of product (for Sweden and the United States respectively) with an average value of 0.47 tonne CO_2 per tonne. Scandinavian countries have the highest use of renewables and biomass, hence the lowest emissions, while the United States has the highest use of fossil fuel. The pulp and paper industry generally relies heavily on bio-energy and hydro-power, and therefore has a low emissions intensity and limited CO_2 reduction potential.

In chemical pulp production, only the cellulose and semi-cellulose fraction of the input material is used. In the process, lignin is separated from cellulose and combined with water and other chemicals to create 'black liquor'. This is used as an energy source, using low pressure or high pressure Tomlinson boilers. High pressure designs, which predominate in Japan, have higher electric efficiencies but also higher investment costs.

Black liquor production is projected to grow from 72 Mtoe in 2005 to 79 Mtoe by 2025 (IEA, 2008). Potentially, some 330 Mt of CO_2 could be captured from the black liquor production process.

Hektor and Berntsson (Hektor and Berntsson, 2007a) have analysed the use of chemical absorption technology for black liquor boilers and conclude that capture and storage would be economic at a CO_2 price of USD 30/t CO_2 to USD 50/t CO_2. These costs apply to modern pulp mills that generate sufficient surplus heat for the capture process. The same authors (Hektor and Berntsson, 2007b) conclude that the most economically advantageous approach would be for integrated pulp and paper mills to be powered by NGCC electricity coupled with CCS, allowing biofuels to be used in other applications. This result depends on the CO_2, electricity and oil price assumptions.

Möllerstern (Möllerstern, 2003) and Hektor and Berntsson (Hektor and Berntsson, 2005) have evaluated black liquor boiler designs. Black liquor IGCC technology is similar to coal-fired IGCC technology and can be fitted with CO_2 capture with an electric efficiency penalty of three percentage points (from 28% to 25%) but no change in steam efficiency (44%). Capital costs increase by USD 320/kW electricity with CO_2 capture (Möllerstern, 2004).

For various reasons, this application seems further away from widespread application than CCS in other industry sectors. However, the option warrants further attention and development.

Fossil Fuel Production and Transformation

The extraction of oil, gas and coal produces almost 400 Mt CO_2 a year. The fuel transformation sector is an even larger emissions source. Petroleum refineries and liquefied natural gas (LNG) production together account for 700 Mt CO_2 per year. This is expected to increase significantly in the future. On the fuel supply side, LNG production will increase significantly as larger quantities of natural gas need to be transported over longer distances where pipelines do not constitute a viable alternative.

Currently, emissions from the use of oil products considerably exceed the emissions from oil production and processing. But this may change in the future. Heavier crude oil types that require more upgrading are likely to gain market share as the quality of the remaining oil reserves declines. Synfuel production (*e.g.* through Fischer-Tropsch (FT) synthesis) is considerably more energy-intensive than conventional refining. Synfuels are projected to gain an increasing market share. Synfuels such as hydrogen, methanol, dimethyl ether, and synthetic gasoline and diesel can be produced from natural gas, coal or biomass. CO_2 capture could be applied to these production processes. The use of hydrogen as a transportation fuel would result in the possibility of zero vehicle tailpipe emissions and a significant potential to capture CO_2 from hydrogen production.

Figure 3.11 shows the emissions associated with various oil and gas processes including conventional oil, heavy oil, and Gas-to-Liquids (GTL).

Sour Gas

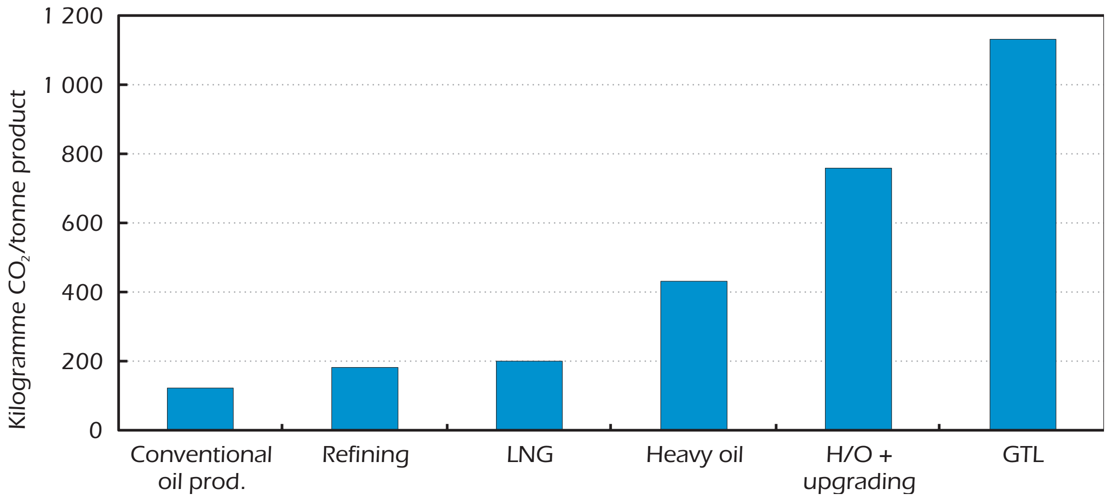
Natural gas in commercial operations includes varying amounts of CO_2 ranging from sweet (CO_2-free) gas in Siberia to high CO_2 content gas (*e.g.* as high as 90% in the Platong and Erawan fields in Thailand, or 72% to 80% in the Carmito Artesa field in Mexico). The Natuna field in the Greater Sarawak Basin (Indonesia) is the largest gas field in south Asia, with an estimated 46 trillion cubic feet of recoverable reserves. But this has a 71% CO_2 content. Worldwide estimates of CO_2 content in commercial fields are 2% by volume (IPCC, 2005) producing a total 100 Mt CO_2 every year.

CO_2-content specifications are about 2% by volume so CO_2 has to be separated where gas supplies have a higher CO_2 content than this. Some of the technologies for CO_2 separation, including chemical and physical solvents and membranes, have been used for decades. For

Figure 3.11 CO_2 Emissions (in kg) per Tonne of Product for Upstream and Downstream Operations

Key point

CO_2 emissions from upstream and downstream vary widely; for transport, a full-cycle analysis should be carried out.



Sources: IEA, 2005a; Klovning, 2007.

relatively low concentrations, gas is most frequently sweetened using alkanoamines (MEA, DEA). For higher CO_2 content gas, membranes are preferred.

Projects involving CO_2 separation from natural gas represent the bulk of the CCS projects today. The costs of compression, transportation and storage are limited where the resulting CO_2 can be re-injected into the gas well. Moreover, gas wells are readily adaptable to the storage of CO_2, so little additional expertise or equipment is required. Ongoing demonstration and commercial activities include the Sleipner and Snohvit fields in Norway, the In Salah project in Algeria, the K12B project in Netherlands, the Gorgon project in Australia, and the Carmito Artesa project in Mexico.

Heavy Oil and Tar Sands

Over time, as traditional sources of oil decline, progressively heavier crude oil is being extracted. Unconventional oil production is also growing. These unconventional crude oil types require special refining operations to adjust the hydrogen to carbon (H/C) ratio. These processes result in higher CO_2 emissions per unit of product than conventional oil.

Unconventional oil production is forecast to increase from 1.6 million bbl per day in 2004 to 9 million bbl per day in 2030. The bulk of the increase will come from Canadian oil sands and from Venezuelan extra-heavy bituminous crude oil (IEA, 2006).

Steam-assisted gravity drainage is a popular technology for adjusting H/C ratios, constituting some 45% of new projects. But it is very energy-intensive. Before the heavy oil can be refined, it needs to be upgraded using hydrogen, commonly produced from natural gas. With oil to steam ratios typically ranging from 0.3 to 0.5, the production of a tonne of heavy oil leads to the emission of 0.25 tonne CO_2 to 0.4 tonne CO_2. Producing lighter crudes requires 6% of the energy content of the hydrocarbon produced; the same ratio would rise to 20% to 25% for heavy oil/tar sands (IEA, 2005). The net effect is the emission of 0.6 tonnes to 0.8 tonnes of CO_2 per tonne of product.

The development of alternative techniques for energy generation and heavy oil recovery is critical. A technology roadmap, published by the Alberta Chamber of Resources in 2004 (ACR, 2004), investigated CO_2 reduction options in the different phases of heavy oil extraction. An average reduction of 25% in CO_2 emissions is achievable. Given its high purity, the CO_2 produced by upgrading plants can be captured at relatively low cost, and can be used for EOR and enhanced coal-bed methane recovery. Alternative production techniques being investigated include the use of solvents such as light hydrocarbons, and microbial techniques, to reduce in-situ the hydrocarbon viscosity.

Refineries

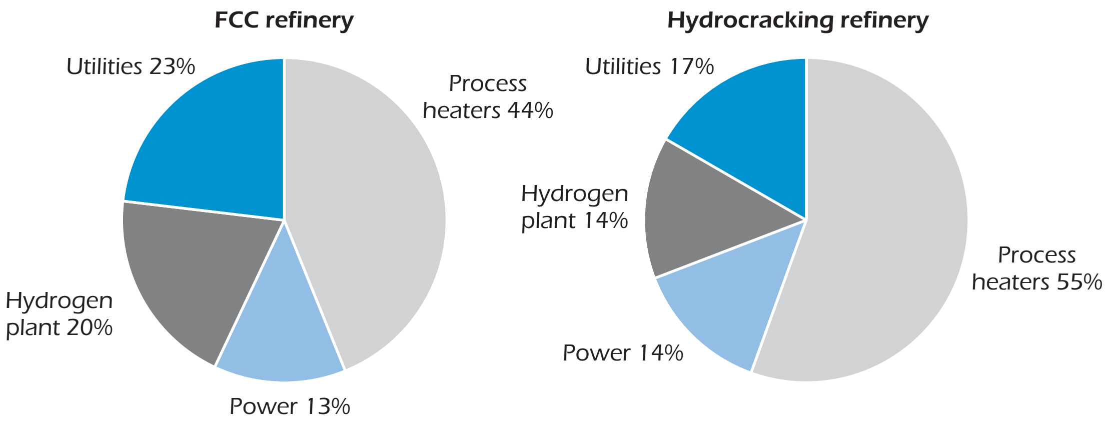
The IEA GHG global CO_2 emissions database (IEA GHG, 2006) lists 638 refineries with emissions larger than 0.1 Mt CO_2 per year, which together produce 801 Mt CO_2. Forty-five refineries have emissions greater than 3 Mt CO_2 per year. The average CO_2 concentration in the gas stream from refineries is 3% to 13%.

Oil refineries convert crude oil into oil products. They do so through a wide range of process operations. The most important are distillation, reforming, hydrogenation and cracking. Distillation processes require low temperature heat, hydrogenation requires hydrogen, and cracking produces significant heat and CO_2 from heavy oil residues. The CO_2 emission sources of two types of refinery are shown in Figure 3.12.

Figure 3.12 CO_2 Emissions from Oil Refining

Key point

Process heaters account for half of the CO_2 emissions from oil refining.



Sources: American Petroleum Institute, 2002; Clarke, 2003.

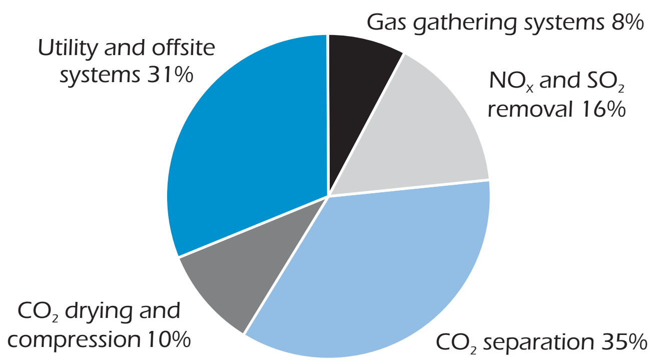
Reformers, fluid catalytic crackers and possibly vacuum distillation units could be equipped with high-temperature CHP units with CO_2 capture. Together, they represent 30% to 40% of the typical refinery's energy consumption. On average, 5% to 10% of the crude throughput of refineries is used for the refining process. Modern refineries that can use heavier crudes and produce more light products, especially gasoline and diesel, produce higher emissions.

Refinery heaters can be equipped with post-combustion CO_2 capture technology. A study for a United Kingdom refinery and petrochemical complex suggests that collecting 2 Mt CO_2 per year would require 10 MW for blowers to push the flue gas through the network and 10 MW for the pressure drop imposed by the packed column absorbers (Simmonds, *et al.,* 2003). This equals 0.32 GJ/t CO_2 captured. Pre-treatment would be needed to reduce NO_x and SO_2 concentrations. The system would need 396 MW natural gas, equivalent to 6.2 GJ of natural gas per tonne of CO_2 captured. This includes the energy needs for the blowers and the steam for the regeneration of the absorbents. This is high relative to the energy needed for CO_2 capture in power plants. There may be room for further improvements in the design. The investment costs would amount to USD 238/t CO_2 with the operational cost largely determined by natural gas costs. A breakdown of the investment costs is shown in Figure 3.13.

Figure 3.13 Investment Cost Structure for a Refinery Complex with CO_2 Capture

Key point

CO_2 separation and compression is responsible for less than half of the capture investment costs for oil refining.



Source: Simmonds, et al.*, 2003.*

The product mix of refineries is changing towards lighter products with a higher H/C ratio, as demand growth is concentrated in transportation markets. Refineries can respond to the hydrogen deficiency by adding hydrogen (a process called hydro-cracking) or by removing carbon (a process called coking). The higher the demand for transportation fuel as a share of total fuel demand, the higher the coking and hydro-cracking capacity (Table 3.8).

Refinery coking capacity is much higher in the United States than in other world regions, while hydro-cracking is concentrated in other OECD member countries and the Middle East. Global hydrogen use for refineries is already substantial, about two EJ in 2000 (0.5% of global primary energy use).

Hydrogen (H_2) Production

Hydrogen (H_2) is a gaseous, clean energy source that could be used in almost any stationary or mobile application. It produces no greenhouse gases other than those which result from its production. As it does not occur in nature in any significant amount it needs to be produced from fossil fuels (natural gas reforming, coal gasification), nuclear and renewable energy (biomass

Table 3.8 Regional Refinery Structure, 2006

	Crude (million bbl per day)	No of refineries	Coking (Index)	Catalytic hydrocracking (Index)	Gasoline and diesel in the efinery product mix (%)	Comment
Africa	3.21	45	1	2	55	
Canada	2.04	19	2	11	72	
Eastern Europe & Former Soviet Union	10.27	91	3	4	51	Heavy crude
Japan	4.68	31	2	4	51	
Korea	2.58	6	1	5	34	
Middle East	7.04	42	1	10	41	Heavy crude
Mexico	1.54	6	3	1	47	Heavy crude
USA	17.27	131	13	9	71	
Western Europe	14.89	102	2	6	63	
Developing countries	21.68	185	4	3	44-55	
World	**85.18**	**658**	**5**	**5**		

Note: Index crude distillation = 100.

Source: Oil & Gas Journal, 2006.

processes, water splitting by high temperature heat, photo-electrolysis, and biological processes), or electricity (water electrolysis). Gasification processes can also be used for hydrogen production from solid fuels (petroleum coke and refinery residues) and heavy oils. If hydrogen is produced from renewable and nuclear energy, or from natural gas and coal with CCS, it is virtually carbon-free. The production of hydrogen from these sources offers the prospect of decarbonising energy use as well as diversifying energy supply.

Current hydrogen production is estimated to be 65 Mt per year, with 48% from natural gas (via steam reforming), 30% from refineries/chemical off-gases, 18% from coal, and the rest from electrolysis (IEA, 2005b). The various uses of hydrogen require quite different purity: for combustion in a gas turbine, purity requirements are very low but for a PEM fuel cell, the purity must be extremely high. Depending upon the use of the hydrogen, various process steps are involved. While most of today's use of hydrogen is in the chemical and refinery industries, future use includes decentralised power generation and space heating, and in transport for fuelling gas turbines, fuel cells and combustion engines. However, only centralised production plant can realistically and economically be equipped with CCS.

Natural gas reforming is a mature technology used in the refinery and chemical industries for large-scale H_2 production. Small scale reformers are at the demonstration stage in H_2 refuelling stations. Three steps are required. First, methane is reformed catalytically at high temperature and pressure to produce a syngas with H_2 and carbon monoxide (CO). This syngas is then combined through a catalytic shift reaction to produce H_2. The H_2 is then purified using adsorption. Production costs are very sensitive to natural gas prices, process design and scale. Reforming options include steam methane reforming (SMR) and partial oxidation. CCS costs are expected to add an extra USD 1/GJ to USD 3/GJ of H_2 to the large-scale cost of USD 6/GJ of H_2.

Coal gasification produces a gas mixture of H_2, CO, CO_2 and methane. CO can then be converted into relatively pure CO_2 (ready for compression, transport and storage) and additional H_2 through a water-gas shift reaction. Large-scale IGCC is considered an attractive option for centralised co-generation of electricity and H_2 with comparably low CCS costs. For a cost of USD 1/GJ to USD 1.5/GJ of coal and USD 35/MWh to USD 40/MWh for electricity, and with 45% electrical efficiency, the cost of H_2 production with CCS is projected to range between USD 7/GJ of H_2 and USD 10/GJ of H_2 (IEA, 2005b). Co-generation would reduce the cost by about 10%.

The EU-funded Hypogen project plans a large-scale test facility for advanced technology evaluation of hydrogen production from fossil fuels, including the treatment of CO_2 and H_2 and the geological storage of CO_2. Alternative fuel options (gas, hard coal, lignite) are being evaluated within the DYNAMIS project.

Another project combining hydrogen and CCS is the planned BP Carson Hydrogen power plant in California which will use petroleum generated as a by-product from refineries and recycled waste power. The hydrogen that is generated will fuel a 500 MW power station, and will have 4 Mt CO_2 captured and used in EOR and storage.

Gasification and Hydrocarbon Synfuel Production

The gasification of carbon-containing feedstocks followed by hydrocarbon synfuel production has received much attention in recent decades given the potential for the production of synthetic transportation fuels to reduce dependency on oil. Coal, natural gas and biomass can be used as feedstocks. A number of synfuels have been proposed: methanol, DiMethyl Ether (DME), naphtha/gasoline and diesel. The energy efficiency of the production processes for these fuels ranges from 40% to 70% (Table 3.9). As a result, they emit large volumes of CO_2. This could be captured and stored.

Fischer-Tropsch (FT) production of synfuels is an established technology. Production of gasoline and diesel from coal was developed in Germany during the Second World War and further developed by Sasol in South Africa during the oil boycott of the 1980s and 1990s. Shell has a plant in Sarawak (Malaysia) that uses similar technology to convert so-called 'stranded' gas

Table 3.9 CO_2 Emissions in Various Refining and Synfuel Production Processes

	Efficiency[6] (%)	CO_2 (kg/GJ product)	CO_2 (Mt/yr/plant)
Syncrude oil/tar sands	74	34	18
Flexicoker	84	24	5.4
FT natural gas	70	7	0.25-0.5
FT coal	40	160	10-15
FT biomass	40	210	0.2
Methanol/DME from coal	65	110	5-10
Methanol/DME from natural gas	70	8	0.25-0.5

FT = Fischer-Tropsch synthesis.

Sources: Steynberg and Nel, 2004; IEA data.

6. Excludes electricity use for pumps etc. With coal, the efficiency to liquid products is 41.1% with the power export amounting to 5% of the coal input.

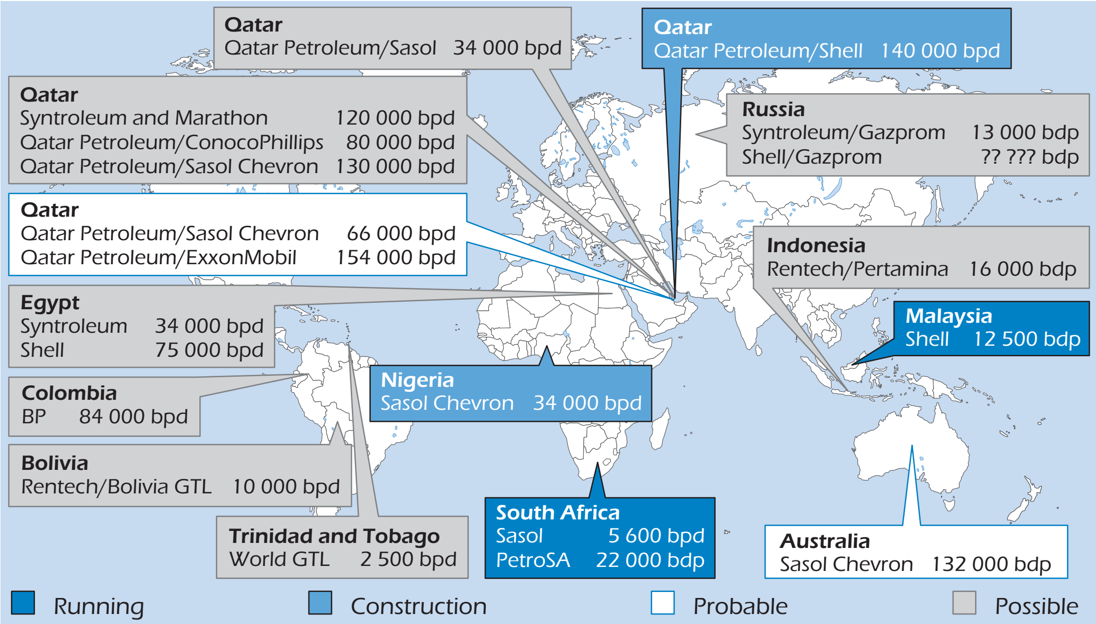
into longer chain hydrocarbons. The technology is based on fuel gasification to a mixture of CO and H_2 followed by catalytic chain building. The product mix consists of condensate and is predominantly a wax that can be cracked to yield diesel and gasoline. The product mix depends on the process condition and catalyst choice (Zhou, *et al.,* 2003).

Gas to liquids (GTL) is currently the most attractive FT option. Plants producing a total of up to one million bbl per day are in operation or expected to come on-stream in the next decade in locations with stranded gas such as Qatar and Nigeria (Heydenrich, 2007) (Figure 3.14). All these plants primarily produce diesel. While economies of scale would tend to decrease costs, recent supply increases have significantly impacted upwardly the cost of projects such as the Qater Petroleum 140 000 bbl per day GTL plant. In the 2006 IEA *World Energy Outlook* Reference Scenario, gas-to-liquids is forecast to increase from 8 billion m3 in 2004 to 29 billion m^3 in 2010 and 199 billion m^3 in 2030 (IEA, 2006).

Figure 3.14 GTL Commercial and Planned Plants

Key point

A number of GTL projects have been announced, but cost escalation is an issue.



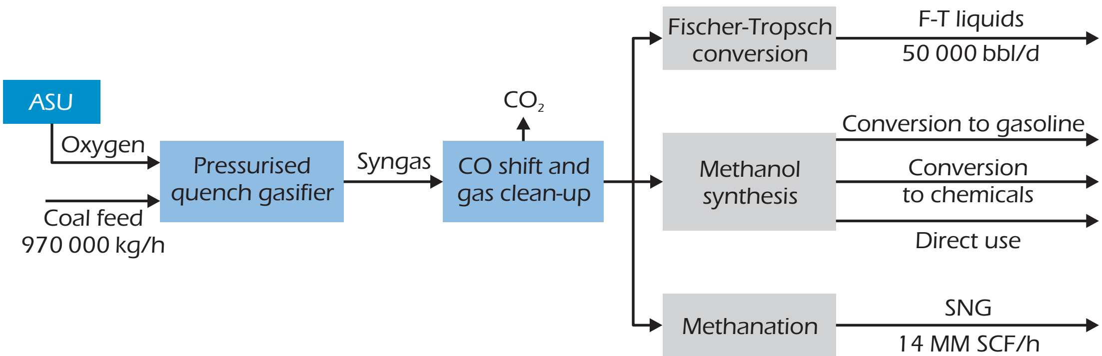
Source: Heydenrich, 2007.

The Coal Utilisation Research Council (2002) has described the production of FT transportation fuels from coal with CO_2 removal. Currently a 40% liquid product yield (in energy terms) can be attained. The common feature of the direct liquefaction processes is the dissolution of a high proportion of the coal in a solvent at high pressure and temperatures followed by catalysed hydro-cracking of the dissolved coal with hydrogen gas (CIAB, 2006). The first direct liquefaction unit is under construction by the Shenhua Group in China. Indirect liquefaction is another route, using coal gasification to produce synthesis gas ($CO + H_2$) and FT synthesis. Several indirect liquefaction projects are being evaluated in China, including a 20 000 bbl per day unit, with the objective to produce one million bbl per day by 2020. The United States has introduced incentives for coal-based transport fuels and, through the Department of Defense, proposes testing the use of coal-based liquids for air transport. Figure 3.15 shows an overview of the coal to liquid fuels, synthetic natural gas and chemicals processes.

Figure 3.15 Coal to Liquid Fuels, Synthetic Natural Gas and Chemicals

Key point

Overview of the coal to liquid fuels, synthetic natural gas and chemicals processes.



Source: MIT, 2007.

The amount of CO_2 available for capture is much higher for coal-based processes than for gas-based ones. The energy requirements for CO_2 capture are proportional to the quantity of CO_2 in the flue gas. At a gas price of USD 0.5/GJ, FT supply costs are USD 25/bbl to USD 30/bbl (Marsh, *et al.*, 2003). The capital cost for a coal-based process is about twice that of a gas-based process. A coal-based plant is also less energy efficient. Production costs starting from coal are twice as high at the same feedstock price. However, the cogeneration of fuels and electricity can reduce these costs (Steynberg and Nel, 2004). Very high oil prices may make coal or gas-based FT transportation fuel production economically viable. The 2008 IEA Clean Coal Centre report on CTL provides an updated analysis of the technology deployment, cost and forecast, and concludes that CTL is likely to remain a niche activity during the period up to 2030 (IEACCC, 2008).

Biomass feedstocks can also be used (Ree, 2000). Investment costs for FT bio-diesel without CO_2 capture are projected to decline from USD 60/GJ in 2000 to USD 36/GJ by 2020. This is twice the investment cost for coal because of the smaller scale of plant. A plant would use 2 GJ of biomass and 0.03 GJ of electricity per GJ of product. At a biomass feedstock price of USD 4/GJ, the transportation fuel production cost in 2020 would be USD 15/GJ. This is about three times the current production cost of gasoline and diesel. CO_2 capture would add 0.05 GJ electricity use per GJ fuel produced (including CO_2 pressurisation). Investment costs would increase by 30% (Marsh, *et al.*, 2003). About 120 kg CO_2 could be captured per GJ fuel produced. The net emission reduction, compared to diesel and gasoline from crude oil, amounts to 264%. The emission reduction in excess of 100% is explained by the sum of the replacement of fossil fuels and storage of CO_2 from the process flue gas. The emission mitigation cost would amount to USD 60/t CO_2 but would depend critically on the biomass feedstock cost.

4. CO_2 TRANSPORT AND STORAGE

KEY FINDINGS

- Transporting CO_2 via pipelines is an established technology, with large volumes handled in the United States. It has an excellent safety track record. The most effective regional infrastructure for CO_2 transportation is a hub-and-spoke system. The cost of pipelines has increased significantly over the last five years, leading to new, higher, estimates for CO_2 transportation costs.
- Sub-surface storage in deep saline formations, depleted oil and gas fields, and use of CO_2 for enhanced fossil-fuel recovery are the only proven storage options. Saline formations with good storage prospectivity are more evenly distributed around the world than oil and gas reservoirs. Ocean storage is presently viewed as unacceptable due to uncertainties related to its environmental impact.
- Methodologies for estimating storage capacity have been adopted by the technical communities. The total worldwide capacity of saline aquifers to store CO_2 is very uncertain. But most estimates suggest that deep saline formations have the capacity to store several hundreds of years of global CO_2 emissions.
- The costs of CO_2 storage have followed the same rising trends as upstream oil and gas production costs over the last decade, increasing by over 100%.
- Criteria for the use of CO_2 for enhanced oil recovery (EOR) have been defined on the basis of past experience. There are significant opportunities for expanding the current range to larger oilfield reservoirs. CO_2-EOR could provide the basis for early CO_2 infrastructure development. The window for the cost-effective application of such technologies towards the end of the production of oil from individual fields is however small. CO_2-EOR may provide early cost-effective opportunities for CCS, but it is not a necessary prerequisite for the development of other CO_2 capture technologies.
- The use of CO_2 for enhanced gas and enhanced coalbed methane recovery requires field-scale evaluation.

CO_2 Transportation

CO_2 Transportation Options

CO_2 can be transported as a gas in pipelines and ships and as a liquid in pipelines, ships and road tankers. Transporting CO_2 as a solid is not currently cost-effective or feasible from an energy usage standpoint. Pipelines are a cost effective mode of transport for large quantities of CO_2. Economies of scale make it economic to transport 1-5 Mt per year over 100-500 km or 5-20 Mt per year over 500-2 000 km.

Pipeline Transportation

Shipping supercritical CO_2 in pipelines is an established technology for small quantities up to a few Mt per year (IPCC, 2005). Globally, approximately 5 600 km of long-distance CO_2 pipelines with diameters ranging up to 0.762 metres (30 inches) currently handle over 50 Mt per year (Gale, 2002).

CO_2 pipelines are similar to natural gas pipelines. The CO_2 is dehydrated to reduce the likelihood of corrosion. Pipelines are made of steel, which is not corroded by dry CO_2. A corrosion resistant alloy is used for short sections of pipeline before dehydration stations (IPCC, 2005). The oldest CO_2 pipeline is the 1972 Canyon Reef pipeline, which carries 5 Mt CO_2 a year from gas processing plants. The largest in the United States is the Cortez pipeline. With its recent expansion to include more than a dozen new CO_2 wells, 17 km of additional pipeline and additional compression and pumping capacity, Cortez has a capacity of over 30 Mt per year of CO_2 over 800 km.

The risks associated with CO_2 pipelines have been extensively documented (IPCC, 2005). CO_2 presents no explosive or fire-related risks but gaseous CO_2 is denser than air and can accumulate in low-lying areas where, at high concentrations, it can create a health risk or be fatal. The presence of impurities such as hydrogen sulphide (H_2S) or sulphur dioxide (SO_2) can increase the risks associated with potential pipeline leakage from damage, corrosion, or the failure of valves or welds. External monitoring for leaks and visual inspections, including through the use of internal inspection devices (known as 'pigs') or distributed fibre optic sensors, can mitigate corrosion-related risks. The safety record of CO_2 pipelines up to 2006 shows a lower rate of leakage per kilometre of pipeline than gas pipelines, and no recorded injuries.

The legal and regulatory classification of CO_2 by different authorities determines the regulatory regime that applies to CO_2 pipelines (see Chapter 5 for additional information). CO_2 pipelines are not designated in the same way as natural gas and oil pipelines in most legal codes and are therefore not regulated like other large-scale pipeline systems. In the United States, Department of Transportation (DOT) regulations list CO_2 as a Class 2.2 hazardous material (non-flammable). Its designation as a commodity or as a pollutant will determine whether its transportation and the siting of pipelines fall under the authority of the US Surface Transportation Board or of the Federal Energy Regulatory Commission (FERC), which regulates natural gas and oil pipelines that are deemed common carriers.

The development of sufficient pipeline infrastructure is critical for the long-term success of CCS. The existing US network was developed largely under a favourable tax regime that included accelerated depreciation. Although current federal tax law provides no special or targeted tax benefits to CO_2 pipelines, investments in CO_2 pipelines do benefit from tax provisions targeted on EOR and from accelerated depreciation rules that generally apply to any capital investment, including petroleum and non-CO_2 natural gas pipelines. Some US States such as Kansas and Montana, for example, have enacted legislation that offers CCS tax credits.

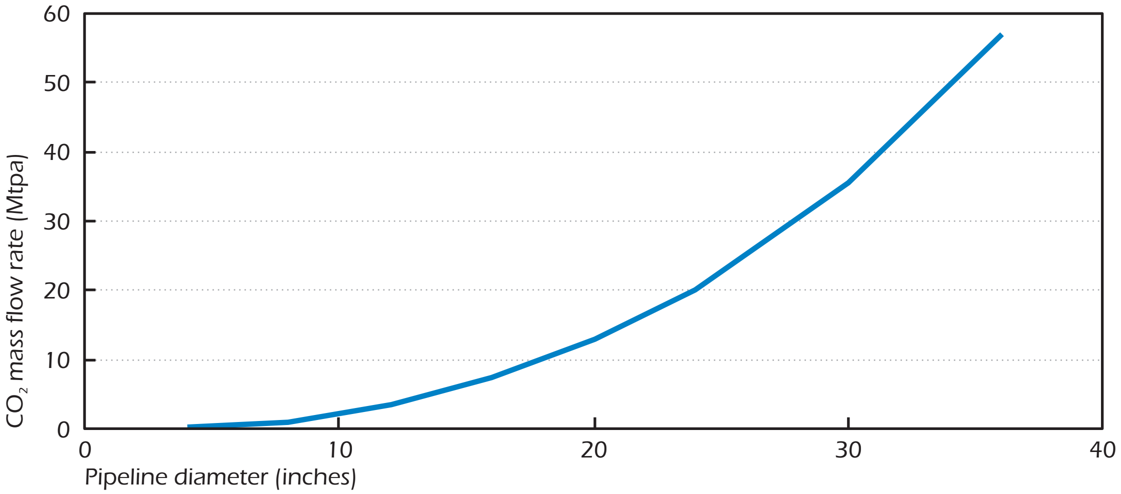
Figure 4.1 shows the relationship between pipeline diameter and the maximum flow rate of CO_2. A 0.61 metre (24 inch) line can transport up to 20 Mt CO_2 per year and a 0.91 metre (36 inch) pipe can carry more than 50 Mt CO_2 per year. The IEA *Energy Technology Perspectives 2008* (IEA, 2008) ACT Map scenario projects that 500 Mt CO_2 per year will be captured and stored in the United States in 2030 and that in 2050 this will exceed 1.5 Gt CO_2 per year, or more than 10 and 40 times respectively the existing levels. Since CO_2 is transported in a supercritical state (ten times denser than methane), and since the assumed average distance between booster stations would be 200 km (compared to between 120 km and 160 km for natural gas), transporting

CO_2 will require less energy than transporting natural gas over the same distance. Even so, the magnitude of the investment needed is significant: by 2050, the CO_2 network in the United States would need to transport a mass equivalent to three times the total amount of gas transported in natural gas pipelines. The structure of the pipeline network (dedicated source to sink lines or hub-and-spoke with a number of feeder and smaller-capacity branches combined with larger trunk lines) needs to be assessed relative to the capacity of storage sites and their proximity to populated areas. Simulations of potential European CO_2 networks indicate that, depending on the configuration of the network, between 30 000 km and 150 000 km of pipelines will be needed in Europe alone (IEA GHG, 2005a).

Figure 4.1 Pipeline Diameter Relative to Flow Capacity

Key point

The most appropriate pipeline diameter for CO_2 transport depends on the volume transported and operating conditions.



Note: Such curves depend on the input-output pressure, here 80-120 bars. In offshore conditions, pressures may be higher.

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

Cost of CO_2 Pipeline Transportation

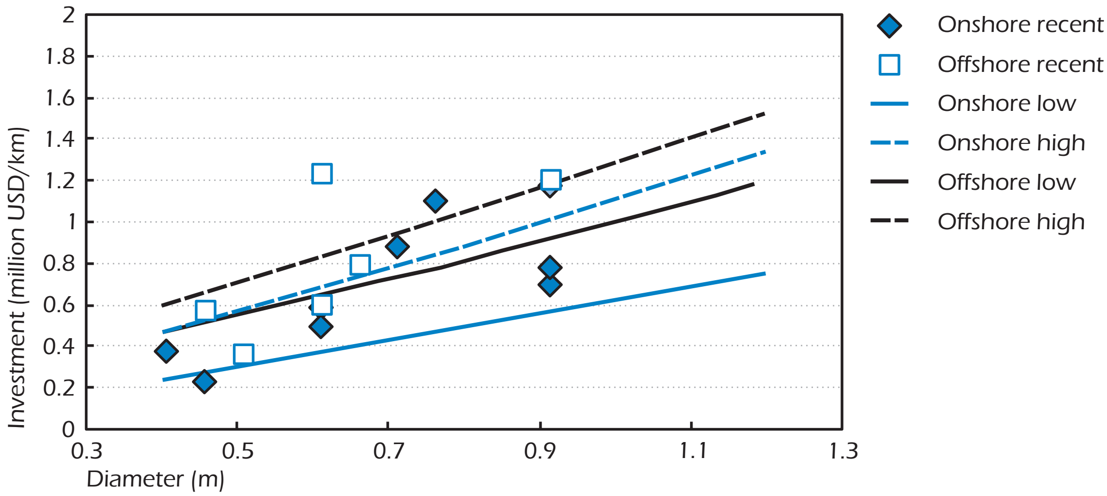
The cost per kilometre of pipeline transport depends on a number of factors such as location (*e.g.* onshore or offshore), terrain, size and composition of the pipeline, operating pressure, booster stations, rights of way and labour costs. Cost multipliers between a flat unpopulated area and a populated area can be as high as 15. Several cost curves have been developed, including the IEA GHG 2002 model for pipeline transportation and two IEA GHG reports on building cost curves for Europe and North America (IEA GHG, 2005a; IEA GHG 2005b). Cost estimates are generally based on the costs of natural gas pipelines, which are similar in design and operation.

The 2005 IPCC *Special Report on CCS* provides a comparison between several relevant studies (IPCC, 2005). Recently, however, the price of large-diameter steel pipe has been increasing far faster than inflation because of sharp increases in worldwide demand. A 2008 *Congressional Research Service* Report shows that US prices for double-submerged arc-welded pipes with a diameter larger than 0.61 metre (24 inches) had doubled, rising from USD 600/t CO_2 in 2003 to USD 1 200/t CO_2 in 2006 (Parfomak, 2008). As the relative contribution of the costs of materials to the overall project costs increases as the diameter of the pipeline increases, the costs in the earlier studies need to be adjusted, especially for pipe diameters larger than 0.61 metres (24 inches). Figure 4.2 graphs the curves showing the upper and lower limits for onshore and offshore pipelines (low and high ranges) from the IPCC report (IPCC, 2005b) and a worldwide compilation of recent project costs based on the *Oil and Gas Journal* (OGJ, 2007). Several data points for recent onshore costs now lie outside the two higher boundaries, largely because of steel costs but also because of higher labour costs in the oil and gas sector. An updated engineering-economic model for CO_2 pipeline transport estimates that for a 100-km onshore US pipeline handling 5 Million tonnes of CO_2 (*e.g.* from a 800 MW coal-fired power station), the cost is about USD 1.16/t CO_2 (Mc Coy and Rubin, 2008).

Figure 4.2 Estimated Costs for Recent Gas Pipelines, 2005-2007

Key point

Cost of gas pipelines has increased significantly due to the cost of materials.



Sources: IPCC, 2005; OGJ, 2007.

The cost of transporting CO_2 per unit of weight is much lower than for natural gas or hydrogen because it is transmitted in a liquid or supercritical state with a density 10 to 100 times higher than that of natural gas. Several technical and financial parameters determine the estimated costs per tonne of transported CO_2, which vary from USD 2/t CO_2 to USD 6/t CO_2 for 2 Mt transported over 100 km per year, and from USD 1/t CO_2 to USD 3/t CO_2 for 10 Mt transported per year over the same distance.

CO_2 Transportation by Ship

The intrinsic pressure, volume and temperature (PVT) properties of CO_2 allow it to be transported either in semi-refrigerated tanks (at approximately -50°C and 7 bars) or in compressed natural gas (CNG) carriers. Current engineering is focusing on ship carriers with a capacity of 10 kt to 50 kt. Transporting CO_2 by ship offers flexibility, as it allows the collection and combination of product from several small-to-medium size sources and a reduction in infrastructure capital costs.

It can also adapt to storage requirements in terms of time and volumes. For example, delivery can change when an oilfield approaches the end of its productive life after CO_2-EOR. The cost of ship transport, including intermediate storage facilities and harbour fees, varies from USD 15 for 1 000 km to USD 30 per tonne of CO_2 for 5 000 km (IEA GHG, 2004).

CO_2 Geological Storage

Geological Storage Mechanisms and Capacity Estimates

The IPCC report (IPCC, 2005) describes three main mechanisms for CO_2 storage:

- Physical trapping by immobilising CO_2 in a gaseous or supercritical phase in geological formations. This can take two main forms: static trapping in structural traps and residual-gas trapping in a porous structure.
- Chemical trapping in formation fluids (water/hydrocarbon) either by dissolution or by ionic trapping. Once dissolved, the CO_2 can react chemically with minerals in the formation (mineral trapping) or adsorb on the mineral surface (adsorption trapping).
- Hydrodynamic trapping through the upward migration of CO_2 at extremely low velocities leading to its trapping in intermediate layers. Migration to the surface would take millions of years. Large quantities of CO_2 could be stored using this mechanism.

Figure 4.3 shows the relative security timeframes of the different trapping mechanisms. The injection period, during which physical trapping is the main mechanism, takes a few decades. The CO_2 storage period is expected to last for hundreds or thousands of years with no major leakage in that timespan (van der Meer, 1996).

Worldwide storage capacity has been estimated using a number of different approaches. The Carbon Sequestration Leadership Forum (CSLF) recognised the need for a consistent methodology and in 2005 its technical group created a taskforce to review and develop standard methodologies for storage capacity estimation. Phase I of the taskforce report, completed in 2005, documented the issues. In 2007, phase II provided a methodology for estimating deep geological storage capacity. Similar to the classifications used for oil and gas reserves, the methodology defines discovered and undiscovered resources and reserves (CSLF, 2007).

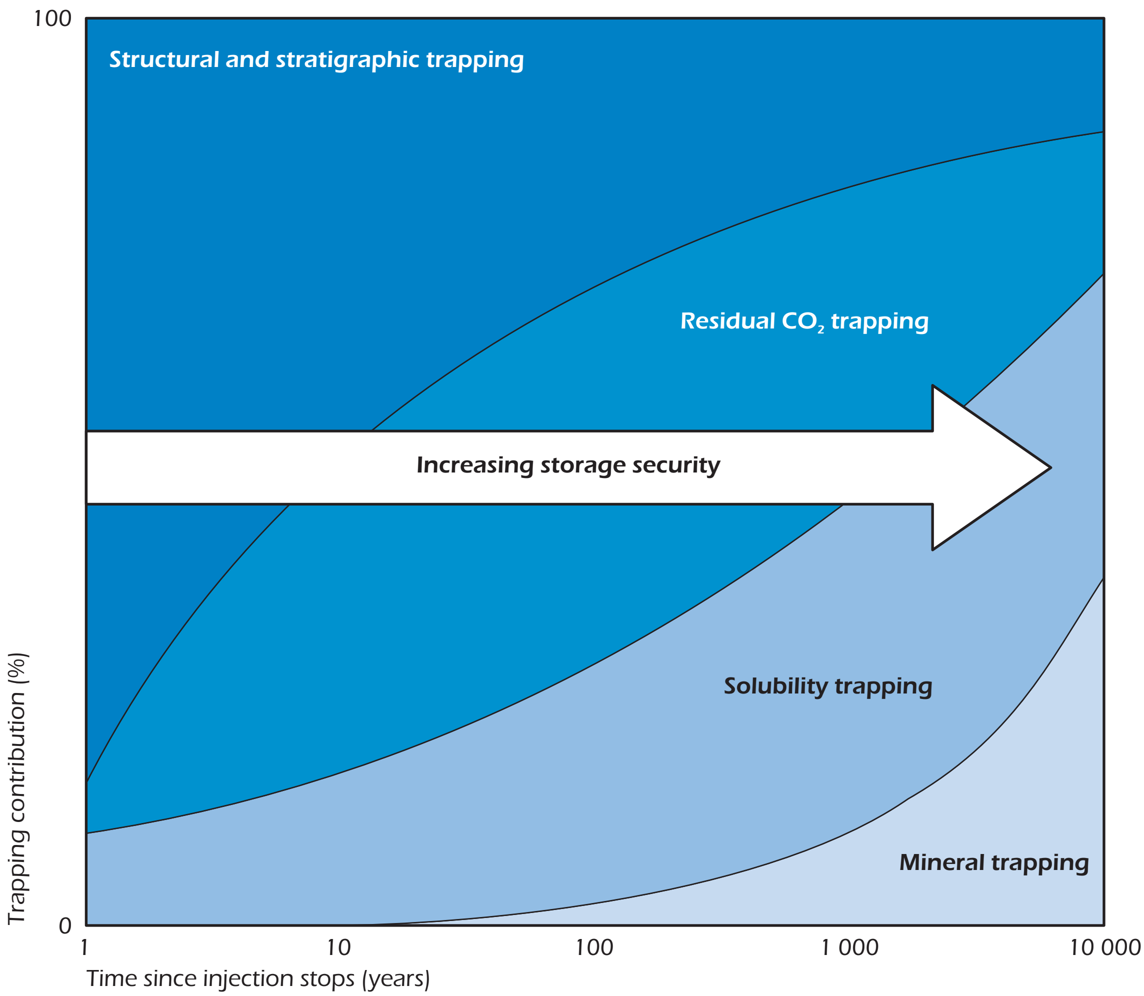
In the report, a techno-economic resource pyramid (Figure 4.4) shows (left) the growing certainty of storage potential (from theoretical to effective to practical and then matched capacity) and (right) the rising cost of storage. The taskforce also defined the assessment scale and the resolution, from countrywide to basin and local/site assessment, with a focus on developing consistent methods at the basin and regional scales. Site-specific estimates require much more detailed simulation. An important factor in the basin assessment concerns the use of reduction coefficients, which relate the practical storage capacity to the theoretical capacity. Different projects on basin capacity estimates have used different reduction factors. As a result, estimates need to be reviewed and consolidated on a consistent basis.

Figure 4.5 illustrates the variability of the storage capacity estimates of different studies, which vary by up to two orders of magnitude in some cases.

Figure 4.3 CO_2 Trapping Mechanisms and Timeframes

Key point

Different elements of the CO_2 storage process happen over different time scales.

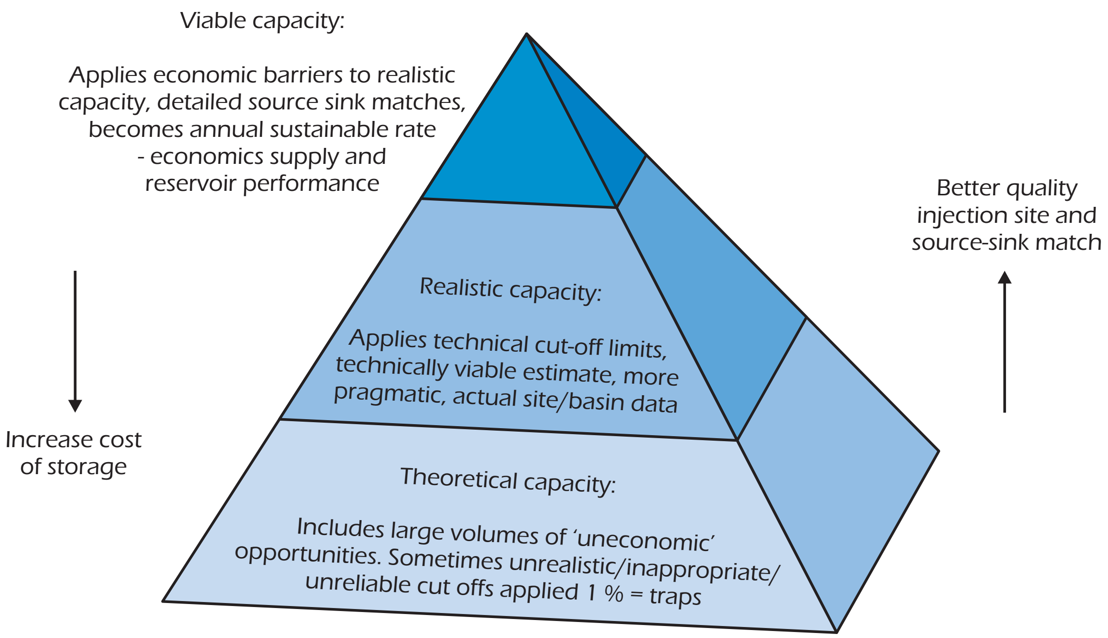


Source: IPCC, 2005.

Figure 4.4 Techno-Economic Resource Pyramid for CO_2 Storage

Key point

The resource pyramid illustrates the relationship between cost of storage and available capacity.

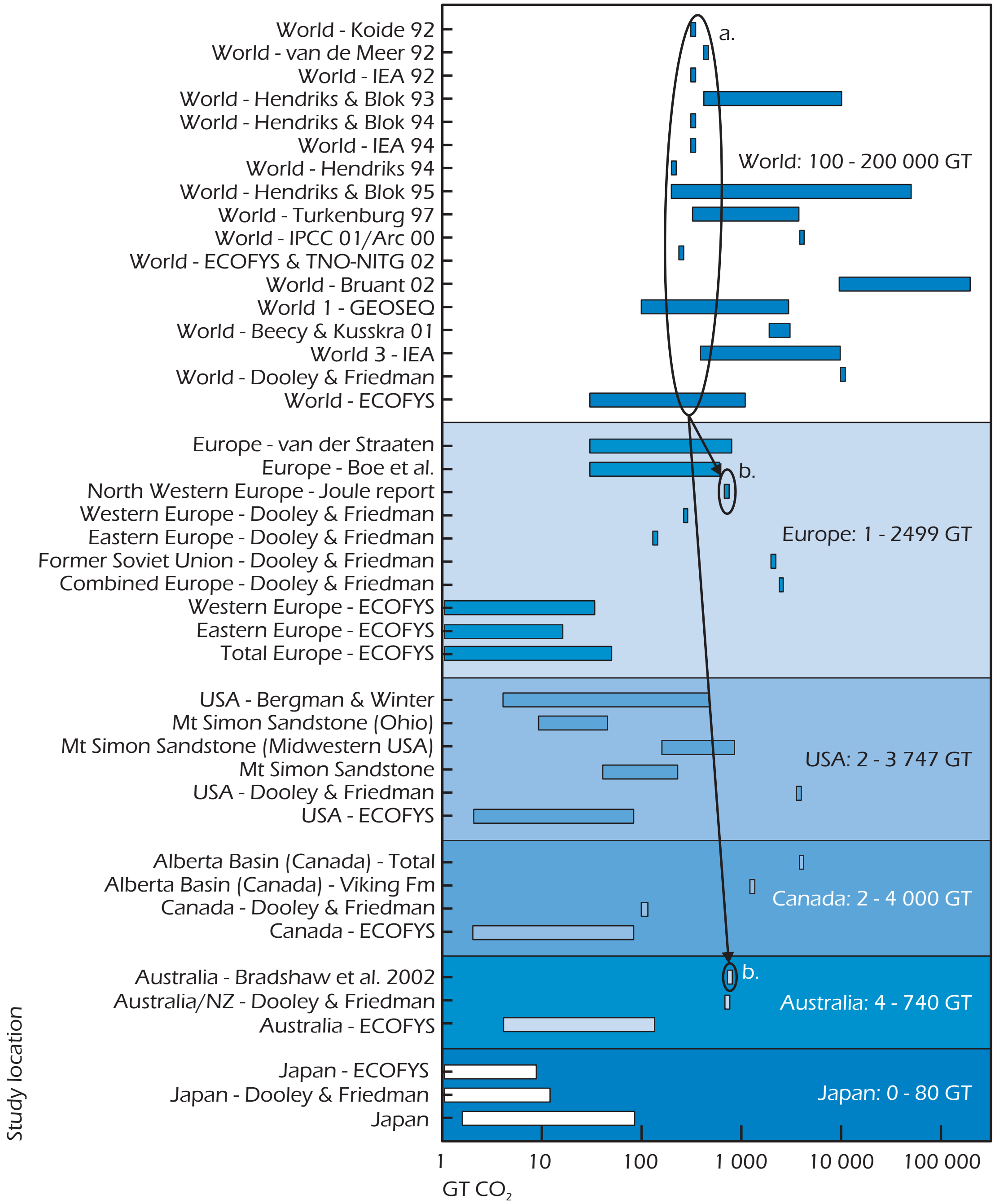


Source: CSLF, 2007.

Figure 4.5 Regional and Worldwide Estimates of Storage Capacity

Key point

Storage capacity estimates vary widely.



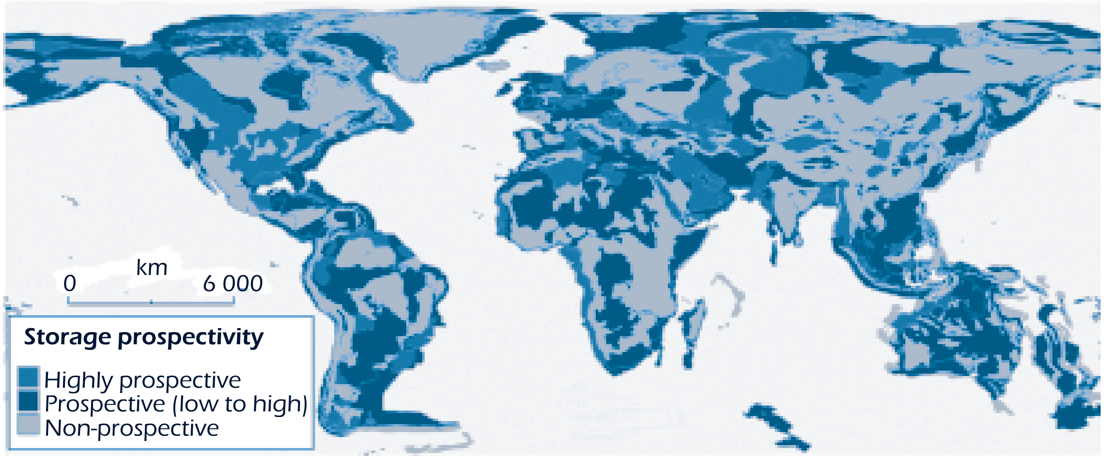
Source: Bradshaw, et al., *2006.*

Potential CO_2 storage sites are associated with sedimentary basins. Figure 4.6 shows a classification of basins with high, medium and low storage potential.

Figure 4.6 Map of Sedimentary Basins and their Storage Potential

Key point

Geological basins that are highly prospective for CO_2 storage are mainly found in the United States and Canada, Siberia, the Middle East and North Africa, as well as offshore.



Source: Bradshaw and Dance, 2004.

Cost of CO_2 Storage

CO_2 storage costs have been evaluated for a number of different geographical situations. The IEA has reported on the cost of European and North American storage projects and described the methodologies used (IEA GHG, 2005a; IEA GHG, 2005b). Costs include capital expenditures (CAPEX) that cover site evaluation and development costs, drilling costs, surface facilities, and monitoring costs such as seismic and operational expenditures (OPEX), which include operational and maintenance items as well as other monitoring activities.

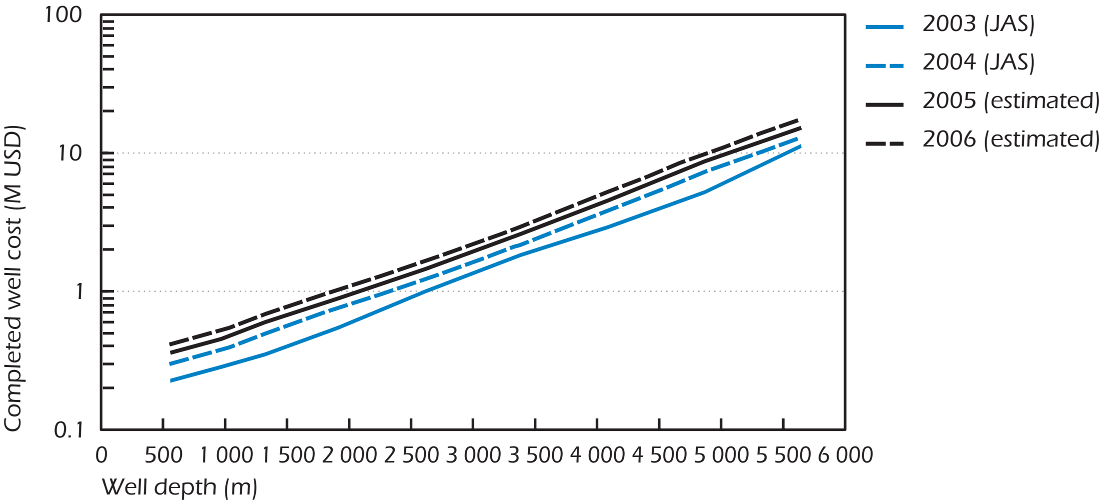
Costs for drilling oil and gas wells can be used to approximate CO_2 injection well costs. The main variation relates to the additional costs of well bore isolation (mostly cementing) to account for the potential interaction between CO_2 and cement. The cost of installing and running CO_2 monitoring equipment is generally small compared to storage costs. Figure 4.7 shows the average completed cost of onshore oil and gas wells in the United States as a function of well depth, using the Joint Association Survey on Drilling Costs (JAS, 2004). Offshore wells cost significantly more than onshore wells, as a function of water depth and well complexity, and can be more than four times higher even in shallow water environments. Deep-water wells are much more expensive. The cost of oil and upstream operations (drilling, completion and production) has risen significantly over the past five years due to increases in the price of materials and a shortage of resources (*e.g.* drilling rigs and crews, engineering expertise, etc., as shown in Figure 4.8).

Overall storage costs, using a Monte Carlo analysis, were estimated in the IEA GHG reports. Because of the cost escalation, storage costs have been updated with the cost increase factor in Figure 4.8. In Europe (onshore and offshore), 30 Gt of saline aquifer capacity could be used at a cost of USD 10-20/t; and 5 Gt of depleted oil and gas field capacity could be used at USD 10-25/t.

Figure 4.7 Average Completed Onshore Oil and Gas Well Cost in the USA

Key point

Well drilling and completion costs have increased significantly.

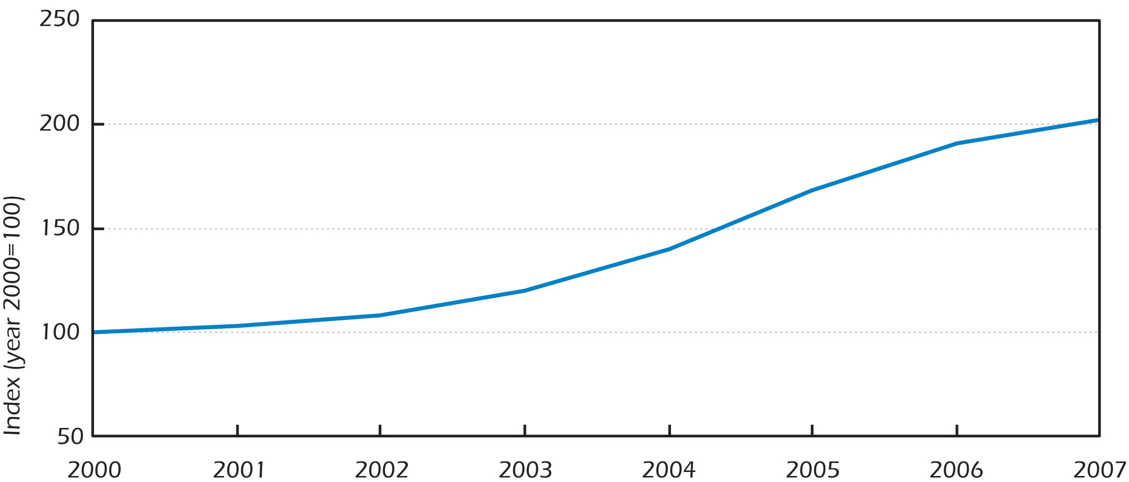


Sources: 2003 and 2004 data from JAS, 2004; 2005 and 2006 data from IEA estimates.

Figure 4.8 Global Upstream Oil and Gas Cost Index, 2000 to 2007

Key point

Upstream oil and gas costs have increased significantly over the last 6 years, which impacts CO_2 storage costs.



Source: IEA, 2006.

In North America, between 3 500 Gt and 4 000 Gt of capacity (including saline aquifers, depleted oil and gas, and coal-bed methane (CBM)) could be available for a storage cost of between USD 15/t and USD 25/t.

Enhanced Oil Recovery and CO_2 Injection

CO_2 has been injected to enhance oil recovery in wells for over three decades and has become the second largest EOR technique after steam flooding (IEA, 2005). The selection of EOR technologies depends on a number of technical and economic variables including oil density and viscosity, the minimum miscibility pressure, microscopic sweep effects, and the formation of vertical and lateral heterogeneities (Green and Whilhite, 1998; Jarrell, *et al.,* 2002; Gozalpour, *et al.,* 2005; Damen, *et al.,* 2005). Table 4.1 shows a summary of the parameters that influence the appropriateness of the most prevalent EOR technologies, *i.e.* gas injection (nitrogen gas (N_2), CO_2, hydrocarbon), steam or combustion, and chemical (polymer, microbial) flooding. The gravity of the hydrocarbon (Figure 4.9) is the most important factor. CO_2 is generally miscible with crudes with gravity higher than 24˚ on the API scale (or a density lower than 910 kg/m^3). For heavier oil, or when the pressure in the reservoir is not sufficient for miscibility, immiscible displacement, in which CO_2 can partially dissolve in the oil, is possible. Although this significantly reduces viscosity (giving up to a ten-fold increase in mobility), the economics of CO_2-immisicle displacement are rarely favourable.

CO_2-EOR is limited to oilfields deeper than 600 metres where a minimum of 20% to 30% of the original oil is still in place and where primary production (natural oil flood driven by the reservoir pressure) and secondary production methods (water flooding and pumping) have been applied.[9] Few oil fields have reached this stage. The presence of a large gas cap also limits the effectiveness of CO_2 flooding.

Table 4.1 Key Factors for Selecting an EOR Method

EOR method	°API	Viscosity (cp)	Composition	Oil saturation (% PV)	Formation type	Net thickness (m)	Per-meability (md)	Depth (m)	T (°C)	Cost (USD/bbl)
N_2 (and flue gas)	>35/48	<0.4/0.2	High % C1-C7	>40/75	Sandstone/Carbonate	Thin unless dipping	-	>2 000	-	
Hydrocarbon	>23/41	<3/0.5	High % C2-C7	>30/80	Sandstone/Carbonate	Thin unless dipping	-	>1 350	-	
CO_2	>22/36	<10/1.5	High % C5-C12	>20/55	Sandstone/Carbonate	-	-	>600	120[1]	7 – 30[2]
Micellar/polymer, Alkaline/polymer Alkaline flooding	>20/35	<35/13	Light, intermediate	>35/53	Sandstone	-	>10/450	<3 000/1 100	<95/25	8 – 12
Polymer flooding	>15/<40	<150/>10	-	>70/80	Sandstone	-	>10/800	<3 000	<95/60	5 – 10
Combustion	>10/16	<5 000/1 200	-	>50/72	High porosity sand/sandstone	>3	>50	<4 000/1 200	>40/55	3 – 6
Steam	>8/13.5	<200 000/4 700	-	>40/66	High porosity sand/sandstone	>6	>200	<1 500/500	-	3 – 6

Source: Green and Whilhite, 1998.

1. For miscible CO_2 floods.

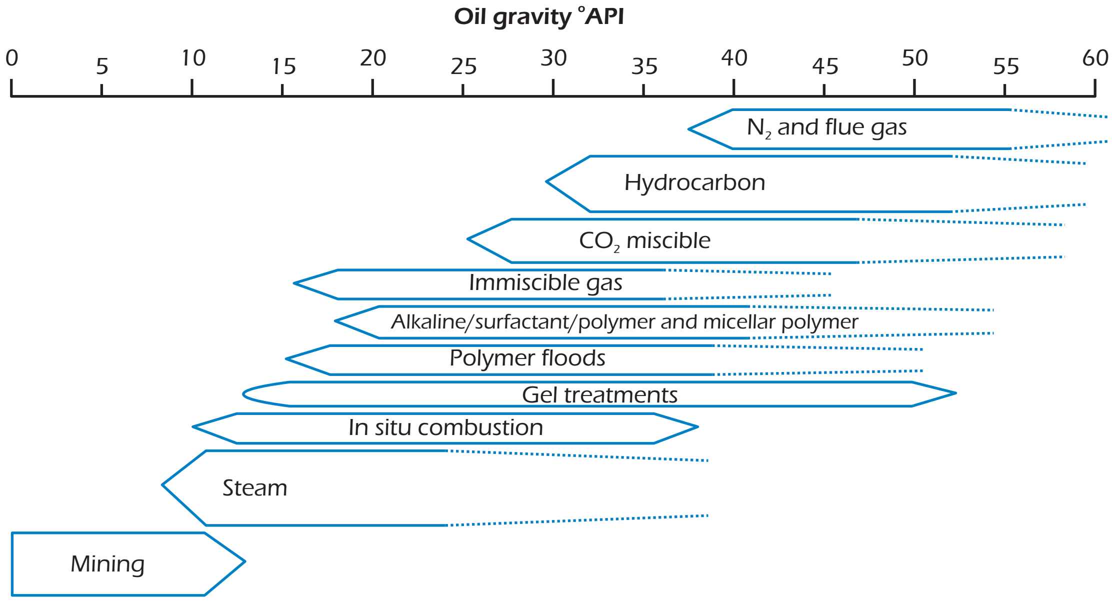
2. Lower end assumes that CO_2 is available for free; higher end includes the cost of CO_2.

9. Examples exist of CO_2-EOR being applied as secondary oil production technology.

Figure 4.9 Most Effective EOR Methods, by American Petroleum Institute (API) Gravity Range

Key point

The selection of EOR technology is a function of the oil gravity and other factors.



Note: Relative production (barrels per day) indicated by type size.

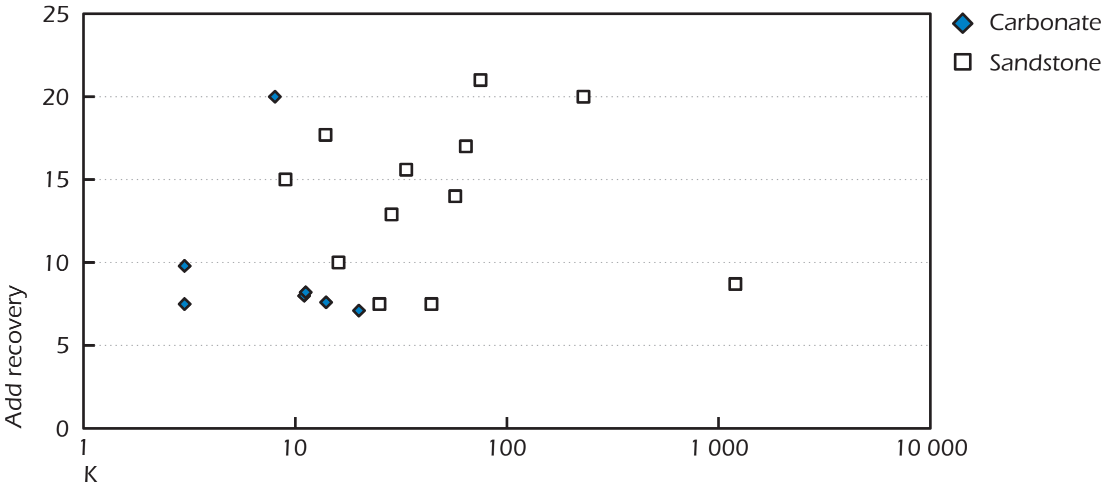
Source: Taber, et al., *1997.*

CO_2-EOR can enhance oil production substantially, depending on the characteristics of the hydrocarbon and on the reservoir conformance. Additional recovery can amount to 5% to 20% of the total quantity of original oil in place, thus increasing total recovery for an average field by as much as 50%. Depending on the geology of the oil field and the oil type, enhancement can range from 25% to 100%. The gravity of the oil is one of the key variables; the lighter the hydrocarbon, the greater the incremental recovery. Figure 4.10 shows the effect of the permeability on the additional recovery for carbonate and sandstone formations. However, CO_2-EOR cannot be applied to all fields: successful CO_2-EOR projects generally require good results from water flooding and good continuity of the reservoir. Injecting alternating stages of CO_2 and water (known as WAG–Water Alternated Gas) tends to improve the recovery. Optimum ratios of CO_2 and water should be used on the basis of detailed reservoir simulation. The economics of CO_2 supply and infrastructure upgrade/construction need to be factored in to assess the applicability of the technique. The average retention factor in CO_2-EOR projects in the United States is of the order of 60%, *i.e.* after breakthrough, 40% of the injected CO_2 recycles through the producing wells. An estimate made for Norway indicates that EOR can increase ultimate oil production by 300 million m^3 (Mathiassen, 2003) or about 10% of production to date plus the remaining reserves. This suggests that CO_2-EOR can increase long-term conventional oil supply substantially.

Figure 4.10 Additional Recovery vs. Reservoir Lithology and Permeability

Key point

Incremental recovery rates from CO_2-EOR from existing (onshore) projects range from 7% to over 20 %.



Sources: Jarrell, et al.*, 2002; IEA analysis.*

Detailed field-by-field assessments are necessary to accurately estimate the potential benefits of CO_2-EOR prospects. CO_2 storage in the case of miscible EOR ranges from 2.4 to 3 tonnes CO_2 per tonne of oil produced. Estimates for storage potentials vary widely, from a few Gt CO_2 to several hundred Gt CO_2. The cumulative global storage capacity (the total quantity that can be stored over the entire period up to that year) increases with time as EOR can be applied in more depleted oilfields. In a study matching CO_2 sources and sinks, 420 'early opportunities' for CO_2-EOR projects were identified, where capture sources and depleted oil fields were within 100 km of each other and EOR could start relatively soon (IEA GHG, 2002). Assuming approximately one Mt CO_2 storage per year per project, this suggests almost 0.5 Gt per year of storage potential (Bergen, *et al.,* 2004).

CO_2-EOR Costs

Project costs vary depending on the size of the field, pattern spacing, location and existing facilities. In general, total operating expenses include capital costs of about USD 1-2 per barrel (bbl), operating costs of about USD 3-6/bbl, royalty taxes and insurance of USD 3-6/bbl and CO_2 costs of USD 3-15/bbl. Those costs, initially given by Kinder (2002), have been updated with the upstream cost increase factor, discussed earlier. Given the current limits on readily available CO_2 supplies in the United States, CO_2 prices at the wellhead for new contracts have increased by a factor of three compared to the beginning of the decade, exceeding USD 30 per tonne. This translates into a current CO_2 supply cost (for new contracts) equivalent to an additional cost of USD 10-15/bbl of oil.

Typically, to justify CO_2-EOR, a field should have more than five million barrels of original oil in place and more than 10 producing wells (Kinder, 2002). With EOR, total production costs (excluding CO_2 costs) are approximately USD 7/bbl to USD 14/bbl oil or about USD 45/t to USD 90/t of oil. At a wellhead oil price of USD 60/bbl and assuming an injection rate of 2.5 t CO_2 per tonne of oil, the revenues amount to USD 150/t CO_2 if the CO_2 is available for free. Note that this assumes a high level of oil recovery per tonne of CO_2. Oil revenues would be lower for most fields.

The bulk of the capital costs for storage are associated with the drilling of injection wells. For depleted oil and gas wells, new CO_2 injection wells are recommended as the use of old and possibly damaged production wells increases the risk of a blow out (Over, *et al.,* 1999). The integrity of completion also needs to be checked during the field assessment. One of the largest operating expenditures is the cost of the electricity required for CO_2 treatment and producer pumps, estimated to cost in respect of EOR around 4 kW/bbl of oil per day (EPRI, 1999).

CO_2-EOR Potential

A number of studies have addressed the potential for CO_2-EOR in Europe, North America and China (see Box 4.1, Figures 4.11-4.13). Other regions with the largest potential for CO_2-EOR (the Middle East, the former Soviet Union, West Africa, South America) are generally not close to large CO_2 emission nodes with the exception of fields in the vicinity of Qatar, the Volga-Ural fields in Russia and the Western Venezuelan deposits.

Box 4.1 The North Sea EOR Potential

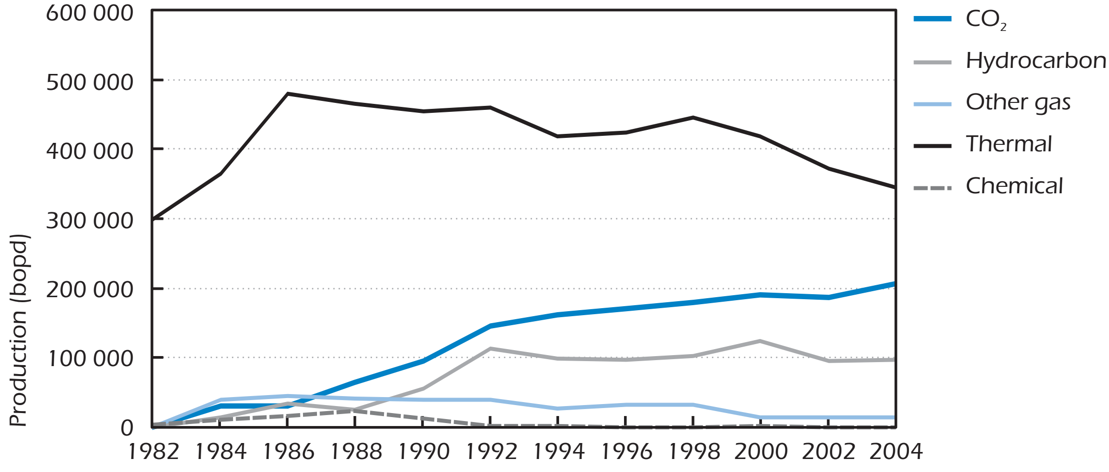
There is considerable interest in the idea of establishing a 'backbone' CO_2 supply system for the many North Sea oil fields that will mature in coming decades. This is being pursued through the CENS (CO_2 for EOR in the North Sea) project. The North Sea offers a unique opportunity because of the proximity of large anthropogenic CO_2 sources and oil fields. Preliminary estimates suggest that up to 30 Mt CO_2 per year could be used for EOR over a period of 15 to 25 years (Hustad, 2003; Marsh, 2003; Mathiassen, 2003; Karstad, 2003). The total potential from 81 of the largest oil fields averages 2.7, 4.2 and 0.4 billion barrels for the United Kingdom, Norway and Denmark respectively (Tzimas, et al., *2005). A considerable amount of work has been done with regards to the best CO_2-EOR prospects on the Norwegian Continental Shelf and United Kingdom (Gullfaks, Oseberg East, Brage, Snotre, Volve, Draugen, Forties). These prospects have been constrained by disappointing results in terms of CO_2-EOR oil yields, together with escalating CAPEX costs for the conversion of offshore installations, including facilities and wells for CO_2 injection.*

A recent study within Norways's Climit BIGCO$_2$ project has provided updated predictions for 19 Norwegian and 30 United Kingdom North Sea oil fields (Holt and Lindeberg, 2007). For a total investment cost of USD 60 billion, an average incremental oil recovery of 8.8% could be obtained, and 4-5 billion incremental barrels could be recovered. The study also highlights a critical element, which is the optimum time-window for CO_2-EOR. Attempting to use EOR any later than 2012 would generally require much larger investments. This would make EOR projects even more challenging commercially.

Figure 4.11 United States EOR Production, 1982 to 2004

Key point

In the United States, CO_2-EOR has risen steadily since the early 1980s.

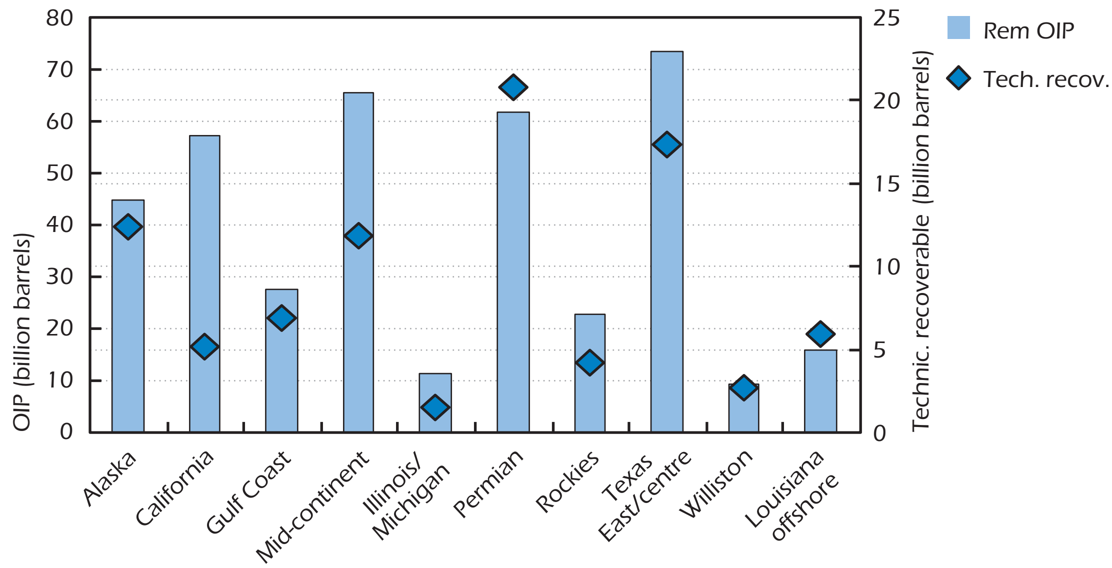


Source: OGJ, 2008.

Figure 4.12 Remaining Oil in Place and Technically Recoverable Oil for 10 United States Basins

Key point

Basin assessment shows significant CO_2-EOR potential in the United States.

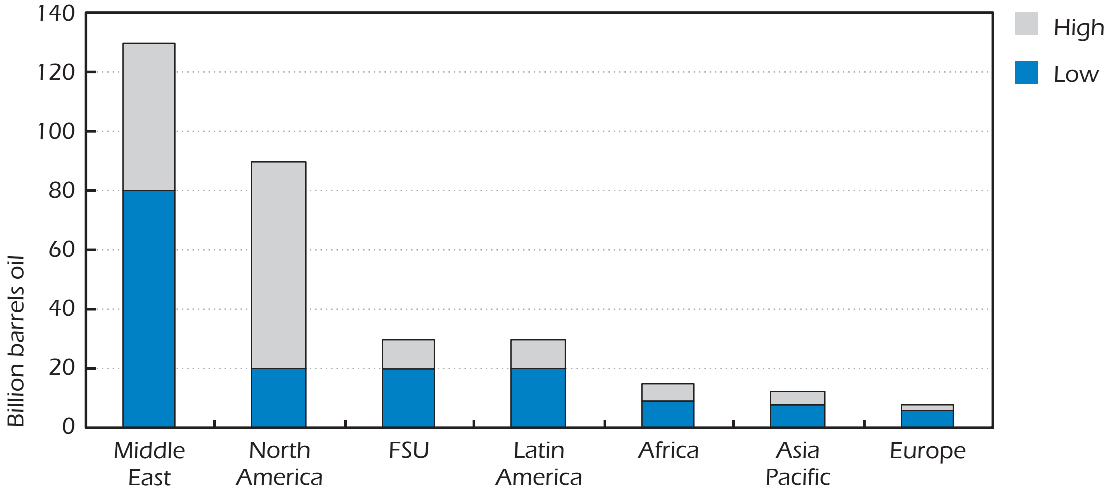


Source: US DOE, 2005.

Figure 4.13 CO_2-EOR Potential

Key point

Estimates of CO_2-EOR potential vary widely but even conservative estimates suggest considerable potential.



Sources: Khatib, 2006; Kuuskraa, 2006.

Techno-Economic Challenges for CO_2-EOR

Ongoing and past CO_2-EOR projects have worked in a range of formation characteristics. To that extent, the technology is considered to have reached a mature stage, although RD&D programmes are needed to extend the application of the relevant technologies and to improve their performance. Particular attention needs to be given to developing CO_2-EOR case studies in offshore environments, as there have been none to date.

The main techno-economical challenges include (Gozalpour, *et al.,* 2005):

- Improving sweep efficiency in the case of formation heterogeneities that may induce CO_2 channelling.
- Handling offshore environments. These are likely to operate with larger spacing within the reservoirs than most existing projects.
- Determining the optimum window of opportunity for EOR with offshore infrastructures.
- Retrofitting surface facilities (especially offshore) to handle corrosive fluids and well completions.
- Developing an infrastructure that minimises the cost of CO_2 delivered for various projects that will have different life spans.

The proposed next-generation CO_2-EOR technologies will include the following (Kuuskraa, 2006):

- greater use of real-time reservoir management techniques, including flood-monitoring technologies;
- higher volumes of CO_2 injection;
- more effective well bore isolation;
- novel chemical agents for improved sweep performance; and
- innovative well placement and flood designs.

Will CO_2-EOR Take off?

Increasing oil prices may provide the opportunity for a growing number of CO_2-EOR prospects to become economical. But in many cases, projects are held back by uncertain economics, the lack of appropriate fiscal and legal regimes, the lack of engineering resources, the lack of infrastructure, or relatively low rankings in oil and gas companies' opportunity portfolios.

Figure 4.13 shows the global size of the CO_2-EOR opportunity, with low and high ranges. Tertiary recovery is forecast to play an important role in the supply of oil by 2030, with estimates ranging between 8-10 million bbl per day (Russell, 2008; Armstrong, 2008). CO_2-EOR has a potential of 5-6 million bbl per day in 2030. Lifting a number of the barriers outlined above will increase the rate of uptake. The availability of a CO_2 transport infrastructure network would provide a particularly important stimulus for an order of magnitude increase in the use of CO_2-EOR.

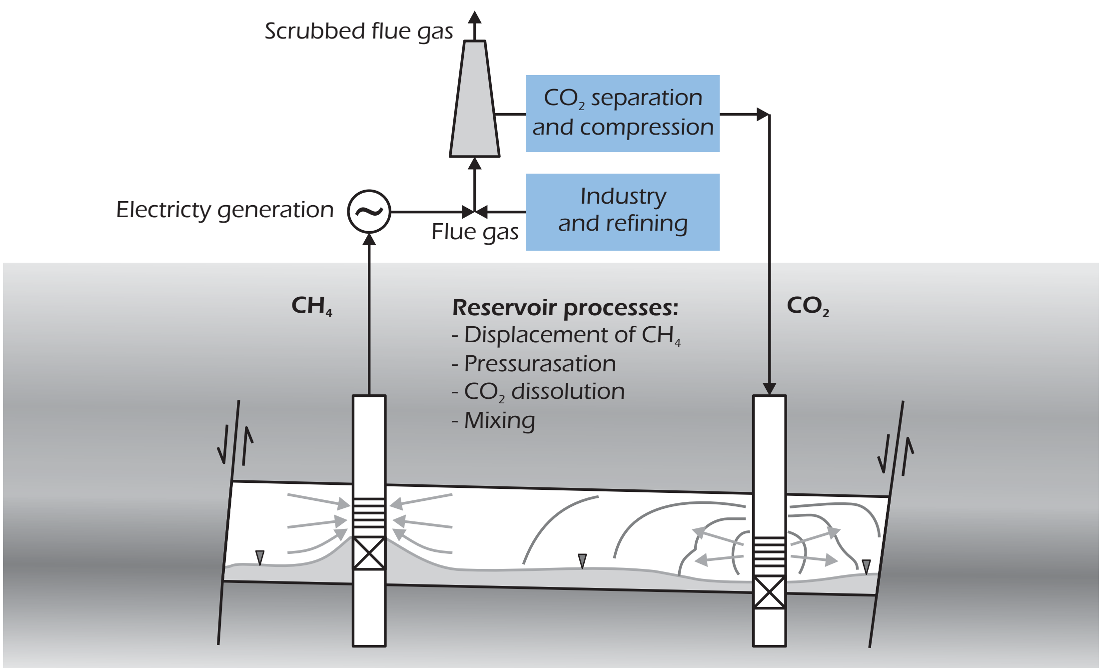
Carbon Sequestration with Enhanced Gas Recovery (CSEGR)

It is possible to inject CO_2 to re-pressurise depleted gas fields to increase gas recovery and to reduce drawdown-related subsidence, generally after more than 80% of the gas in place has been produced. Whatever its phase (gas, liquid or supercritical), CO_2 is significantly denser than natural gas and tends to flow downwards, leading to gravity-stabilised displacement (see Figure 4.14). CO_2 injections are less mobile (more viscous) than methane (CH_4) and therefore tend towards a stable displacement. CO_2 is also more soluble than CH_4 in formation water, which delays breakthrough. The applicability of carbon sequestration with enhanced gas recovery (CSEGR) depends on the drive mechanism (*i.e.* depletion, compaction or water-influx drive) in

Figure 4.14 Carbon Sequestration with Enhanced Gas Recovery Concept

Key point

CO_2's higher density makes it flow downwards, displacing natural gas.



Source: Oldenburg, 2004.

the reservoir (van der Meer, 2005). Depletion can remove all but 10% to 20% of the original gas. Water-influx drive can leave up to 40% (Oldenburg, 2004). Compaction drive is the least effective as depletion leads to a significant decrease in pore space.

The economics of CSEGR are less favourable than CO_2-EOR, as the revenue per tonne of CO_2 injected is lower. About 0.03-0.05 tonnes of CH_4 are recovered for each tonne of (dense phase) CO_2 injected. Using estimates of USD 0.50/GJ CH_4 to USD 3/GJ CH_4, CSEGR can result in revenue of USD 1-8 per tonne of CO_2 injected. An initial screening of gas fields for CO_2 injection (Stevens, *et al.,* 2000) suggests a worldwide storage potential of 800 Gt in depleted gas fields at a cost of USD 120/t CO_2 (more than 6 times the EOR cost). At USD 50/t CO_2, the total CO_2 storage potential in depleted gas fields is more than 100 Gt.

CSEGR has not yet become a demonstrated technology, and significant demonstration efforts are required before the technology becomes established. The K12B injection offshore in the Netherlands is the only CSEGR project of a significant size to have been undertaken (Dreux, 2006). The gas produced from the field operated by Gaz de France contains a high amount of CO_2 (13%). The Dutch Government-funded CRUST programme has investigated the feasibility of re-injecting the separated CO_2 at between 3 500 metres and 4 000 metres (the deepest CO_2 injection to date), and at temperatures of 130°C. After an initial assessment phase involving a number of Dutch and European R&D programmes (CATO, CASTOR, CO_2GEONET), injection started in May 2004. The first phase aimed at testing the injection facilities, proving the feasibility of the injection and evaluating the reservoir response. The injection of 30 000 m^3 of CO_2 per day between May 2004 and January 2005 confirmed that permeability had not been altered by the presence of CO_2. The next test sought to investigate the CO_2 phase behaviour, assess the CSEGR impact, and evaluate the impact of CO_2 on the metallurgy of the injector well tubing. Two types of tracers were used. A breakthrough occurred at one producing well. These results were valuable for matching the predictions of the numerical simulators.

CO_2 Storage in Depleted Oil and Gas Fields

Depleted oil and gas fields present early technical opportunities for CO_2 storage, given:

- readily available and extensive geological and hydraulic assessments from the oil and gas operations;
- the presence of sealing mechanisms that would be expected to contain gaseous systems for extended periods of time; and
- an existing infrastructure for CO_2 injection (wells, surface facilities, and possibly pipelines).

Worldwide storage estimates of the capacity of depleted oil and gas fields vary between 675 Gt and 1 200 Gt. Before converting these depleted fields into CO_2 storage, the following assessments and evaluations must be made:

- improved overburden assessment;
- well bore integrity assessment; and
- evaluation of chemical interactions between CO_2 and formation minerals and *in situ* fluids.

Storage costs depend on the condition of existing facilities and are likely to be higher if abandoned wells require repair or surface facilities require significant recommissioning. Storage costs per tonne of CO_2 in depleted oil and gas fields have been estimated by the 2005 IPCC *Special Report on* CCS, but they need to be updated to reflect recent cost increases in the oil and gas upstream sector. Onshore and offshore costs have evolved at different speeds, and are also subject to regional variations.

CO_2 Enhanced Coal-Bed Methane (ECBM) Recovery

Methane from Unmineable Coal Seams

Unmineable coal seams are those that are either too deep or too thin to warrant commercial exploitation. Most coal contains methane absorbed into its pores. The injection of CO_2 into deep unmineable coal seams can be used both to enhance the production of coal bed methane and to store CO_2.

The first application of ECBM has been under consideration, along with nitrogen injection, for more than a decade (Gale, 2004). N_2 and CO_2 enhance CBM production using different mechanisms. Nitrogen promotes methane desorption by reducing the methane partial pressure, while CO_2 is preferentially adsorbed on coal (compared to CH_4). Coal can absorb about two moles of CO_2 for every mole of CH_4 that it initially contained. Recent results have shown that some United States low rank coals could store 5 to 10 times as much CO_2 as the methane they originally contained.

Coal-Bed Methane Production (CBM)

CBM field development techniques vary as a function of several parameters including the depth, coal rank, permeability and configuration of geologic layers. Table 4.2 compares three coal formations (the United States Warrior Basin, the United States Power River Basin and the Western Canadian fields) (Boyer, 2006). Permeability, *i.e.* the ease with which fluids flow through the formation, varies from a few millidarcies to thousands of millidarcies. Tighter fields require hydraulic fracturing to produce methane commercially. New technologies include improved characterisation through well bore logging and novel fracturing fluids that prevent the migration of coal fines. Some of the Western Canadian fields require nitrogen fracturing.

The world's largest CBM resources are located in the United States, China, the Former Soviet Union (mainly Russia, Ukraine and Kazakhstan) and India, followed by Canada, South Africa,

Table 4.2 CBM from Different Coal Formations

Basin	Warrior	Powder river	Western Canadian
Coal rank	High volatile bituminous – semi-anthracite	Lignite – sub-bituminous	Sub-bituminous – high volatile bituminous
Total coal thickness, m	6 – 12	15 – 40	6 – 15
Producing depth, m	150 – 1 000	75 – 500	200 – 700
Gas content, m^3/t	8 – 15	1 – 4	2 – 6
Gas in place,10^6 m^3/well	40	10	60
Permeability, mD	1 – 30	100 – 2 000	5 – 75
Water saturation, %	100	100	<5
Completion type	Multi-Zone Fracturing	Single Zone under-reaming	Multi-Zone N_2 Fracturing
Well costs, thousand USD	250 – 500	50 – 100	100 – 300

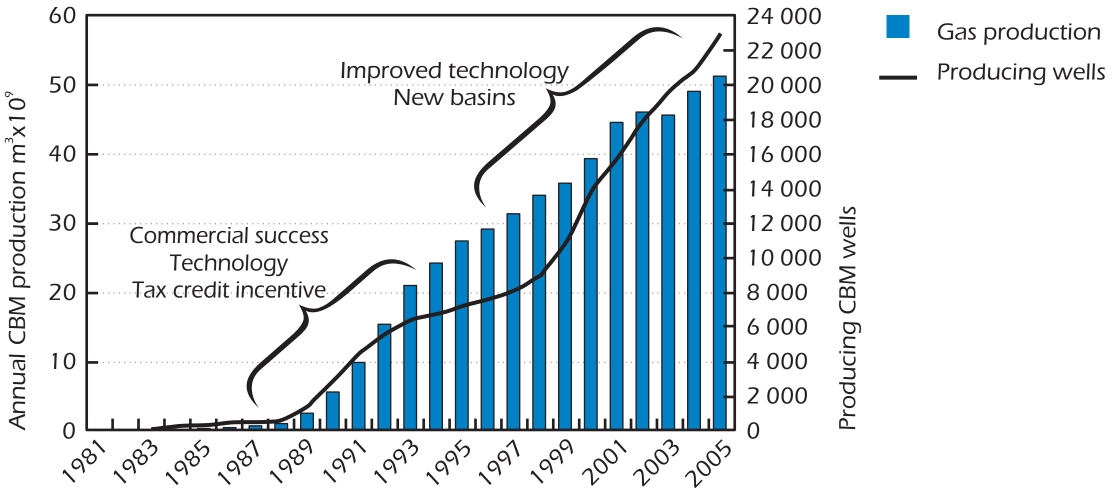
Source: Boyer, 2006.

Zimbabwe and Central Europe. Commercial CBM production started in the United States in the late 1980s, with tax credits as a key incentive (Figure 4.15).

Figure 4.15 United States Coal-Bed Methane Production

Key point

CBM production grew significantly in the United States over the last two decades.



Source: Boyer, 2006.

A second phase of production growth coincided with high gas drilling activity in the mid 1990s and improved production technologies that allowed access to more basins. Canada's commercial CBM production started in 2003, and is expected to double from 2005 to 2010. Australia's CBM activity started in 1998, and by 2006 had 15 active operators producing 1.7 Gm^3 of methane a year. Table 4.3 compares the production among the three countries and shows that average production per well is the highest in Australia, followed by the United States. Commercial production prospects are being evaluated in China, Romania, India, France, Russia and Poland.

Table 4.3 Coal-Bed Methane Production, 2005-2006

	United States	Canada	Australia
Number of wells	23 000	4 000	400
CBM production (Gm^3)	51	3.4	1.7
Average production/well (Mm^3)	2.2	0.85	4.25

Source: Boyer, 2006.

Enhanced Coal-Bed Methane (ECBM) Prospects

To be suitable for ECBM, coal-bed reservoirs need to meet several criteria. In addition to the existence of cost-effective gas transport routes, the following geological factors need to be taken into account (Shi and Durucan, 2005):

- coal-bed depth (up to 1 500 metres), pressure and temperature;

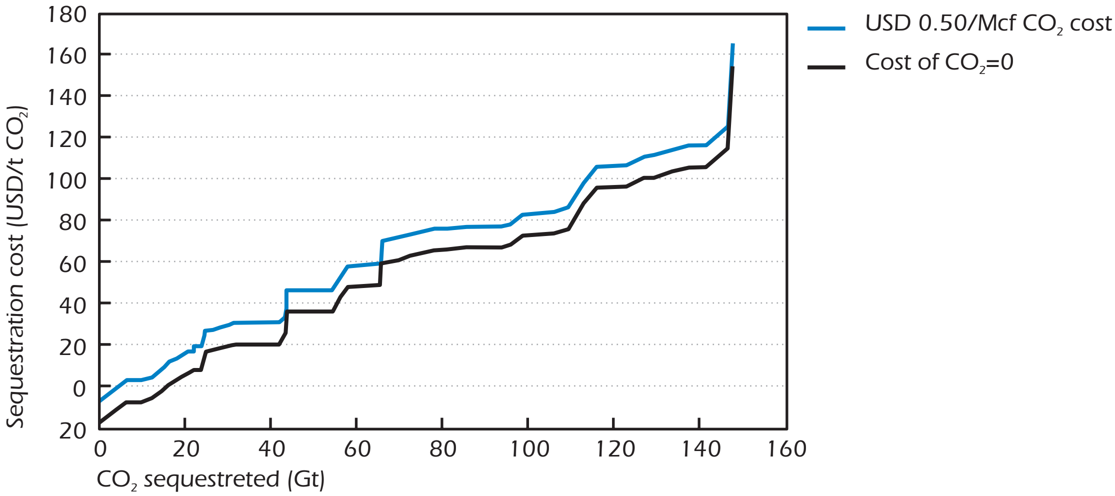
- coal rank, composition and ash content;
- local hydrology and ability to dewater;
- sufficient thickness of coal seams and good lateral continuity; and
- minimum faulting and folding.

The IEA GHG R&D Programme studied the economics of ECBM and the determination of candidate formations. Figure 4.16 shows the potential of CO_2 storage, assuming a wellhead gas price of USD 0.07/m^3 in the United States and USD 0.11/m^3 outside the United States. The global sequestration potential in geologically high-grade coal basins was estimated at 148 Gt.

Figure 4.16 Volume of CO_2 Storage in Coal-Bed Methane vs. Sequestration Costs

Key point

The costs of storing CO_2 in coal-bed methane basins rise in parallel with the amount of CO_2 stored.



Source: Gale, 2004.

Table 4.4 provides a list of countries with significant ECBM potential and Table 4.5 lists the major basins where ECBM can be demonstrated to be cost-effective.

Table 4.4 ECBM Potential by Country

Country	Sequestration potential (Gt CO_2)
United States	35 – 90
Australia	30
Indonesia	24
Former-CIS	20 – 25
China	12 – 16
Canada	10 – 15
India	4 – 8
South Africa and Zimbabwe	6 – 8
Western Europe	3 – 8
Central Europe	2 – 4
Total	**146 – 228**

Sources: Gale, 2004; Reeves, 2003.

Table 4.5 Early Opportunities for ECBM Projects

United States	San Juan, Raton, Uinta
Australia	Sydney, Bowen
Canada	Western Canada
Europe	Upper Silesian, Poland
China	Qinshui, Ordos
Indonesia	Sumatra, Kalimantan
India	Cambay, Damodar
Russia	Kuztnesk

Source: IPCC, 2005.

ECBM RD&D Projects

Table 4.6 lists the current main ECBM demonstration projects and Figure 4.17 compares project sizes (injection rates and volumes). Reeves, 2003 provides a summary of the largest project (in terms of the volume of CO_2 injected) at the San Juan field sites. The economics of the injection in the Allison and the Tiffany units is well-documented as follows:

- 181 million m^3 of CO_2 was injected in four wells with limited breakthrough;
- methane was collected through 9 producing wells;
- gas in place recovery increased from 77% to 95%;
- at 2002 gas prices, the net present value of the project was USD 15 million and the profits were USD 34/t CO_2, for a capital investment of USD 2.6 million.

The RECOPOL/MovEcbm project is a major EU-funded initiative to investigate the techno-economic feasibility of CO_2 injection for ECBM in the Silesian basin in Poland. Low coal permeability limits injection, and hydraulic fracturing is required to ensure adequate volumes and rates. Other projects in Canada, China and Japan are discussed in more detail in Chapter 6.

Table 4.6 ECBM Pilot Project Characteristics

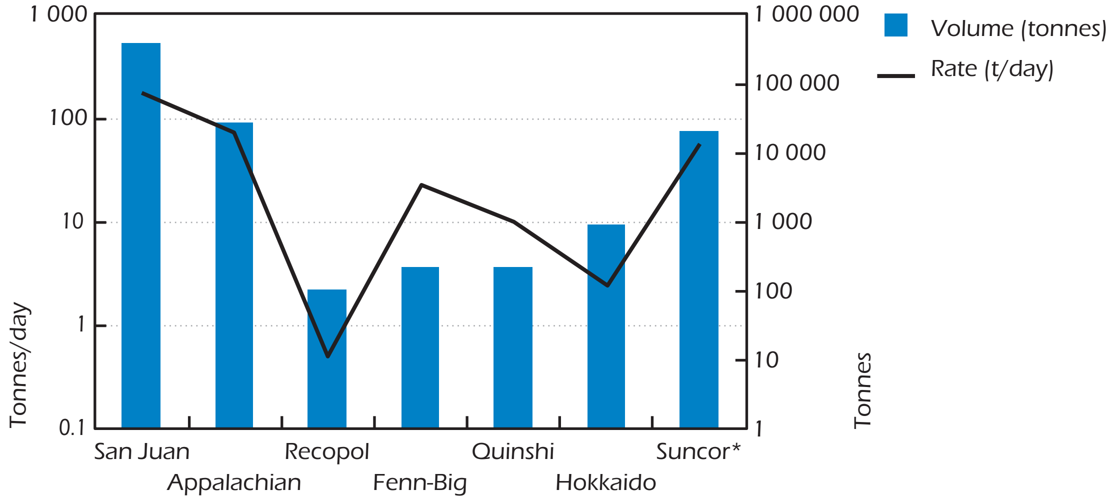
Basin	Depth (m)	Perm. (mD)	Coal-type	Objective
San Juan	900	100	Bituminous	Large injection volumes
Appalachian	420	3-5	Bituminous	Horizontal wells
RECOPOL	1 100	0.1-1	Bituminous	Low injectivity/hydraulic fracture
Fenn-Big	1 260	2-4	Bituminous	Huff and puff CO_2
Quinshi	480	0.1-1	Anthracite	Huff and puff CO_2
Hokkaido	870	1	Bituminous	Small scale

Source: IEA analysis.

Figure 4.17 Injection Rates and Volumes for Pilot ECBM Projects

Key point

Pilot ECBM projects have shown a range of results to date.



Source: IEA Analysis.

Technology Gaps in ECBM

The key technology issues that are being addressed by ongoing RD&D projects include:

- interaction between CO_2 and the coal (as the coal matrix adsorbs CO_2, swelling may occur, leading to decreased permeability and lower injectivity, reducing CBM recovery and lowering CO_2 storage potential);
- chemical interaction of the CO_2 with in-situ water;
- the impact of heterogeneities, especially vertical formation layering;
- monitoring technologies (field-wide, cross-well and well bores);
- cap rock integrity; and
- field-wide simulation software that combines fluid flow, geo-mechanical and geo-chemical effects, building from industry comparisons that have evaluated the performance of existing ECBM simulators and developed benchmark tests.

Storage in Deep Saline Aquifers

Deep saline aquifers represent in the long term the largest potential CO_2 sink. They have generally been much less well-characterised than oil and gas fields due to the absence of commercial drivers.

Characteristics of Deep Saline Aquifers

Aquifers are layers of sedimentary rocks that are saturated with water. They can be either open or confined. Open aquifers have no natural barriers to water flow and water circulates naturally at a very low rate. Many aquifers, particularly those in sandstone and carbonate rocks, are permeable enough for water to be pumped from them or for fluids to be injected. Crystalline and metamorphic rocks such as granite do not have the porosity and primary permeability necessary for CO_2 storage, and they are usually fractured in ways which may create potential leakage paths. Volcanic areas are typically unsuitable for storage because of their low capacity and fractured nature.

An aquitard is a layer of rock, usually comprised of shales, from which water cannot be produced but which has enough porosity to allow water to flow on a geological time scale. Water in aquifers that are deep below the ground in sedimentary basins is confined by overlying and underlying aquitards and/or aquicludes, layers of rock such as salt and anhydrite beds with almost no porosity that do not permit the flow of water. The water in these closed aquifers may have been there for millions of years, and usually has a high content of dissolved solids (brackish water and brine) making it unsuitable for human consumption. These aquifers, which are confined and which offer few if any alternative applications, have been proposed as CO_2 storage sites.

Geological CO_2 storage in relatively tectonically stable divergent basins (such as the foreland basins east of the Rocky Mountains and the Andes, the Michigan basin and the North Sea) is much safer than storage in convergent basins (*e.g.* California, Japan and New Zealand). Old continental core areas (*e.g.* the Canadian and Brazilian shields) and mountain-forming areas do not have the rock characteristics necessary for CO_2 storage (Bachu, 2000). Sedimentary basins can be further subdivided by a number of criteria (Bachu, 2003). Based on this analysis, only some basins are suited for CO_2 storage.

CO_2 Injection and Storage in Deep Saline Aquifers

CO_2 injected in deep saline aquifers is trapped and stored in several phases:

- in its free phase as a plume at the top of the aquifer and in stratigraphic and structural traps similar to oil and gas accumulations;
- as bubbles trapped in the pore space after passing a plume;[10]
- dissolved in aquifer water; and
- as a precipitated carbonate mineral resulting from geochemical reactions between the CO_2 and aquifer water and rocks.

Empirical studies have shown that, during the active period of injection, up to 29% of the CO_2 can dissolve in the brine (Bachu, 2000). As CO_2 has a lower density than brine, the remainder of the CO_2 floats on top of the brine and accumulates below the cap rock. Part of this CO_2 may later dissolve in the brine or react with the aquifer rock matrix. Dissolution continues after the injection has ceased such that, over a period of a thousand years or more the entire plume of CO_2 is likely dissolve.

The geochemical reaction that would permanently sequester the CO_2 would take several thousand years to have a significant effect. Where there is no stratigraphic or structural trap, the CO_2 would flow and spread over a large area below the aquifer cap rock. Modelling studies suggest that this spread may extend to tens or hundreds of square kilometres, depending on the properties of the aquifer (thickness, porosity and permeability), on the topography of the cap rock and on the volume of CO_2 that is injected(Saripalli and McGrail, 2002).

10. This process, also called imbibition trapping or residual gas trapping, has received attention recently, with claims that it could trap 5% to 25% of the CO_2 injected. These estimates are based on model observations calibrated with models for natural gas production reservoirs. A fundamental difference is that CO_2 dissolves in water while natural gas does not. Diffusion may reduce this pore phase trapping so that in the longer term it might not contribute to permanent CO_2 storage.

Modelling studies have generally shown that, depending on aquifer characteristics and the injection rate and well spacing, a plume of CO_2 may spread between 5 and 12 km from the injection well over a period of a thousand years. Other studies suggest that the plume would dissolve entirely. The size of the area complicates the monitoring and verification of any leakage. The lower the initial CO_2 saturation of the brine, the smaller the area over which the undissolved CO_2 will spread, as more CO_2 would dissolve in the brine.[11] Initial brine concentration could be one criterion for aquifer selection.

Model studies suggest that a fracture situated 8 km from an injection well could result in the first leakage of CO_2 after 250 years and 10% to 20% leakage over the next 2 000 years (less than 0.01% per year) (Lindeberg, 1997). Anthropogenic damage of the cap rock due to abandoned oil and gas exploration and production wells may cause additional leakage (Celia and Bachu, 2003). In regions where the oil and gas industry are well developed, more than five wells occur per km^2. Most abandoned wells are sealed, but CO_2 reacts with the cement that is often used to seal them, which can result in leakage. In addition, small gaps may exist between the well plug and casing. Leaking CO_2 may dissolve in other aquifers above the storage aquifer thus preventing an emission to the atmosphere. It is not yet clear whether or not this leakage mechanism poses a serious problem.

The temperature profiles in underground sediments differ by location because of variations in geothermal gradients and in surface temperatures. As a consequence, the state of CO_2 underground will vary as will its density at a given pressure (Bachu, 2000). This affects both the storage potential per unit of surface and the relevance of leakage mechanisms.

On-Going Large-Scale Storage Projects

Large-scale storage in saline aquifers is currently being studied in the Sleipner CO_2 storage project in the North Sea and in the In Salah gas project in Algeria. In the Sleipner project, CO_2 is separated from natural gas produced from the Sleipner field and stored in the Utsira aquifer below the gas field. The project has been storing 1 Mt CO_2 per year since late 1996. The results to date from extensive time-lapse seismic and other monitoring technologies combined with modelling suggest that there is no leakage and that CO_2 storage is technically feasible. There is still considerable uncertainty about the storage potential, particularly the extent to which the aquifer pore volume can be filled with CO_2. Calculations from the 1990s suggest that 2% of the aquifer volume can be filled with CO_2 (van der Meer, 1992) but more recent estimates suggest figures between 13% and 68% (Holt, *et al.,* 1995). The higher the storage efficiency, the fewer the number of wells required, the lower the storage costs and the higher the storage potential. Monitoring CO_2 migration in the In Salah project is part of CO_2ReMoVe, a large-scale EU-funded programme designed to optimise the use of measurements in CCS projects.

Storage Potential Estimates of Deep Saline Aquifers

Aquifer CO_2 storage estimates vary widely, as shown in Table 4.7.

The United States Regional Carbon Sequestration Partnerships have developed the *North American CCS Atlas* using consistent methodologies to improve estimates of CO_2 storage potential by area and type of storage (see Chapter 6 for more information).

11. It may be possible to mix CO_2 with brine before injection and inject the CO_2 in its dissolved state rather than as a gas. While this option is speculative, it would reduce the leakage risk.

Table 4.7 Estimates of CO_2 Storage Potentials in Deep Saline Aquifers*

	(Gt CO_2)
Alberta (Canada)	1 000 – 4 000
United States	900 – 3 400
Europe	30 – 577
Worldwide	2 000 – 20 000

**Including offshore aquifers.*

Sources: IPCC, 2005; DOE, 2007; Bentham and Kirby, 2005.

Economics of Storage in Deep Saline Aquifers

The IPCC, 2005 gives estimates of storage costs in saline aquifers for different regions of the world, as follows (in USD per tonne of CO_2 stored):

- USA onshore: from USD 0.40/t CO_2 to USD 4.50/t CO_2;
- Europe onshore: from USD 1.90/t CO_2 to USD 6.20/t CO_2;
- Europe/North Sea: from USD 4.70/t CO_2 to USD 12/t CO_2;
- Australia onshore: from USD 0.20/t CO_2 to USD 5.10/t CO_2; and
- Australia offshore: from USD 0.50/t CO_2 to USD 30/t CO_2.

These costs have likely increased since the publication of the IPCC report by a factor similar to the oil and gas upstream cost factor. The recent In Salah gas project required an additional investment of USD 100 million for CO_2 storage (with a proposed additional USD 30 million for a comprehensive monitoring programme). As the project aims at injecting 17 Mt CO_2, the average cost of storage is nearly USD 6/t CO_2 in a remote onshore environment.

Ongoing studies are attempting to match potential capture sites with storage sites. This is a real issue on a practical level. For example, a 500 MW coal-fired power plant would have to store about 3 Mt of CO_2 per year. Assuming a storage density of 0.5 t/m^3 and an effective CO_2 layer density of one metre,[12] 6 km^2 of aquifer would be needed for storage every year. A power plant with a lifespan of 40 years would therefore require 240 km^2. To store 16 Gt CO_2 per year implies an underground storage area of 200 km by 200 km per year, an area the size of the Netherlands.

The cost for CO_2 compression and injection in the Sleipner project amounted to USD 80 million.[13] The investment costs for the Snohvit project (compression, transportation and injection) will amount to USD 191 million (Audus, 2003). Clearly, these cost levels are higher than the values used for regular CCS assessment studies and may be explained by the extreme situations in the North Sea offshore and the Arctic, respectively, and by the fact that these are first-of-a-kind facilities. Yet compressors and pipelines constitute the bulk of the cost (Figure 4.18) and should be considered as well-established pieces of equipment for which the learning potentials are limited. Therefore, a careful case-by-case cost evaluation is needed.

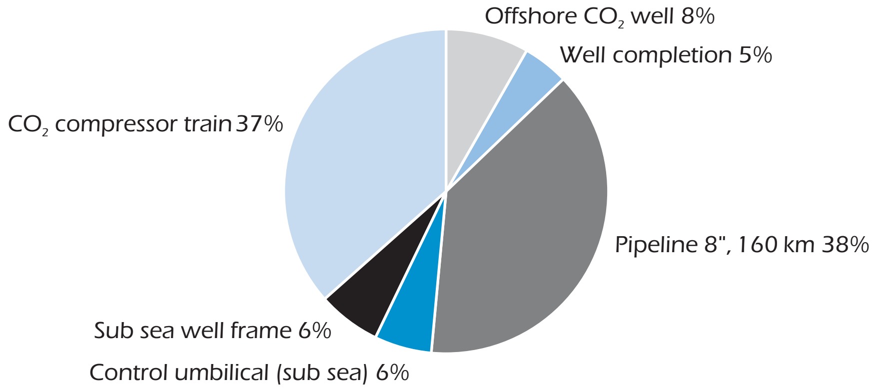
12. A sediment porosity of 30% means the top three metres of the aquifer are filled with CO_2.

13. Note that currency fluctuations as well as cost escalation would mean increasing by a factor of 2-3 to reflect 2008 conditions.

Figure 4.18 Cost Structure of Norway's Snøhvit Pilot Project

Key point

Pipeline and CO_2 compressor costs account for three-quarters of Snøhvit's investment costs.



Sources: Kaarstad 2002; Audus 2003.

Technology and Knowledge Gaps

There is considerable experience in modelling flows in porous media. The main technology gaps relate to the long-term interactions of the injected fluid and the minerals and fluids in place and the behaviour of the cap rock. Challenges include (ZEP, 2006):

- cap rock integrity and upscaling of seal characteristics with the injection of large volumes of CO_2;
- geochemical and geo-mechanical modelling of the reactive transport of CO_2;
- the impact of CO_2 on faults;
- developing cost-effective permanent monitoring technologies;
- developing accurate dynamic simulation models; and
- the development of workflows from seismic surveys to reservoir simulation.

Other Storage Options

Other CO_2 disposal options include other geological media, ocean storage, mineral carbonation, limestone ponds, algal bio-sequestration, and industrial uses.

Other Geological Media

Salt caverns have been used to store hydrocarbon products for decades. Despite their high injectivity, their use for CO_2 storage is limited by their low capacity, shallow depth and concerns about their capacity to contain CO_2. Abandoned mines are also unsuitable because sealed shafts do not adequately prevent CO_2 leakage.

In oil and gas shales, CO_2 adsorbs onto the organic material with a trapping mechanism similar to CBM. Given the large occurrence of oil shales in the United States, Brazil, China and Russia, with a combined three trillion barrels of potentially recoverable oil, a large capacity is available. However, the shallow depth of the deposits and their very low permeability, together with the technical challenges of oil extraction, would prevent their use as a storage system.

Basalts occur widely worldwide. Their low permeability (mainly from fissures and fractures) and low porosity make them a favourable medium for CO_2 injection. Further research is required, especially with respect to mineral carbonation.

Ocean Storage

The principle of ocean storage is to transport the CO_2 via pipelines or ships to an offshore site where it would be injected into the water column or the sea floor at depths over one thousand metres. The Intergovernmental Panel on Climate Change's *Special Report* gives a summary of the state of knowledge concerning ocean CO_2 storage (IPCC, 2005). Several international projects have investigated feasibility in laboratories and small field tests, but knowledge about the impact of a large point source injection of CO_2 on the marine ecosystem is limited. Ocean injection has generated significant controversy and protests by environmental groups have led to the cancellation of pilot projects in Hawaii and Norway.

Model calculations have shown that over 90% of the CO_2 injected at depths greater than 1 500 metres would be retained for over one hundred years. While no industrial scale experiments have been carried out in a controlled ecosystem, the implications of injecting large quantities of CO_2 from a point source on the marine environment can be significant for marine life. If limestone or another buffer does not neutralise CO_2 acidity, the disturbances from increased water acidity due to the injection of hundreds of Gt CO_2 would be significant. In 2007, the marine protection treaty OSPAR issued a Decision to prohibit the storage of carbon dioxide streams in the water column or on the sea-bed.[14]

Mineral Carbonation

The concept of mineral carbonation is based on the reaction of ground magnesium and calcium silicate with CO_2 to form solid carbonates as follows:

$$Mg/Ca - silicate(s) + CO_2(g) \rightarrow (Mg/Ca)CO_3(s) + SiO_2$$

The process requires the milling of a mineral ore and its reaction with a concentrated CO_2 stream. A considerable amount has been written on the applications of the process to store CO_2. Reviews by the IEA GHG, 2005 and Huijgen, *et al.,* 2003 provide a comprehensive bibliography on the subject. The IEA GHG, 2000 assessed six different mineral sequestration processes: direct carbonation (gas-solid, molten salt), indirect carbonation (use of hydrochloric acid or acetic acid), and the use of seawater-dissolved dolomite. Other processes include aqueous carbonation and iron carbonates.

Peridotites and serpentinite are the preferred rocks because of their magnesium and calcium content and their worldwide occurrence. However, the process yields are large in terms of the volume of materials: between 1.6 tonnes and 3.7 tonnes of silicate need to be mined for each tonne of CO_2, and the reaction generates 2.6 tonnes to 4.7 tonnes of material. A 500 MW coal-fired power plant would produce about 30 kt of magnesium per day. The process would cost in the range of USD 50 t/CO_2 to USD 100/t CO_2. If this is to become economically viable, significant technological advances will be required. Several environmental issues would also need to be addressed. It is unlikely that mineralisation will offer an opportunity for sequestering large volumes of CO_2.

14. For more information about the legality of offshore CO_2 storage under International Marine Environment Protection Treaties, see Chapter 6.

Limestone Ponds

The concept of limestone ponds combines capture and storage. Limestone is dissolved in water in a pond. Flue gas is bubbled through the pond. The CO_2 in the flue gas reacts with the limestone. The carbonate solution is dissolved in seawater as follows:

$$CO_2(g) + H_2O_{(l)} + CaCO_{3(s)} \rightarrow Ca^{2+}{}_{(aq)} + 2\ HCO_{3\text{-}(aq)}$$

There have been preliminary cost estimates of USD 21/t CO_2 for storage with this method (Sarv and Downs, 2002). This process has not been proven on a pilot scale. The transport of CO_2 into the solution is a significant limiting factor: most experts claim that it is impossible to produce bubbles that are sufficiently small, and the size of the ponds would be prohibitive. This technology can at best be considered highly speculative.

Algal Bio-Sequestration

The use of coccolithphorid algae offers a possibly efficient route to the conversion of CO_2 into carbonates given of their growth and CO_2 uptake rates, and their potential to extract CO_2 from feedstocks with relatively low CO_2 concentrations. Research co-funded by the US Department of Energy is being carried out to determine the most suitable algal species and the potential for generating bio-fuel. A large-scale experiment on an algae bioreactor is being carried out at the 1 040 MW Redhawk power plant in Arizona.

Industrial Uses

Within the fast-growing industrial gas business, CO_2 is third-largest gas consumed by volume after oxygen and nitrogen. Applications of CO_2 include food and beverage, horticulture, welding, and safety devices. The source of the CO_2 is either high-concentration industrial plants (ammonia, hydrogen) or CO_2 wells. However, the volume for such applications is small compared to the storage requirements (100 Mt CO_2 to 200 Mt CO_2 per year as compared with the need to store several Gt of CO_2 per year) and many applications involve only temporary storage in any case.

5. FINANCIAL, LEGAL, REGULATORY AND PUBLIC ACCEPTANCE ISSUES

KEY FINDINGS

- **Financing Carbon Capture and Storage (CCS)**
  - Investment in CCS will only occur if there are suitable financial incentives and/or regulatory mandates. Various financial and regulatory options exist. The most appropriate package of measures will vary country by country. However, for significant uptake of CCS, it will be necessary to provide a policy framework that combines near-term technology financing with carbon constraints and/or CCS mandates.
  - Of particular concern is the financial gap and risks facing the critical first round of CCS demonstration projects. It is clear that greenhouse gas (GHG) market mechanisms alone will not be sufficient to achieve the G8 Energy Ministers' stated goal of launching 20 full-scale CCS projects by 2010, wich have a cost between USD 30 billion and USD 50 billion.
  - Financing of the necessary CO_2 transport infrastructure will also be essential. Governments may need to subsidise or take ownership of CO_2 transport pipelines in some manner. More analysis of appropriate options is required.
  - The approval of a CCS project methodology under the Clean Development Mechanism (CDM) is an important first step that will help developing countries to begin mitigating their fossil plant emissions in the near- to medium-term.
- **Development of Legal and Regulatory Frameworks**
  - Governments are making important progress in developing suitable CCS policy frameworks. However, significant work remains to be done. To facilitate early demonstration projects, governments should start by adapting existing regulatory frameworks, with an eye toward flexibility, as regulations will need to be adapted based on experience over time.
  - CCS deployment will require extensive coordination between supranational, national, provincial/state and local jurisdictions. Regulators at all levels will need adequate resources to increase their capacity to manage the growing area of CCS regulation.
  - CO_2 pipeline regulations will require increased coordination across provincial/state and possibly national borders to eliminate inconsistencies in pipeline access and CO_2 purity requirements, and to address pipeline access and rate issues.
  - The success of a CCS projects will be heavily dependent on successful site characterisation, including demonstration of the necessary injectivity, capacity and storage integrity of proposed sites. International guidelines for CO_2 storage site selection need to be further developed.
  - Governments in many countries, including the United States, Canada, and Australia, need to clarify the property rights associated with CO_2 storage, including access rights and ownership of storage reservoirs.

- Long-term liability at CO_2 storage sites needs to be addressed. Models in other industries may offer possible solutions. Governments should work with the insurance and finance sectors to clarify the issues and develop appropriate risk management tools and funding mechanisms.

■ **Increased Public Awareness and Support for CCS**

- The public generally has not yet formed a firm opinion of CCS and its role in the response to climate change. It is vital that government and industry significantly expand efforts to educate and inform the public about CCS.
- While some countries have begun strong CCS public awareness and education programmes, there is a lack of focused international discussion among experts about the lessons learned. More could be done to synthesise early results to facilitate future CCS public awareness efforts.

Introduction

A number of non-technical challenges need to be overcome if the full potential of CCS is to be achieved. These include:

- financing near-term demonstration projects;
- setting a long-term, sufficiently high and stable price for CO_2;
- establishing legal and regulatory frameworks; and
- educating the public to foster awareness and acceptance.

These critical non-technical issues are discussed in this chapter, beginning with perhaps the most important challenge: how to pay for CCS.

Financing CCS

In the current fiscal and regulatory environment, commercial fossil-fuel power and industrial plants are unlikely to capture and store their CO_2 emissions, as CCS reduces efficiency, adds costs, and lowers energy output.[13] Even in the European Union (EU), which has carbon constraints in place, the benefits of reducing carbon emissions are not yet sufficient to outweigh the costs of CCS. These barriers can be partially overcome by government support in the form of tax credits and other incentives. Even then, inertia in technology change and the lack of sufficient business incentives to bear the cost of CCS mean that there will need to be significant government and industrial financial support to facilitate CCS. The wider penetration of CCS will require such support at all stages of project development including near-term

13. Note that this is not true of CO_2-EOR, which can provide attractive early opportunities for CCS.

demonstration project financing, together with carbon constraints and/or CCS mandates and clear principles for the handling of long-term liability. All of these aspects can be considered part of the CCS financing chain.

This section describes the options available to governments and industry to finance CCS, and concludes by discussing ways in which a long-term enabling framework might be created for CCS that can effectively link climate change mitigation and energy policies.

Financing CCS Demonstration Projects

Recent IEA analysis estimates that between USD 30 billion and USD 50 billion will need to be invested to achieve the stated G8 goal of launching 20 full-scale CCS demonstration projects in the next few years (IEA, 2008). Government assistance is particularly needed at the early stages. Public-private partnerships have been formed to address this gap, but many projects have been cancelled or scaled back due to difficulties in locating sufficient resources to pay for them.

Experience from early CCS projects will guide subsequent future commercial deployment and foster the learning needed to facilitate CCS for the power generation and industrial sectors. There are a variety of promising early opportunities for CCS, including expanding existing CO_2 capture in natural gas processing, or in ammonia or hydrogen manufacturing where the CO_2 is already separated, and developing EOR activities where there are financially attractive storage options (Karstad, 2007). CO_2-EOR offers a particularly promising opportunity for early projects that are supported commercially by the value of additional recovered oil. Large volumes of CO_2 are currently being captured and used for EOR in the United States, the Middle East and other regions. With the right carbon pricing signals, the EOR market could provide important early demand for CO_2, estimated in total at 80 Gt given current technologies and CO_2-EOR practices (see Chapter 3).

The majority of CCS demonstration projects will need to be implemented in the electricity generation sector. There is limited worldwide experience of carbon capture from coal-fired power plants, and no experience of an integrated CCS project at a coal-fired power plant. There has been much debate about the minimum project size needed for meaningful demonstration of the relevant technologies. While the average power capacity of demonstration plants could be in the 400-500 MW range, anything much smaller than 100-200 MW will not meaningfully demonstrate the feasibility of CCS at scale.

Unlike EOR projects, electricity generation projects do not offer additional sources of revenue, and will indeed have higher costs. As a result, significant additional resources will be needed to stimulate investment. In addition, the cost of investing in the infrastructure required for CCS demonstration (and all energy sector) projects has grown in the past few years.[14] Governments are taking a variety of approaches to address the financing gap faced by electricity sector CCS demonstration projects, some of which are described in Box 5.1.[15] More information on power sector and other countries' CCS demonstration initiatives can be found in the regional overviews in Chapter 6.

14. At least three demonstration projects were cancelled or restructured in the past year as a result of escalating costs, including the US FutureGen project (see Box 5.1).

15. This list only highlights major CCS funding/policy efforts. More comprehensive information can be found, for example, in the CCS project list maintained by the IEA Greenhouse Gas R&D Programme (see web resources in Annex 3).

Box 5.1 Status of Major CCS Demonstration Funding Efforts

The ***Australian*** *Government's National Low Emissions Coal Initiative (NLECI) aims to accelerate the use of low-emission coal technologies, including CCS. The NLECI co-ordinate national efforts to achieve the commercial availability of CCS technologies by 2020. The strategy will identify priorities for research and demonstration technologies. The initiative is underpinned by a AUD 500 million (Australian dollar) National Low Emissions Coal Fund, to build a AUD 1.5 billion programme with State and coal industry funding. Elements of the NLECI include:*

- *a 7-10 year national low emissions coal research programme;*
- *demonstration of relevant technologies; and*
- *a national carbon mapping and infrastructure plan.*

The NLECI builds on the 2005 AUD 500 million Low-Emission Technology Demonstration Fund which is funding five projects (Cook, 2007).

In July 2008, the Alberta Provincial Government in ***Canada*** *created a CAD 2 billion (Canadian dollar) fund to advance CCS, with money allocated to encourage large-scale demonstration projects. The government will invite bids from industry and other stakeholders and award funding after an evaluation process (Scott, 2008).*

In 2008, to help administer ***Norway's*** *participation in funding and managing new CCS projects, the Norwegian government established the state-owned Gassnova SF. Gassnova will plan and execute CCS projects in co-operation with industrial partners, including:*

- *the Kårstø natural gas-fired power plant, with retrofitting to provide for* CO_2 *capture by 2010; and*
- *the Mongstad European test centre, a public-private partnership to establish a full-scale CCS project storing up to 1.4 Mt* CO_2 *per year by the end of 2014.*

The ***United Kingdom*** *Government is supporting the development of a commercial-scale CCS demonstration project. The project will capture the* CO_2 *produced by a 300-400 MW coal-fired power plant using post-combustion capture technology. The* CO_2 *will be stored offshore. The Government launched a competition in November 2007 to select the winning project and aims to have an operational project by 2014. Proposals from four groups were short-listed in May 2008 (BERR, 2008).*

The ***United States'*** *FutureGen Project was designed as a public-private partnership with a total cost of USD 1.5 billion. The costs were intended to have been shared between the federal government (USD 1.12 billion) and an "Industrial Alliance" of coal producers and users (USD 0.38 billion). The project was planned to take place in the State of Illinois (FutureGen Industrial Alliance, 2007). However, in January 2008, the United States Department of Energy (US DOE) announced that it was restructuring the project due to higher than expected costs. The US DOE now plans to equip a number of new cleaner-coal power plants with advanced CCS technology instead of funding one large demonstration project. The move is likely to delay the project as industrial partners seek to replace the missing federal government funds.*

Financing CO_2 Transport

Another important challenge to the wide-scale utilisation of CCS is the need to finance the infrastructure required to transport large volumes of CO_2 from capture sites to storage sites. The nature and extent of the network of CO_2 pipelines that will be needed will depend on many factors, including the distance between capture and storage sites, the costs of acquiring pipeline right-of-ways and associated permits, the cost of constructing pipelines, and the costs of operating the pipelines and complying with operations and maintenance regulations. The IEA estimates that in the first round of CCS demonstration projects, CO_2 transport and storage costs are likely to be in excess of USD 20/t CO_2 (IEA, 2008).

The development of shared CO_2 transport networks will generate efficiency benefits on a system level (ACCSEPT, 2007). But the costs and benefits of such networks will go well beyond the interests and budgets of individual CCS projects. As a result, governments may need to play a role in fostering the development of CO_2 transport pipelines, *e.g.* by taking ownership of existing pipelines and requiring users to pay a fee and/or by subsidising the construction of pipelines. In the European Union, a partnership for CO_2 transport pipelines could be modelled on the existing Trans-European Energy Networks.[16] Under this programme, the EU finances electricity and gas transmission infrastructure feasibility studies that are of European interest. Projects typically cross national boundaries and have an impact on several member states. More detailed analysis is needed to identify the best ways forward for financing CO_2 transport networks worldwide.

The Role of International/Multilateral Institutions in Financing CCS

Given the large sums of money that will be needed adequately to demonstrate CCS, the potential climate change benefits, and the need for the international transfer of knowledge and technology, international financial institutions have an important role to play in financing CCS. The new Carbon Partnership Facility (CPF) at the World Bank is a relevant project. The CPF will be established at the end of 2008 to develop GHG mitigation projects through the sale and purchase of GHG emission reductions. The first tranche of funding will provide several hundred million Euros. The World Bank forecasts that the CPF could grow to a multi-billion EUR funding facility over time. The first tranche will extend to GHG reduction programmes in various sectors using a range of technologies. In recent consultations on the CPF, a number of entities have already expressed strong interest in exploring the possibility of a CCS focused tranche in order to pilot carbon finance in the CCS context (World Bank, 2008).

Other multilateral development banks and financial institutions could also play a role in financing CCS technology transfer. In June 2008, the European Investment Bank (EIB) announced that it had dedicated EUR 10 billion to support risk-sharing in CCS projects in Europe, as well as another EUR 3 billion to finance projects outside the EU. The EIB has also expressed interest in funding CCS research and development (Maystadt, 2008). While organisations such as the EIB are lending institutions that provide loans (not grants) to commercial projects, their support is a helpful step.

CCS and Greenhouse Gas Regulations: A Long-Term Enabling Framework

For CCS to achieve its full climate mitigation potential, power plant and industrial plant investors must be able to justify the additional cost of CCS when they are selecting new technologies and constructing new plants. For this to happen, the cost of eliminating any fossil-fuel related CO_2

16. For more information on Trans-European Energy Networks, visit http://ec.europa.eu/ten/energy/studies/index_en.htm.

emissions must become a standard cost of doing business in the power and industrial sectors. A number of different policy tools have been suggested to achieve this, including:

- establishing a **GHG cap-and-trade** system;
- **mandating CCS** for new (and/or retrofit of existing) fossil fuel plants;
- developing **utility mandates** that require electricity generators to achieve a CO_2/kWh output standard over time, or that offer feed-in tariffs for CCS;
- **energy regulator approval of increasing electricity costs** for consumers (in regulated electricity markets, as in some states in the United States); and/or
- creating a dedicated **CCS Trust Fund** to manage CCS investments.

Each of these policy options is discussed briefly below.

GHG Market-Based Mechanisms and CCS: Current Status

One strategy for controlling GHG emissions from power and industrial plants is for governments to set mandatory caps on CO_2 emissions, coupled with emissions trading as a compliance mechanism. A number of jurisdictions have adopted market-based mechanisms like cap-and-trade schemes and more are under development.

Existing caps, such as those within the EU Emission Trading Scheme (ETS) and in proposed bills before Congress in the United States, are not stringent enough to trigger the high and sustainable CO_2 price levels that would result in substantial CCS investments. If the cost per tonne of CO_2 avoided through CCS is higher than the allowance price, entities covered by a scheme will buy allowances in the market (generated by lower-cost CO_2 reduction projects) rather than install CCS. Recent IEA analysis concludes that an incentive of at least USD 50/t CO_2 is needed by 2020 in OECD countries (by 2035 in non-OECD countries) to make CCS commercially viable (IEA, 2008). As a result, some have advocated the creation of special "bonus" allowances or other special treatment for CCS within cap-and-trade schemes. Other proposals combine cap-and-trade schemes with other policy instruments designed to overcome the cost difference between CCS and the standard business-as-usual technologies (MIT, 2007; Peña and Rubin, 2007).

Accounting for CCS in GHG Inventories. Under the United Nations Framework Convention on Climate Change (UNFCCC), Annex I Parties[17] are required to publish national inventories of human-induced GHG emissions and removals based on the Intergovernmental Panel on Climate Change (IPCC) *National GHG Inventory Guidelines.* Under the Kyoto Protocol, Annex I Parties must also provide emissions data on transactions under the three Kyoto flexible mechanisms and activities related to land use, land use change and forestry. Many governments also draw on the IPCC accounting guidelines in developing and administering domestic and regional mitigation policies, including emissions trading schemes.

At present, Annex I Parties are required to account for and report their emissions data based on the IPCC 1996 *Guidelines* and related 2000 *Good Practice Guidelines,* neither of which includes inventory methodologies for CCS.[18] In contrast, the 2006 *National Greenhouse Gas Inventory*

17. Annex 1 Parties include the industrialised countries that were members of the OECD (Organisation for Economic Co-operation and Development) in 1992, plus countries with economies in transition (the EIT Parties), including the Russian Federation, the Baltic States, and several Central and Eastern European States.

18. As a result, Norway reported the Sleipner CCS project in its latest national GHG inventory to the UNFCCC. Although the inventory applies the 1996 Guidelines *and 2000* Good Practice Guidelines *as required, it details the methodology used to account for emissions at the Sleipner site (SFT, 2006).*

Guidelines contain a dedicated section on CCS accounting procedures for the injection and geological storage of CO_2 (IPCC, 2006). These make clear that emissions avoided through CCS can only be claimed in national inventories if governments are enforcing the monitoring and reporting obligations outlined in the guidelines.

While not currently required as the basis for Annex I reporting, the 2006 Guidelines create a methodological basis for geological storage-related emissions reductions to be included in emissions trading or offset schemes. However, no CCS project has been involved in an emissions trading or offset transaction to date. The potential of the Kyoto Protocol's Clean Development Mechanism (CDM) and the EU ETS to support such transactions is discussed in further detail below.

The Clean Development Mechanism and CCS. The Kyoto Protocol provides three 'flexible mechanisms' to assist Annex I Parties to meet their binding emissions reduction targets: emissions trading, joint implementation (JI), and the CDM. Emissions trading involves the sale of surplus emissions allowances from one Annex I Party to another. JI and CDM are project-based mechanisms that provide investment incentives for reducing GHG emissions beyond a specified business as usual baseline. Emissions trading and JI activities take place within and between Annex I countries, while the CDM involves Annex I Parties financing the implementation of projects in non-Annex I Parties.

Developing countries with coal-fired electricity usage offer substantial opportunities for CCS and there have been at least three proposals to include CCS projects under the CDM.[19] The CDM Executive Board (EB) first considered the possible inclusion of CCS projects in the CDM at its 22nd meeting in November 2005, but was unable to agree on how CCS should be handled. Consequently, the EB requested the Conference of the Parties (COP) to the UNFCCC acting as the Meeting of the Parties (MOP) to the Kyoto Protocol (COP/MOP) to provide guidance, taking account of methodological issues. At the next two COP/MOPs, it was decided that more time was needed to consider these methodological issues. At the June 2008 meeting of the UNFCCC and Protocol's Subsidiary Bodies in Bonn, parties were not able to reach conclusions on inclusion of CCS in the CDM and deferred further consideration of the issue to the next Subsidiary Body meeting, which will take place in Poznan, Poland in December 2008.

The main challenges to the inclusion of CCS in the CDM include (de Coninck, 2008):

- the possibility that CCS projects, because of their large size, might "crowd out" other CDM project types;[20] and
- methodological and regulatory uncertainty about storage permanence, project boundaries (including trans-boundary issues), and leakage.

The first of these challenges is not likely to be significant. There are considerable threshold costs for reducing CO_2 emissions using CCS, so projects are unlikely to go ahead if the international carbon price is low. CCS projects will also have considerable lead times for implementation; and institutional capacity-building will also be required. As a result, few CCS CDM projects would be commissioned by 2012 (Philibert, *et al.,* 2007). Given the importance of mitigating developing country emissions from fossil fuels, the possibility of CCS crowding out other project types should

19. None of these projects is for a coal-fired power plant with CCS. The projects are: the White Tiger Field project in Vietnam involving CO_2 capture from natural gas combined-cycle plant and storage in offshore or onshore oil field with EOR; a Petronas project in Malaysia involving CO_2 and hydrogen sulfide (H_2S) capture from an offshore gas well with storage in an aquifer; and a small-scale project involving anthropogenic ocean sequestration by alkalinity shift (Kirkman, 2008).

20. By one estimate, widespread uptake of just the short-term CCS opportunities could more than double the current CDM portfolio of 380 Mt of credits annually between 2008 and 2012 (Philibert, et al., *2007).*

be considered in any post-2012 revision of the CDM and/or in the development of any additional or alternative flexible mechanism that may form part of the post-2012 international climate change architecture. The methodological issues are more challenging, but could be addressed in a step-by-step fashion by approving a methodology for a "simple"[21] CCS project first, and adapting this methodology to cover more complicated project types over time (Philibert, *et al.,* 2007).

EU Emissions Trading Scheme (ETS). The EU ETS was introduced as the main instrument to bring the EU's emissions into line with its international GHG emissions reduction objectives. The scheme comprises the world's largest market for installation-level emissions trading. In the first period, 2005-07, approximately 45% of EU emissions and more than 15 000 installations were covered. Electricity generation accounts for more than half of all emissions covered by the scheme.

The ETS is considered by the European Commission (EC) to be a principal policy instrument for encouraging future CCS activities within the EU (EC, 2008). Under the scheme, CO_2 emissions captured in qualifying CCS operations are recognised and counted as CO_2 that is not emitted. In the second phase of the ETS (2008-12), CCS projects can be "opted in" under Article 24 of the Emissions Trading Directive (Council Directive 96/61/EC). This Article requires that a chain from CO_2 source, through capture, transport and injection to storage is treated as one installation, and sets down relevant monitoring and reporting guidelines (MRGs). The installation as a whole is allocated allowances in line with similar installations not employing CO_2 capture. No additional allowances are provided for the capture, transport and storage activities. This approach allocates all the risk and liability for emissions to the installation. In the medium-term it might be useful to provide more flexibility within the scheme to deal with the potential for multiple operators using common carriage networks.

For the third phase of the ETS (2013-20), the EC has proposed to amend the Emissions Trading Directive to provide separate allocations for each of the three phases of capture, transport and storage (EC, 2008). This is important for CCS, as full auctioning of CO_2 certificates is proposed for the electricity sector and CO_2 that is captured and stored will be regarded as non-emitted. Thus, CO_2 certificates will not have to be purchased by CCS power plants, giving CCS plants a comparative advantage over power plants not using CCS. As set out in further detail in Chapter 6, these proposals include chain of custody MRGs, a clear basis for storage site closure, and arrangements for the assignment of liability for sites, among many other features. If adopted, these proposals could pave the way for more comprehensive coverage of CCS under the EU ETS. To be more fully included in the EU ETS, detailed chain of custody MRGs need to be developed from source to storage, providing the basis for accounting of any emissions of the captured CO_2 across the CCS chain.

The Commission's January 2008 proposal does not propose that CCS be explicitly mandated in any form or for any processes. Rather, it allows the market to drive the uptake of CCS. As a result, the Commission envisages that CCS will not contribute substantially to the EU's emissions reductions until after 2020, with an estimated capture of over 13% of all EU CO_2 emissions in the electricity and steam sector by 2030 (EC, 2008). More will need to be done to facilitate CCS deployment in the near- to medium-term if longer-term performance is to be improved.

Other announced or proposed emissions trading schemes include the Japan Voluntary Emissions Trading Scheme, the New South Wales and the Australian Capital Territory Greenhouse Gas

21. A "simple" CCS project is one located in a single national jurisdiction, with only one CCS project in the reservoir, without fossil fuel extraction from the reservoir, and without abandoned oil fields tied to the reservoir (Philibert, et al., 2007).

Abatement Scheme, the Norwegian Trading Scheme (now linked to the EU ETS), the Swiss opt-in Emissions Trading Scheme, the New Zealand Emissions Trading Scheme, the Regional Greenhouse Gas Initiative in the United States and Alberta's Climate Change and Emissions Management Act in Canada.[22]

In addition, a number of cap-and-trade proposals are actively being considered in the United States Congress, many of which include allowance set-asides or other special treatment to advance CCS. However, it seems unlikely that these measures will facilitate near-term deployment of CCS as the cost of capture and storage is likely initially to be higher than the allowance price. Additional components such as free bonus allowances, subsidies from allowance auctioning, or performance standards for new plants may be needed if investment in CCS is to be stimulated in this timeframe (Sussman, 2008).

Technology mandates. Most countries have air pollution control regulations that require new power and industrial plants to meet pre-defined best available technology (BAT) emissions standards for various pollutants, including sulphur dioxide, nitrogen oxides and particulates. Some have proposed that such mandates be extended to cover emissions of CO_2. In such circumstances, the BAT for new coal-fired power plants might be defined by reference to integrated gasification combined-cycle (IGCC) plant fitted with CCS (Sussman and Berlin, 2007). Alternatively, regulations could more explicitly provide for the mandatory inclusion of CCS in all new fossil-fuel power plants, or even mandate the inclusion of CCS in any retrofit of plants. While this might lead to greater certainty in investment costs, and might speed up technology development and deployment rates, differing interpretations across jurisdictions could increase transaction costs. For example, technology mandates might lock in or force the use of technologies which might be more expensive than alternatives with a similar CO_2 profile. For these reasons, as the EC found when it considered mandating CCS as one option for encouraging deployment, BAT technology mandates may be less cost-effective than market-based approaches such as emissions trading (EC, 2008).

Utility mandates. To level the playing field between traditional fossil-fuel electricity generation and power plants with CCS, retail "generation performance standards" and similar tools are under discussion as a means of encouraging electricity companies to invest in CCS (Sussman and Berlin, 2007). Such standards could be applied to electricity retailers either as a net CO_2 emission rate per kWh sold or as a required (and rising over time) percentage for low-carbon electricity generation. Plant owners would meet commitments by generating electricity from units equipped with CCS, by purchasing electricity from such units or by purchasing credits from other low-carbon generators. Such an approach would spread the costs of building new CCS plants across all generators by requiring those utilities that do not build CCS plants to subsidise those that do. The main drawback to such an approach is that utilities are deterred from significant investment in CCS because of the risk that they will recover their investment in a suitable time period. Alternatively, feed-in tariffs could offer a guaranteed purchase price for all electricity from facilities fitted with CCS.

Electricity regulator approval of higher costs. CCS mandates and GHG emissions caps will result in higher costs for electricity generators and industry. In jurisdictions where electricity markets are regulated, electricity generators need to be reassured that the cost of their investments in new technology will be recoverable either directly or through regulated prices (Cowart, *et al.,* 2007). In setting prices, energy regulators are attempting to strike a balance between acknowledging the investment risks faced by electricity producers and the need to protect consumers from inefficient investment or excessive profit taking.

22. For an update on global ETS activities up to December 2007, see *Reinaud and Philibert, 2007.*

To address investment risk and uncertainty, some have proposed that CCS power projects be pre-approved for cost recovery. In 2006, for example, the Ohio Public Utilities Commission allowed the American Electric Power (AEP) utility to recover its preconstruction costs for an IGCC CO_2 capture plant, including the costs for an engineering and design study. The Indiana Public Utilities Commission also approved a settlement providing cost recovery for IGCC engineering and design costs under USD 20 million (Cowart, *et al.,* 2007). However, in April 2008, the Public Service Commission of West Virginia and the Virginia State Corporation Commission both denied cost recovery for a proposed AEP IGCC plant in West Virginia, saying that the risk for customers was too great since the costs were likely to be double the costs of a traditional coal-fired power plant (Wald, 2008).

The approval of cost recovery may provide greater incentive and certainty to electricity generators to move forward with CCS. However, this approach is not likely to be the answer in all cases – even in regulated markets – as regulatory commissions must take into account a range of factors in reaching a decision, such as the risks to and impacts on consumers.

Creation of a dedicated CCS Trust Fund. Another approach that has been proposed in the United States is to develop a government programme to jump-start 10 to 30 early demonstration CCS projects by reimbursing the incremental costs, including the electricity output capacity lost due to CCS operation (Kuuskraa, 2007). These costs are estimated at USD 10 billion to USD 30 billion over a 10 to 15 year period. The programme would be funded through the creation of a dedicated CCS Trust Fund modelled on other similar funding mechanisms such as the 1950s US Highway Trust Fund. Under this model, a fund would be established to receive specified revenues taken by the government (such as from the auctioning of GHG allowances created under a cap-and-trade system), or from a tax on electricity generated or coal purchased by utilities, with another entity holding the money in a trustee capacity to be expended on designated programmes or activities (Peña and Rubin, 2007). The argument for adopting such an approach is that it may be difficult to impose stringent CO_2 control requirements (including generator performance standards or CCS mandates) until the viability of CCS has been proven. The next phase of the EU ETS is widely expected to include the auctioning of allowances. Subject to the agreement of EU member states, some of revenue derived from auctioning could similarly be dedicated to a CCS Trust Fund (EC, 2008c).

Combination of approaches. Each of the approaches above has merits and disadvantages, and an approach that works in one regulatory setting or market context may not work in another. Market-based approaches are likely to offer the most cost-effective options. But they are unlikely to encourage sufficient technology deployment in the near-term. They may also impose a high marginal cost on all CO_2 sources if CCS is entirely supported by the price mechanism, while other policy options may help lower its cost. In considering different approaches, governments will need to examine relative costs, the extent to which adequate technical and regulatory infrastructure exists or can be developed in time and any co-benefits, for example reducing air pollution or enhancing energy security.

A short table of the potential benefits and limitations of each approach is provided in Table 5.1. These approaches are not mutually exclusive. Governments can and should consider combining approaches. For example, a CCS Trust Fund might be combined with a stringent GHG cap-and-trade system to ensure the optimal role for CCS in an energy and climate change programme. A general guiding principle is that governments should seek to combine assured financial support in the near-term with stringent emission standards to achieve optimal outcomes.

Table 5.1 Options for Financing CCS

	Emissions trading	Mandating CCS	Utility mandates	Energy regulator approval of higher costs	CCS trust fund or other specific govt subsidies
Benefits	***Market selection:*** allows the market to select CCS if it is the most cost-effective mechanism for reducing GHGs (compared to other means such as renewable energy or energy efficiency). ***Cost-effectiveness:*** for this reason, it may be one of the most cost-effective means of encouraging CCS.	***Faster pace of deployment:*** higher technology development and CCS deployment rates in the near-term. ***Wider deployment:*** likely also to encourage more extensive deployment.	***Distributing the cost:*** spreads the costs of building CCS infrastructure to all generators, by requiring those utilities that do not build CCS plants to subsidise those that do.	***Possibility for incentives and certainty:*** when approved, it may provide greater incentives and certainty to electricity generators to move forward with CCS.	***Simpler:*** such an approach may be easier to implement. ***Certainty:*** arguably provides for a more certain, stable source of funding. ***Faster pace of deployment:*** may encourage faster deployment and technology development.
Limitations	***Slow to take off:*** may be insufficient to encourage rapid development of CCS, particularly in the near-term.	***Higher costs:*** may not be the most cost-effective means of reducing GHGs in the near-term. ***Technology lock-in:*** risks locking in non-optimal technology or discouraging further innovation.	***Higher risk for first to invest:*** utilities that invest in CCS up front will have to assume significant risk that they will recover their investment in a suitable time period.	***Uncertainty***: regulatory commissions will vary in their decisions – taking account a range of factors such as the risks to and impacts on consumers – and are also likely to take time to do so. This kind of process may therefore slow down CCS development and in some instances, reduce certainty.	***Higher costs:*** this may be a more costly option for governments, particularly in the near-term.
Comments	Impacts may vary depending upon the precise nature of the proposal, such as whether a cap-and-trade scheme is combined with other policy instruments to overcome cost differences between CCS and 'business-as-usual' technologies.	Risks locking in particular technologies, which could distort costs.			

Source: IEA analysis.

Legal and Regulatory Issues

CCS regulations will need to evolve as scientific and technical experience grows. An adaptive, evolutionary regulatory process will be required. Full-scale CCS demonstration projects will provide important data and experience with CO_2 retention monitoring and verification procedures and technologies. These results will then need to be fed back into regulatory development.

Initially, full-scale demonstrations are likely to be operated under existing regulations, modified to account for specific CCS issues, covering the injection of liquid wastes, oilfield brines, natural gas, acid gas, steam and other fluids. Data from early projects can then be used to help develop more broadly applicable CCS regulations that can govern commercial deployment. The transition from early to mature regulations could be accomplished through existing regulatory bodies. New institutions and/or mechanisms may also be required to co-ordinate and integrate emerging knowledge and establish the long-term regulatory and legal framework for CCS. Governments should guard against becoming tied to a regulatory structure that may be appropriate for early demonstration projects but suboptimal for the widespread commercial use of CCS.

The expansion of CCS will raise a number of legal and regulatory issues. The most important of these include: developing regulations for CO_2 transport; establishing jurisdiction among international, national, state/provincial and local government actors; establishing ownership of storage-space resources and legal means for acquiring the rights to develop/use such resources, including access rights; developing clear guidelines for site selection, permitting, monitoring and verifying CO_2 retention; clarifying long-term liabilities and financial responsibility for CO_2 storage operations; and, in the case of offshore CO_2 storage, complying with appropriate international marine environment protection instruments.

Many of these issues were covered in detail in the IEA publication *Legal Aspects of Storing CO_2 - Update and Recommendations* (IEA, 2007). The following sections update and expand upon this material, by discussing legal aspects of CO_2 transport, among other issues.

Box 5.2 International Collaboration on CCS Legal and Regulatory Issues

Since 2004, the IEA has managed an international effort to provide and exchange information on the legal and regulatory aspects of CCS. The IEA has co-sponsored workshops with the Carbon Sequestration Leadership Forum in 2004, 2006 and 2008, producing a series of IEA publications titled Legal Aspects of Storing CO_2 *in 2005 and a much-expanded update in 2007.*

In May 2008, the IEA launched the International CCS Regulators Network. *This comprises regulators from around the world who share case studies, challenges and solutions as jurisdictions attempt to develop workable, effective and harmonised regulatory frameworks to govern CCS. The Network hosts regular web conferences on specific CCS legal or regulatory topics and an annual update meeting to share experiences and new developments.*

For more information, see www.iea.org/Textbase/subjectqueries/ccs_legal.asp.

Legal Issues Associated with CO_2 Transport

The safe and effective transportation of CO_2 requires the management of local environmental and safety risks and the mitigation of the potential impacts of CO_2 leakages on the global environment. There are different options for transporting CO_2 from capture sites to storage locations, including pipelines and pressurised road and sea tankers. Given the large volumes of CO_2 that are likely to need to be injected, pipelines offer the most cost-effective means of transport. As a result, most governments are focusing in the near-term on pipeline regulations (MCMPR, 2005). If other, non-pipeline transport mechanisms are used, they will require suitable regulatory frameworks to minimise safety and environmental risks. The most difficult issues in CO_2 pipeline regulations relate to funding, pipeline siting, and pipeline access.

Managing environmental and safety risks. Given decades of international experience with the transport of natural gas by pipeline with few safety and environmental incidents, CO_2 transport is not expected to create major concerns (IPCC, 2005). A number of early EOR projects already transport CO_2 through pipelines in the United States, Canada, and other jurisdictions. The main differences between transporting natural gas and CO_2 via pipeline from an environmental regulatory perspective are (MCMPR, 2005):

- when CO_2 mixes with water it becomes acidic and corrosive;
- CO_2 is heavier than air;
- CO_2 is transported at almost double the pressure of natural gas;
- CO_2 is odourless; and
- CO_2 is not flammable.

It is envisaged that many of the safety measures and monitoring techniques employed by the natural gas industry can be applied to CO_2 transport via pipeline, with modifications to take into account the differences between natural gas and CO_2. The requirements include assignment of liability for leakage or other hazard to the pipeline owner and development of appropriate standards for the design, construction and maintenance of pipelines. A number of governments and Non-Governmental Organisations (NGOs) are working on guidelines and standards (see, *e.g.* WRI, 2008; Whitbread, 2008).

Pipeline siting and access. There are a number of regulatory and financial issues related to CO_2 pipeline access and siting. Inter-provincial CO_2 pipelines currently exist in Canada, and are governed by existing natural gas pipeline regulations. In the United States, CO_2 pipeline safety is regulated at the federal level by the Department of Transportation; pipeline siting, construction and rate regulations are handled by individual States. CO_2 pipelines in the United States may also be subject to access and rate conditions imposed by the Bureau of Land Management when they cross Federal lands (Vann and Parfomak, 2008).

Given the anticipated increases in the volumes of CO_2 being transported to accommodate the expansion of CCS, there will be a major need for new CO_2 pipelines, which will require existing regulatory frameworks to be adapted. Siting a new CO_2 pipeline will involve determining the route, acquiring the rights of way, and assessing the environmental impacts of the proposed route. The right of way typically involves gaining access to a portion of a current access route, or obtaining access via easement or other mechanism to private property. The pipeline owner must acquire the use of the land along the pipeline right of way. A pipeline developer can either use an existing right of way corridor or create a new one by negotiating with each landowner along the route. Regulators may need to secure land for CO_2 pipeline infrastructure where that is deemed to be in the public interest.

As a CO_2 transport system develops from a series of unlinked state or national pipelines to a network of regional or inter-state pipelines, there will be a need to harmonise CO_2 pipeline regulations across state/province or national borders to eliminate inconsistencies in pipeline access and CO_2 purity requirements, and to address rate "pancaking" issues.[23] There will also be a need to evaluate the necessary pipeline capacities for particular regions as CO_2 storage activities expand. Co-ordinated efforts will be required to create coherent inter-state/provincial and international planning and regulations for CO_2 transport pipelines. One approach that is already used in the natural gas sector to streamline pipeline construction and access is to create a "one stop" agency for pipeline permitting, where various approvals are handled by one entity in consultation with stakeholders (WRI, 2008).

Jurisdiction: Assigning Regulatory Responsibility for CCS

Regulatory responsibility for CCS will include authorities at the international, national, state/provincial and local levels. It is clear that the successful expansion of CCS also requires national commitments and programmes of research, demonstration, regulatory development and ultimate deployment via financial or other incentives. For example, verifying and trading CO_2 allowances will require national oversight, even within international schemes. Offshore CO_2 storage projects will be subject to international and national regulations to a greater extent than onshore projects. However, environmental and health issues might be best addressed at the state or local level. As a result, CCS deployment will require extensive coordination between supranational, national and state/provincial and local jurisdictions.

State/provincial or local government responsibilities for CCS projects might include, among other things (Cowart, *et al.,* 2007):

- issuing air and other environmental permits;
- issuing injection permits and/or oil and gas management rules for EOR;
- siting approvals for plants, pipelines or transmission pathways;
- regulatory approval for higher consumer electricity rates; and
- assignment of physical and financial risks.

In the United States, Canada and Australia, the states and provinces have been the principal regulators of EOR, as well as natural gas storage and acid gas disposal. Regulations already exist in these sub-national jurisdictions covering many of the same issues that need to be addressed in the regulation of CO_2 storage. Such regulations may provide a framework for CO_2 storage (IOGCC, 2005; MCMPR, 2005; Bachu, 2008).

States and provinces can also play other roles in CCS projects. For example, some states in the United States have provided regulatory and financial support to planned CCS projects, including direct expenditure or tax credits in Illinois, creation of a "one-stop" agency to streamline CCS power plant transport and storage approvals in Ohio, pre-screening of CO_2 storage sites in New York, and limiting liability for any accidental release of CO_2 in Texas (Cowart, 2008). Local regulators are also likely to play an important role in areas like CO_2 injection and the regulation of health, safety and environmental concerns. Regulators at all levels will need sufficient resources to allow them to increase their expertise to manage the growing area of CCS regulation.

*23. Rate pancaking occurs when a common carrier (*e.g.*, pipeline or electricity transmission system) spans state/provincial borders and a number of carrier owners or operators collect their own access charges.*

Site Selection, Monitoring and Verification

Local and global environmental risks of CO_2 storage can best be managed accomplished through the establishment of a sound set of MRGs for site selection, monitoring and verification. Local risks include: the seepage of CO_2 to the atmosphere or near the surface; migration to sensitive ecosystems and/or groundwater aquifers; and direct human exposure to concentrated CO_2. A number of publications document these risks in detail (Celia and Bachu, 2003; Wilson and Gerard, 2007; Benson, *et al.*, 2002). In addition to local risks, there are also global environmental risks if stored CO_2 leaks to the atmosphere and compromises the effectiveness of a national or international system for GHG emissions reductions. Such risks can have important financial and contractual implications. Governments have not yet adopted comprehensive guidelines to address these issues.

Risks Associated with CCS

The principal risks associated with CCS arise during CO_2 storage site injection and immediately after site closure.[24] The IPCC estimates that, provided that geological reservoirs are appropriately selected and managed, the CO_2 fraction retained underground is (IPCC, 2005):

- very likely to exceed 99% over 100 years (with a probability greater than 90%); and
- likely to exceed 99% over 1 000 years (with a probability higher than 66%).

The main risks of CO_2 geological storage arise from the following conditions (Heidug, 2006):

- inadequate (poorly designed and/or aging) injection wells;
- unidentified and/or poorly abandoned wells;
- inadequate cap rock characterisation; and
- seismic events and migration via natural fractures or hydrologic flow.

The most prevalent risk is the migration of CO_2 within well bores, through the interfaces between the well, the cement and the geological formation, or through the un-cemented or poorly cemented portions of a well. In the presence of water, CO_2 becomes acidic. This can affect the integrity of the wellbore cement, although some cement may also form a protective layer of carbonate that will stop further cement degradation. Methodologies have been developed for cementing oil and gas well bores, even in high CO_2 and H_2S environments such as the Caspian Sea and deep gas reservoirs in the foreland basins of the Rocky Mountains, but these wells typically have a life of only a few decades. CO_2 storage will require assured isolation for hundreds of years, and industry standards (and technologies) need to be developed accordingly. New methodologies need to be developed to test the integrity of the cementing material in presence of supercritical CO_2 along with CO_2-resistant materials that provide long-term integrity (Barlet-Gouedard, *et al.*, 2007). Alberta has had relevant experience regulating acid gas injection that may also be relevant.[25]

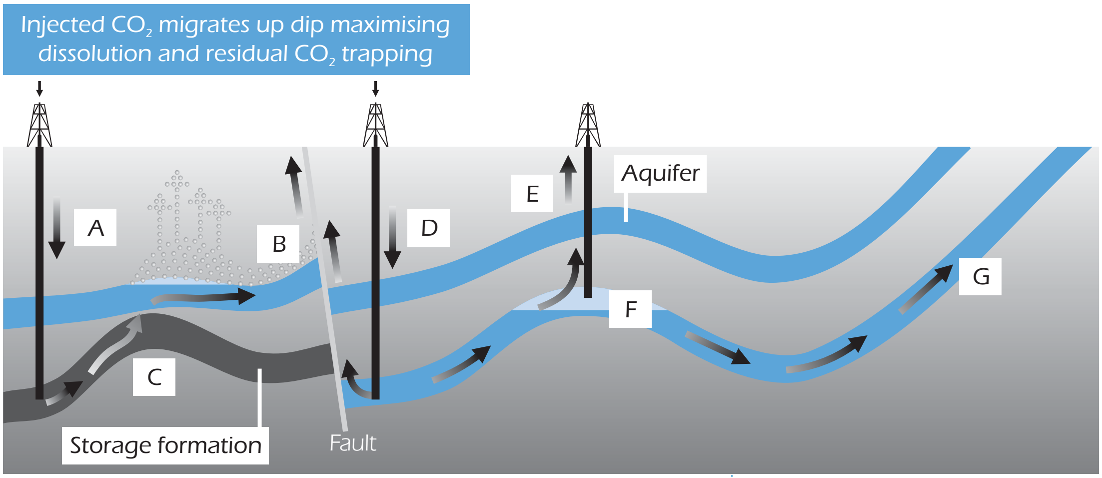
24. The risks associated with CO_2 capture are limited. Impurities that are captured along with the CO_2 can be separated out and treated, although in some cases it may be beneficial to inject them together with the CO_2 given their toxic nature and high cost of separation. CO_2 transport risks are discussed above.

25. See www.nrcan.gc.ca/es/etb/cetc/combustion/co2network/htmldocs/project_details_2_e.html *for more information.*

Figure 5.1 CO_2 Potential Leakage Routes and Remediation Actions

Key point

There are a number of remediation options to control CO_2 leakage.



Potential escape mechanisms

A. CO_2 gas pressure exceeds capilarity pressure and passes through siltstone
B. Free CO_2 leaks from A into upper aquifer up fault
C. CO_2 escapes through " gap" in cap rock into higher aquifer
D. Injected CO_2 migrates up dip, increases reservoir pressure and permeability of fault
E. CO_2 escapes via poorly plugged old abandoned well
F. Natural flow dissolves CO_2 at CO_2/water interface and transports it out of closure
G. Dissolved CO_2 escapes to atmosphere or ocean

Remedial measures

A. Extract and purify ground water
B. Extract and purify ground water
C. Remove CO_2 and re-inject elswhere
D. Lower injection rates or pressures
E. Re-plug well with cement
F. Intercept and re-inject CO_2
G. Intercept and re-inject CO_2

Source: Heidug, 2006.

Remediation options to control possible CO_2 escapes are summarised in Figure 5.1, although it is not expected that such escapes should happen in well-selected and designed storage sites.

Site Selection

Successful CO_2 storage will depend on successful site characterisation, including a demonstration that a proposed site has the necessary injectivity, capacity and storage integrity (IPCC 2006; IRGC, 2007). The challenge with CO_2 storage site selection is to identify geologic formations that are well-suited to long-term CO_2 retention. Although there are regulatory frameworks for site characterisation for related industries, there is a strong need for detailed, flexible CCS site selection guidelines.

The performance of CO_2 during and after injection can be predicted using CO_2 simulation models. This step is important as a quality assurance and optimisation requirement. Modelling and simulation also play a key role in determining the requirements for site closure and post-injection monitoring. As technology and monitoring/assessment processes mature it will be important to develop a consensus on guidelines for site assessment and selection to ensure that the highest quality sites are selected. Large-scale demonstrations will provide critical information in this regard. Assessment systems could assign appropriate weights to individual criteria, and assign scores based on each criterion, and then rank potential storage sites.

Monitoring and Verification

CO_2 storage project monitoring involves the direct, indirect, or inferred measurement of properties and variables related to storage performance. Monitoring provides a basis for risk management to ensure that CO_2 remains contained within pre-defined geological structures, and does not flow back to the surface or into subsurface zones where it may be detrimental to other resources such as fresh water or oil and gas reservoirs. Monitoring also offers an important opportunity for model validation and optimisation. For GHG regulatory certainty and public acceptance, monitoring provides critical evidence of the integrity of projects and expected CO_2 emission reductions.

Monitoring requirements will be different for different phases of a CO_2 storage project (Benson, 2007):

- During site **selection, assessment and certification,** measurement will be essential for setting the project baseline from an environmental and hydrological perspective.
- During **injection,** monitoring will help to enable the control of injection parameters (*e.g.* rates of injection) and confirm the validity of predictions from modelling simulations. In the event of discrepancies, monitoring will allow project operators to update and re-optimise the project parameters.
- Monitoring during **closure and after closure** will also be necessary. After CO_2 injection has stopped, and a project's performance has been assessed, government and project operators must work together to establish post-closure monitoring parameters. The post-closure phase will involve the documentation of CO_2 plume migration and information on well monitoring, among other things.

Figure 5.2 shows the stages of a CO_2 storage project from the initial site characterisation to the long-term stewardship that will need to continue after the project is closed.

Lessons can be learned from other similar activities. A century of experience with underground natural gas storage (UGS), industrial waste storage, acid gas disposal, and oil and gas trapping may provide pointers as regulators develop MRGs for CO_2 storage (Benson, *et al.,* 2002; Heinrich, *et al.,* 2004). UGS facilities are generally in brine-filled aquifers and salt caverns, and have been operating for almost a century with strong safety records, due to the monitoring frameworks that have been developed to address specific risks.[26] Acid gas disposal operations in North America have used deep saline aquifers and depleted oil and gas reservoirs as injection zones with a good safety record for 20 years (Bachu and Gunter, 2005). Acid gas disposal is also common in Europe at empty natural gas fields.

There are no international or national standards for the performance of CO_2 storage sites. In 2006, the IPCC published specific accounting guidelines for CCS projects for the first time its *Guidelines for National GHG Inventories.* In the near future, these guidelines are likely to be the main source of monitoring and accounting methodologies. In the future, MRGs may be developed by other international, national or regional bodies. While the IPCC believes that more than 99% of the CO_2 stored in geological reservoirs is likely to remain there for over 1 000 years, the potential migration of CO_2 must be considered.[27] The IPCC offers procedures for estimating and reporting emissions for CO_2 storage sites in Figure 5.3.

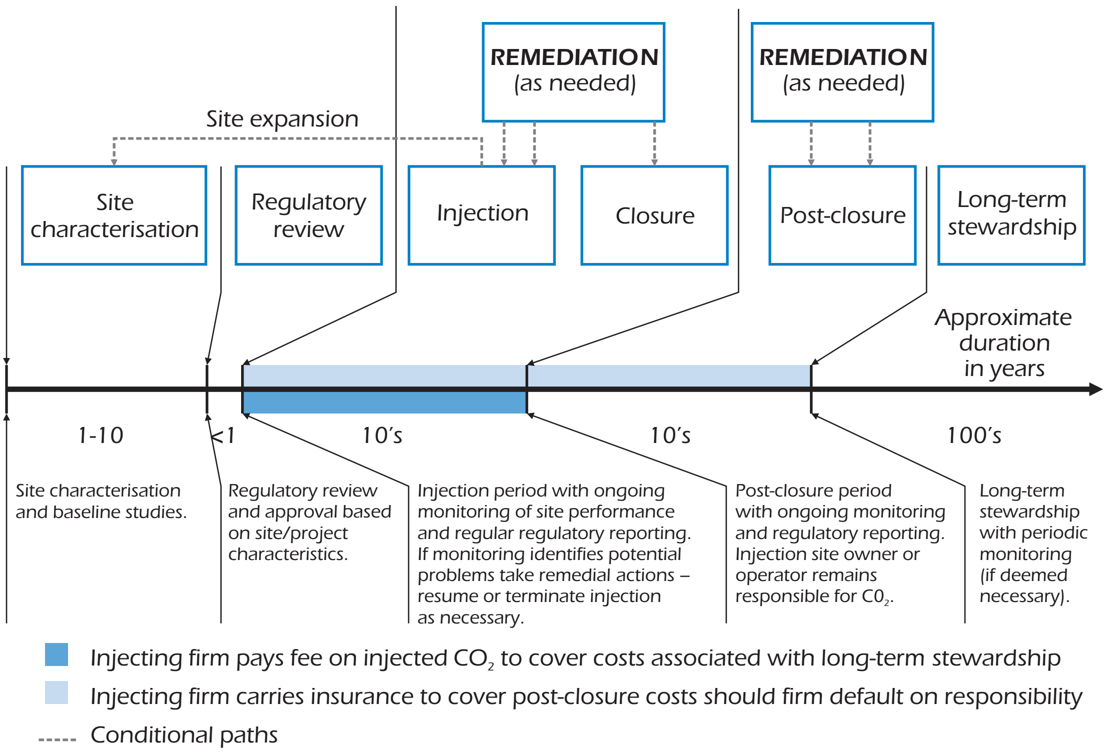
26. Most of the leaks that have occurred have been the result of well bore failures (inadequate cementing, or plugging and abandonment) that were easily remediated (Benson, 2002).

27. The only emissions pathways that need to be considered in the IPCC accounting are CO_2 leakages to the ground surface or seabed from the geological storage reservoir (IPCC, 2006).

Figure 5.2 Stages of a CCS Project

Key point

Regulatory needs and liability are different for each stage of a CO_2 storage project.



Source: Rubin, 2007.

Box 5.3 International Collaboration on CCS Monitoring and Risk Assessment

The IEA GHG R&D Programme manages a number of networks dedicated to CCS risk assessment and monitoring. ***The Monitoring Network*** *was established in 2004 and has developed a set of CO_2 monitoring techniques. As no single technique could meet all the different monitoring needs, the network has sought to focus more on monitoring programmes than on individual techniques.* ***The International Risk Assessment Network****, established in 2005, compares approaches and methodologies and exchanges lessons learned and best practices from risk assessment activities around the world. A dedicated* ***Network on Wellbore Integrity*** *was spun off from the Risk Assessment Network in 2005 to document approaches for well construction and isolation monitoring.*

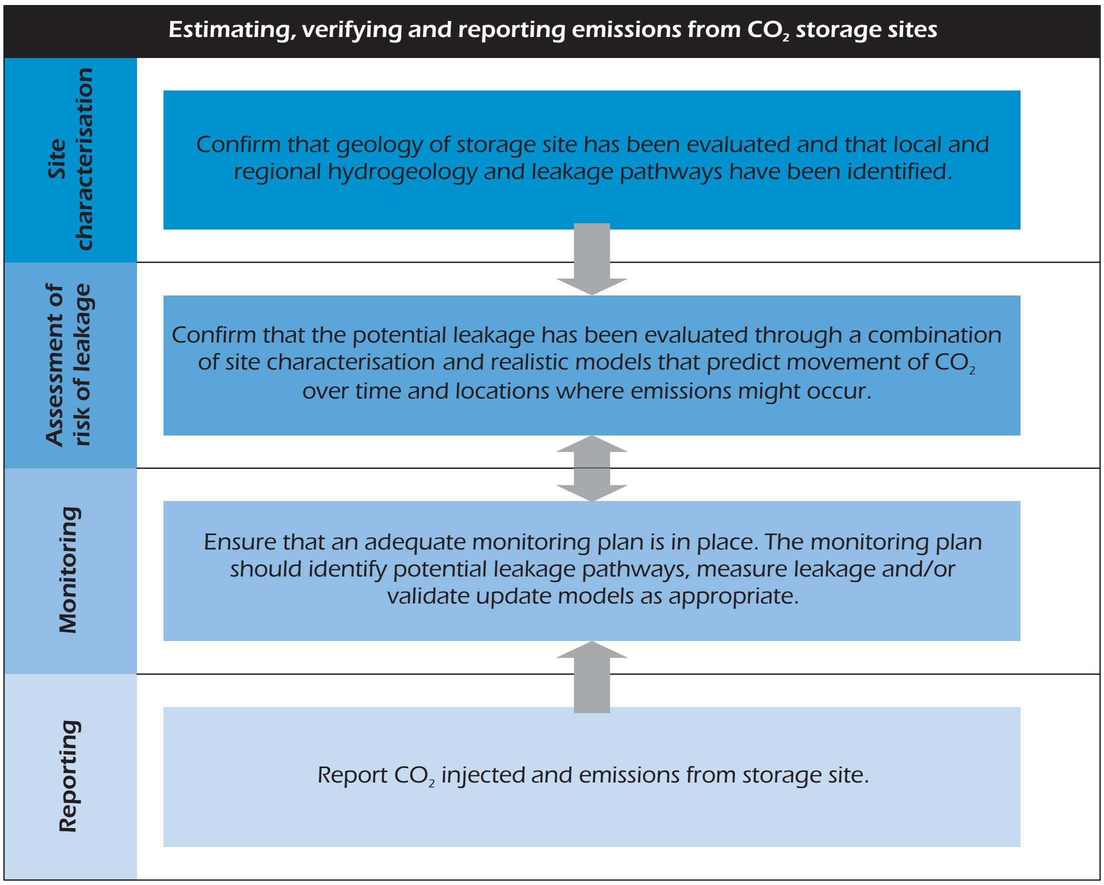
The IEA GHG R&D Programme has also developed a monitoring selection toolbox to identify and rank technologies for CO_2 storage monitoring, including all phases from site screening and assessment to post-closure. The toolbox includes 39 monitoring techniques, spanning atmospheric measurements to monitoring sub-surface variables, and can be used as a reference tool.

For more information, see http://www.co2captureandstorage.info/co2tool_v2.1beta/index.php.

Figure 5.3 IPCC Procedures for Estimating Emissions from CO_2 Storage Sites

Key point

The IPCC methodology is a starting point for future CCS monitoring and verification frameworks.



Source: IPCC, 2006.

The IPCC *Inventory Guidelines* suggest several elements of a CO_2 storage site monitoring plan to ensure that the site operation (and closure) is consistent with the leakage assessment and modelling results. At the very least, verification will require measurement of the quantity of CO_2 injected and stored. Demonstrating that CO_2 remains within the storage site requires a combination of models and monitoring. Monitoring requirements may be site-specific, depending on the regulatory environment and risk of leakage. The IPCC 2006 *Inventory Guidelines* provides a protocol for assessing storage performance based upon site characterisation and monitoring, allowing zero leakage assumptions to be made if monitoring indicates this is appropriate (IPCC, 2006). Verification oversight will probably be handled by regulators, either directly or using independent third parties.

Long-Term Liability

Any regulatory and liability framework for CO_2 storage sites needs also to define the roles and financial responsibilities of industry and government after site closure and permanent decommissioning. The level of risk associated CO_2 storage project will evolve as the project progresses along its life cycle (see Figure 5.4).

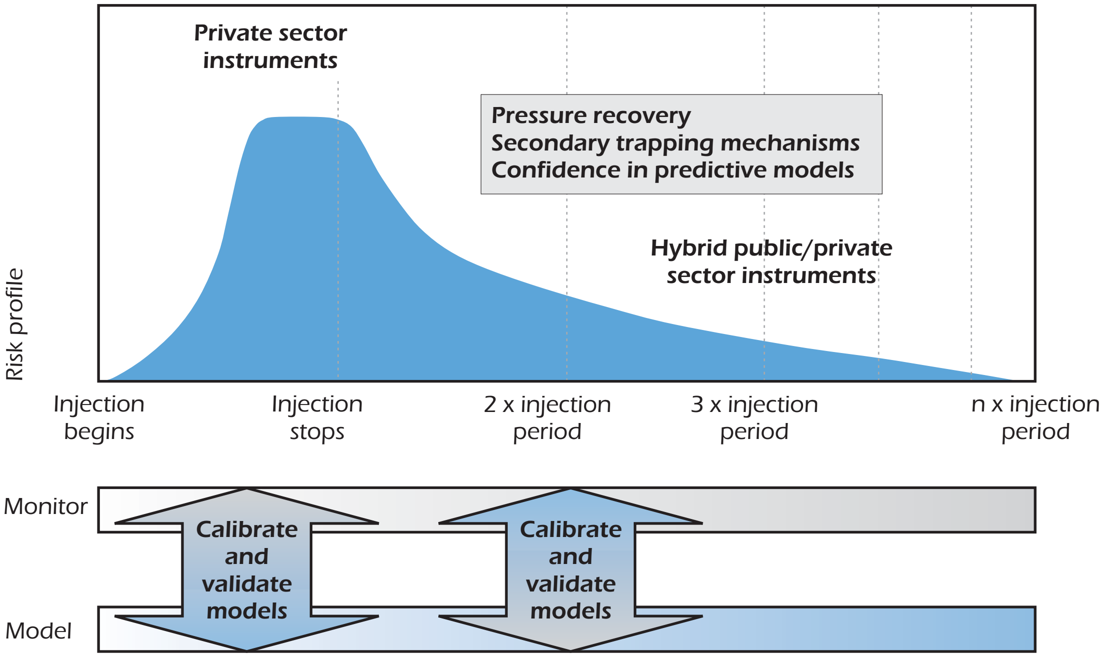
An effective risk management framework will assure that funds are available to pay for the minimisation of potential CO_2 releases over the long-term, and detect problems before they adversely impact the public or the environment. There are a number of possible models from other industries that have already developed liability frameworks for long-term storage, including insurance pools and the creation of special purpose funds.[28] Remediation might also be funded in part from revenues from the auction or set-aside of CO_2 credits from national or international GHG emission trading schemes, or through the establishment of special-designated funds into which operators pay a certain amount per tonne of CO_2 stored (IOGCC, 2005; Bachu, 2008).

As illustrated in Figure 5.5, a range of financial responsibility mechanisms can be used to manage risks during each phase of the CO_2 storage project life cycle. The range of financial instruments can be divided into three broad categories: third-party instruments, including trust funds, letters of credit, insurance, and bonds; self-insurance instruments which may include financial tests predicated on the financial strength of the developer, owner or operator;[29] and public-private pooling frameworks.

Figure 5.4 Conceptual Risk Profile for CO_2 Storage

Key point

The level of risk evolves along a CO_2 storage project's lifetime; the area of most concern is the long-term "tail".



Source: WRI, 2007.

28. These industries include include the nuclear waste, natural gas storage, hazardous waste, and oil and gas industries, among others (Patton and Trabucchi, 2008).

29. Notably, self-insurance instruments are predicated on the firms' financial solvency, and with few exceptions, there is no third-party guaranteeing payment.

Figure 5.5 Liability (Risk) Management Options

Key point

Existing financial responsibility mechanisms provide a good starting point for future CCS long-term liability discussions.

Financial responsibility mechanisms	**Geological storage project phases**		
	MMV (injection/ operation)	Plugging, abandonment and post-closure	Long-term stewardship (**after** prescribed post-closure)
1. Third-party instruments (trust funds, LOCs, insurance, bonds)	✓	✓	✓
2. Self-insurance (financial test, corporate guarantee)	✓	✓	✗
3. Public-private pooling frameworks ▸ Compensation funds ▸ Insurance models	✗	✗	✓

Source: Patton and Trabucchi, 2008 (MMV = Measurement, Monitoring and Verification).

In general, the third-party and self-insurance instruments are best suited to the injection, closure, and post-closure periods. The risk profile of the project is clear while the site is active and the developer, owner or operator is best able at this stage to leverage the funds necessary to finance the instruments. In addition, during these phases, the estimated costs associated with closure and post-closure activities (*e.g.* monitoring and measuring CO_2 transport) are reasonably quantifiable (WRI, 2007). Conversely, the activities associated with corrective (remedial) care over the long-term, *i.e.* after the site developer, owner or operative has completed any prescribed closure and post-closure activities, are more difficult to estimate. Specifically, the long-tailed risk profiles of CO_2 storage sites (see Figure 5.4) result in an uncertain probability of risk exposure, which will make it difficult to define the degree (and cost) of any necessary remedial activities. It is also difficult to identify (and monetise) the damages that could result from the long-term leakage of CO_2.[30]

It is difficult to assign the upper limits of financial liability that underpin the more traditional third-party and self-insurance financial instruments. In these circumstances, a public-private pooling structure, either in the form of an insurance pooling model, or a compensation (trust) fund model, is likely to be most suitable to provide the necessary financial assurances over the long-term. Both these models involve a blend of financial instruments designed to pool potential risk. However, careful consideration in the design of a public-private pooling structure is needed to assure against moral hazard, *i.e.* the risk that project developers, owners or operators can ignore (or avoid activities that will prevent or mitigate) future losses, including injury to public welfare and the environment, because the burden to pay for such losses rests with another party. For this reason, the financial limits of liability for either model must align with the evolution of the long-term risk profile of the relevant CO_2 storage sites.

*30. This is a challenge shared by other industries (*e.g.* oil spills), and useful analogies exist to address cost estimation for uncertain future damages. See Patton and Trabucchi (2008) for a proposal for the United States to create a new government corporation to manage CO_2 storage liability.*

Governments are considering when they will take overall responsibility for managing a closed CO_2 storage site. Many commentators have stated the need for governments to assume ultimate long-term liability for CO_2 storage permanence, given that government is the organisational entity most likely to be in existence for the long-term (MIT, 2007; IRGC, 2007). However, there is still a need to clarify the extent of this transfer and the exact circumstances when this transfer of responsibility occurs. For example, the proposed EU CCS Directive envisages the transfer of liabilities to individual member states when "...all available evidence indicates that the stored CO_2 will be completely contained for the indefinite future" (EU, 2008). More work is needed to clarify the conditions that might justify this transfer of responsibility.

The conclusion from this analysis is that governments and industry need to expand their discussions with the insurance industry on possible models for long-term liability. Any early CCS projects that receive special treatment regarding long term liabilities (*e.g.* government risk sharing) could be asked to make commitments in return, *e.g.* regarding providing data on project performance and the independent assessment of risks and performance (IRGC, 2007).

International Marine Environment Protection Instruments: Recent Developments

When CO_2 storage activities take place offshore in international waters, a variety of international instruments may apply, particularly those which aim to minimise potential risks to the marine environment. The primary international marine environment protection treaties are the Law of the Sea, the London Convention (and London Protocol), and the OSPAR Convention and other regional treaties. An overview of the issues associated with offshore CO_2 storage under these international frameworks has recently been published (IEA, 2007). This section provides an overview of recent London Protocol and OSPAR Convention amendments and developments in respect of monitoring guidance. These legal developments must be taken into account as governments and industry attempt to harmonise international approaches to CO_2 storage monitoring and verification.

The London Protocol

In 2007, an amendment came into force under the London Protocol which allows for the storage of CO_2 if the disposal is into a sub-seabed geological formation, if CO_2 streams are "overwhelmingly" carbon dioxide, and as long as no wastes are added.[31] This amendment provided for the first time a basis in international environmental law to regulate CO_2 storage in sub-seabed geological formations. The effect of this Amendment is that Contracting Parties are required to establish a licensing process that involves CO_2 project developers undertaking impact evaluations and establishing monitoring requirements as a prerequisite to the receipt of an offshore CO_2 storage permit. In accordance with Annex 2 and Article 4 of the Protocol, permits must contain data and information on the dumping operations, including proposed monitoring and reporting requirements. There is also a provision for governments to review permits at regular intervals and to report to the London Protocol Secretariat on a regular basis.

31. London Protocol 1996, Annex I, subsection 4, amended by "Resolution LP.1(1) on the Amendment to Include CO_2 Sequestration in Sub-Seabed Geological Formations in Annex 1 to the London Protocol", adopted on 2 November 2006 (IMO Doc No LC-LP.1/ Circ.5).

To address existing gaps in knowledge about monitoring of CO_2 storage, the Parties adopted in November 2007 guidelines which provide additional information regarding:[32]

- the selection of underground reservoirs with the greatest potential for permanent storage;
- site-specific risks to the marine environment from CO_2 storage;
- the development of management strategies to address uncertainties; and
- the reduction of risks to acceptable levels.

The guidelines establish project stages or steps that must be considered before a government Party issues an offshore CO_2 storage permit.[33] This London Protocol framework forms the beginning in international law of a system for CO_2 storage project monitoring and verification. This precedent should be considered by national and other jurisdictions charged with the development of CO_2 storage MRGs.

OSPAR Convention

In June 2007, the OSPAR Commission, which covers the Northeast Atlantic Seas, followed the London Protocol and adopted amendments to allow for the offshore geological storage of CO_2 if completed under an authorised permit from a responsible national government.[34] Under the amendments, Parties' competent authorities are responsible for ensuring that sufficient regulations are in place to govern CO_2 storage. These regulations should be made in accordance with the *OSPAR Guidelines for Risk Assessment and Management of CO_2 Streams in Geological Formations,*[35] which provide general guidance for Parties when considering a CO_2 storage permit. Under these Guidelines, a decision to grant a permit may only be taken after the competent authority is satisfied that there has been a suitable risk assessment and management process. The decision provides a list of items that are to be included as a minimum in an offshore CO_2 storage permit, including:[36]

- a description of the project, including injection rates;
- types, amounts and sources of CO_2;
- the location of the facility;
- characteristics of the geological formation;
- methods of transport; and
- a risk management plan, with monitoring and verification measures, mitigation steps and a site closure plan.

The Decision also requires Parties to notify the Executive Secretary of OSPAR when they decide to issue a CO_2 storage permit. The Secretary will then notify all other OSPAR Parties. OSPAR Parties with CO_2 storage activities will then be required to report on these activities annually. These OSPAR amendments will come into force (for those Contracting Parties which have ratified the amendments) 30 days after the time when at least 7 Parties have ratified. For the remaining Parties, it will then come into force 30 days after that time.

32. Details for these stages may be found in Annex 4 of "Report of the Twenty-Ninth Consultative Meeting and the First Meeting of Contracting Parties [London Convention and London Protocol]" (IMO Doc No LC 29/17).

33. See www.imo.org/includes/blastdataonly.asp/data_id=17361/7.pdf.

34. The Commission further legally ruled out the placement of CO_2 into the water column of the sea and on the seabed.

35. Available on the OSPAR website at www.ospar.org.

36. OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations, *section VII., Permit and Permit Conditions, point 18b.*

Public Awareness and Support

Public awareness and support for CCS is critical if it is to achieve its potential as a GHG mitigation solution. There are a variety of types of public support that will be needed, including:

- political support for government incentives, research funding, long-term liability, and the use of CCS as a component of a strategy to combat climate change;
- property owners' co-operation to obtain necessary permits and approvals for CO_2 transport rights-of-way and CO_2 storage sites; and
- local residents' informed approval of proposed CCS projects in their communities.

Public awareness about CCS is currently low, which has in part led to low public support for government programmes and for funding which promotes CCS. The public generally has not yet formed a firm opinion of CCS and its role in mitigating climate change (IRGC, 2007). The response from environmental NGO's has been so far mixed, ranging from opposition (groups like Greenpeace) to acceptance (Bellona and others), with other organisations such as the WWF in the middle. To help inform the debate, it is vital that government and industry actors significantly expand their efforts to educate and inform the public, including key stakeholders, about CCS.

Building Public Awareness and Support: Lessons Learned

A number of studies and surveys have been conducted on the topic of public awareness and support for CCS technologies (see, *e.g.* IEA, 2007; de Coninck, *et al.,* 2006; Curry, *et al.,* 2007). This work has continued to expand. For example, in September 2007, Climate Change Central hosted the first-ever Carbon Capture and Storage Communication Workshops in Calgary, Canada together with the Institute for Sustainable Energy, Environment and Economy and the International Institute for Sustainable Development. These workshops linked the latest in international research on public perceptions of CCS to practical applications for Canadian industry, government and NGOs.[37]

Other efforts, including the IEA Working Party on Fossil Fuels (WPFF) (see box), the Regional Sequestration Partnerships in the United States, the Australian Commonwealth Scientific and Industrial Research Organisation (CSIRO) and the Centre for Low Emission Technology's work, and the EU's ACCSEPT project, have done important early work in this area. The ACCSEPT Project concluded in 2007 that CCS communication to the public has not yet been convincing. The project's review of existing CCS outreach activities found very few, if any, examples of high-quality programmes. It also found a lack of coordination among the various CCS communication efforts (ACCSEPT, 2007). The lessons learned from these and other recent efforts can be summarised as follows:

- Public perception will be heavily influenced by early CCS demonstration projects. It is therefore essential to ensure that projects are well-designed and operated, that they are monitored thoroughly, that they strive toward continuous improvement and that they provide transparent information about their results to policy makers and the public.
- Governments must take a leading role in improving the perception of risks associated with CCS by establishing clear regulatory responsibility for CCS project evaluation, approval and monitoring.
- Governments (and project developers) must use effective communication techniques to engage and educate different audiences including the public, the NGO community, local

37. See *http://cslforum.org/documents/CCS_Workshop_Final_Report.pdf.*

environmental groups and media, with special attention paid to developing guidelines for local community consultation for proposed CCS projects.

- For long-term stewardship, the public acceptance of this long-term responsibility will only come if CCS is clearly communicated as an essential long-term climate change mitigation technology that is being deployed along with other important technologies, including renewable energy, energy efficiency, and other solutions.

In the future, it will be important to develop a more robust international network of CCS public awareness and education professionals that includes national and sub-national experts. This will enable these lessons learned to inform future public awareness efforts.

Box 5.4: Public Education and Awareness Tool

The IEA Working Party on Fossil Fuels (WPFF) developed a public education brochure Geologic Storage of Carbon Dioxide: Staying Safely Underground *which answers important stakeholder questions about CCS, including:*

- *Why store* CO_2 *underground?*
- *What is* CO_2*?*
- *Where can the* CO_2 *be stored?*
- *How will* CO_2 *storage be conducted?*
- *Will the* CO_2 *stay underground?*
- *What impacts could storage have?*
- *How will storage be monitored?*
- *How can leaks be fixed?*

The brochure also includes questions that local communities can ask CO_2 *storage developers who would like to site a CCS project in their area. Available at: www.ieaghggreen.co.uk.*

6. CCS REGIONAL AND COUNTRY UPDATES

KEY FINDINGS

- In most of the major world economies, carbon capture and storage (CCS) is seen as an important greenhouse gas (GHG) abatement option. In many regions, energy and environmental policy frameworks are beginning to be established to support CCS, but significant gaps still remain.
- Some large countries and the European Union (EU) have ambitious CCS technology research and development programmes. However, current spending and activity levels are not sufficient to achieve the stated goal of commercial deployment of CCS in the next decade. In addition, some major countries are not significantly investing in CCS research and development (R&D). This will make it more difficult to commercialise CCS.
- Several countries and regions have begun important work to assess and document the viability of potential CO_2 storage sites. But much more evaluation is needed to refine assessments and identify early storage options.
- International collaboration on CCS will be essential to achieve the ambitious national and international goals for GHG stabilisation. While important building blocks have been established, more must be done to increase international coordination, particularly in the following areas:
  - Developing a complementary set of CCS demonstration projects around the world, using different technologies and geologic settings for storage; and
  - Expanding CCS activities in rapidly growing coal-using countries like China, India and Russia, as well as taking advantage of the important enhanced oil recovery (EOR) potential in North Africa and the Middle East.

Introduction

A large and growing number of CCS-related activities are under way around the world, and new announcements are made almost weekly. A number of countries and regions have invested significant resources in CCS research, development and initial deployment, including the evaluation of CO_2 storage potential. The policies and regulations needed to underpin the wider takeup of CCS are also increasing in number and in detail.

This chapter provides a geographic overview of the status of CCS activities worldwide. It includes updates for select countries and regions both on regulatory and policy activities and on research and technology demonstration efforts. Regional updates are provided for the European Union and the Middle East and North Africa, followed by national updates for countries with major CCS activity. The chapter concludes with brief status updates for other important countries.

The European Union

Policy Framework

On 10 January 2007, the European Commission released an energy and climate change strategy document, entitled *An Energy Policy for Europe.* This called on the European Council of Ministers and European Parliament to approve, among other things (EC, 2007):

- an EU commitment to achieve a reduction of at least 20% of GHG emissions from the 1990 levels by 2020 (rising to a 30% reduction if a comprehensive international climate change agreement is concluded); and
- a mandatory EU target that 20% of EU energy consumption should come from renewable energy sources by 2020, including a target that 10% of transport fuels from sustainable biomass sources.

This strategy contained a number of CCS proposals, including a goal of 12 large-scale demonstration projects for coal- and gas-fired power plants by 2015, the incorporation of CCS in all new coal-fired power plants commissioned after 2020, and a requirement that all new plants commissioned before 2020 be capture-ready and that they should be retrofitted rapidly after 2020.

This strategy was endorsed by the European Parliament in February 2007 and the targets were adopted by the European Council of Ministers in March 2007. In response to the Council's invitation, the Commission subsequently released several proposals. One of these, the January 2008 climate change and renewable energy package, addressed CCS. The package includes a proposed directive on an EU-wide framework for encouraging CCS (referred here after as the "CCS Directive"),[38] and a related communication on early demonstration (EC, 2008a). These were developed after a series of consultations and an extensive impact assessment (EC, 2008c).

Among other things, the CCS Directive seeks to ensure environmental security, to address issues of liability, to remove existing legislative barriers to deploying CCS, to provide incentives for deploying CCS, and to provide an enabling (rather than a mandatory) framework for CCS. It provides for the use of existing legislation where possible, in particular for capture under the Integrated Pollution Prevention and Control Directive (96/61/EC) and for transport under the Environmental Impact Assessment Directive (85/337/EEC) at the member state level. It also proposes new legislation to address CO_2 storage.

The new legislation provides the following framework for acceptable CCS projects (EC, 2008a):

- criteria for site **assessment and permitting;**
- a requirement that the **CO_2 stream concentration** be "overwhelmingly" CO_2;
- specifications for a **CO_2 storage monitoring** system;
- **liability measures,** including the surrendering of EU Emission Trading Scheme (EU ETS) allowances for any leakage, action under the Environmental Liability Directive (2004/35/EC) and financial provision for future liabilities;
- **transfer to governments of long-term responsibilities** under certain performance-based conditions after CO_2 site closure; and

38. The CCS Directive focuses on CO_2 storage mainly.

- the **amendment of existing legislative barriers to CCS,** in particular, certain provisions of the Water Framework Directive and waste legislation.

The legislation also establishes that, for the purposes of the EU ETS, CO_2 captured, transported and stored safely will not be considered as emitted and that there will be no allocation in the third phase of the EU ETS for CO_2 capture, transport and storage.

The communication on *Supporting Early Demonstrations of Sustainable Power Generation from Fossil Fuels* (EC, 2008b) was released in the context of the European Council's previous endorsement of a goal to develop up to 12 demonstration plants of sustainable fossil fuel technologies in commercial electricity generation by 2015. In the communication, the Commission proposed the establishment of a European initiative on CCS to demonstrate the viability of CCS by 2020. It also noted that significant investment will be necessary if demonstration plants are to be financed. Since CCS demonstration financing is outside the scope of the EU budget, it was recognised that such funding would need to come from public-private partnerships funded predominantly from national budgets and private investment. A decision from the European Parliament on the CCS Directive is expected toward the beginning of 2009. European directives would then need to be transferred into national law of Member States.

European Union CCS Research, Development and Deployment Activities

In 1990, the EU began CCS research under the JOULE programme. The related JOULE II project included a feasibility concept for CCS and an initial evaluation of CO_2 storage potentials in various European basins. The EU Fourth Framework Programme (THERMIE, 1994-98), built on JOULE and the Saline Aquifer CO_2 Storage (SACS) project, which investigated advanced monitoring and modelling methodologies for the Sleipner project in Norway.

Selected European Union CCS R&D Projects, 1998-2006

Under the EU Fifth Framework Programme (FP5) for Research (1998-2002),[39] the following projects were undertaken (O'Brien, 2004):

- The Advanced Zero Emission Power plant aimed to advance membrane cycles and to develop a zero-emissions gas turbine-based power generation process to reduce CO_2 separation costs by 25% to 35% in five years, using conventional air-based gas-turbines with the possibility of retrofitting.
- The Grangemouth Advanced CO_2 Capture project evaluated post-combustion capture from a range of process heaters and boilers in a refinery/petrochemical complex.
- The European potential for Geological Storage of CO_2 from Fossil Fuel Combustion (GESTCO) project provided an evaluation of the potential to match sources and sinks in Benelux, Denmark, Germany, Norway, France, Greece and the United Kingdom.
- The CO_2STORE project built on SACS to evaluate the CO_2 storage potential of four sites (Midt Norge, Norway; South Wales, United Kingdom; Schwarze Pumpe, Germany; Kalundborg, Denmark).
- The Development of Next Generation Technology for the Capture and Geological Storage of CO_2 from Combustion Process project developed a monitoring methodology and subsurface modelling tools for site selection and risk management.

39. *See* http://ec.europa.eu/research/energy/nn/nn_rt/nn_rt_co/article_1153_en.htm for more information.

- The ICBM Project included the development of advanced reservoir characterisation and simulation tools for improved coalbed methane recovery. ICBM helped to establish an understanding of CO_2-methane adsorption, flow and interaction with coal through the evaluation of coalbeds in Germany, the United Kingdom and France.
- The RECOPOL Project's objective was to evaluate the feasibility of CO_2 storage in subsurface coal seams in Poland, with a focus on the potential for enhancing coalbed methane (CBM) production.
- The ACS2 project supported the monitoring of CO_2 injection in the Sleipner field in Norway and provided information on methods to characterise CO_2 diffusion, to identify leakage and to evaluate natural seal mechanisms.
- The Natural Analogues for the Geological Storage of CO_2 project addressed issues associated with geological CO_2 storage, including the long-term safety and stability of underground storage and the potential environmental effects of leakage.
- CO_2NET is a European thematic network of researchers, developers and users of CO_2 technology, and facilitates co-operation among European projects on CO_2 geological storage, CO_2 capture and zero emissions technologies.

Under the EU 6th Framework Programme (FP6) (2002-06), the EU CCS R&D targets were to reduce the cost of captured CO_2 from between EUR 50/t (Euros) and EUR 60/t to between EUR 20/t and EUR 30/t, with capture rates higher than 90%, and to assess the reliability and long-term stability of CO_2 storage. The main FP6 projects are (European Commission, 2007):[40]

- CO_2SINK is a laboratory located at Ketzin, Germany which aims to characterise a CO_2 injection site using innovative monitoring technologies. The target reservoir is an aquifer at a depth of 600 m, underlying a redundant gas storage layer. The plan to inject 0.03 Mt CO_2 a year for up to 3 years will involve a detailed risk assessment and a communication plan with all stakeholders, including local authorities, residents and other parties.
- The ENCAP (Enhanced Capture of CO_2) project is developing pre-combustion technologies for enhanced capture of CO_2 in large power plants that can reduce capture cost by 50%.
- The CASTOR (CO_2 from Capture to Storage) project focuses on post-combustion capture with the aim of developing and validating technologies needed to capture 30% of the CO_2 emitted by European power and industrial units, while reducing capture cost to below EUR 20/t CO_2 to EUR 30/t CO_2. Another objective is to extend the CO_2STORE study to four additional European sites. A final goal is to develop an integrated strategy for infrastructure options in Europe.
- The CACHET effort focuses on CO_2 capture and hydrogen production from gaseous fuels. The emphasis is on technologies for natural gas-fired combined-cycle gas turbines with hydrogen side-streams. Project pilot plant trials are planned for 2009.
- The *in situ* CO_2 Capture Technology from Solid Fuel Gasification Project aims to develop a new process using high-temperature sorbents to upgrade high moisture low-rank brown coals yielding three products: fuel gas (mainly hydrogen), nearly-pure CO_2 (>95%), and a pre-calcinated feed for a cement kiln.
- The Chemical Looping Combustion Gas Power effort targets the up-scaling of chemical looping combustion technology for gaseous fuels via an industrial 20 MW to 50 MW demonstration unit.

40. See http://ec.europa.eu/research/energy/pdf/co2capt_en.pdf.

- The CO_2REMOVE (Research on Monitoring and Verification) project focuses on CO_2 storage and aims at developing and testing methods for site assessment and baseline site evaluation, as well as new tools for monitoring storage and identifying potential leakage.
- The DYNAMIS effort investigates the viable routes for large-scale cost-effective combined electricity and hydrogen production with integrated CO_2 capture and storage. The project is part of the Hydrogen and Power Generation (HYPOGEN) programme that targets pilot-scale demonstration by 2010, the construction of demonstration plant by 2012, and operation and validation by 2015, with a total budget of EUR 1 300 million.
- The ULCOS (Ultra-Low CO_2 Steelmaking) initiative includes 47 partners and 15 European countries working to find breakthrough technologies to reduce CO_2 emissions from the steel industry by 50% to 70% of today's benchmark level.
- CO_2GEONET is a network of excellence between R&D labs in Europe, focusing on CO_2 storage technologies. Its objectives are to develop a comprehensive laboratory infrastructure for storage research, to train the next generation of CCS experts, and to pool resources when needed for fast-tracking research in critical areas/demonstration projects.
- The INCA-CO_2 (International Co-operation Actions on CO_2 Capture and Storage) support action is aimed at advancing international CCS knowledge-sharing and co-operation.
- The C3-Capture (Calcium Cycle for Efficient and Low-Cost CO_2 Capture using Fluidised Bed systems) project aims to develop an advanced CO_2 capture system.

The suite of CCS programmes included above has required a significant amount of funding. The total programme, including partner funding, increased from EUR 35 million to EUR 120 million between FP5 and FP6, with an increasing share for capture-related projects.

The EU 7th Framework Programme (2007-13) earmarked a budget of approximatively EUR 360 million for CCS and Clean Coal Technologies. Three major strands of work relevant to cleaner power generation were funded, including (Sánchez, 2007):

- the CAESAR programme for carbon-free electricity, which includes advanced materials, reactor and process design;
- the DECARBIT programme, which aims to enable advanced pre-combustion capture techniques and plants; and
- the STRACO_2 project (support to regulatory activities for carbon capture and storage), launched in February 2008, which will use the regulatory framework of the EU to support the ongoing development of a comprehensive regulatory framework for CCS in China.

CCS Demonstration in Europe: The Zero Emissions Platform

In 2005, the European Commission, together with the European energy industry, non-governmental organisations, research organisations, academia and financial institutions, established the Zero Emission Fossil Fuel Power Plants platform (ZEP) to enable near-zero emissions from European fossil fuel power plants by 2020.[41] One of its main goals is to initiate the large-scale deployment of CCS, with 10 to 12 industrial-scale demonstration projects by 2015 or earlier. The platform also recommended in its Strategic Deployment Strategy:

- kick-starting the CO_2 value chain with commercial incentives, including qualifying CCS under the EU ETS and early funding mechanisms for demonstration projects;

41. While the European Commission partly finances the ZEP, and the Commission works closely with the ZEP, the ZEP opinions do not necessarily reflect those of the EC.

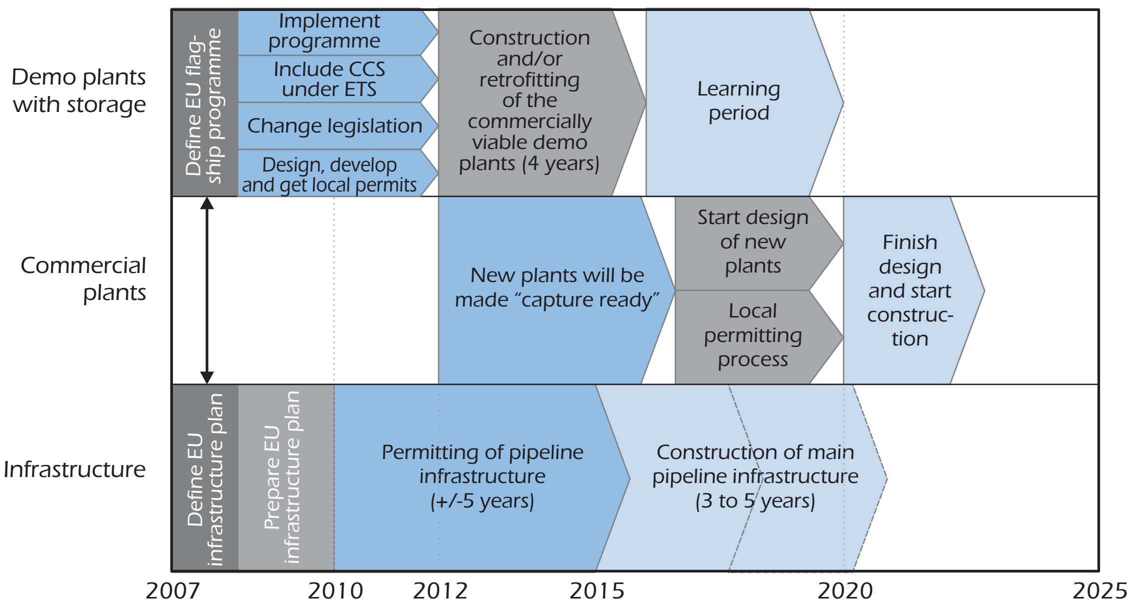
- establishing a legal and regulatory framework for CO_2 storage; and
- fostering public support through a comprehensive information campaign including EU-wide media outreach and local focused outreach to support the demonstration projects.

There are over 20 demonstration projects now under consideration in the EU. Recognising that more needs to be done to ensure the commercial viability of CCS by 2020, the ZEP proposed in 2007 an EU FLAGSHIP programme on CCS. The FLAGSHIP's aim is to lead a comprehensive programme of CCS demonstration projects in Europe, with work groups on funding, sources-to-sinks infrastructure, legal and regulatory frameworks, and knowledge management. Planning for the FLAGSHIP programme is shown in Figure 6.1.

Figure 6.1 European FLAGSHIP Programme to Develop 10 to 12 CCS Demonstration Projects

Key point

The European Union has developed a roadmap for the FLAGSHIP Programme.



Source: ZEP, 2007.

The Middle East and North Africa

Policy Framework

Many nations in the Middle East region are signatories of the United Nations Framework Convention on Climate Change (UNFCCC) and Parties to the Kyoto Protocol. However, they do not have binding quantitative GHG targets. As a result, countries in the Middle East have no incentive within the UNFCCC regime to implement GHG reductions. Even so, they are implementing a growing number of energy and environmental strategies aimed at increasing energy efficiency, energy security, and the use of cleaner energy. Given the Middle Eastern region's leadership in oil and gas resource development, CCS is becoming an important consideration for the region, especially for CO_2-EOR.

CCS Research, Development and Deployment Activities

At the end of 2007, members of the Organization of Petroleum Exporting Countries (OPEC) pledged a total of USD 750 million to a new fund aimed at supporting clean technologies including CCS. Saudi Arabia has pledged USD 300 million, and the United Arab Emirates (UAE), Qatar and Kuwait have pledged USD 150 million. The fund's scope of work includes scientific research related to energy, environment and climate change.

Saudi Aramco, a large state-owned oil company in Saudi Arabia, has been addressing CO_2 management through an R&D investigation of screening criteria for CO_2-EOR in a variety of reservoir configurations (Fageeha, 2006). Along with a Saudi Aramco carbon management technology roadmap, a phased approach for implementing the technology includes a 1-2 Mt CO_2 per year pilot storage project to develop in-house expertise, leading to full deployment in the longer-term. The aim is to prioritise CO_2-EOR within the company's strategic priorities.

Also in 2007, the UAE launched the Masdar Advanced Energy and Sustainability programme, which includes CCS. The project will be managed from the city of Abu Dhabi by the Abu Dhabi Future Energy Company. The scope of the project includes a preliminary engineering study to evaluate and rank options for CO_2 capture from onshore and offshore facilities, CO_2-EOR, and developing a local CO_2 transport infrastructure. A study performed by SNC-Lavallin has identified 4 to 6 projects with a potential combined emissions abatement of 6 Mt CO_2 to 8 Mt CO_2 per year.[42] One of these is the BP/Rio Tinto DF4 Hydrogen Energy project, which involves CO_2 capture from hydrogen power production using natural gas and CO_2-EOR (Chiaro, 2008).

In addition, a concept project involving capture from a gas-fired power plant, hydrogen generation and use of CO_2 for EOR is under evaluation by oil company BP, in collaboration with the Abu Dhabi National Oil Company (ADNOC). ADNOC has been evaluating CO_2 as an alternative to sweet gas injection (Braek, 2006). CO_2 industrial sources have been screened to identify high purity sources, including ammonia plants. The oil company Shell has also launched studies to investigate CO_2 infrastructure requirements in the Gulf Countries with a special focus on new GTL plants in Qatar.

The BP-Sonatrach-Statoil project in In Salah, Algeria, was the first large-scale CCS project outside Europe and North America (Haddadji, 2006). The project is estimated to have 230 billion m^3 of recoverable gas reserves. CO_2 is separated in the Krechba processing plant using an ethanol-amine solvent and subsequently compressed to 200 bars for injection in the Krechba carboniferous aquifer reservoir under a thick (950 m) low permeability mudstone. Injection started in 2004 with an expected 1 Mt CO_2 per year to be stored and a total of 17 Mt CO_2 during the life of the project. Additional costs for CCS are estimated at USD 100 million (approximately USD 6/t CO_2). Monitoring costs alone are expected to be of the order of of USD 30 million. Lessons learned from new CO_2 monitoring technologies will be used in the EU-funded CO_2REMOVE project to develop industry guidelines for the monitoring and verification of CO_2.

CO_2 Storage Potential

Given the size of the sedimentary basins in the area, there is very significant potential storage in the Middle East. Hendriks, *et al.* and the Very Long-Term Energy and Environment Model (Hendriks, *et al.,* 2004; VLEEM, 2003) provide the following preliminary ranges:

- 105 Gt to 1 000 Gt in onshore oil and gas fields;

42. See http://www.ameinfo.com/124875.html.

- 75 Gt to 200 Gt in offshore oil and gas fields; and
- 1 Gt to 500 G5 in aquifers.

Table 6.1 outlines the results of an early study that attempted to identify the largest oil and gas sites and their estimated CO_2 storage capacity. However, more work needs to be done in the Middle East region to verify CO_2 storage potential. In addition, while CO_2-EOR provides an attractive early opportunity, higher oil gravity requirements pose technical challenges for CO_2-EOR deployment in the Middle East, and merit further study.

Table 6.1 *Potential Oil and Gas CO_2 Storage Sites in the Middle East*

Province	Sequestration capacity in Gt (with Tcf in brackets)
Qatar Dome	53 (1 000)
Zagros Fold Best	42 (794)
Mesopotamian Foredeep	42 (787)
Greater Ghawar Uplift	36 (684)
Rub Al Khali	24 (456)

Source: Stevens, et al., *2001.*

Most of the potential for CCS in North Africa is related to the capture of CO_2 from produced gas and its re-injection for storage or enhanced hydrocarbon recovery. The gas fields in Algeria, Tunisia and Libya offer the greatest potential. Further work is required to characterise the suitability of deep saline formations in the Middle East for CO_2 storage. The type of sealing formations, mainly composed of evaporites, provide a positive indication that large storage volume could be available.

Australia

Policy Framework

Australia has the world's fourth-largest coal reserves, and therefore has a strong interest in promoting cleaner coal applications, including CCS. Some CCS activities fall under the jurisdiction of state governments; other activities are the responsibility of the federal Commonwealth Government. These include offshore activities beyond three nautical miles to the outer limit of Australian waters, and some onshore cross-boundary activities. So the development of a regulatory framework for CCS involves the application of federal and state/territory law, as well as co-operation between both levels of government.

Existing state level legislation provides for pipeline transport and the storage of CO_2 in natural reservoirs. Federal, state and territory legislation provides a basis for authorising and regulating the capture and storage of CO_2 separated from a petroleum stream as part of the integrated petroleum operations of the licensee.[43]

43. See, for example, the Petroleum and Gas (Production and Safety) Act 2004 in Queensland and the Petroleum Act 2000 in South Australia.

In the light of the complex state-federal arrangements in this area, the Ministerial Council on Mineral and Petroleum Resources (MCMPR), comprising the relevant ministers from the federal, state and territory governments, endorsed a set of *Regulatory Guiding Principles for Carbon Capture and Storage* in November 2005. Designed to facilitate the development of consistent regulatory frameworks for CCS in all Australian jurisdictions, the principles address: assessment and approvals processes; access and property rights; transportation issues; monitoring and verification issues; liability and post-closure responsibilities; and financial issues (MCMPR, 2005).

In May 2008, the federal government released draft legislation, known as an 'exposure bill', which proposes to amend the federal Offshore Petroleum Act to allow for CO_2 injection and storage in offshore areas. The Bill was introduced into the federal parliament in June 2008. The draft legislation, known as the Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill 2008, will provide for new offshore titles for pipeline transport, injection and storage of CO_2 and other GHGs in offshore geological formations through the amendment of existing legislative provisions governing acreage release and injection licences. As many sedimentary basins that could be suitable for storage sites are located within petroleum regions, the draft legislation seeks to ensure the appropriate co-existence of petroleum and GHG injection and storage activities.

Existing legislation would also be amended by the Bill to provide for safety management, including procedures for site selection, risk identification and monitoring, and to equip the regulators with powers to require mitigation and remedial actions. Once the legislation is passed, the first CCS acreage and exploration permits can be issued. It is envisaged that the state governments will seek to pass similar legislation governing state waters once the federal legislation is passed. The way in which CCS relates to the planned national GHG emissions trading scheme and issues around the financing and regulation of a common CO_2 transport infrastructure remain to be resolved (Squire, 2008).

CCS Research, Development and Deployment Activities

The Australian Government is establishing the National Low Emissions Coal Initiative (NLECI) which aims to accelerate the use of low-emission coal technologies in Australia, including CCS, in order to achieve large cuts in coal-based GHG emissions.[44] In addition, since 2003, national technology roadmaps for reducing emissions from fossil energy have been developed by COAL21, a partnership between the coal and electricity industries, research and public stakeholders.

The CO2CRC (Cooperative Research Centre for Greenhouse Gas Technologies), which is one of the world's largest collaborative CCS research projects, involving academia, industry and government representatives from Australia and New Zealand, also plays an important role in CCS with a budget of USD 140 million over seven years, to 2010.

In addition to these larger government funding and R&D efforts, there are several other CCS demonstration activities underway in Australia, including:

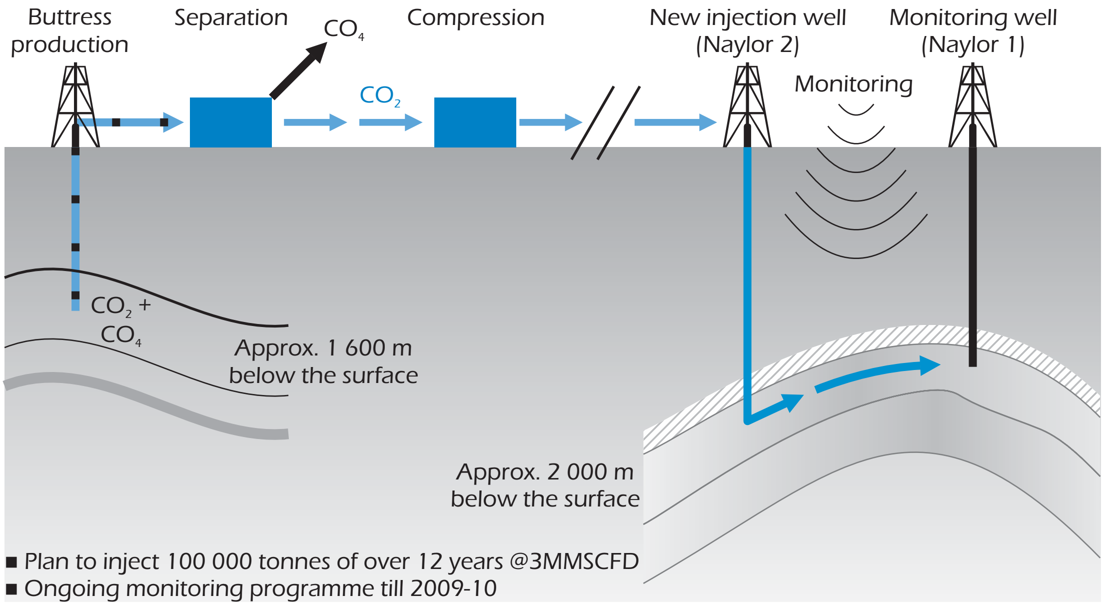
- The Callide Oxyfuel Project in Queensland. This is a demonstration project that is converting an existing 30 MW unit at Callide A for CO_2 capture. The second stage of the project will commence in 2010 and involve the injection and storage of up to 0.5 Mt of captured CO_2 in saline aquifers or depleted oil and gas fields, and will continue for up to five years. This project is expected to cost USD 170 million. Partners involved in this project include CS Energy, IHI, ACA, Schlumberger, CCSD and CO2CRC.

44. See Chapter 5 for a summary of the NLECI, which is funding five projects demonstrating various aspects of CCS.

Figure 6.2 The CO2CRC Otway Project

Key point

The Otway Project involves significant monitoring of CO_2 storage.



Source: CO2CRC, 2008.

- The CO2CRC Otway Project in Victoria is Australia's most advanced CO_2 storage project. In April 2008 it started injection of 0.1 Mt CO_2 from a nearby gas well into a depleted gas field at a depth of 2 km (see Figure 6.2). A major programme of monitoring and verification has been implemented. The USD 40 million project, which is supported by 15 companies and 7 government agencies, involves researchers from Australia, New Zealand, Canada, Korea and the United States. CO2CRC Pilot Project Ltd, the operating company, comprises interests from AngloCoal, BHP Billiton, BP, Chevron, Schlumberger, Shell, RioTinto Solid Energy, Woodside and Xstrata.
- The Coolimba Power Project in Western Australia is a proposal for the development of two 200 MW oxyfuel coal-fired base-load power stations, with subsequent conversion to capture CO_2 for storage expected to begin in in 2012.
- The FuturGas Project in South Australia is a joint venture between Hybrid Energy Australia and Strike Oil to research and develop the CO_2 storage component of another project which involves the gasification of lignite for the production of synfuels. It is proposed that the CO_2 (captured post-gasification) will be stored in the Otway Basin to the south of the lignite resources. The project is expected to begin by 2016.
- The Gorgon Project in Western Australia involves Chevron (as operator), Shell and Exxon. The separated CO_2 will be injected under Barrow Island to a depth of about 2 500 m, with injection of 3 Mt CO_2 to 4 Mt CO_2 per year beginning in around 2012, and a total of 125 Mt injected over the life of the project. A test well has been drilled and a study of the subsurface is underway.
- The Hazelwood and Loy Yang Post-Carbon Capture (PCC) Projects in Victoria involve the drying of brown coal and retrofitting post-combustion CO_2 capture. Work is underway on

a CO2CRC pilot-scale facility at Hazelwood that will capture and chemically sequester CO_2 at a rate of 10–20 kt CO_2 per year. A CSIRO mobile pilot PCC facility to be tested at Loy Yang will capture around 5 kt CO_2 per year. Partners in these projects include Hazelwood Power, Loy Yang Power, CO2CRC, CSIRO and the Process Group. Capture is expected to start in late 2008.

- The HRL IDGCC (integrated drying gasification combined-cycle) Project in Victoria is a proposed 400 MW power generation plant using brown coal. CO_2 emissions will be captured at a pilot scale initially. The total project is estimated to cost over USD 730 million. Partners include HRL Technology, Harbin and CO2CRC.
- The Monash Energy CTL Project in Victoria is a proposed project that will involve the drying and gasification of brown coal for conversion to synthetic diesel, followed by the separation of the produced CO_2 (up to 13 Mt per year), with transport and injection into a suitable storage site. This project will start in 2015 and is estimated to cost USD 6 billion to USD 7 billion. Partners involved in this project include Monash Energy, Anglo American and Shell.
- The Moomba Carbon Storage Project in South Australia is currently at the early feasibility stage, with the objective of establishing a regional carbon storage hub in the Cooper Basin. The demonstration phase, to begin in 2010, will involve capturing CO_2 from existing gas processing facilities and injecting 1 Mt CO_2 to re-pressure oil reservoirs for EOR. Partners in this project include Santos and Origin.
- The Munmorah PCC Project in New South Wales will investigate the PCC ammonia absorption process, and the ability to adapt this process to suit Australian conditions. Capture of up to 5 kt CO_2 for the pilot phase is expected to begin in 2008. Partners involved in this project are Delta Electricity, CSIRO and the ACA.
- The ZeroGen Project in Queensland proposes to demonstrate integrating coal-based gasification and CCS by 2012. The CO_2 will be transported approximately 200 km by pipeline for storage in the Denison Trough at a rate of up to 0.4 Mt CO_2 per year. A feasibility study is underway. In Stage 2, a 300 MW coal gasification plant is expected to come online by 2017. The project is estimated to cost in excess of USD 1 billion. Companies involved in the project include Shell and Stanwell.

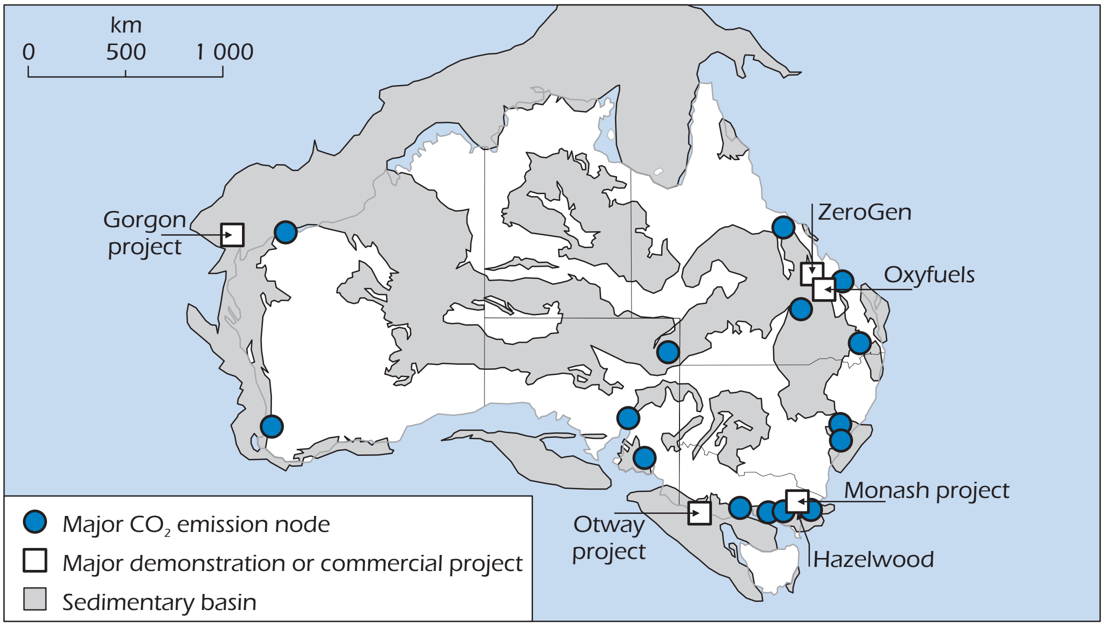
CO_2 Storage Potential

Australia's CO_2 storage potential has been assessed by the GEODISC project. A 2004 analysis screened 300 known sedimentary basins using criteria such as depth, thickness and lithology, and identified 65 environmentally sustainable sites for CO_2 injection. At that time, a capacity of 750 Gt was assessed for these sites, the bulk of which was located offshore and associated with hydrodynamic traps (Bradshaw, 2004). Since that time, international practices on CO_2 storage assessment have developed. It is no longer accepted that gross volumetric evaluations can be used to estimate CO_2 storage capacity due to the complexity of the trapping mechanisms that are involved, the time scales on which they operate and the uncertainty of the efficiency of the CO_2 sweep through the reservoir (Bachu, *et al.,* 2007; US DOE, 2006). As a result, work continues to evaluate the total potential of Australia's deep saline reservoirs on this new basis, focused on site-specific studies based on detailed numerical modelling (see Figure 6.3). The capacity of the offshore saline aquifers is however still judged to be very large.

Figure 6.3 Potential CO_2 Storage Sites in Australia

Key point

Australia has CO_2 storage potential in many geologic settings.



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.

Source: CO2CRC, 2008.

Brazil

Policy Framework

Fossil fuels account for only 25% of Brazil's GHG emissions due to its abundance of hydropower resources. As such, there is less of a focus on the deployment of CCS technologies in Brazil than in other countries, with the national government concentrating its climate change mitigation efforts on forestry and land-use solutions, including biofuels. However, coal represents the second-largest energy resource in Brazil, with an estimated 32 Gt of reserves. In order to cope with increasing energy demand in the south of the country, an increased use of coal is forecast with opportunities to match sources and sinks (Zancan and Cunha, 2007). The recent discovery of major oil fields also suggests that fossil fuels and CCS may play an increasingly important role in Brazil's future.

The country does not have binding international GHG emissions targets or an overarching national climate change strategy. It is nonetheless committed to climate change mitigation (Cunha, *et al.*, 2007a) and various sector-specific programmes have been developed such as its National Electrical Energy Conservation Program (PROCEL) and the National Program for the Rational Use of Natural Gas and Oil Products (CONPET) (MST, 2004). There is at present no government programme specifically relating to CCS. Nonetheless, for the oil and energy company PETROBRAS, as well as other industrial entities, CCS represents an opportunity to mitigate emissions, to transition to a more sustainable energy future, and to address local development needs (Cunha, *et al.*, 2007a).

There are currently no legislative provisions directly relating to CCS in Brazil. The national regulatory framework will need to be further developed if Brazil is to proceed with full-scale CCS activities. Legislation governing oil and gas activities, administered by the National Agency of Energy (ANP), requires oil and gas entities to invest 0.5% of their oil field revenue in R&D in national institutions. This is considered a driver for further investment in CCS. Among various activities to further CCS technology development, a national Carbon Sequestration and Climate Change Network of public and private entities has been established to facilitate the development of technological infrastructure and capabilities in Brazil. It is hoped that it will be possible to establish 17 centres of excellence researching specific aspects of CCS in Brazil (Cunha, *et al.*, 2007b).

CCS Research, Development and Deployment Activities

There are a number of activities regarding CCS research, development and deployment (RD&D) in Brazil. CARBMAP, a Brazilian map for CCS, is being developed by the Brazilian Carbon Storage Research Center (CEPAC) at the Pontifical Catholic University of Rio Grande do Sul (PUCRS) to document CO_2 sources and calculate the storage capacity of petroleum fields, saline aquifers and coal seams (Ketzer, *et al.,* 2007). Carbometano Brasil is an initiative led by CEPAC and PETROBRAS to develop enhanced coalbed methane (ECBM)-CO_2 technology. Its initial focus is the coal seams of the Paraná Basin, in southern Brazil. Carbogis is another initiative led by CEPAC and PETROBRAS aiming to develop feasibility studies for underground coal gasification with CO_2 storage in deep coal resources and unmineable coal seams. In addition, a Research Centre for Coal Clean Fuels and Environment Pre-capture has been established as an interdisciplinary centre for the research, development, and demonstration of technologies in CO_2 storage. It is a joint initiative of PETROBRAS and PUCRS. Its research activities involve the analysis of potential, risk, capacity, durability and profitability of CO_2 storage (Ketzer, *et al.,* 2007). Finally, Petrobras plans to develop four major CCS projects in the next few years.

CO_2 Storage Potential

The CARBMAP project has estimated storage potential in Brazilian geological reservoirs to be around 2 000 Gt in petroleum fields, saline aquifers and coal deposits (Ketzer, *et al.,* 2007b). A preliminary source-sink matching indicates that most of the CO_2 stationary sources are in the south and southeast of the country and are associated with reservoirs in the onshore Paraná Basin (saline aquifers and coal seams), offshore Campos and Santos basins (saline aquifers and petroleum fields), and the onshore São Francisco Basin (saline aquifers). Ongoing EOR operation in the Reconcavo Basin in northeastern Brazil makes it an important candidate (Ketzer, *et al.,* 2007a).

Canada

Policy Framework

As in other federal countries, such as Australia and the United States, the regulation of CCS in Canada involves a complex interaction between federal and provincial laws and policies. With regard to climate change mitigation strategy, the federal government has explicitly incorporated CCS into its mitigation policy framework. In April 2007, the federal government released its *Turning the Corner* plan to reduce GHGs and air pollution through the development of a regulatory framework. The plan includes mandatory and enforceable targets for GHG emissions from all major industrial sources (Government of Canada, 2007). The regulation of industrial GHGs is intended to make a significant contribution to meeting the federal government's target of an absolute reduction of Canada's total GHG emissions of 20% from 2006 levels by 2020.

Further details of the *Turning the Corner* plan were released in March 2008 after consultation with stakeholders. The framework sets out industrial emissions intensity targets that increase in stringency over time. Coal-fired power plants and oil sands plants coming into operation in 2012 or later will face stringent targets, which are likely to require the use of CCS or equivalent technology by 2018. CO_2 emissions at a regulated facility that are captured and stored will be considered as emission reductions. The framework also provides for various compliance options, or flexibility mechanisms, to incentivise investments in CCS. Further work will now be carried out by the federal government to define capture-readiness and to establish protocols for measuring and crediting CO_2 reductions, among other issues (Environment Canada, 2008).

Various measures to encourage or mandate GHG mitigation, including via CCS, also exist or are being developed at the provincial level. In Alberta, the provincial government anticipates that CCS will account for 70% of its intended emissions reductions of 14% below 2005 levels by 2050 (Government of Alberta, 2008). Saskatchewan's climate change policy framework provides for EOR with a view to developing a market for clean coal (Hegan, 2008). As with other aspects of climate change policy, further work will need to be undertaken by the federal and provincial governments to ensure consistency and the harmonisation of any CCS-related obligations on industrial entities.

Existing federal and provincial oil and gas legislation covers certain aspects of CCS, including CO_2 capture and transportation-related issues, such as construction and health and safety issues. In most Canadian jurisdictions, CO_2 storage activities, in particular the definition of CO_2 storage, property rights (storage and access rights) and injection and post-injection activities (regulatory permitting, monitoring and liability) still remain to be addressed (Bachu, 2008; Hegan, 2008).

Property rights relating to CO_2 storage are of particular interest in Canada. At the provincial and federal level, there is at present no legislation specifically dealing with property rights relating to storing CO_2, though analogues exist in oil and gas legislation (Hegan, 2008). To address this, the Canada-Alberta EcoENERGY CCS Task Force recommended in January 2008 that existing legislation governing oil, gas and water activities be extended to address CO_2 storage property rights (EcoENERGY CCS Task Force, 2008). The Task Force also recommended that CCS regulatory authority be vested in the existing oil and gas regulatory agencies, as they have significant knowledge and infrastructure in place for regulating similar subsurface activities such as oil and gas production, natural gas storage, and acid gas and deep waste disposal.

CO_2 injection falls under provincial jurisdiction unless it takes place in territorial waters or in territories administered by the federal government. It is anticipated that injection can largely be covered by existing legislation on CO_2 for EOR, natural gas storage and acid gas disposal. Future work needs to address the following issues (Bachu, 2008; Hegan, 2008):

- acquiring storage and access rights;
- permitting for the large volumes required by CCS;
- remedial liability for storage sites (a provincial matter);
- standards for measurement, monitoring and verification; and
- long-term liability for health and in situ damage (provincial) and CO_2 leakage (federal and provincial).

A number of activities are being undertaken to address these regulatory issues. Following the recommendations of the Canada-Alberta EcoENERGY CCS Task Force, Alberta has established a government-industry CCS Development Council, which hopes to report on CCS technologies and infrastructures, legal and regulatory, and economic and financial issues by the end of 2008 and make recommendations regarding CCS implementation in Alberta. Saskatchewan is considering amending its oil and gas regulations, and British Columbia has introduced legislation on CO_2 storage property rights. The federal government is also funding several research projects that will address outstanding regulatory issues. For example, the CCS Research Group at the University of Calgary will develop guidelines for protocols and frameworks for managing risks. In addition, the Final Phase of the IEA Weyburn-Midale CO_2 Monitoring and Storage Project will develop a Best Practices Manual with technical, regulatory, communications and business environment guidance for future CO_2 storage projects (Hegan, 2008).

CCS Research, Development and Deployment Activities

A number of organisations are involved in CCS RD&D, including eight federal and provincial government agencies, at least two dozen research organisations and universities, and over 20 private sector companies. The federal government, in collaboration with provincial governments, industry and universities, co-ordinated the production of two reports, *Canada's CO_2 Capture & Storage Technology Roadmap (2006)* and *Canada's Clean Coal Technology Roadmap (2005)*. The initial phases of the Roadmap include:

- demonstration of gasification technology in respect of oil sands and capture of CO_2 from the new facilities;
- a 300 MW to 400 MW clean coal demonstration facility; and
- early implementation of CO_2 transport infrastructure.

Canada's goal is that clean coal technologies, including CCS, will be achieve a total combined capacity of 4 000 MW in Canada by 2030. To support this, a CO_2 pipeline infrastructure needs to be developed in the Western Canada Sedimentary Basin (WCSB), which covers Southwestern Manitoba, the southern half of Saskatchewan, most of Alberta, and Northeastern British Columbia.

CCS RD&D Projects in Canada

There are a number of CCS-related RD&D initiatives underway in Canada. Significant projects include:

- The Boundary Dam CCS Project will rebuild an existing 100 MW unit using post-combustion capture to store 1 Mt CO_2 per year by 2015. This project is a partnership between the Government of Canada, the Province of Saskatchewan and industry and builds on work conducted by the Saskatchewan International Test Centre.
- The Alberta CO_2-Enhanced Coal Bed Methane Recovery Project made a proof of concept for the injection of CO_2, nitrogen and other flue gases into coal. The project's pilot phase involved modelling and a small field test.
- The CANMET Energy Technology Centre's R&D Oxyfuel Combustion for CO_2 Capture project involves a 300 kW oxyfuel pilot project near Ottawa with a goal of achieving higher than 95% CO_2 purity and controlling other air pollutants.
- The IEA GHG Weyburn-Midale Monitoring and Storage Project began in 2000 and ended in 2004. The objective was to predict and verify the ability of an oil reservoir securely to

store and economically to contain CO_2. This was done through a comprehensive analysis of the various process factors as well as monitoring/modeling methods designed to measure, monitor and track the CO_2 in the EOR environment (Wilson and Monea, 2004). The project is currently in its Final Phase, which will run from 2007-11. The objective is to develop a Best Practices Manual, which will serve as a practical technical guide for the design and implementation of CO_2 storage projects.

- Since 1990, more than 6 Mt of acid gas produced at natural gas plants has been disposed of through deep injection. More than 40 injection projects in Western Canada are currently providing an alternative to sulphur recovery and acid gas flaring, and currently have a combined storage of 1 Mt CO_2 per year (Bachu and Gunter, 2005). In 2008, Spectra Energy announced it will conduct a feasibility study of injecting up to 1.2 million tonnes of acid gas per year into deep underground saline reservoirs in the North-East of British Columbia. With funding from both the U.S. Department of Energy (Plains CO_2 Reduction Partnership) and the Government of British Columbia, Spectra is proceeding with drilling two test wells.
- The Zama Acid Gas EOR Project in Northwest Alberta aims to evaluate the impact of acid gas injection on EOR, assessing the integrity of the cap rock and monitoring and verifying the storage integrity of the injected gases (NRCAN, 2006).
- The Pembina Cardium EOR project in Central Alberta has been evaluating the feasibility of CO_2-EOR in the Pembina Cardium oil field. This is the largest conventional oil field in Canada with an estimated 7.8 billion barrels of oil originally in place. A pilot CO_2 injection was successful in 2005.
- The EPCOR 500 MW integrated gasification combined-cycle (IGCC) plant at Genesee in Alberta could be one of the first large-scale projects to be built under the auspices of the Canadian Clean Power Coalition, a group of power and coal mining companies. The project is currently undergoing engineering and design. A sanctioning decision is expected by the end of 2010, with a potential operation date of 2015.[45]
- The Alberta Saline Aquifer Project is an industry-supported initiative with 26 participating energy industry groups. It has two phases:[46]
  - Phase 1 will identify the top three suitable deep saline formations with good storage prospectivity, and is expected to be completed by the end of 2008; and
  - Phase 2 will include a pilot project with storage leading to a long-term large-scale sequestration operation.
- The Wabamun Aquifer Storage Project is a project conducted at the University of Calgary to identify CO_2 storage sites in deep saline aquifers in the vicinity of major coal-fired power plants in central Alberta, west of Edmonton.
- The Heartland Area Redwater Project seeks to demonstrate CO_2 storage in the water-saturated Redwater reef that has an oil cap (the third-largest oil reservoir in Canada). It is located northeast of Edmonton in central Alberta near major refineries, petrochemical and chemical plants and oil sands plants.
- In July 2008, the Government of Alberta announced it will provide CAD 2 billion to support three to five CCS projects in the province. A number of oil sands facilities and coal-fired electricity plants are expected to compete for this funding to construct large-scale CCS projects in Alberta. The projects are expected to reduce CO_2 emissions by up to 5 million tonnes annually by 2015.

45. See www.canadiancleanpowercoalition.com/Customer/ccpc/ccpcwebsite.nsf.

46. See www.carbonsensesolutions.com/documents.

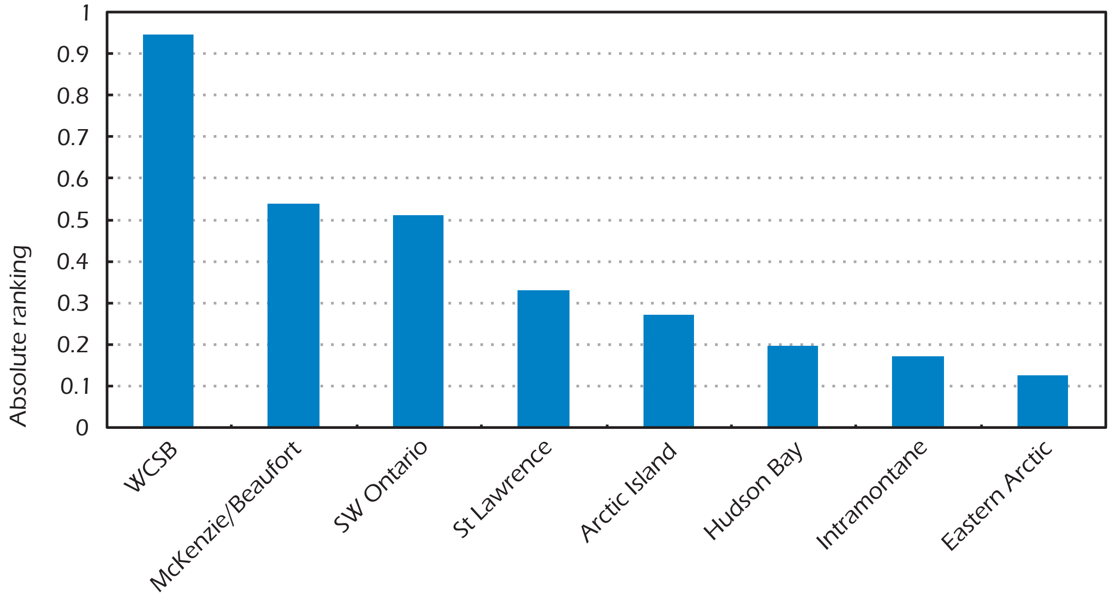
CO_2 Storage Potential

Estimates of Canada's CO_2 storage potential come from several studies. The Western Canada Sedimentary Basin has the highest ranking, with southwest Alberta having the highest potential, followed by southeast Alberta. Northeast Alberta has the lowest ranking (see Figure 6.4) (Bachu, 2003). A national CO_2 Storage Capacity Atlas project was started in 2008 to define, map and evaluate storage capacity across Canada.

Figure 6.4 Ranking of Canada's Basins for Geological Storage

Key point

The Western Canada Sedimentary Basin in Alberta has the most significant CO_2 storage potential in Canada.



Source: Bachu, 2003.

Table 6.2 compares three capacity estimates in the literature. This shows that, where there is already a high level of characterisation, the ranges for oil and gas basins in different studies are consistent. Estimates of coal and aquifer potential vary much more widely.

Table 6.2 CO_2 Storage Capacity Estimates in Canada

Formation type	Capacity – Gt CO_2 Dahowski, *et al.*, 2004	Capacity range (Gt) Bachu and Shaw, 2005	Capacity range (Gt) Hendriks, *et al.*, 2004
Deep saline formations	1 000		2–78
Coal basins	5.4		0–51
Depleted gas basins	4.2	3.2–8.6	0.8–9.4
Depleted oil basins	0.94	0.56-0.9	0.7-1.5

Sources: Bachu, 2005; Dahowski, 2004; Hendriks, 2004.

China

Policy Framework

China is the world's largest coal user. Coal accounts for 63% of the country's total primary energy supply (IEA, 2007). Since 1997, annual coal output has increased by 1.1 Gt, more than the United States total coal production in 2007. China was also the largest contributor to global CO_2 emissions in 2007, although per capita emissions are still relatively low (IEA, 2007).

China is a party to the UNFCCC and the Kyoto Protocol, but as a non-Annex I country, is not required to meet a binding emissions reduction target. The Chinese government's approach to climate change has developed within the context of energy security and economic development. As a result, the government has focused on reducing energy consumption through increased energy efficiency and on increasing the use of renewable energy. In addition, China is the largest global market for Clean Development Mechanism projects.

China sees CCS as a potential option for GHG emissions abatement in the future and is beginning to ramp up its CCS activities. In December 2005 and February 2006, the Ministry of Science and Technology signed a CCS memorandum, marking the formal start of a government research programme. China has also included CCS as a leading-edge technology in its 11th 5-year plan (2006-10) via the National High Technologies Programme and in the National Medium- and Long-term Science and Technology Plan to 2020 (Fu, 2007).

CCS Research, Development and Deployment Activities

Despite an increased level of CCS activity, current development trends suggest it is unlikely that these technologies will achieve large-scale application before 2030, as shown by the roadmap developed by the China Coal Research Institute in Figure 6.5.

Figure 6.5 China Coal Research Institute Technology Roadmap for CCS

Key point

China has established a long-term CCS technology roadmap.

Task	2010	2020	2030	2040	2050
CO_2 capture	Dissemination of capture technologies for low-concentration CO_2 and cost reduction				
	Demonstration and dissemination of oxygen-rich combustion technologies and cost reduction				
Decarburisation to produce hydrogen	Demonstration of coal-based hydrogen production		Commercialisation of coal-based hydrogen production		Provision of hydrogen energy, including pipelines and hydrogen stations
CO_2 transport	Technical and economic feasibility	Application of CO_2 storage and transport			
CO_2 storage	Research and geological investigation of storage potential	Demonstration and verification	CO_2 capture-transport-storage monitoring plan		

Sources: IEA (forth coming); Cleaner Coal in China; OECD/IEA, Paris.

CCS R&D and demonstration projects currently underway in China include:

- A micro-pilot ECBM project in Qinshui, Shanxi Province. The initial results indicate a four-fold increase in the CBM recovered, and show that CO_2 storage in high-rank anthracite coal seams is possible in the Qinshui Basin (Jianping, *et al.,* 2005).
- A green coal-based power generation project (GreenGen) was launched in 2000 with the goal of increasing power generation efficiency with near-zero CO_2 emissions. Activities include coal gasification, hydrogen production and power generation, and CO_2 storage. Phase I of the project, which ended in 2005, focused on building a pilot system for CO_2 separation and storage at natural gas power plants. This was followed by Phase II, which involves the construction of a demonstration plant by 2010. Phase III of the project involves completing the demonstration and preparing for commercialisation in the 2015-20 time frame. GreenGen's shareholders include the country's top five electricity generators, the two biggest coal producers and the State Development and Investment Corporation. Electricity generator China Huaneng Group owns 51% of GreenGen with the other partner companies owning 7% each (PetroChina, 2007). A demonstration project at the Yantai IGCC Plant (with the option of future CCS and hydrogen production) has been announced. The 300 MW to 400 MW demonstration power plant that is planned for 2010 will burn high sulphur (2% to 3%) bituminous coal and will closely follow the GreenGen first stage plan for a 250 MW IGCC (Shisen, 2006).

China also has extensive experience of EOR applications, making CO_2-EOR a key opportunity for early implementation (Wenying, 2006). CO_2 injection has been in use in Daqing (1990 to 1995) and I Subei (1996), where 0.7 Mt CO_2 has been injected. Flue gas injection from a natural gas steam boiler containing 12% CO_2 was tried in the Liaohe field in the 1990s. This significantly increased recovery but there was an issue of corrosion. CO_2-EOR projects are also planned in Shengli and Zhongyuan. China National Petroleum Corporation and seven Chinese Universities have established a joint project to optimise EOR applications. The use of CO_2-EOR in larger fields offshore is also possible, but costs need to be assessed (Wenying, 2006).

In 2002, the IEA Greenhouse Gas R&D Programme documented early opportunities for CCS in China for large industrial CO_2 emitters located within 50 km of a potential EOR or ECBM site. Table 6.3 lists these prospects.

International Collaboration

Due to its size and substantial coal resources, China has an important role to play in the development of CCS technologies and in knowledge transfer. China participates actively in the IEA and the Carbon Sequestration Leadership Forum activities, and a number of multilateral and bilateral efforts as well. The main programmes are listed below.

- The US-China Energy and Environment Technology Centre has goals to mitigate CO_2 emissions and assess CO_2 storage options. The initiative includes two R&D centres: China's Tsinghua University, in collaboration with the Chinese Academy of Sciences, and Tulane University in collaboration with Battelle Memorial Institute and Montana State University in the United States. China also participates in the FutureGen and other US projects.
- The CCS Co-operation Action within China-EU project (also called the Near-Zero Emissions Coal (NZEC) project) has been working since 2006 to develop and demonstrate advanced near-zero coal emissions technology including CCS. The project has three phases. Phase 1

(2006 to 2008) will explore CCS options in China; Phase 2 will design a demonstration plant by 2010; and Phase 3 involves the construction and operation of the plant by 2020.[47]

- In May 2008, Japan and China announced a cooperative project to capture CO_2 from a Chinese coal-fired power plant and inject it into a Chinese oil field for EOR. The project is due to start in 2009, and will involve Japanese industry investments from companies like Toyota Motor Corp and JGC Corp. On the Chinese side, the China National Petroleum Corporation and others are expected to take part in the project (Reuters, 2008).
- China is also working with Australian research agency CSIRO on a USD 4 million research project to fit a post-combustion capture system to one of the Huaneng Group's pilot plants in Beijing. The project hopes to capture 3 000 t CO_2 per year.[48]

CO_2 Storage Potential

The Asia-Pacific Economic Co-operation (APEC) Energy Working Group established a three-phase project in 2004 to explore the potential for geological CO_2 capture and storage technologies in APEC regions, including China. The 2005 APEC study provides a high-level estimate of China's storage basins and potential matches between CO_2 sources and sinks. Figure 6.6 shows basins classified by their storage potential and magnitude of emission sources.

Other studies (Table 6.3) have been completed as well. A preliminary estimate of storage volumes in China includes (Lu Xuedu, 2006):

- 68 unmineable coalbeds with methane recovery, with a capacity of 12 Gt CO_2;
- 46 oil and gas reservoirs, with a capacity of 7 Gt CO_2; and
- 24 deep saline formations, with a capacity of 1 000 Gt CO_2 to 2 000 Gt CO_2.

Table 6.3 Early CO_2 Storage Opportunities in China

CO_2 source	Location	Volume (kt CO_2/yr)	Storage site
Anshan Fertiliser Plant	Anshan	763	Tangshan ECBM
Dahua Group Ltd.	Dalian	1 631	South Sichuan ECBM
Erlian Fertiliser	Erlian	1 038	Bayanhuxu ECBM
Hunang Zijiang N_2 Fertiliser	Leugshujiang	521	Lyanyaugn ECBM
Inner Mongolia Fertiliser	Hohehot	1 145	Hedong-Weibei ECBM
Jilin Chemical Sinopec	Jilin	1 575	Sanjian ECBM
Lutianhua Group	Heijiang	1 145	East Sichuan ECBM
Shaanxi Chemical Industry	Huaxian	677	Taihang Mts ECBM
Shanghai Wujing Chemical	Wujing	577	N. Yell River ECBM
Urumqi Petrochemicals	Urumqi	579	Junggar ECBM
Yunthianhua Group	Shuifu	1 152	So. Sichuan ECBM
Cangzhou Fertiliser	Cangzhou	1 152	Tert. Lacustrine EOR
Qilu Petrochemical Corp	Zibo	500	Tert. Lacustrine EOR

Source: IEA GHG, 2002.

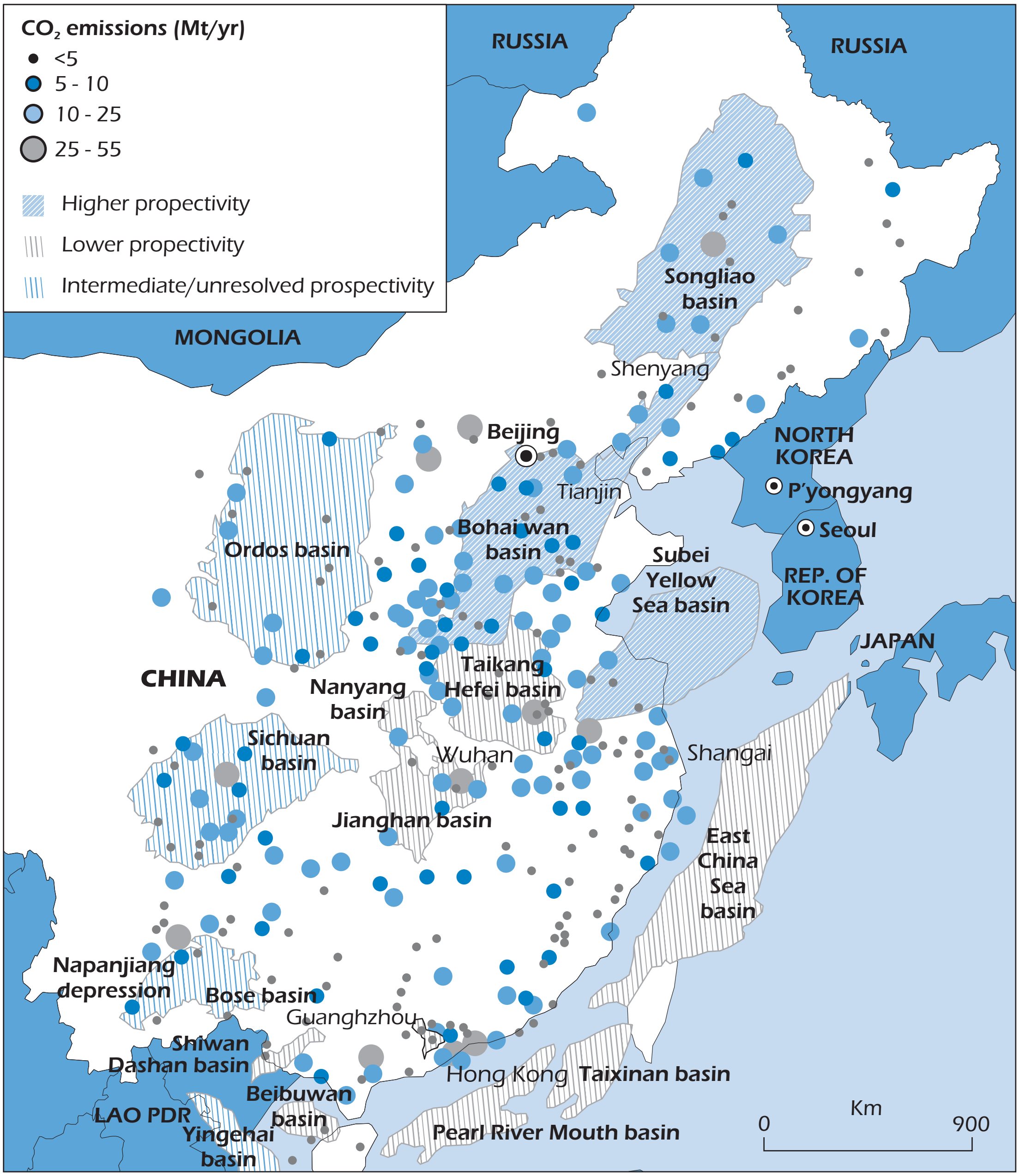
47. See www.nzec.info/en/what-is-nzec.

48. See www.csiro.au/news/carboncapturemilestone.html.

Figure 6.6 CO_2 Sources and Sinks in Eastern China

Key point

CO_2 storage estimates for China are improving, but more work must be done.



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Source: APEC, 2005.

Li Xiaochun's summary of the prospects for CO_2 storage includes both hydrodynamic and solubility trapping mechanisms and covers major deep saline formations in the 1 000 m to 3 000 m depth range. Much more granularity is needed to refine storage estimates which currently vary from 150 Gt to 2 000 Gt (Li Xiaochun, 2005).

China's CBM resources represent a total of more than 30 trillion m^3 of gas in place (Lako, 2002). The best prospects for implementing CO_2-ECBM include the following (Hongguan, *et al.,* 2007):

- the South Quinshui Basin in Shanxi Province which has a coal seam thickness of 10 metres to 20 metres, a permeability of 5 to 10 millidarcies and 5.5 trillion m^3 CBM resources in place; and
- the Ordos Basin in Ninqxi province which holds the largest gas reserves and has a high permeability (1 to 40 millidarcies). Potential CO_2 storage volumes are in the 4 Gt range.

A 2007 study matched sources and EOR sinks using updated capture, transport and storage/monitoring cost curves as well as oil and gas revenues. The potential CO_2-EOR pairings are the Nanjing Chemical Industry Plant-Zhenwu oil field, the Dong Ting Ammonia Plant-Plangchang oil field and the Hubei Ammonia Plant-Wangchang oil field. The CO_2-ECBM demonstration matches the Weihe, Huainan and Nanjing ammonia plants with the Ordos and northeastern coal-bearing regions (Meng, *et al.,* 2007).

France

Policy Framework

French estimates indicate that CO_2 emissions will increase by 39% from 2000 to 2030 (DGEMP, 2005). The *"Facteur 4"* group was created in 2006 to determine paths towards a four-fold decrease in GHG emissions in France by 2050 from today's levels. Requiring CCS to be fitted to new coal-fired power stations is one of three key recommendations from today's levels (Facteur 4, 2006).

CCS Research, Development and Deployment Activities

French R&D institutions, universities and industry are strongly involved in international CCS projects. The majority of French CCS projects are co-funded by the newly created Agence Nationale de la Recherche (ANR) and the French Environment and Energy Management Agency (ADEME). The ANR has supported more than 27 CCS-related R&D projects with funding of EUR 27 million, covering technology, risk management, and social acceptability issues. Projects supported by ANR and/or ADEME include:

- joint industry projects led by the Institut Francais du Petrole (IFP), including CO_2 WIN (Well Injectivity of CO_2) and CO_2 SECURE on storage integrity;
- METSTOR led by the Bureau de Geologie et Recherche Miniere (BRGM) that will deliver through the design and implementation of a website transparent information to the public on methodologies for selecting CO_2 storage sites;
- E-CO_2, co-led by IFP and Alstom, which analyses the required infrastructure for CCS, including a comparison between post-combustion and oxyfuelling options.

In February 2007, the first CCS pilot project in France was announced by Total and Air Liquide in partnership with IFP, BRGM and others, with an investment of EUR 60 million. After an oxy-combustion boiler is installed, the CO_2 will be captured from a steam production unit at the Lacq gas processing plant in southwest France. After purification and compression, the CO_2 will be transported via a 30-km pipeline to the depleted Rousse gas field and injected to a depth of 4 500 m. Injection of up to 150 kt CO_2 is scheduled to take place over a two-year period starting at the end of 2008.[49]

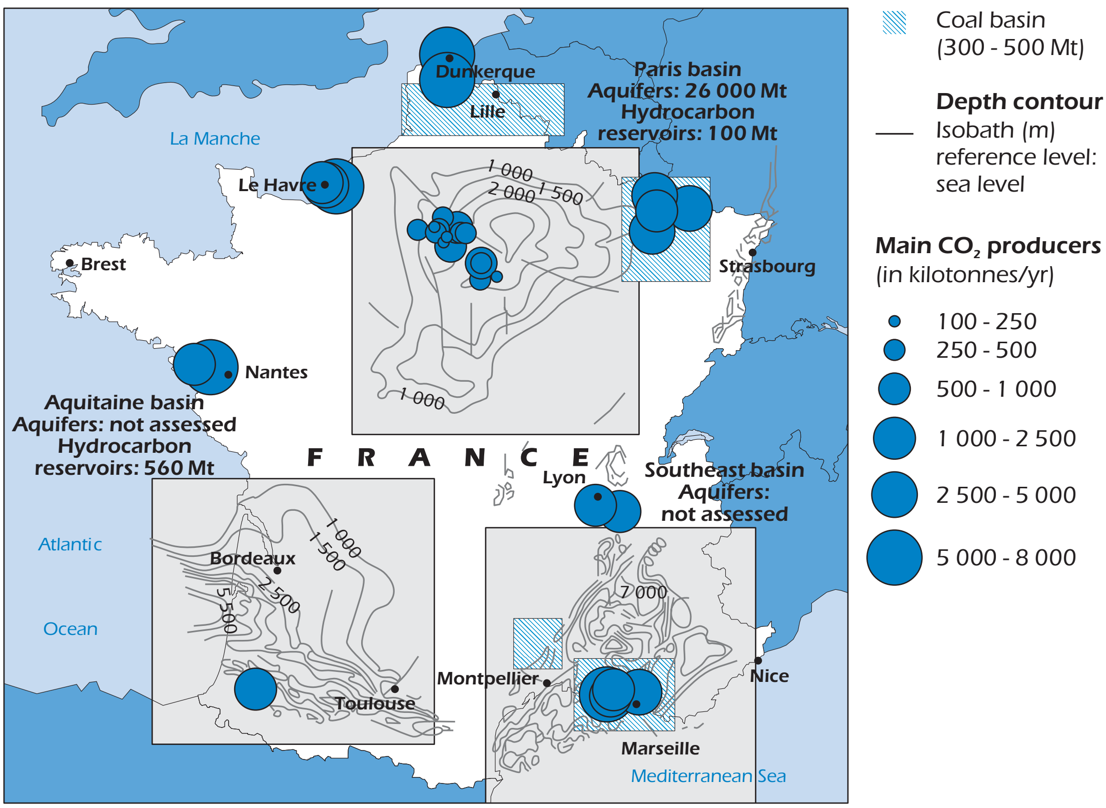
CO_2 Storage Potential

CO_2 storage capacity in France is currently not well-characterised. The METSTOR project is attempting to improve this situation. The GESTCO study screened three main sedimentary basins: the Paris basin, the Aquitaine basin in southwest France, and the Southeastern basin (Figure 6.7). The largest capacity is provided by the Triassic aquifers in the Paris basin with capacities in the 0.6 Gt to 22 Gt range, followed by the Dogger basin (0.01 Gt to 4.3 Gt). Estimates of storage capacity in oil and gas fields ranges from 0.2-0.7 Gt. Storage in deep coal seams is in the range of 0.3-0.5 Gt. Capacity estimates have not been made for aquifers in the Southeastern basin, the Aquitaine basin and the Rhine area.

Figure 6.7 France's Main CO_2 Emitters and Potential Storage Sites

Key point

Many CO_2 sources in France are located near potential CO_2 storage sites.



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Source: BRGM, 2007.

49. *For more information, see* http://www.total.com/en/corporate-social-responsibility/special-reports/capture/Carbon-dioxde-Total-Commitment/Carbon-dioxide-Lacq-pilot_11357.htm.

Germany

Policy Framework

Germany's commitment under the Kyoto Protocol is to reduce GHG emissions by 21% by the end of 2012. At the Bali Conference of the Parties in 2007, the German government went further than its Kyoto target and announced a national climate protection programme with a target to reduce national anthropogenic CO_2 emissions 40% by 2020 if the EU as a whole reduces its GHG emissions by 30% (Stroink, 2008). In addition to energy efficiency and renewables, the German Federal Government sees CCS as an important CO_2 mitigation option in Germany and has included it as an important part of the 2007 Integrated Energy and Climate Programme. In the fiscal year 2008, a budget of about EUR 3.3 billion is available for this programme.

CCS Research, Development and Deployment Activities

The Federal Ministry of Economics and Technology and the Federal Ministry for Education and Research have given high priority to two national CCS R&D programmes (Höwener, 2007):

- CO_2-Reduction-Technologies (COORETEC) was launched in 2002 with annual funding of EUR 25 million, increasing to EUR 35 million in 2010. Projects started in 2004 with the objectives of improving power plant technology and assessing new technology options. Five technology-related working groups have been created: natural gas combined-cycle, steam-cycle power plants, IGCC with CO_2 capture, oxyfuel plants, and CO_2 storage. COORETEC is funded by the Federal Ministry of Economics and Technology.
- The Geo-Technologien Programme, with an annual funding of approximately EUR 30 million, focuses on the assessment of CO_2 storage potential, and has 130 projects distributed among 21 research institutes, 38 universities and 25 industrial partners.[50] The programme is funded by the Federal Ministry of Education and Research.

In addition, German CCS demonstration projects include:

- The Ketzin CO_2 injection pilot project, managed by the GeoForschungs-Zentrum in Postdam, will provide improved knowledge of the interaction of CO_2 with rocks, and mid- to long-term analysis through advanced monitoring technologies.
- The EUR 60 million Vattenfall Oxyfuel Schwarze Pumpe 30 MW pilot plant will research the complete process chain. The CO_2 will either be stored (at Ketzin or another site), or used in industrial applications. The construction of this plant started in May 2006; operation began in 2008. On the basis of the experience gained on the Schwarze Pumpe plant, Vattenfall plans to construct a commercial-scale CCS demonstration plant in the same location.

CO_2 Storage Potential

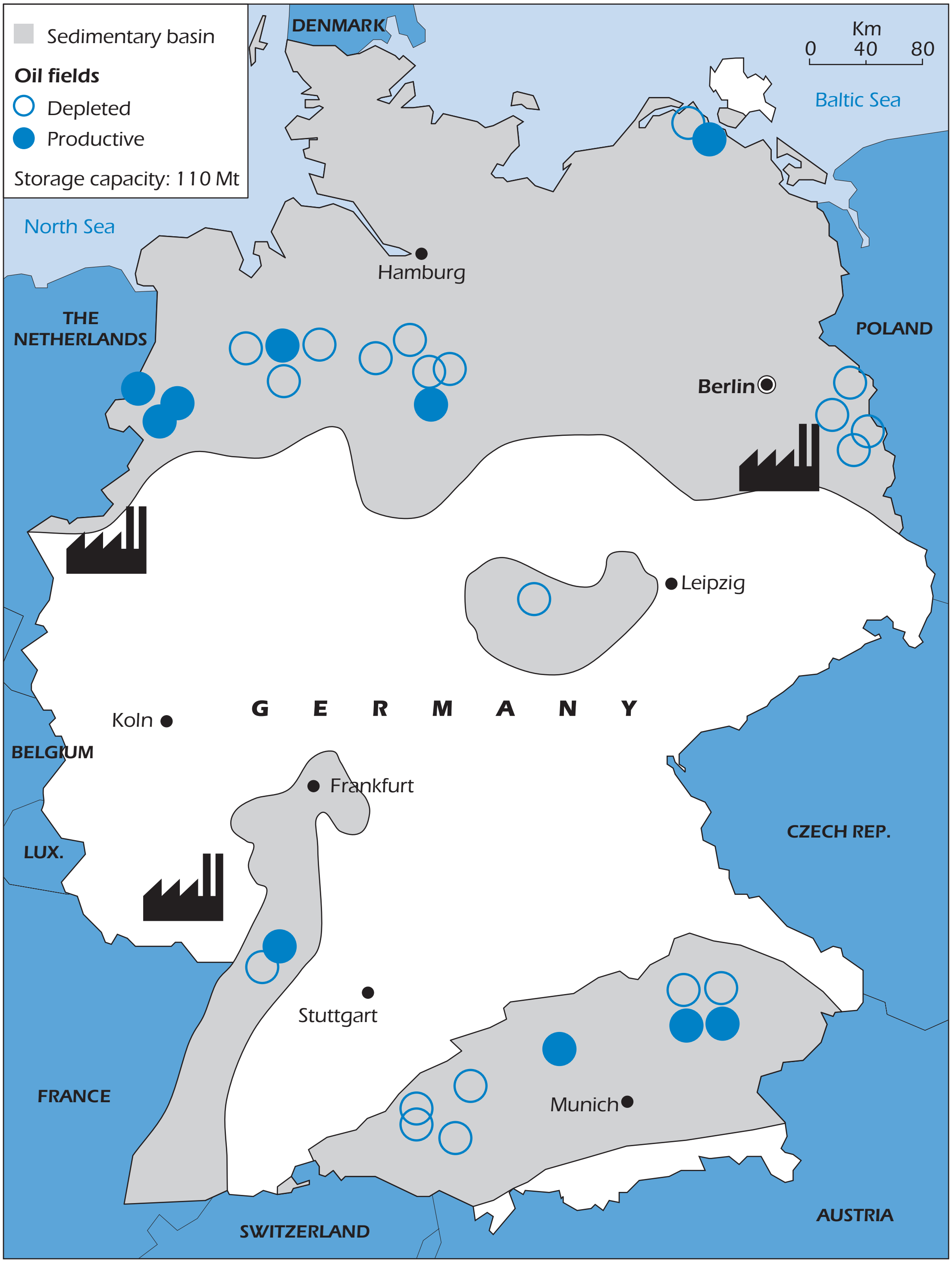
CO_2 storage capacity in Germany has been evaluated by several programmes (Figure 6.8 and Table 6.4). The largest sinks are saline aquifers, primarily located in northern Germany, and gas reservoirs. The Altmark gasfield is the second largest natural gas field in Europe with a potential storage capacity of 500 Mt CO_2 and offers the potential to study enhanced gas recovery (EGR) and safe storage of CO_2 (Stroink, 2008).

50. See www.geotechnologien.de/portrait_en/portrait2_en.html.

Figure 6.8 CO_2 Storage Distribution in Germany

Key point

There are a number of CO_2 storage options in Germany.



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Source: Stroink, 2004.

Table 6.4 CO_2 Storage Capacity in Germany

Storage type	Volume (Gt)
Gas fields	2.7
Saline aquifers	20 ± 8
Coal seams	0.4-1.7
Oil fields	0.1

Source: May, 2007.

India

Policy Framework

India is the world's third-largest coal user. Coal accounts for 62% of the country's energy supply and its use is expected to grow rapidly (IEA, 2007). Nearly 75% of the coal produced in India is used in electricity generation, the remainder being used in the steel, cement, and fertiliser industries. Given the abundance of coal in India, combined with rapidly growing energy demand, the government of India is backing an initiative to develop up to 9 Ultra-Mega Power Projects. This will add approximately 36 GW of installed coal-fired capacity, offering important opportunities to test CCS. India's current annual CO_2 emissions amount to over 1 300 Mt, about half of which is from large point sources that are suitable for CO_2 capture. The 25 largest emitters contributed around 36% of total national CO_2 emissions in 2000, indicating the potential existence of a number of important CCS opportunities (IEA GHG, 2008).

As a non-Annex I country to the UNFCCC, India has agreed to complete GHG emission inventories but is not required to meet a binding emissions reduction target under the Kyoto Protocol. India faces a number of technical and regulatory barriers to the application of CCS and clean coal technologies as part of a larger climate change strategy (Shahi, 2007). To address these issues, the government has developed a Clean Coal Technology Roadmap with a view to helping the targeting of clean coal development and policy interventions. A clean coal research centre has also been established by industry. Capacity-building programmes have been proposed to further CCS technology development (Goel, 2007). In addition, India has joined a number of international efforts to advance the development and dissemination of CCS technologies. India is one of the founding member countries of the Carbon Sequestration Leadership Forum.

CCS Research, Development and Deployment Activities

The Department of Science and Technology and Technology Bhawan in New Delhi launched the Indian CO_2 Sequestration Applied Research network in 2007 to facilitate dialogue with stakeholders and to develop a framework for activities. CCS research in India includes CO_2-EOR scoping studies in mature oil fields. Acid gas from the Hazira processing plant is planned to be injected. The costs of CO_2 capture have also been assessed. For example, capture is estimated to be 21% more expensive from IGCC and high-ash coal plant than from pulverised coal plant and 12% more expensive than from Ultra Super Critical plant (Sonde, 2007). The Fertilisers Corporation of India has installed two CO_2 capture plants with capacity of 450 t per day at its Aonla and Phulpur complexes. Research in Deccan Basalt Province in Western India, one of the largest flood basalt provinces in the world, has begun in collaboration with United States Pacific Northwest National Laboratory (Goel, 2007).

CO_2 Storage Potential

Estimates of geological storage potential in India are in the range of 500 to 1 000 Gt CO_2, including onshore and offshore deep saline formations (300-400 Gt), basalt formation traps (200-400 Gt), unmineable coal seams (5 Gt), and depleted oil and gas reservoirs (5-10 Gt) (Singh, *et al.,* 2006). A recent assessment of coal-mining operations in India gives a theoretical CO_2 storage potential in deep coal seams of 345 Mt (see Table 6.5). However, none of the fields has the ability to store more than 100 Mt. CO_2 storage in deep coal seams is still in the demonstration phase (IEA GHG, 2008).

Table 6.5 CO_2 Storage Capacity of Indian Coal Mines

Depth of coalbeds	Coal grade/category	CO_2 storage capacity
0 – 300 m	All grades of coal	Nil
300 – 600 m	Coking coal	Nil
	Superior grade non coking coal	Nil
	Mixed (Superior:Inferior 1:1)	10%
	Inferior (E-G) grade	30%
	Inferior under thick trap	50%
600 – 1 200 m	Coking coal	Nil
	Superior non coking coal	Nil
	Mixed grade (1:1 ratio)	50%
	Inferior grade under trap	100%

Source: IEA GHG, 2008.

Analysis of oil and gas fields around India shows that relatively few fields have the potential to store the lifetime emissions from even a medium-sized coal-fired power plant. However, recently discovered offshore fields could provide opportunities in the future. The potential for CO_2-EOR needs to be further analysed on a basin-by-basin basis. It is not possible to develop a suitable estimate today (IEA GHG, 2008).

Deccan Volcanic Province, a basalt rock region in the northwest of India, is one of the largest potential areas for CO_2 storage. The total area is 500 000 km^2 with a total volume of 550 000 km^3 with up to 20 different flow units. It reaches 2 000 m below ground on the western flank. Storage capacity is around 300 Gt CO_2 (Sonde, 2006). Thick sedimentary rocks (up to 4 000 m) exist below the basalt trap. In order to model the long-term fate of CO_2 injection in such mineral systems, geo-chemical and geo-mechanical modelling of interaction between fluids and rocks is required.

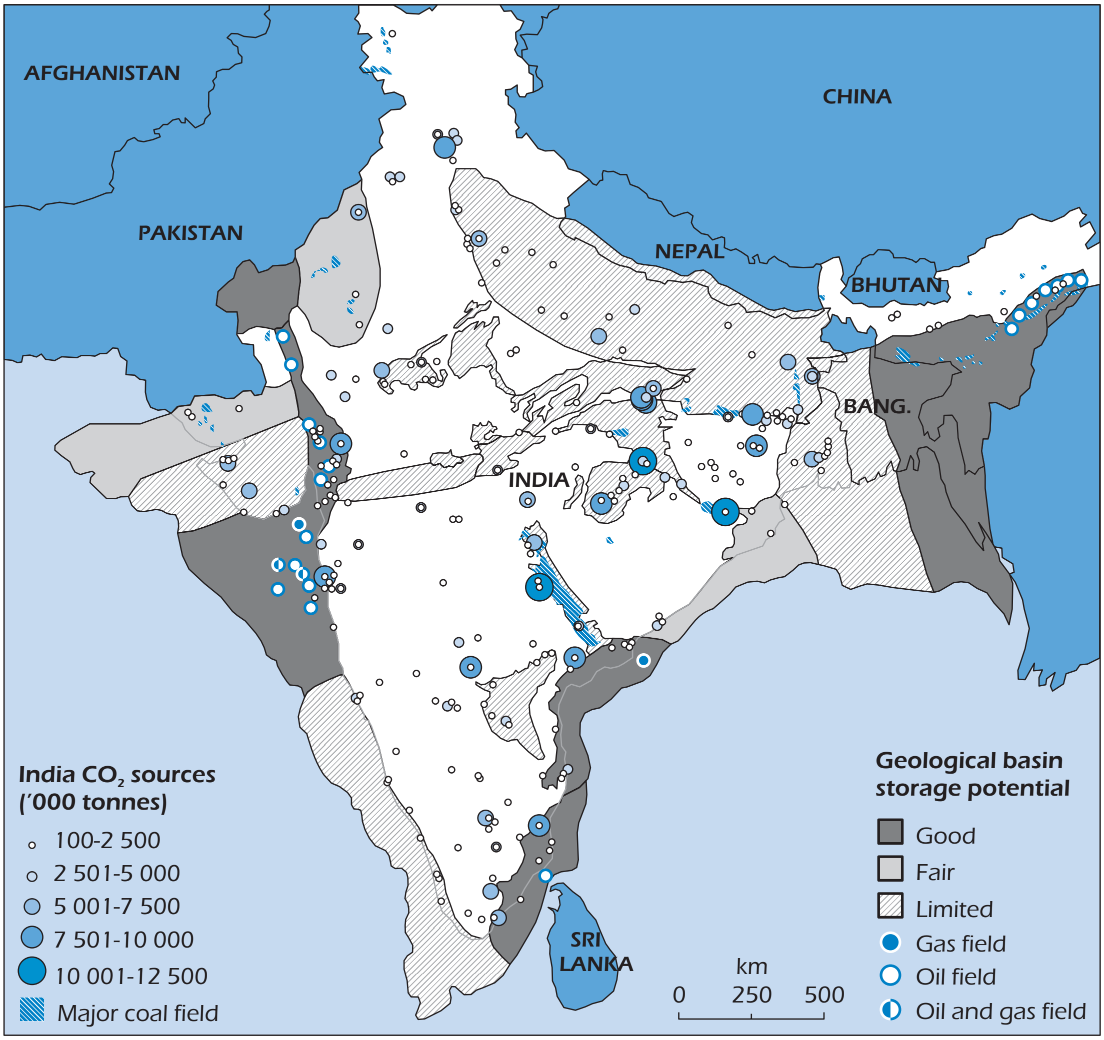
There is considerable potential for CO_2 storage in deep saline aquifers, particularly at the coast and on the margins of the Indian peninsula, and in Gujarat and Rajasthan (see Figure 6.9). Aquifer storage potential has also been demonstrated around Assam, although these reservoirs are 750-1 000 km from the nearest large point sources.

The Indo-Gangetic area is an important potential storage site (Friedmann, 2006). The Ganga Eocene-Miocene Murree-Siwalik formations have good storage potential as deep saline formations, but high salinity and depth preclude economic use. The Ganga area has a basin area of 186 000 km^2, with a large thickness of caprock composed of low permeability clay and siltstone (Bhandar, *et al.,* 2007). The proximity of sources to the potential storage site makes it a good candidate for a pilot project.

Figure 6.9 Point Sources of CO_2, Storage Basins and Oil and Gas Fields on the Indian Subcontinent

Key point

Work has begun to assess India's CO_2 storage potential but more needs to be done.



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Source: IEA GHG, 2008.

Italy

Policy Framework

Interest in CCS technologies is growing in Italy as an emissions abatement option, as the country uses natural gas and coal to generate most of its electricity. Italy is also interested in technological co-operation with emerging economies on CCS under the Clean Development Mechanism, and launched the first Italian CCS International School in November 2007 with Indian and Chinese students (Scajola, 2008). Italy will host the G8 Ministerial in July 2009, which will raise the profile of climate change and clean energy technologies, including CCS.

CCS Research, Development and Deployment Activities

A number of CCS R&D projects are being carried out in Italy, mainly led by the private sector, with the government focusing on communication and public acceptance (Quattrocchi, 2007). The Ministry of Economic Development's Fund for R&D on the Electricity System funds clean coal and CCS research at a level of EUR 10 million per year, but at the moment only funds CO_2 capture. The previous political administration did not fund CO_2 storage, and reduced CO_2 storage research funding for the Industria 2015 initiative. The Italian Ministry of Research has funded two CCS R&D projects for CO_2 capture:

- coal gasification with CO_2 separation (ZECOMIX);[51] and
- coal syngas production with CO_2 and hydrogen separation (COHYGEN).[52]

The private sector has also invested in CCS. For example:

- In 2006, Enel began a project to demonstrate an oxyfuel combustion process with a 50 MW thermal pilot plant at the Brindisi power station by 2010, including a 35 MW electricity demonstration plant by 2012.
- Demonstration of post-combustion capture is being investigated with the coal-fired Torrevaldaliga Nord 2 000 MW electricity power station providing a suitable storage site studied by an ongoing feasibility study, led by INGV with IES S.r.l. to be ready for 2012.[53]
- A CO_2 storage feasibility study has been started in the Porto Tolle (Venice) area, involving research institutes including INGV, OGS and Cesi Ricerca S.p.A.
- In June 2008, SEI S.p.A., a company controlled by Rätia Energie, Hera S.p.A., Foster Wheeler Italiana and venture capital APRI Sviluppo, began a 1 320 MW CO_2 capture-ready coal-fired power plant at the former Liquichimica industrial site of Saline Joniche (Reggio Calabria) in southern Italy.[54] INGV, CNR-IGAG and IES S.r.l. universities are studying CO_2 storage feasibility in the Calabria Region.
- Two CO_2 storage pilot plants, based on ECBM technology, will be built by Carbosulcis with Sotacarbo/ENEA and the Regional Government of Sardinia at the Sulcis coal fields in Sardinia,[55] and by Independent Resources plc in co-operation with INGV and OGS at Ribolla in Southern Tuscany, near the Larderello and Amiata geothermal fields.[56,57]

CO_2 Storage Potential

In 2004, the EU's JOULE II project gave a preliminary estimate of the CO_2 storage potential in Italy at 440 Mt in deep aquifers (75% onshore) and 110 Mt and 1 690 Mt in depleted oil and gas fields (onshore and offshore).[58] A further comprehensive survey of Italy's storage capacity, including saline aquifers, was undertaken in 2006 by Italy's R&D institutes (Moia, *et al.,* 2007; Quattrocchi, 2007; Quattrocchi, *et al.,* 2008). This produced larger capacity estimates, especially for aquifers (10-40 Gt). These estimates still need to be verified.

51. See www.aidic.it/H2www/webpapers/30%20Calabro'.doc.

52. See www.sotacarbo.it/index.php?sezione=pagine&cat=CoHyGen.

53. See www.enel.it/attivita/novita_eventi/energy_views/archivio/2008_03/art04/index.asp.

54. See www.melitoonline.it.

55. See www.co2captureandstorage.info/project_specific.php?project_id=133.

56. See http://legacy.ingv.it/comunicati-stampa/2006%20mondo/141106_nairobi.html.

57. See www.investegate.co.uk/Article.aspx?id=20080429070017M8252.

58. See Holloway S (Ed) (1996) Final Report of the Joule II Project No. CT92-0031 - The Underground Disposal of Carbon Dioxide, *British Geological Survey.*

Potential storage sites have been identified along the Adriatic Sea (North and South) offshore and partially inshore, along the Bradanic Basin, throughout the Po Valley, in the central part of the Tyrrhenian Sea, and along the coasts of the Calabria and Sardinia Region (Angelone, *et al.,* 2004). ENI is also working with Italian universities to screen the storage potential of 20 depleted reservoirs managed by the company. This study will be used to select the first ENI pilot CCS project with CO_2 capture from a refinery and injection into a depleted gas field (Savino, *et al.,* 2005).

Japan

Policy Framework

CCS is being addressed in Japan in the context of the country's wider climate change mitigation efforts. In May 2007, the Japanese Prime Minister announced the Cool Earth 50 initiative, proposing the long-term goal of a 50% reduction of global GHG emissions by 2050 and identifying the importance of innovative technologies in meeting this goal. In the subsequent development of the Cool Earth-Innovative Energy Technology Programme, the Japanese government identified 21 priority technologies and associated roadmaps for their development. CCS was one of these technologies, with a technology roadmap targeting the first CCS projects in 2020, increasing until 2050 (METI, 2008). The Japanese government is also considering public-private partnerships to promote CCS implementation.

With regard to the regulation of CCS activities, including offshore CO_2 storage, the Law Relating to the Prevention of Marine Pollution and Maritime Disaster provides for the protection of the marine environment and also for the domestic implementation of several international treaties such as the London Convention and Protocol. After a series of government and public consultations from September 2006 to January 2007, this law was amended in May 2007 to implement amendments to the London Protocol to allow for offshore CO_2 storage. Three related Ministry of Environment Ordinances were passed in September 2007 for the determination of methods for measuring concentration of CO_2 streams, for offshore CCS permits, and for notification of offshore CCS permits. Together, these Ordinances address (Maeda, 2008):

- permits for CO_2 storage in under the seabed geological formations, including the documents and processes required for permitting;
- designation of a CO_2 storage site by the Minister of the Environment;
- site selection criteria and reporting;
- environmental impact assessment reporting;
- CO_2 purity standards for post-combustion using amine solvents and for capture through the hydrogen production process at a petroleum refinery; and
- the development of monitoring plans.

CCS Research, Development and Deployment Activities

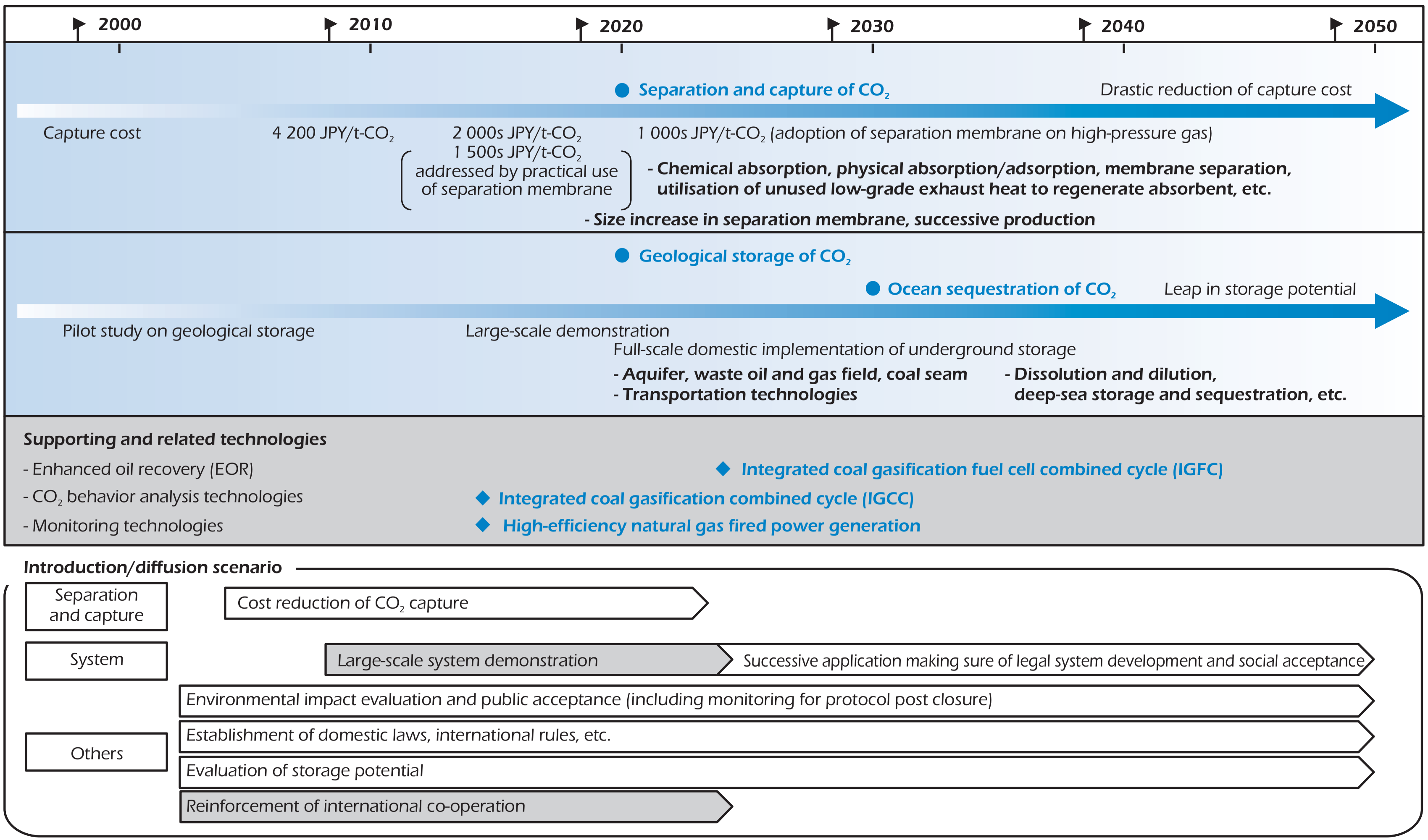
CCS RD&D activities are co-ordinated under Japan's CCS Roadmap (Figure 6.10). This envisages large-scale implementation of CCS by 2020.

Japan has several CCS-related R&D projects underway, including (Nishio, 2007):

Figure 6.10 Japan CCS Roadmap

Key point

Japan has ambitious plans for CCS technology demonstration and deployment.



Source: Cool Earth-Innovative Energy Technology Program (METI, 2008).

- The RITE (Research Institue of Innovative Technology for the Earth) R&D project on CO_2 storage. Components include a small-scale CO_2 injection field test into an onshore aquifer and a geological survey of prospective offshore deep saline formations.
- The Nagaoka project in central Japan injected CO_2 from 2003-05 into a saline aquifer at a depth of 1 100 m. Extensive sub-surface characterisation preceded the injection, including logging, cross-well seismic tomography and micro-seismicity and three observation wells. Over 10 kt CO_2 was injected at a rate of 20-40 t per day (RITE, 2007).
- The Japan CO_2 geo-sequestration in Coal Seams Project began in 2002 to evaluate the technical and economic feasibility of methane production with CO_2 storage in coal seams. The micro-pilot test started in 2002 in the Ishikari coalfield in Hokkaido with a pair of injection and observation wells. Initial well matching confirmed that CBM production had been enhanced by CO_2 injection (METI, 2008).
- CO_2 capture from a coal-fired power plant in Sakai city near Nagasaki. The plant recovers 10 t CO_2 per day from flue gas containing 14.1% CO_2. The Sumitomo Chemicals Plant in Chiba (Japan) has had a CO_2 capture rate of 150 tonnes per day since 1994.
- The Petronas Fertiliser ammonia/urea production plant hosted the first commercial flue gas CO_2 recovery plant using KS-1 solvent. At this plant, CO_2 is recovered from the flue gas of an ammonia steam reformer plant and delivered to a CO_2 compressor for urea synthesis (METI, 2008).

Takagi (Takagi, 2007) and Akimoto (Akimoto, *et al.,* 2006) have also evaluated the cost of CCS technology and development scenarios.

CO_2 Storage Potential

Early studies of CO_2 storage potential in Japan (Tanaka, *et al.,* 1995) have been recently re-evaluated (Ohsumi, 2007). Table 6.6 summarises the findings.

Table 6.6 *Japan's CO_2 Storage Potential in Aquifers*

Data source \ Type of aquifer		Aquifer with closure	Geological formation of stratigraphic trapping
Depleted oil and gas	Data obtained during operation	3.5 Gt CO_2	27.5 Gt CO_2
Identified aquifer	Public domain data by seismic and drillhole	5.2 Gt CO_2	
Identified closure	Public domain data by seismic survey only	21.4 Gt CO_2	88.5 Gt CO_2
Sum		30.1 Gt CO_2	116.0 Gt CO_2
Total		**146.1 Gt CO_2**	

Source: Ohsumi, 2007.

The Netherlands

Policy Framework

The Dutch government's Kyoto target is a 6% reduction in GHG emissions by 2010. The government has also announced a 30% GHG reduction target for 2020, and sees CCS as an important option for the transition towards a sustainable energy production system. The Netherlands shows great potential for CCS, given the country's concentrated industrial base and number of potential CO_2 storage fields. Working with the energy sector, the government has created a CCS Task Force which is developing a vision and approach to the implementation of CCS. It has also formed an internal government CCS Team which involves the Ministries of Energy, Environment, Transport, and SenterNovem. In June 2008, the Dutch government also announced an Energy Plan designed to deploy new technologies and to foster energy innovation through R&D. This Plan includes EUR 8 billion for technology deployment from 2008 to 2011, EUR 1 billion of which is dedicated to R&D. CCS is one of a number of technologies that this Plan will fund (Ministry of Economic Affairs, 2008).

CCS Research, Development and Deployment Activities

In the Netherlands, CCS R&D activity is carried out under the national CATO (CO_2 Capture, Transport and Storage) project,[59] which is funded with over EUR 25 million from 2004-08 (Lysen, 2007). CATO is co-ordinated by the Utrecht Centre for Energy Research and has 17 partners. Its work includes systems analysis, CO_2 capture, CO_2 storage and outreach. A related programme focusing on the transition to sustainable use of fossil fuels is co-ordinated by Utrecht University and includes system analysis, and public opinion surveys. In addition, Dutch research institutes and companies are leading a number of European projects, including RECOPOL, CO_2REMOVE and the European Zero Emissions Technology Platform.

The government also funds three CO_2 capture projects at EUR 10 million each. These include the NUON IGCC multifuel project and EnecoGen's Cryogenic project which uses liquefied natural gas in a combined cycle gas turbine and freezes the flue gases, with a goal of expanding to a 850 MW gas-fired power plant with CO_2 storage (Schreurs, 2008). The GDF-Netherlands project at the depleted K-12B gas field is the world's first pure CO_2 EGR project.[60] The gas produced from an offshore field 100 km from the Den Helder coast has a 13% CO_2 content, which is reduced to 2% using amines. The separated CO_2 is injected into a deep (3 900 m) storage reservoir. The first phases (2004-06) included a demonstration period with injection of 20 kt CO_2 per year. Scale-up will include a third injection phase of up to 480 kt CO_2 per year (Mulders, 2007).

E.on, TNO, and the University of Utrecht have installed a post-combustion pilot capture plant (CATO CO_2 Catcher) at the site of E.on's coal-fired power plant at Maasvlakte near Rotterdam. Capture capacity varies from 0.07-0.25 t CO_2 per hour. The plant will test different solvents and membranes from 2008-10, with a plan to upgrade to a larger pilot plant of 30 MW by 2014.

Other recently announced CCS projects include:

- The Rotterdam Energy Port Project at the Rotterdam Harbour Industrial Complex which aims to capture, re-use and sequester up to 20 Mt CO_2 per year by 2025.[61]
- The SEQ Zero Emission Power Plant (ZEPP) in Drachten involves a 68 MW power plant that will use a novel oxyfuel type of technology. ZEPP will be equipped with an innovative gas generator in which the combustion takes place with pure oxygen. The project plans to inject 175 kt CO_2 annually.
- The 1 200 MW Nuon Magnum multi-fuel power plant in Eemshaven will use IGCC technology and plans CO_2 storage in onshore depleted gas fields. CO_2 storage will be increased from 1 Mt CO_2 per year in 2020 to over 4 Mt CO_2 per year in 2040 (De Kler, 2007).

59. *See* www.co2-cato.nl.

60. *See* http://esd.lbl.gov/co2sc/co2sc_presentations/Site_Characterization_Case_Studies/Geel.pdf.

61. *See* www.rotterdamclimateinitiative.nl/documents/2008_RCI_CCS_Brochure_Piebalgs.pdf.

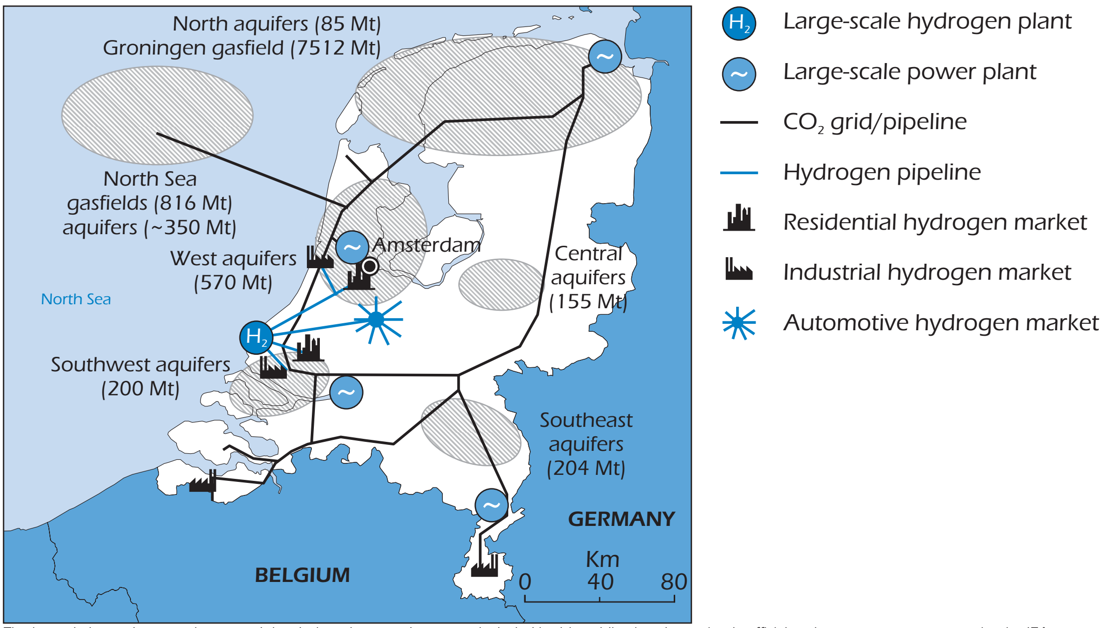
CO_2 Storage Potential

CO_2 storage capacity in the Netherlands is estimated to be more than 13 Gt CO_2, including the Groningen and North Sea gas fields (over 10 Gt), aquifers in the North, Southeast, Southwest and the North Sea (1 Gt), and deep coal (1 Gt) (GESTCO, 2004). Figure 6.11 shows a system analysis by CATO of potential CO_2 infrastructure in the Netherlands.

Figure 6.11 Potential CCS Infrastructure in the Netherlands

Key point

The Netherlands has begun important planning for CO_2 transport and storage infrastructure needs.



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.

Source: CATO Project (www.co2-cato.nl).

Norway

Policy Framework

Despite its relatively small contribution to global GHG emissions, Norway has been a leader in CCS technology demonstration, policy development and international collaboration. Since 1991, Norway has had a tax on CO_2 emissions from oil and gas activities on the continental shelf. The tax, collected by the Norwegian Petroleum Directorate, is calculated on burned hydrocarbons or CO_2 released, and is equivalent to USD 50/t CO_2 (Enoksen, 2007). The revenues from this tax have been used for CCS activities.

To further its leadership on CCS, the Norwegian Government is advancing the following activities:

- enhancing existing public-private co-operation on CCS;

- identifying potential CO_2 capture, transport and storage chains;
- providing robust public funding; and
- requiring under the Energy Act and Pollution Control Act that all new gas-fired power plants allow for CO_2 capture.

Currently, there is no framework legislation to guide the construction and operation of CO_2 pipelines and the exploration, development and use of offshore reservoirs for permanent CO_2 storage.[62] As a result, the government anticipates developing a licensing scheme and other regulations to addressthe following outstanding issues:

- exploration, development and operation of subsea geological structures for the permanent storage of CO_2;
- construction and operation of CO_2 transport pipelines;
- a requirement to carry out environmental impact assessments for planned transport and storage activities;
- risk analyses to address safety issues;
- responsibility for long-term monitoring of storage reservoirs; and
- third-party access to CO_2 pipelines and storage reservoirs, with possible division of responsibility for injected CO_2.

CCS Research, Development and Deployment Activities

The Norwegian Government provides strong support for CCS R&D through research groups and the private sector, including Statoil Hydro, DnV and others (Norwegian Ministry of Petroleum and Energy, 2007). The country's first project was started by SINTEF in 1987, and included offshore natural gas power with CO_2-EOR. Since then, more than 40 projects have been started. In addition, in 2005, the government launched the CLIMIT national gas technology programme to foster co-ordinated research on natural gas-fired power plants that include CCS. About EUR 16 million is allocated to the CLIMIT programme every year.

The Sleipner project, which began in 1996, involves the separation and injection of one Mt CO_2 per year into the Utsira saline aquifer formation 1 000 m below the seabed. The project has made an important contribution to the validation of monitoring technologies. The Snohvit project involves the production of natural gas and condensates in the Barents Sea. By the end of 2007, 0.7 Mt CO_2 per year had been separated and re-injected in a formation 2 600 m below the seabed.

To help administer the State's participation in funding and managing new CCS projects, in 2008 the Norwegian government established Gassnova SF, a state-owned company. Gassnova will plan and execute the following CCS projects in co-operation with industrial partners:

- The Kårstø natural gas-fired power plant started operating at the end of 2007 with the plan to retrofit it with full-scale CO_2 capture. Engineering has been started to capture 1.2 Mt CO_2 per year from 2012. Captured CO_2 will be stored in underground formations on the Norwegian Continental Shelf.
- The Mongstad European test centre (Figure 6.12) is designed to test and accelerate the development of CCS technology. This public-private partnership was signed in June 2007

62. *This is not the case where CCS activities are part of a petroleum operation. If so, existing petroleum legislation would apply.*

Figure 6.12 The Mongstad European Test Centre

Source: Utseth, 2007.

to build the test centre in conjunction with the future Mongstad combined heat and power station and other flue gas sources at the refinery. The centre will have a capture capacity of 0.1 Mt CO_2 per year and test two different capture technologies (amin and carbonate-based CO_2 capture). The Mongstad project is expected to store up to 1.4 Mt CO_2 per year by the end of 2014 (Utseth, 2007).

CO_2 Storage Potential

Onshore CO_2 storage capacity in Norway is limited. But there is significant potential offshore in saline aquifers, depleted oil and gas fields and EOR/EGR. The Utsira formation alone is estimated to have the capacity to store more than 42 Gt CO_2, although this requires further investigation. JOULE II and GESTCO estimates of total capacity vary and range between 13 Gt (traps) and 460 Gt (open). Natural gas fields are also estimated to have an additional potential storage capacity of 12.7 Gt (Christensen, 2006).

Poland

Policy Framework

Poland has abundant coal resources and generates 96% of its electricity from coal, the highest rate in the EU. As a non-Annex I country under the UNFCCC, Poland does not have GHG reduction targets. But the government recognises the need to improve the environmental profile of the country's coal use in order to achieve compliance with EU Directives and realise other air pollutant reductions. CCS is expected to play a growing role in Poland's clean coal activities in the future.

CCS Research, Development and Deployment Activities

Poland has considerable R&D activity related to clean coal technologies, including CCS. Active organisations include companies (the Polish Oil and Gas Company PGNiG and energy and coal companies) and three research institutes: the Krakow Technology Academy, the Central Mining Institute in Katowice and the Institute of Chemical Coal Processing in Zabrze. A Joint Technology Initiative for Clean Coal has also been established.

In 2008, Poland announced a National Programme for Geological Storage of CO_2, which aims to deploy two demonstration-scale CCS projects by 2015. This programme will involve the National Geological Institute, the Academy of Mining and the Metallurgy and the Central Mining Institute. It will develop scenarios for CO_2 capture, will evaluate CO_2 storage options and will identify possible policy tools that will be needed to engage industry (Sciazko, 2008).

Poland undertook Europe's first industrial CO_2 storage in a gas reservoir in the Borzecin field (Lubas, 2006). Since 1995, acid gas by-products of an amine-gas sweetening process containing 60% CO_2 and 15% hydrogen sulfide (H_2S) have been injected into an aquifer underlying the Borzecin reservoir. In addition, the Polish RECOPOL project is the first ECBM project outside North America. CO_2 is obtained from an industrial gas company and injected at the Silesia coal mine. CO_2 injection began in 2004 and reached an average of 12-15 t per day in 2005.

A number of other CCS prospects are being evaluated, including IGCC and oxyfuel options:

- The Government-owned utility BOT Elektrownia Belchatów S.A. is planning two new "zero emission" power plants of 858 MW and 959 MW capacity. These plants will burn brown coal and hard coal respectively, and are due to become operational by 2016. The nearly 1 GW plants will utilise IGCC. It is not clear whether CO_2 storage is also envisioned (Wroblewska, 2008).
- The Tarnow project in Southeastern Poland, managed by the Polish Oil and Gas Company, expects to inject CO_2 from fertiliser plants for EOR in the Triassic Sandstones of Tarnow.[63]
- A retrofit of a 400 MW power plant with CCS by Vattenfall Heat Poland by 2014.
- A 50-100 MW CCS demonstration unit within the new 460 MW Lagisza plant.
- The Polish utility company Południowy Koncern Energetyczny SA plans to retrofit the Blachownia power station between 2010 and 2016 to capture and liquefy CO_2. It is not clear whether this project also includes plans for CO_2 storage.

CO_2 Storage Potential

A variety of possible CO_2 storage locations in Poland have a combined potential of several dozen Gt CO_2 (ZEP, 2007a), including:

- the Jura and Kreda aquifers;
- hard coal mines at Krupinski and Silesia;
- EGR at the Kamien Pomorski and Borzecin fields;
- offshore Baltic reservoirs; and
- depleted oil and gas fields in western and southeastern Poland.

63. *See* http://recopol.nitg.tno.nl/index.shtml.

Russia

Policy Framework

Russia is a party to the Kyoto Protocol, and has significantly reduced its GHG emissions since 1990. As a result, there is not as strong an incentive for the development of CCS as there is in other developed countries that are likely to face greater difficulty in achieving their emission reduction targets. Russia is just beginning to explore its options for CCS. The Russian Academies of Science issued a joint statement with the other Academies of Sciences of the G8+5 economies promoting RD&D in the areas of carbon sequestration for energy sustainability (IAC, 2007). However, there are no known CCS R&D or demonstration programmes currently under way in Russia.

CO_2 Storage Potential

The use of CO_2 from anthropogenic sources in Russia has been investigated since the early 1980s (Kuvshinov, 2006). Large-scale pilot tests have been carried out to inject CO_2 and other flue gas for the purposes of EOR. Russia has a very high CO_2 storage potential, with more than 2 000 Gt estimated to be available (Hendricks, *et al.,* 2004). The capacity of depleted oil and gas fields in the Western Siberian Basin alone is in the order of 150-200 Gt. However, most significant CO_2 emissions sources are in the western part of Russia far from the location of potential storage sites, mostly in Western Siberia. As a result, pipelines of 2 000-4 000 km would be required, significantly increasing the cost of CCS activities. Nonetheless, some areas offer the prospect of matching sources and sinks, including the Black Sea area (oil fields near Krasnadar), the Baskortostan (near Ufa), Tatarstan (near Samara) and the Perm oil fields. ECBM potential also exists in the coal fields in southern Russia.

United Kingdom

Policy Framework

The United Kingdom champions CCS as part of its support for Carbon Abatement Technologies (CAT). The G8 climate change discussions at Gleneagles in 2005 raised the profile of emissions from fossil fuels significantly. The publication of the Department of Trade and Industry's CAT Strategy in the same year recognised CCS as a critical building block in tackling GHG emissions. Since then, the government has put in place a wide range of activities which, together, are making a significant contribution to moving CCS forward. The United Kingdom's Energy Bill includes enabling powers establishing a regulatory framework for offshore CO_2 storage, and the Government has recently launched a consultation on the implementation of this framework.

The shared resource of the North Sea has led to constructive United Kingdom and Norwegian co-operation under the North Sea Basin Task Force. The Netherlands and Germany have recently joined this effort. The United Kingdom has helped advance amendments to the London Protocol and OSPAR Conventions to allow for sub-seabed CO_2 storage. The Government is now working to encourage ratification of the OSPAR amendment. The United Kingdom is also trying to ensure that CCS is approved for inclusion in the Clean Development Mechanism, as the Government believes that this is essential to encourage the deployment of CCS in emerging economies and developing countries (Crisp, 2008).

In the context of the EU, the United Kingdom is working with the European Commission and other Member States to ensure the quick agreement of the draft Directive on the geological storage of CO_2, and is in discussions as to whether there are further mechanisms that could be implemented at the EU level to incentivise CCS demonstration projects in order to meet the European Commission's ambition of up to 12 operational projects by 2015. The Government also wants to ensure that CCS is appropriately reflected in the EU ETS.

In the area of CO_2 transport, the United Kingdom Health and Safety Executive (HSE) is undertaking studies and analysis to determine the proper regulatory framework for the CCS process. Under the Pipelines Safety Regulations of 1996, general duties apply to all pipeline operators, and additional duties are levied on pipelines which transport hazardous fluids. HSE is evaluating whether dense phase CO_2 should be considered a hazardous fluid under this regulation and possibly other legislation. To undertake this evaluation, HSE is quantifying its toxicity, and preparing a comparative study of hazard ranges from CO_2 and natural gas. HSE is also estimating the consequences of a dense phase CO_2 release using new modeling tools, determining pipeline failure rates, and is planning to work with other stakeholders to develop best practices for CO_2 containment and mitigation (Whitbread, 2008).

CCS Research, Development and Deployment Activities

At the level of basic research, the Natural Environment Research Council and the Engineering and Physical Science Research Council are funding a GBP 2.2 million (British pounds) consortium led by Imperial College to explore issues related to CCS. For industry-led applied research, the United Kingdom's Technology Strategy Board has provided GBP 11 million to support 16 CAT projects. The newly formed Energy Technologies Institute – a 50:50 partnership between Government and industry which aims to raise up to GBP 1.1 billion over 10 years for transformational R&D in low-carbon energy technologies – has identified CCS as a priority area.

The UK Government is also supporting the development of a commercial-scale CCS demonstration project. The project will capture the CO_2 produced by 300-400 MW of coal-fired electricity generation, using post-combustion capture technology. The CO_2 will be stored offshore. The Government launched a competition in November 2007, and announced the pre-qualification of four bidders in July 2008. The project is on course to be operational by 2014. In addition to sponsoring this demonstration project, in 2005 the Government established a fund of GBP 35 million to encourage the industry-led demonstration of elements that contribute to CAT including CCS.

The United Kingdom is also working with the Chinese Government to support the EU NZEC project in China (see discussion in the European Union section above). The United Kingdom has funded the Phase 1 assessment of the wider EU-China NZEC agreement signed in 2005, which has the objective of commercial demonstration of CCS for coal-fired electricity generation in China by 2020.

CO_2 Storage Potential

Estimates of United Kingdom CO_2 storage capacity have been completed for different basins using different methodologies. Table 6.7 gives an overall estimate for the United Kingdom and North Sea of 18 Gt CO_2, including saline aquifers. This figure rises to 250 Gt CO_2 when unconfined aquifers are

Table 6.7 Estimated Storage Capacity in the United Kingdom (including the North Sea) (Gt CO_2)

Depleted oil fields	Depleted gas fields	Deep saline aquifers (traps)	Deep saline aquifers (unconfined)
2.6	4.9	10.9	240

Source: Freund, et al., *2003.*

added (Freund, *et al.,* 2003). Unmineable coal fields, including those in eastern England, the Cheshire Basin and Oxford/Berkshire areas, have a total capacity 2.3 Gt CO_2. The main aquifers lie in the North Sea (North, Central and Southern), the East Irish Basin and the Western Channel Basin.

The United States

Policy Framework

Climate change mitigation in the United States is primarily a technology-driven voluntary effort, although regional GHG reduction efforts, such as the Regional Greenhouse Gas Initiative, are developing mandatory CO_2 cap-and-trade systems. The United States has invested significantly in CCS R&D efforts and CCS is an important consideration in United States climate policy discussions. The United States has large indigenous coal reserves and a major expansion of coal-fired power plants is planned in order to meet energy requirements.

There are a number of government actors in the United States with a stake in CCS activities. These include:

- the Department of Energy (US DOE), which leads R&D and demonstration activities and international CCS collaboration;
- the Department of Transportation (US DOT), which is responsible for regulating CO_2 transport pipelines;
- the Environmental Protection Agency (US EPA), which is establishing public health and safety regulations governing CO_2 injection and storage under its Underground Injection Control (UIC) programme; and
- several states, including Illinois, Kansas, Montana, New Mexico, North Dakota, Texas, Washington and Wyoming, that are actively pursuing CCS through implementing UIC and other environmental regulations and by enacting a variety of incentive and regulatory programmes (IOGCC, 2007).[64]

In 2007, the US EPA announced a proposed regulation for commercial-scale CO_2 storage under the UIC programme. To implement this activity, the US EPA formed a workgroup with the States and other stakeholders to assess the impacts of CO_2 storage on groundwater resources and to develop a set of regulatory options to address CO_2 storage. The regulation was formally announced in July 2008,[65] and is expected to include site characterisation, well construction and operation, monitoring and post-closure care andpublic participation. In addition, the regulation will

64. Current information on US State CCS activities is available on the IOGCC website at www.iogcc.state.ok.us.

65. See www.epa.gov/safewater/uic/wells_sequestration.html.

require an investigation of novel elements associated with CO_2 injection and storage, including anticipated large volumes of CO_2, the buoyancy and viscosity of stored CO_2, and the corrosiveness of CO_2 on injection and storage equipment. The draft regulation was published in 2008 with finalisation targeted for early 2011 (Kruger, 2008).

The US DOT has jurisdiction over the movement of hazardous materials by all transportation modes, including CO_2 transport by pipeline. This authority comes from the US DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA). In 1991, the US DOT developed regulations for the safe transportation of CO_2 by pipeline.[66] PHMSA shares oversight authority for CO_2 transport safety with the 50 States, and has extensive experience managing over 6 400 km of CO_2 commercial transport pipelines, amounting to roughly 5% of all hazardous liquid pipelines under the US DOT's jurisdiction (Edwards, 2008). PHMSA also administers a cooperative research programme that investigates the use of new tools to detect and prevent leaks and other threats to pipeline safety. PHMSA has no authority in pipeline siting, however, and must work with the Federal Energy Regulatory Commission to review proposed gas transmission pipelines and respond to safety concerns (Edwards, 2008).

The existing legislative frameworks (*e.g.* the UIC framework at US EPA) within which the US EPA and other agencies are currently working do not address a number of issues. These include the treatment of CCS under the Clean Air Act, accounting for injection and any leakage from CO_2 sites, and long-term liability. It is likely that additional legislation will be needed to manage these issues. In addition, a number of proposals are currently being considered in the US Congress and in individual States that involve GHG regulatory requirements (*e.g.* cap-and-trade schemes) and CCS. These include S.2191, the Lieberman-Warner Climate Security Act. This legislative proposal includes an economy-wide GHG cap, and sets aside "bonus" allowances to reward CCS. The number of allowances are awarded based on a rate of two allowances per tonne of CO_2 stored, declining to zero by 2040. To receive these allowances, CCS facilities must meet CO_2 performance hurdles. The bonus allowances are administered for 10 years after project start-up (Sussman, 2008). This proposal was not voted on in 2008, but is expected to be picked up, along with other climate change regulatory proposals, in 2009.

CCS Research, Development and Deployment Activities

The United States has a large publicly-funded R&D programme for CCS (Figure 6.13).

The US DOE's Office of Fossil Energy manages the US Carbon Sequestration Programme, the implementation of which is managed by the National Energy Technology Laboratory (NETL). The programme's objective is to develop conversion systems for fossil fuel-powered plants with over 90% capture and 99% storage permanence with less than a 10% increase in electricity costs by 2012. In 2007, the US DOE released a CCS technology roadmap in the publication *Carbon Sequestration Technology Roadmap and Programme Plan.* There are three main components to the United States CCS activities: core R&D; demonstration and deployment through the Regional Carbon Sequestration Partnerships; and major demonstration projects that will be supported through the Clean Coal Power Initiative and FutureGen efforts.[67]

A number of CCS R&D activities are under way in the United States. Major projects are led by research organisations, universities and industrial groups. Projects cover a broad variety of issues, including policy development, monitoring and verification, site characterisation, and the

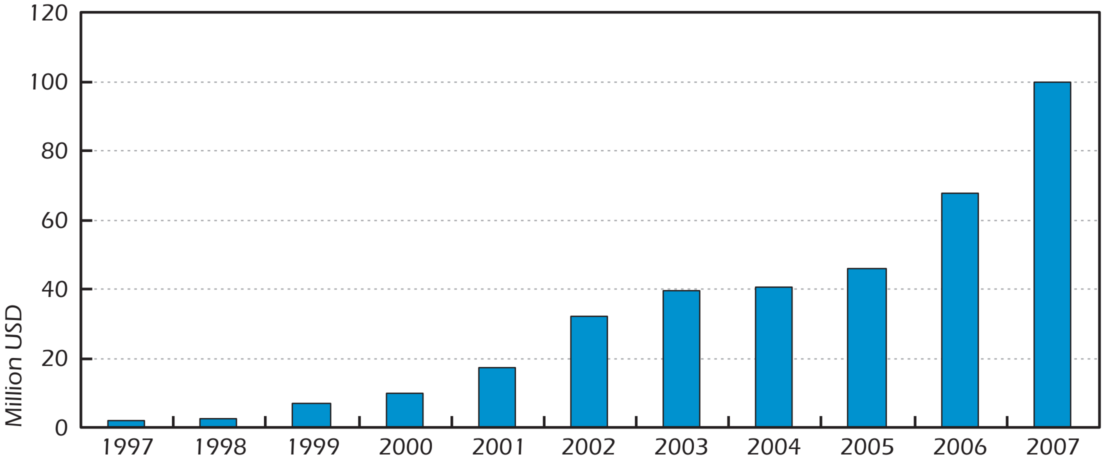
66. 49 C.F.R. part 195.

67. More information about these programmes is available at www.netl.doe.gov/technologies/carbon_seq/index.html.

Figure 6.13 United States Federal R&D Funding for CCS Technologies (excluding FutureGen)

Key point

US CCS technology funding grew rapidly in the last decade.



Source: US DOE, 2007.

demonstration of a variety of capture, transport and storage technologies and practices. Selected projects are outlined below.

- The Allison Unit, operated by Burlington Resources in the San Juan Basin, is the first commercial-scale CO_2-ECBM project. The site has 16 producers and 4 injectors. CO_2 injection was started in 1995 and provided important results for validating CBM simulators.[68]
- Consol Inc., with support from the US DOE, has operated a test CO_2 storage project at a coal mine in West Virginia. The project includes a series of horizontally drilled wells that extend through two overlying coal seams. Once completed, the wells will drain CBM from mineable and unmineable coal seams. After sufficient depletion of the reservoir, centrally located wells in the lower coal seam will be converted from CBM drainage wells to CO_2 injection ports. In addition to metering all injected CO_2 and recovered CBM, the programme includes additional monitoring wells to further examine horizontal and vertical migration of CO_2.[69]
- The Frio Project was the first injection of CO_2 into a saline aquifer to demonstrate the feasibility of injection into high-permeability sandstone (2.5 Darcies) at a depth of 1 500 m. An injection of 1 600 t CO_2 made it possible to test a variety of monitoring techniques including well logging, cross-well seismics, electromagnetics and perfluocarbon tracers (Hovorka, *et al.,* 2006).
- The CO_2 Capture Project, an international effort led by BP and co-funded by the US DOE, seeks to develop and test new breakthrough technologies to reduce the cost of CO_2 separation, capture, and transportation from combustion sources such as turbines, heaters and boilers by up to 75%. Phase 1 of the project included R&D (engineering studies, computer simulation and laboratory experiments) related to the proof of concept of advanced CO_2 separation and capture technologies in pre- and post-combustion and oxyfueling. Phase 2 (2005-08) deliverables included a global study on the public perceptions of CCS, including a prioritised assessment of issues and concerns.[70]

68. *See* www.osti.gov/bridge/product.biblio.jsp?osti_id=825083.

69. *See* www.osti.gov/bridge/servlets/purl/823404-TlAHYV/native/823404.pdf.

70. *See* www.co2captureproject.org/index.htm.

- Since its inception in 1998, the Global Energy Technology Strategy Programme (GTSP) has been assessing the role of advanced energy technologies in mitigating the long-term risks of climate change. The GTSP research programme is built around state-of-the-art Integrated Assessment Models that allow for a comprehensive and integrated approach to exploring all aspects of climate change. A particular focus of the GTSP has been on better understanding the role and likely deployment pathways for CCS technologies. The GTSP's research on CCS was summarised in a major report released in 2006.[71] The GTSP is comprised from a core group of scientists from Battelle, the Pacific Northwest National Laboratory and the Joint Global Change Research Institute.[72]
- The Zero Emission Research and Technology Center (ZERT) is a research collaboration focused on understanding the basic science of underground CO_2 storage and safety issues associated with injected CO_2. The initiative serves as a resource to other CO_2 storage demonstration projects. ZERT is a partnership involving US DOE laboratories (Los Alamos National Laboratory, Lawrence Berkeley National Laboratory, National Energy Technology Laboratory, Lawrence Livermore National Laboratory, and Pacific Northwest National Laboratory) and universities (Montana State University and West Virginia University).[73]
- The Lawrence Berkeley National Laboratory also manages the GeoSeq programme, which involves advanced modelling to simulate subsurface injection of CO_2 and its geochemical interaction with minerals. The programme also tests technologies to detect surface seepage of CO_2, conducts pre- and post-modelling of the Frio Brine injection project and tests new monitoring technologies.[74]
- The Coal-Seq Consortium, led by Advanced Resources International, is a partnership between industry and the US DOE. The primary goal of the Coal-Seq Consortium project is to develop an understanding of the CO_2-sequestration/ECBM process by performing experimental and theoretical R&D on coal reservoir behaviour, and validating the findings against the results from the field projects such as the work conducted in the Allison Unit.

In addition, the US DOE announced in 2003 seven Regional Carbon Sequestration Partnerships that include more than 350 organisations in 42 states and four Canadian provinces. The US DOE provides over USD 10 million annual funding to each partnership and expects to leverage 20% funding from other sources. The partnerships evaluate CO_2 storage potential in their respective areas using a common methodology to support public outreach efforts. They aim to ensure that legal and regulatory requirements are in place for over 20 small-scale geologic field projects throughout the United States and Canada. The seven partnerships include the following activities (Litynski, *et al.,* 2006; Litynski, *et al.,* 2008):

- The Big Sky Regional Carbon Sequestration Partnership covers Idaho and portions of Montana, South Dakota, Wyoming, Washington, and Oregon. The Partnership will demonstrate carbon storage in mafic/basalt rock formations (*e.g.* Columbia River Basalt) to assess the mineralogical, geochemical, and hydrologic impact of injected CO_2. The field test will also incorporate site monitoring and verification activities.
- The Midwest Geological Sequestration Consortium is working in the basins of Illinois, southwestern Indiana, and western Kentucky to investigate storage potentials and related safety issues for unmineable coal seams, mature oil and gas reservoirs, and deep saline formations through six small-scale injection tests. These pilot projects include the testing of unmineable coal seams to

71. *See* www.pnl.gov/gtsp/docs/gtsp_reportfinal_2006.pdf.

72. *See* www.pnl.gov/gtsp.

73. *See* www.montana.edu/zert/home.php.

74. *See* http://www-esd.lbl.gov/GEOSEQ.

adsorb gaseous CO_2, the ability to enhance oil production or recovery by CO_2 flooding, and the injection of CO_2 into deep saline formations at depths up to 3 050 m below the surface.

- The Midwest Regional Carbon Sequestration Partnership (MRCSP) covers the states of Indiana, Michigan, Maryland, Kentucky, Ohio, Pennsylvania, West Virginia, and New York. MRCSP is conducting three small-scale geological storage tests that will provide important information concerning the regional geologic formations and will enable researchers to explore the potential for using different technologies to capture CO_2 from various sources.
- The Plains CO_2 Reduction Partnership (PCOR), covers the states of Minnesota, North Dakota, South Dakota, Iowa, Missouri, Montana, Nebraska, Wisconsin, Wyoming, and the Canadian provinces of Alberta, British Columbia, Manitoba, and Saskatchewan. PCOR is conducting an acid gas injection test to demonstrate the concurrent benefits of CO_2 sequestration, H_2S disposal, and EOR. A second geologic field test is being conducted in an unmineable lignite seam in North Dakota, which involves potential simultaneous ECBM extraction. PCOR's third geologic field test is being conducted to evaluate the EOR potential of the Williston Basin.
- The Southeast Regional Carbon Sequestration Partnership (SECARB) is represented by eleven southeastern states (Arkansas, Louisiana, Mississippi, Alabama, Tennessee, Georgia, Florida, North Carolina, Virginia, Texas, and South Carolina). SECARB is conducting four geologic tests that are utilising EOR/saline stacked formations along the Gulf Coast, coal seams for CBM recovery, and saline formations.
- The Southwest Regional Partnership on Carbon Sequestration (SWP), covers the states of Arizona, Colorado, Kansas, New Mexico, Nevada, Oklahoma, Texas, Utah and Wyoming. The SWP is leveraging its EOR experience to determine the potential of oil, coal, and saline formations to store CO_2. Three geologic field tests are planned for sequestration in conjunction with ECBM and EOR.
- The West Coast Regional Carbon Sequestration Partnership (WESTCARB) comprises the states of Alaska, Arizona, California, Nevada, Oregon, Washington, Hawaii, and the Canadian province of British Columbia. The partnership is conducting a stacked-reservoir field test combining EGR with saline formation storage, making it the first field-scale test in the United States to test CO_2 storage coupled with EGR. A pilot test to investigate CO_2 storage in saline formations in Arizona's Colorado Plateau region will demonstrate the safety and feasibility of CO_2 storage in the region.

In October 2007, three awards representing USD 318 million were granted to the regional Partnerships to conduct large-scale field tests where over 1 Mt CO_2 will be injected into a deep geologic formation at each project site (see Figure 6.14). In December 2007, an additional USD 67 million was awarded to the MGSC for demonstration of CO_2 storage in the Mount Simon Sandstone formation in Illinois. In May 2008, the US DOE announced awards of more than USD 126 million to the WESTCAB and MRCSP for the Department's fifth and sixth large-scale sequestration projects.[75]

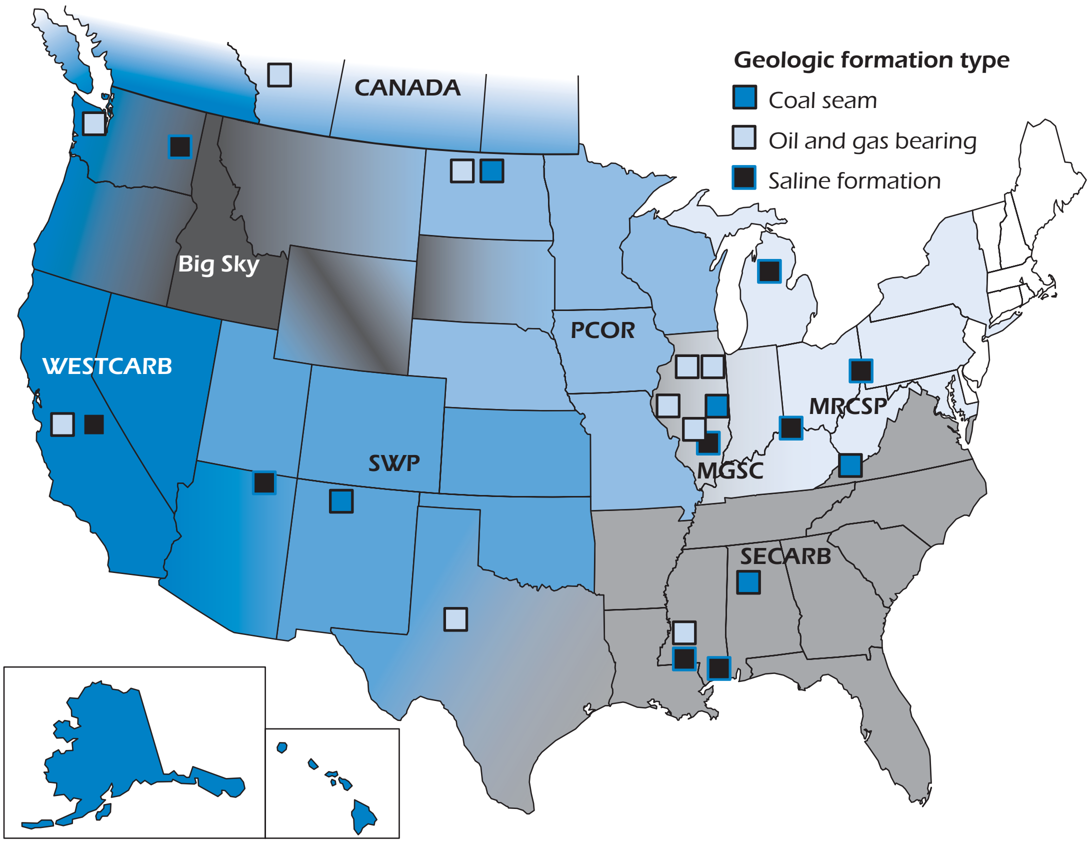
The FutureGen Alliance is a public-private partnership with participants from the power sector (AEP, China Huaneng, Consol Energy, e.on, Southern Company) and coal companies (Anglo American, BHP, Foundation Coal, Peabody, Rio Tinto, Xstrata Coal). It plans to build a 275 MW electricity coal-fired IGCC power plant at a cost of USD 1.5 billion with CO_2 capture and storage and hydrogen production. However, in January 2008, the US DOE announced a restructuring of its approach to FutureGen, and a change for its plans from funding of a single project (in Illinois) to a number of projects, provided they meet the US DOE criteria.

75. *See* www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html*; details about large-scale field tests are available at* www.netl.doe.gov/technologies/carbon_seq/partnerships/deployment-phase.html.

Figure 6.14 Location of the Regional Carbon Sequestration Partnerships Validation Phase Geologic Field Tests

Key point

Regional sequestration partnerships play a large role in CCS implementation in the United States.



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Source: www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html.

DOE's Clean Coal Power Initiative (CCPI) is managed by the US DOE NETL and has been supporting major demonstration projects at scale that can meet the demands of environmental regulations in the United States. The 2008 Energy Policy Act directed the US DOE to focus the programme to support projects that demonstrate technologies to capture and store CO_2 from coal-fired power plants. The CCPI released a draft funding opportunity announcement in October 2007 and is preparing for a release of the final funding announcement in late 2008.[76]

CO_2 Storage Potential

The US DOE has developed the Carbon Sequestration Atlas of the United States and Canada, which was co-ordinated with the NATCARB programme and the Regional Sequestration Partnerships to provide a regional analysis of sources and sinks (Table 6.8).

The DOE has used similar methodologies for storage capacity estimates and has consolidated the potential for oil and gas fields, unmineable coals seams and saline aquifers (excluding gas shales, oil shales and basaltic formations) (Figure 6.15).

76. More information can be found at www.netl.doe.gov/business/solicitations/index.html#43181.

Table 6.8 CO_2 Sources and Sinks in the United States

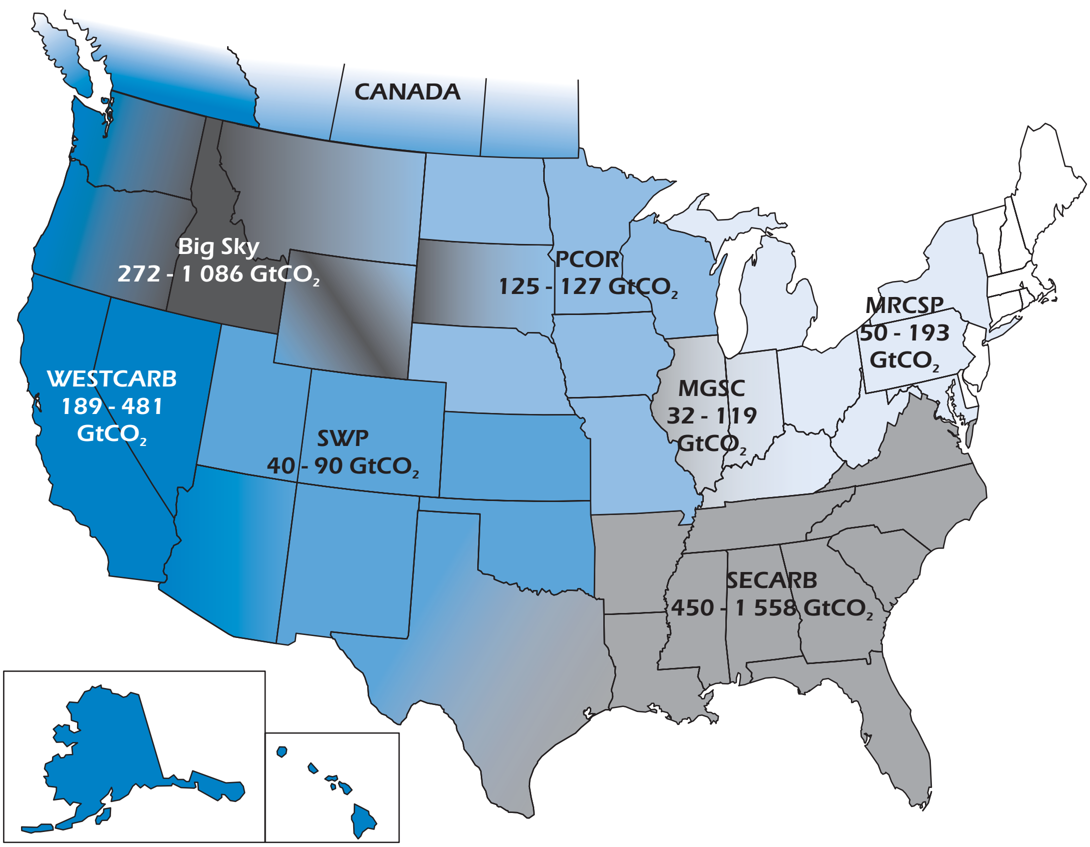
Regional partnership	CO_2 sources		Sequestration capacity (Gt CO_2)					
			Saline formations		Unmineable coal seams		Oil and gas fields	
	Gt CO_2	No. of Sources	Low	High	Low	High	Low	High
Big Sky	0.112	158	271	1 085	0	0	0.8	0.9
MGSC	0.343	212	29	115	2.3	3.3	0.4	0.5
MRCSP	1.319	496	47	189	0.7	1	2.5	2.8
PCOR	0.401	1 037	97	97	8	8	19.6	21.6
SECARB	1.021	981	360	1 440	57.4	82.1	32.4	35.7
SWP	0.336	432	18	64	0.9	2.3	21.4	23.6
WESTCARB	0.132	62	97	388	86.8	86.8	5.3	5.8
Northeast Area	0.144	987						
Total:	**3.808**	**4 365**	**919**	**3 378**	**156.1**	**183.5**	**82.4**	**90.9**

Source: US DOE, 2008.

Figure 6.15: CO_2 Storage Capacity within the Regional Sequestration Partnership Areas

Key point

The United States has begun to assess CO_2 storage potential on a regional basis.



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Source: US DOE, 2008.

Other CCS Activities Worldwide

The above discussion summarises the work of the most active countries in the areas of CCS policy, research, development and demonstration, and estimates their CO_2 storage capacities. However, there are several other countries with important CCS efforts under way. This section includes brief summaries of CCS-related activities in other important countries.

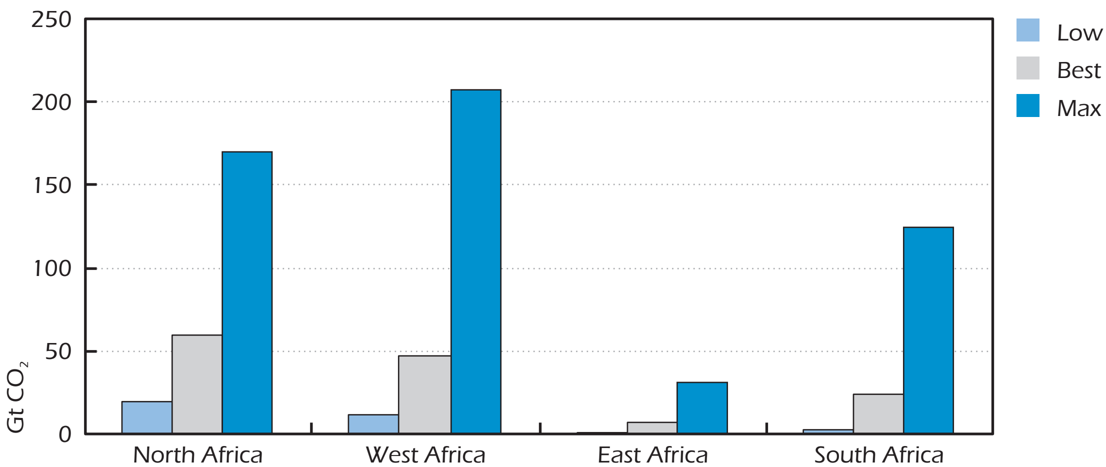
Africa

While estimates for storage capacity in Africa very widely, Hendriks, *et al.* (2004) indicate that the best prospects are in aquifers (6-220 Gt) and oil & gas fields (30-280 Gt) (see Figure 6.16). North and West Africa represent the highest potential for oil and gas fields, while all areas except for East Africa have significant storage space in aquifers (15-60 Gt each). Only South Africa has ECBM potential (8-40 Gt).

Figure 6.16 CO_2 Storage Potential in Africa

Key point

The majority of Africa's CO_2 storage capacity is in North and West Africa sedimentary basins, within existing oil and gas regions.



Source: Hendriks, 2004.

Given the magnitude of the emissions from coal-fired power plants, the largest African potential for CCS is in South Africa. Surridge (2005) gives an overview of South African activities. The Department of Minerals and Energy has performed a study to evaluate the capture from sources and storage potential. Potential storage sites include the Vryheid formation with a capacity of 18.4 Gt and the Katberg formation (1.6 Gt). South Africa has joined the CSLF in its efforts to build capacity for technology transfer in the areas related to CCS.

Argentina

The major part of the CO_2 emissions from fuel combustion in Argentina is from natural gas fired power plants (44%), cement plants (16%) and iron and steel (14%). The major focus thus far has been on NGCC prospects with CO_2 capture (Gomez, 2004). The main onshore sedimentary basins are the Northwest, Cuyana, Neuquen, San Jorge and Austral areas. Taking distance to the largest stationary emitters into account, the first three basins are candidate locations.

Austria

While there may be a potential for aquifer storage in the Molasse Basin and Vienna Basin (particularly in the Aderklaaer Conglomerate), most of the focus has been on opportunities of storage in oil and gas reservoirs (Heinemann, 2003; Scharf, 2006). Two producing oil reservoirs (Schoenkirchen Tief and Voistdorf), and five gas reservoirs (Hoeflein, Schoenkirchen-Uebertief, Reyersdorfer-Dolomite, Atzbach-Schwanenstadt and Aderklaa) have been evaluated. Their total storage capacity is about 0.5 Gt CO_2, and their proximity to industrial sites makes them good candidates. The Austrian oil and gas company OMV has started the OMV Future Energy Fund with an allocation of EUR 100 million over the 2006-2016 time period to promote CCS and renewable activities. The Austrian FENCO initiative has been created between power companies and suppliers to promote clean fossil-fuel technologies and address social and legal questions related to CCS. Storage potential in coal is considered to be negligible.

Early prospects in Austria include the 1 600 metre-deep Atzbach-Schwanestadt gas field as a demonstration. CO_2 sources include a fertiliser plant and a paper mill with CO_2 volumes of 100-200 ktpa.

Bulgaria

Bulgaria has made an early evaluation of sources and sinks (Georgiev, 2007). The largest concentration of sources is in the Stara-Zagora area with over 20 Mtpa. The prospective aquifers lie near the central part of Bulgaria between Varna and Pleven and the oil and gas fields in the Moesian Platform west of Pleven.

Croatia

In Croatia, the use of CO_2 captured at the Molve gas processing plant is being considered to implement CO_2-EOR projects for three mature fields (Domitrovic, 2007):

- near-miscible water-alternated-gas injection: Ivanić and Žutica (North and South);
- immiscible crestal injection: Beničanci.

The EOR project start-up is planned for 2008 and 2010 by INA-Naftalin. More work is required to ascertain the potential storage of the Upper Miocene aquifers.

Czech Republic

The Czech Republic uses considerable brown coal for energy and heat production, and has one of the highest ratios of emissions to energy generated in the EU. The lignite-fired Prunerov power plant, built in 1967, is the 12^{th} largest emitter in Europe with 8.9 Mtpa. The CEZ group is considering two candidate units for the ZEP demonstration projects:

- the North Bohemia 660 MW power plant;
- the 105 MW mixed fuel (lignite-biomass) Hodonin plant.

Denmark

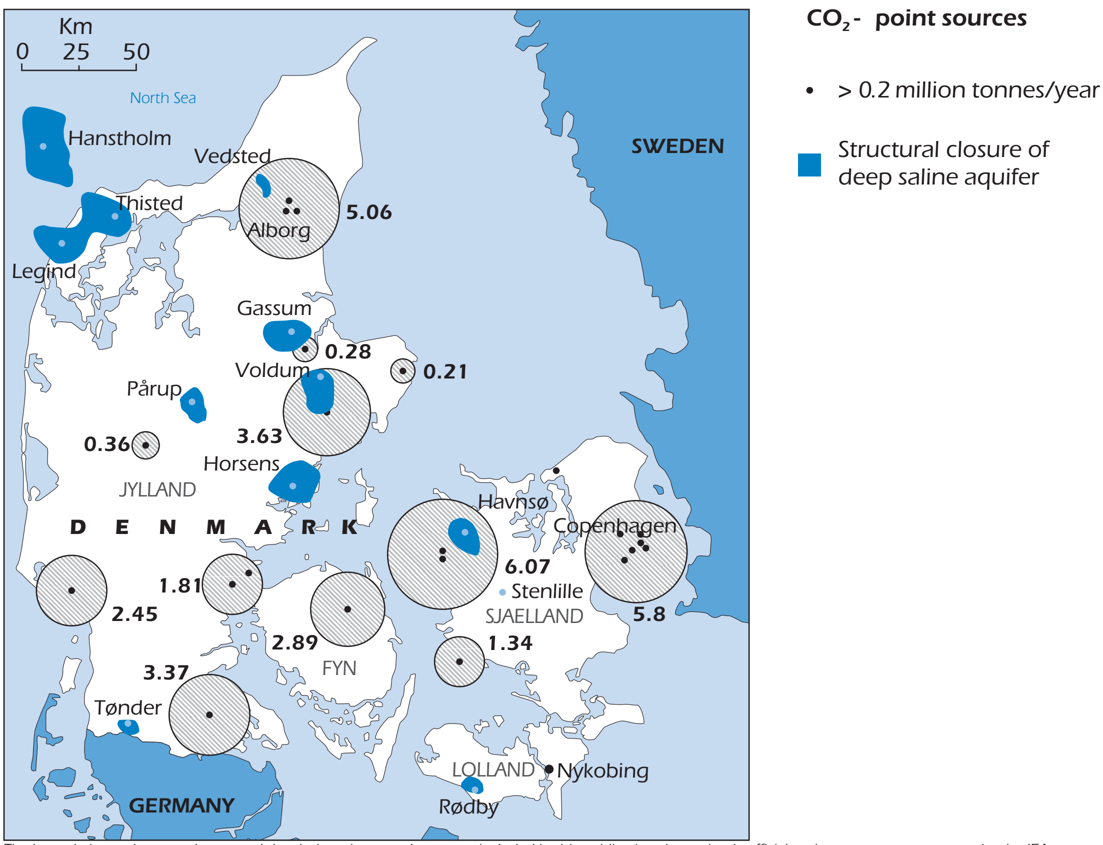
Denmark has been actively involved in international CCS activities through GEUS (the Geological Survey of Denmark and Greenland) since 1993 and plays a leading role in SACS, GESTCO, CCP, CASTOR, Weyburn Monitoring, CO_2STORE, CO_2 for Enhanced Oil Recovery in the North Sea (CENS), GEOCAPACITY and the Zero Emissions Platform.

Estimates of Denmark's CO_2 storage capacity vary widely. Confined traps in the Triassic and Jurassic layers are estimated to have a 5.6 Gt storage capacity (on-shore) and the Joule II project estimated total Danish storage (confined and unconfined) at 47 Gt (Chadwick, 2006). The GESTCO project estimates storage at 16 Gt. Figure 6.17 matches sources to a number of saline aquifers that could act as sinks.

Figure 6.17 *Matching Sources and Sinks in Denmark*

Key point

Extensive CO_2 source and sink matching has been performed in Denmark.



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Source: GEUS, 2004.

A pilot site was selected in the CASTOR project at the Elsam-operated Esbjergvaerket unit 3 plant (Biede, 2006), the largest project for CO_2 capture from flue gas in a coal-fired power station. The first two phases in 2006 involved 2 000 hours of testing using 30% MEA and the two subsequent phases in 2006-08 included 8 000 hours of testing on new solvents.

The COSTORE project included the Danish case study of Kalndborg with two emission sources (the coal fired power plant at Asnæsværket and the Statoil refinery) with combined emissions of 6 Mtpa of CO_2 and a potential storage site 15 km away. The site covers an area of 160 km^2 and has a potential storage capacity of nearly 1 Gt of CO_2.

Estonia

Estonia's fuel for power plants comes mainly from the Narva oil shales: 59% of Estonia's CO_2 emissions are related to the use of these shales. The Eesti and Balti power plants have a capacity of 1 610 and 1 290 MW respectively. The Estonian part of the Baltic Basin is shallower than 800 m, so aquifer storage of CO_2 at supercritical conditions is not available. Up to 300 m of sediments deposited on pre-Cambrian basement are drinking water resources. There are no known hydrocarbon and/or coal deposits in Estonia.

Finland

Finland has two concentrations of large stationary emitters (>1 Mtpa CO_2), near Helsinski and Raahe. There is limited CO_2 storage availability in aquifers (Koljonen, 2002; Zevenhoven, 2005). Mineral carbonation using mineral silicates is the only option but the technology needs significant development.

Greece

Greece has been participating in a number of EU CCS projects, including GESTCO, ENCAP, CASTOR, and ZEP, among others. International collaboration is led by the CERTH/IFSTA centre on CO_2 absorbents and CO_2 mineralisation.

GESTCO evaluated the CO_2 storage potential of Greece. The largest capacity by type is in saline aquifers, with a potential of 2.2 Gt CO_2 (GEUS, 2004). Potential sites within an economically feasible distance of major emission nodes are situated in the Thessaloniki Basin and the Mesohellenic Trough. Additional research is required to characterise other prospects including hydrocarbon and other off-shore basins. The depleted Prinos oilfield has a capacity of 17 Mt CO_2 and provides a demonstration opportunity.

Hungary

Hungary participates in several EU-funded CCS projects through the Eotvos Lorand Geo-physical Institute, including Geo-Capacity, CASTOR and CO_2NET. Storage capacity is mainly in poorly characterised deep aquifers (1 Gt), oil and gas fields (400 Mt), and in unmineable coal seams (200-300 Mt). Except for the Hungarian Oil and Gas Company (MOL), there is currently limited awareness about CCS (ZEP, 2007).

Indonesia

One of the key prospects for CCS in Indonesia is the CO_2-rich Natuna field, one of the world's largest gas fields with 45 Tcf of gas reserves. The Exxon-Mobil operated Natuna D-Alpha field is located 225 km north-east off-shore of Natuna Island in shallow water (150 m) and has an average 71% CO_2 content. Project partners have spent significant money on appraisal, but the high CO_2 content has made the development difficult. Potential injection layers exist in the deep saline formations at the northwest of the field and constitute one of the largest CCS opportunities in the region. CBM resources in Indonesia are high (over 300 Tcf), and potential for ECBM exists in South Sumatra and Barito and Kutei basins in Kalimantan. There are no commercial CBM projects today.

Ireland

Sustainable Energy Ireland carried out an assessment of CCS potential and hydrogen generation in Ireland (SEI, 2005 and SEI, 2006). The studies focused on scenarios, costs and potential demonstrations. One of the options considered is retrofitting the coal-fired 915 MW Moneypoint plant on the Shannon Estuary with post-combustion capture using physical absorption. This plant currently emits 5.9 Mt CO_2/year or 8.6% of Ireland's total emissions. CO_2 would be stored in the Corrib gas field (possibly for EGR), or in deep saline aquifers (as far away as Utsira). Other options include replacing the existing plant with an IGCC plant with CCS.

The Joule II project estimated a capacity of 160 Mt in off-shore gas reservoirs. Aquifer storage potential is likely to be marginal as Irish aquifers are too shallow for CO_2 storage.

A consortium including the Irish CSA Group and Byrne Ó Cléirigh, the CO2CRC and the British Geological Survey was created in 2007 on behalf of SEI, EPA, the Geological Survey of Ireland and the Geological Survey of Northern Ireland to determine the CO_2 storage potential in Ireland and Northern Ireland and to carry out a risk assessment and determine the suitability of sources (CO2CRC, 2007).

Korea

Korea's storage potential appears limited to the three candidate basins all located off-shore: Ulleung basin in the east/southeast, Kunsan Basin in the west and the Cheju-Fukue area in the south. The capacity and seal suitability of these basins require further characterisation. There was no information about Korea's work on other aspects of CCS.

Latvia

Latvia saw a 50% reduction in CO_2 emissions between 1990 and 2004. The emissions are expected to increase by 60% by 2020. Latvia's geological structure is favourable to gas storage with a capacity of over 50 billion m^3. Potential CO_2 storage in the Liepaja structure has been evaluated at 300 million m^3 (Gushcha, 2005). Further work is required to check the suitability of the gas reservoirs for CO_2 storage. Initial estimates of aquifer storage capacity, predominantly in Cambrian sandstones located in western and central Latvia, are greater than 60 Mt.

Lithuania

Lithuania's CO_2 emissions decreased by more than 40% from 1990 to 2004. But a significant increase is expected when the Ignalina Nuclear Power Plant that produces 30% of the total energy in the country is replaced with fossil-fuel power in 2010. Four sources emit between 1 Mtpa and 2.2 Mtpa, and one source emits between 0.5 Mtpa and 1 Mtpa. Several prospective aquifers exist in the Baltic sedimentary basin, with solubility trapping capacities in the range of 13 Gt (Sliaupa, 2007). A small CO_2 storage potential representing about 6 Mt exists with EOR in oil fields in western Lithuania.

Malaysia

The largest concentration of CO_2 emissions is in the Malay basin (76% of the total). Despite good permeability and porosity, the area has limited CO_2 storage potential. High CO_2 gas fields in Malaysia represent a significant CCS and CO_2-EOR opportunity. CO_2 content from Malaysian gas fields varies from 28% to 87% (Darman, 2006) with 13 Tcf of undeveloped gas. One example of an application for CO_2-EOR is to use the CO_2 from the South West Luconia gas fields to increase recovery from Sarawak North East fields (SK-302-SK309). Petronas, the Malaysian oil and gas company, is one the early implementers of Mitsubishi Heavy Industries/Kepco's solvent (KS-1) for flue gas CO_2 recovery from the Kedah fertiliser plant. The technology has been operational since 1999 and has allowed recovery of about 200 t/day of CO_2 and its use for urea production. An application for CDM (under UNFCC-NM0168) has been made for the Bintalu LNG projects involving the capture of CO_2 and H_2S from an off-shore field (off the Sarawak coast) and its storage in deep saline formations.

Mexico

A preliminary assessment of Mexico's CO_2 storage potential was made during Phase 1 of the Asia-Pacific Economic Co-operation (APEC) study (Bachu, 2007). Emissions from 60% of sources are less than 15% pure. Sources are mainly distributed near the Mexico-California and Mexico-Texas borders around the Distrito Federal and along the Gulf of Mexico.

Several areas in Mexico are rendered poor candidates for CO_2 storage because of tectonic activity: the Pacific areas, Baja California and the Southern region. The highest potential from sedimentary basins resides in the Gulf Coast, Salinas, Sabinas and Tampico areas, followed by the Tampico and Vera Cruz regions. When matching sources to sinks within a distance of 300 km, the APEC study concludes that most near-term potential resides with oil and gas reservoirs along the Gulf of Mexico. Deep saline aquifers in the other basins could be medium-term candidates following further assessment.

A large-scale N_2 injection for enhanced oil recovery was carried out in the offshore Cantarell field, representing more than 40% of total worldwide EOR activity. The Cantarell field is not a good candidate for CO_2-EOR due to its API (Tamayo, 2005). Experience with CO_2 injection already exists in the Carmito Artesa field, where high CO_2-content gas is produced (72% CO_2). A membrane-based CO_2 plant is used to treat the 120 Mcf/day gas produced and an injection plant is used to pump 40 Mcf/day of CO_2 at high pressure (over 100 kg/cm^2) into two injection wells to improve recovery. As of November 2005 (after 5 years of injection) the release of 30 Bcf of CO_2 in the atmosphere has been prevented and an additional 1 Mbbls of oil and 2.4 Bcf of gas have been recovered.

The separation, compression and injection of 51 Mcf/day Activo Samaria-Sitio Grande field in south-eastern Mexico has been submitted as a CDM project along with the Water-Alternated Gas (WAG) scheme in the Tamaulipas Constituciones field with 14 Mcf/day CO_2 injection.

New and Candidate EU Member States

The EU-funded initiatives CASTOR, GEOCAPACITY and CO_2NET EAST have work programmes related to CCS potential in new EU Member Countries. A significant effort is required to have more precise capacities, but a compilation of initial storage estimates is provided in Table 6.9. At over 5.5 Gt of storage, Romania has the largest capacity followed by Poland and the Czech

Table 6.9 Early Estimates of CO_2 Storage Capacity in EU New and Candidate Member States

Country	Aquifers ($Mt\ CO_2$)	Oil and gas ($Mt\ CO_2$)	Coal fields ($Mt\ CO_2$)	Total capacity ($Mt\ CO_2$)	CO_2 emissions point sources ($Mtpa\ CO_2$)
Croatia	351	149	-	500	6
Slovenia	147	2	-	149	7
Poland	3 752	572	470	4 794	205
Slovak Republic	1 349	137	-	1 486	40
Hungary	-	408	240	648	28
Czech Republic	2 863	32.6	294	3 190	97
Bulgaria	821	3.5	-	825	52
Romania	3 000	2 500	-	5 500	120

Source: Kucharic, 2007.

Republic. Croatia, Hungary and Romania have a significant experience in EOR and related oil and gas processes.

The Philippines

The Zambalez/Central Luzon Basin, located near Manila is a potential CO_2 storage site, but poor reservoir permeability is expected as a result of the strong tectonic activity and the complex geological structures. This limits the potential for storage sites considerably.

Portugal

Portugal aims to have 800 MW of clean coal generation at Sines by 2020. To research this target, a project was set up under the auspices of the Directorate General of Energy and Geology (DGEG) with the utility Electricidade de Portugal (EDP) and the Instituto Nacional de Engenharia, Tecnologia e Inovação (INETI). Several options have been assessed for project implementation including the characterisation and qualification of deep saline aquifers for storage, separation techniques including the use of membranes and adsorbents, implementation of IGCC with pre-combustion, and oxy-combustion in PCC or CFBC. INETI is investigating the onshore structures in the Mesocenozoic Lusitanian Basin. The collaboration established between entities of the Ministry of Economy and Innovation and EDP included a preliminary study to determine possible sites for CO_2 storage in Portugal (Figure 6.18).

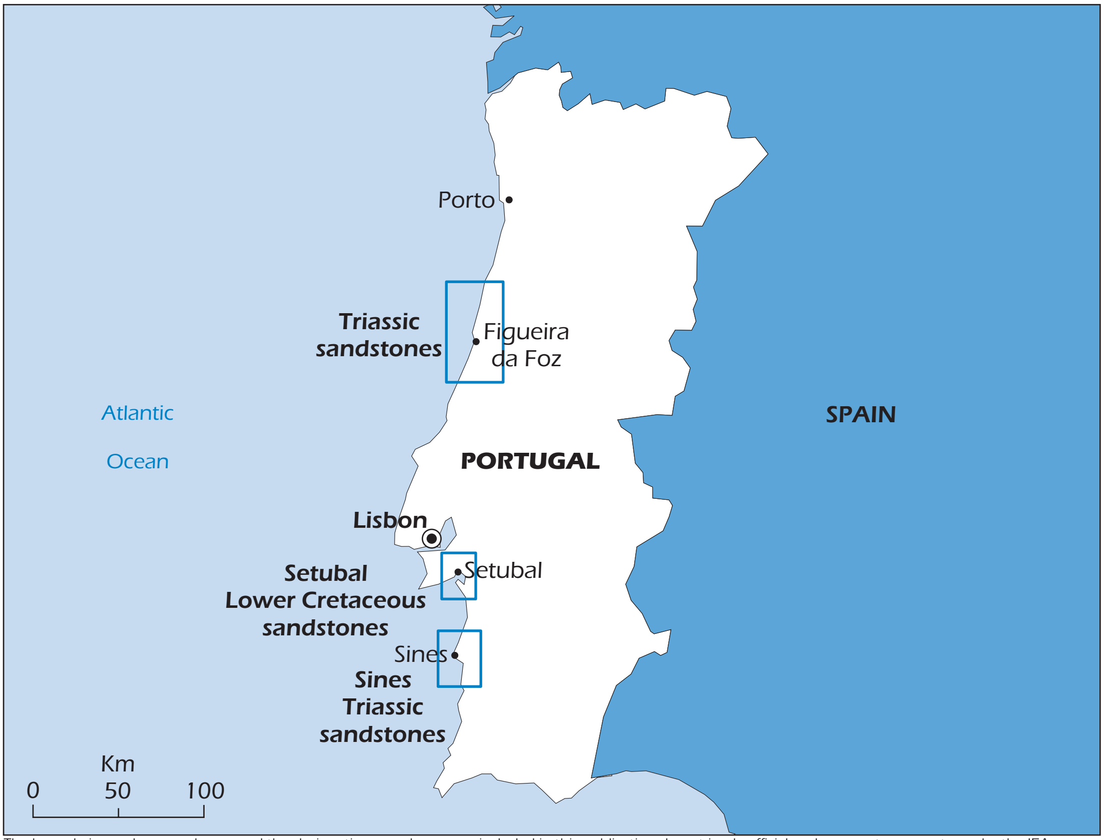
An action plan is being developed to ensure that the target defined by the Portuguese Government will be met. It will include a comprehensive research and development programme and a CCS pilot plant integrating oxy-combustion in a circulating fluidised bed with CO_2 recovery and underground disposal. This project will involve EDP and the future Energy and Geology National Laboratory (LNEG). The Directorate General for Energy and Geology (DGEG) will be responsible for legislation regarding CO_2 capture and storage and for disseminating information to promote public acceptance, which could make the overall programme more complete.

Portugal also participates in European initiatives such as the ZET Platform, CO_2net, and FENCO. The Technical University of Lisbon, the University of Oporto and the University of Fernando Pessoa are carrying out technical studies to establish the potential for ECBM in the Pejão coal mine (INETI, 2007).

Figure 6.18 Potential CO_2 Storage Sites in Portuguese Saline Aquifers Supported by Triassic or Lower Cretaceous Sandstones

Key point

A preliminary CO_2 storage assessment has been made in Portugal.



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Source: INETI, 2007.

Romania

In Romania, there is a long tradition of on-shore and off-shore oil and gas exploitation. The national pipeline is particularly well developed in the south (from the Black Sea coast west and northwest). Seven natural gas storage sites are currently operating. There are known natural CO_2 emanations, predominately in northwest and northern areas and the highest emission point contains over 3 000 mg CO_2/l. Oil and gas storage capacities are estimated at 2.5 Gt and are spread in the Pannonian Basin, the Moesian Platform, the Carpathian Foredeep and the Moldavian Platform. CO_2 storage capacities in aquifers have been estimated at 3 Gt, but need to be re-evaluated using improved methodologies.

Slovenia

Slovenia has 7 major stationary sources, including three power plants totalling 6.3 Mtpa emissions of CO_2. The largest plant, Sostanj, produces an average of 4.7 Mtpa. Storage capacity, mostly in aquifers, is estimated at 149 Mt. Hydrocarbon reserves are very limited, while all known coal deposits are shallower than 500 m. Relatively abundant sediments are promising for CO_2 storage.

Two of the potential basins (Friuli-Veneto and Pannonian) extend to neighbouring countries (Italy/Hungary, Croatia). The geological structure is very complex due to the tectonic history, and there is limited information about the depth range (800-3 000 m).

Spain

In Spain, the following programmes have been set up to investigate abatement options and related technology developments:

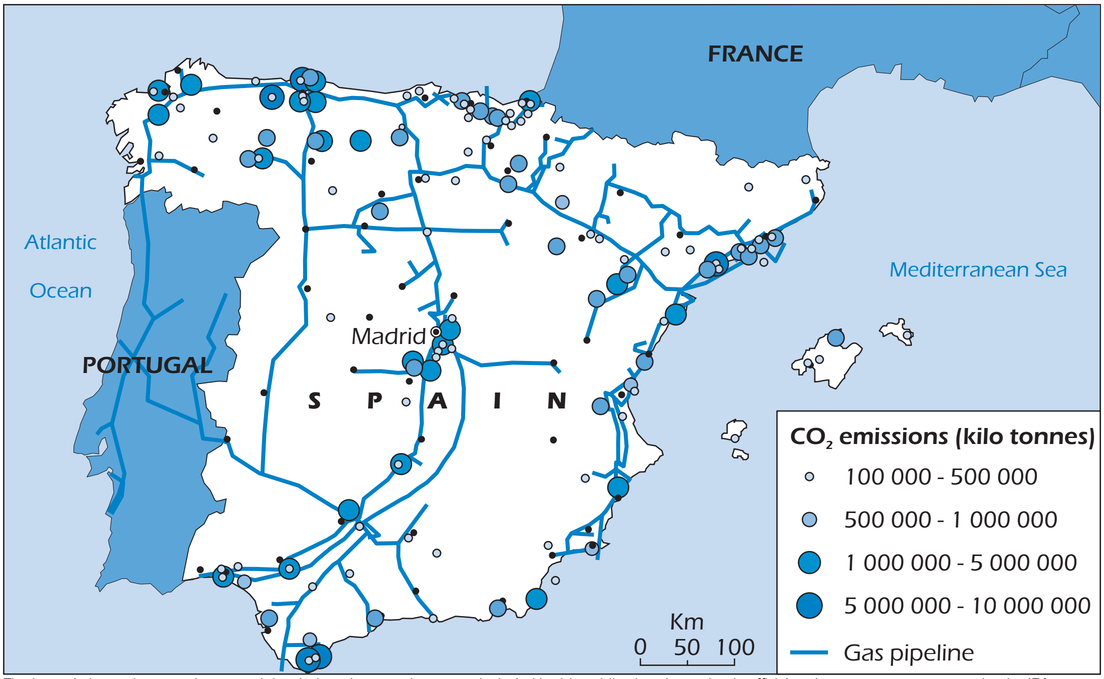
- Consorcio Estratégico Nacional en Investigación Técnica del CO_2 (CENIT CO_2) has a EUR 62 million four-year budget under the leadership of ENDESA and Union Fenosa and industry-wide participation (16 research centres and 13 industrial organisations). The objective is the research, development and validation of new technologies and integrated solutions to reduce CO_2 from power-related fossil-fuel emissions.
- Advanced Technologies of CO_2 Conversion, Capture and Storage (PSE CO_2), under the auspices of the National Energy Programme of the Ministry of Education and Research, is co-ordinated by CIEMAT with the participation by ELCOGAS and several research and engineering companies. The objective is to develop CO_2 capture technologies that allow the sustainable use of coal and to investigate Spanish deep storage sites.

The Spanish CO_2 Technological Platform (PTECO$_2$) was established in 2006 to develop a comprehensive national strategy for CCS, to improve the power efficiency of industrial plants, to advise on legislative issues, and to establish technological alliances with internal programmes.

Figure 6.19 Spain's Major CO_2 Sources and Natural Gas Pipeline Infrastructure

Key point

Spain's major CO_2 emission nodes are generally close to gas pipelines.



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Source: Martinez, 2007.

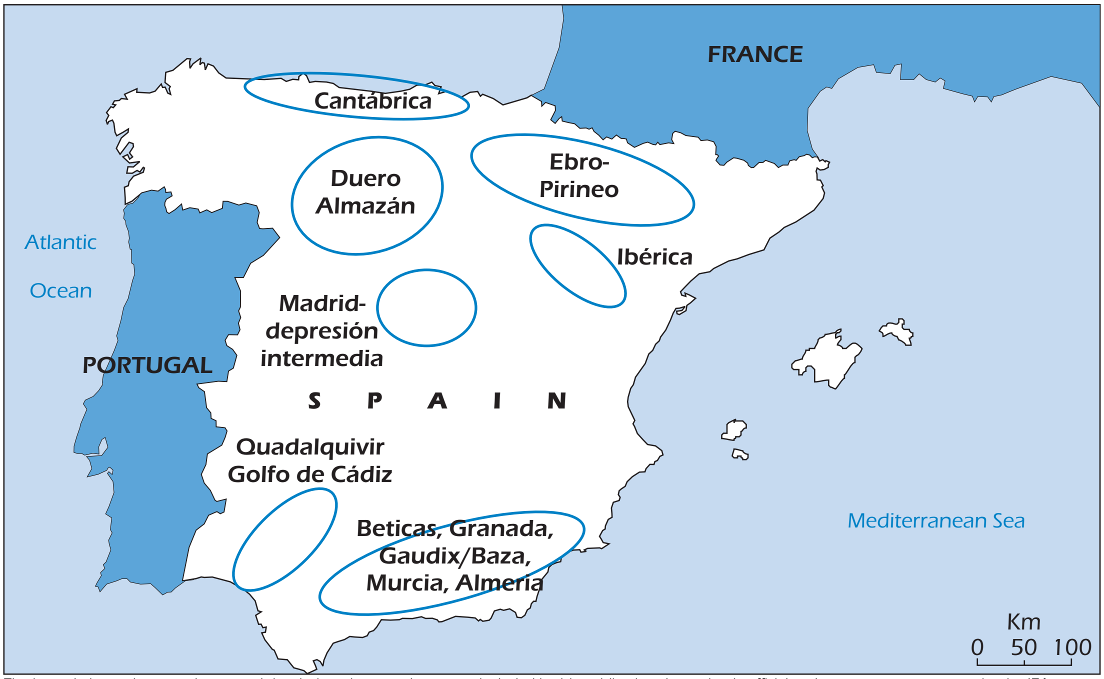
Figure 6.19 shows the main sources and the gas pipeline infrastructure in Spain. Figure 6.20 shows the potential onshore storage basins (Martinez, 2007), which is an early assessment that takes into account the knowledge of geology as well as from oil and gas wells drilled in Spain. The best potential in saline aquifers is in the Ebro, Dureo, Guadalkivir and Madrid basins. Some 40-50 Gt could exist in the seven basins that are located within a short distance of the main emission nodes, in addition to a number of off-shore sites. Further work is needed to determine more precisely basin capacity and suitability for storage, and it is being carried out by the Spanish Geológico y Minero de España (IGME) with the support of the government and industry.

Some early opportunities in depleted offshore oil and gas wells include the Casablanca project in which the REPSOL YPF oil and gas company has been investigating the use of the Casablanca off-shore field northeast of Spain for a pilot project. 500 Kt of CO_2 per year would be captured from the Tarragona refinery plant located 40 km from the injection wells, and pumped into a depleted carbonate formation at a depth of 2 500 m. Coal basins offer limited potential (200 Mt) but the national company HUNOSA is leading a study to develop an underground laboratory of ECBM technologies. Other initiatives include the "Ciudad de la Energía Foundation" with a pilot 20 MW oxycombustion plant, and a R,D&D post-combustion project in Asturias with the Instítuto del Carbon.

Figure 6.20 Spain's CO_2 Storage Potential

Key point

Spain's' main storage prospects are located in geological basins (Ebro, Dureo, Guadalkivir and Madrid).



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Source: Martinez, 2007.

Sweden

Despite having limited storage capacity, Sweden has been active in developing and demonstrating CCS technologies through Vattenfall and the Chalmers University of Technology. In 2006, Vattenfall made a EUR 50 million investment to build a 30 MW oxyfuel pilot plant (located in Germany), with operation scheduled to start in mid-2008. In 2007, E.on and Alstom launched the development of a 5 MW CO_2 capture demo plant located in the Karlshamn power plant in southern Sweden. The plant is to be in operation in 2008 and will be using Alstom's new chilled ammonia technology targeting the capture of 90% of emitted CO_2.

In October 2007, tests were started by Fortum at a small scale on a power plant in Stockholm on a system developed by the Sargas Technology Group. The capture technology uses pressurised filters and absorbers, and requires that the flue gas be under pressure. The technology developers claim a 95% CO_2 removal rate, and a cost of less than USD 20/t.

Under the Nordic Energy Research programme, Chalmers University of Technology has participated in the Nordic CO_2 Sequestration ($NoCO_2$) projects. Research has focused on methods of producing H_2 from natural gas with CO_2 capture using chemical looping combustion (CLC) technology. Opportunities for CO_2 emissions capture from the pulp and paper industry are being studied in the Swedish KTH Royal Technology Institute.

Geological characteristics restrict aquifer storage possibilities to southern Sweden and south western Sweden off-shore. Structural traps are likely to be the main form of storage, although there has been no systematic evaluation of their suitability and their capacity.

Thailand

In Thailand, almost all large stationary CO_2 emission sources are within 300 km of the Gulf of Thailand Basin. Storage opportunities exist off-shore in the Pattani Basin where high-CO_2 gas reservoirs present a challenge for development. The CO_2 content increases from a few percent to 25% and can be higher than 60% in some cases.

Trinidad and Tobago

Trinidad had the first and only CO_2-EOR project in Central or South America. CO_2 from an ammonia plant was injected in an immiscible flood into low performance wells. The injection, which consists of periods of CO_2 injection followed by hydrocarbon production over the last 20 years, allowed a remarkable increase in performance over baseline pre-injection data.

Turkey

Turkey had the first CO_2-EOR project outside North America (Issever, 1993). The Bati-Raman limestone field in the Diyarbakir area was discovered in 1961. It contains low gravity (12-API) heavy oil and would have a recovery rate lower than 2% without a tertiary mechanism. CO_2 was obtained from a high purity reservoir (Dodan) located 90 km from the field and transported via a 1 Mtpa capacity pipeline. The use of CO_2 as an immiscible flood has allowed an increase of recovery by 300% compared to initial estimates. There are no other plans for CCS currently in Turkey.

Venezuela

Most of the potential CO_2 storage capacity in Venezuela is in the eastern offshore areas and in the Lake of Maracaibo, relatively close to a number of sources. Bradshaw's (2006) storage retention analysis estimates 2.7 Gt storage space in the lake in oil and gas fields. Opportunities for EOR also exist as reservoirs are depleting. The Venezuelan national oil and gas company (PDVSA) has embarked on an EOR screening project for a number of maturing fields.

Vietnam

Most of the Vietnamese storage potential is off-shore. Large accumulations of high CO_2 gas (with over 60% content) have been found off-shore, and in deep waters. In 2005, the White Tiger project was submitted as a CDM project (see Chapter 5) involving CO_2 capture from gas-fired power plants and its injection for enhanced oil recovery in the off-shore White Tiger field.

7. CCS TECHNOLOGY ROADMAPS AND RECOMMENDATIONS

KEY FINDINGS

- 20-30 full-scale demonstration projects are urgently needed in the power sector if CCS is to be commercial by 2030. These projects should be co-ordinated internationally in order to leverage national investments and to cover a variety of capture technology configurations in power generation.
- Power plant CCS Retrofits also need to be demonstrated and at least 6 projects are needed at coal plants by 2020. If these projects do not materialise, the retrofit option will lose its significance.
- In addition to the power sector projects, 10-20 full-scale demonstration projects for CO_2 capture in industrial processes should be operational by 2025.
- CO_2 transport needs to be co-ordinated on a regional and national level to assess infrastructure needs, costs, and legal/regulatory issues.
- Demonstration of CO_2 storage needs to be co-ordinated and conducted at a variety of geologic settings.
- CCS is not a stand-alone technology. It needs to be combined with energy efficient conversion processes that generate concentrated CO_2 flows. Integrated Gasification Combined Cycle (IGCC) and Ultra Supercritical Steam Cycle (USCSC) are two such technologies for the power sector. In industry, nitrogen free blast furnaces, smelt reduction processes, black liquor gasifiers are examples of such enabling technologies. As use of oxygen is a prerequisite for high CO_2 concentrations, energy efficient oxygen production should also be a priority.
- Investment in CCS will only occur if there are suitable financial incentives and/or regulatory mandates. A number of financial and regulatory options exist to encourage CCS in the short- and long-terms; the appropriate approach will vary across countries. However, it is clear that market-based solutions alone will not be sufficient to stimulate industry to act with the speed or depth of commitment that is necessary. A clear, long-term vision is needed that can underpin investor confidence to further invest in innovative technologies.
- While governments are making strides toward the development of CCS policy frameworks, more work is needed at all levels – including international treaty frameworks, and supranational, national, state/provincial and local governments – to:
  - develop sound policies and measures to enable more continuous R&D investment in emerging clean technologies like CCS;
  - amend existing frameworks rapidly to enable near-term demonstration projects, then adapt these regulations as lessons are learned;
  - identify and address legal and policy issues associated with safe, effective CO_2 transport and storage, including site selection and monitoring and verification methodologies that share guiding principles;

- identify future actions to ensure consumer acceptance of CCS and to accelerate the adoption of clean technologies; and
- allocate resources and create the educational incentives and viable career paths that are necessary to ensure that skilled staff are available to make the transition to a more sustainable energy future.

- International collaborative frameworks focusing on CCS technology transfer to developing countries must be expanded, notably for China, India, Russia, in the Middle East, and in sub-Saharan Africa.
- International Co-ordination can be enhanced via a CCS Roadmap. This Roadmap is a start. The timeline in this roadmap is very ambitious and will require rapid uptake of CCS technology in both OECD and non-OECD countries at rates which may seem unprecedented. A considerable amount of political will and urgent action from both the public and private sector is needed to achieve the targets outlined in this roadmap.

Introduction

The IEA's 2008 publication *Energy Technology Perspectives* (ETP) developed roadmaps for 17 energy technologies that will be needed to achieve long-term global energy and climate change goals. These roadmaps identify necessary near-, medium- and long-term milestones to guide the international community in technology and policy development.

In ETP 2008, two sample roadmaps were developed for CCS in power generation and CCS in Fuel Transformation and Industry. These roadmaps (shown in this chapter) show that a great deal needs to be accomplished in the next 10-15 years if CCS is to make a meaningful contribution to global Greenhouse Gas (GHG) reduction efforts by 2050. This chapter elaborates these ETP Roadmaps by providing updated, more detailed milestones. It also makes recommendations for a number of financial, legal, and international co-operation developments necessary to underpin the successful expansion of CCS. This chapter offers pointers for future international CCS collaboration.

What is Included in the ETP 2008 Roadmaps

Each roadmap provides a quick assessment of the relevant technology options and the steps that are needed to accelerate their adoption in the commercial marketplace under both the ACT Map (emissions stabilisation) and BLUE Map (emissions halving) scenarios.

Each roadmap includes:

- projections of the potential CO_2 reduction that could be reached by 2050 by adopting the technology, compared to the Baseline scenario;
- projected distributions of the technology by region in 2050 for the ACT Map and BLUE Map scenarios;

- indicative estimates of global deployment needs (with regional details), total investment costs for RDD&D and total commercial investments needed to 2050, as a reference for global RDD&D planning;
- technology targets;
- a timeline indicating when the technology would need to reach specific research, development, demontration and deployment (RDD&D) phases;
- the most important steps needed to bring the technologies to commercialisation; and
- a brief outline of the most promising areas for international co-operation.

The goal of the IEA was to help guide policy and business decision-makers and to encourage international co-operation and global efforts on energy-technology RDD&D. The roadmaps capture the essential RDD&D issues associated with these technologies and identify specific actions that are needed nationally and globally. It is our hope that they will spur discussion among governments, businesses and financial institutions on the feasibility and potential to collaborate to advance these technologies. It is not our intent to prescribe what must be done, only to identify possibilities that exist.

The technology roadmaps were designed as global roadmaps and hence may have a different emphasis than national technology roadmaps. Where possible, national roadmaps have been taken into consideration.

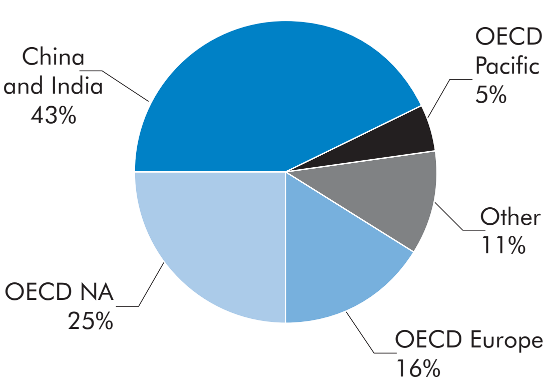
How to Use the ETP 2008 Roadmaps

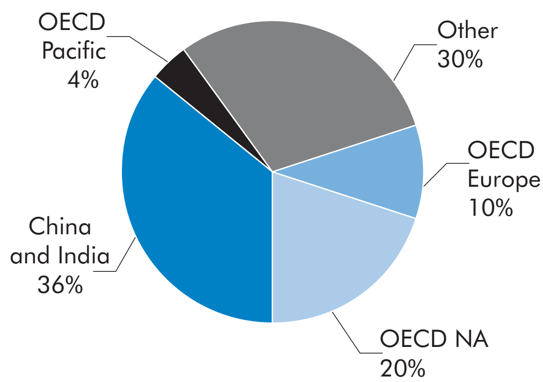
The ETP 2008 roadmaps were designed for policy-makers and aim to help determine:

- how carbon targets could technically be met at least cost (rather than the policies needed to make this happen);
- the milestones consistent with achieving significant outcomes to meet the ACT Map and BLUE Map objectives;
- who should be at the table (in terms of international collaboration, existing frameworks, IEA implementing agreements and industry);
- where deployment would be most likely to occur; and
- the funding that is needed.

These roadmaps provide a snapshot of the technology outlook in 2008. They will need to be updated over time to reflect progress and developments in R&D, policy and the marketplace.

CO_2 Capture and Storage: Fossil Fuel Power Generation





	Global deployment share 2030	RDD&D inv. cost USD bn 2005-2030	Commercial inv. cost* USD bn 2030-2050
OECD NA	35%	25-30	160-180
OECD Europe	35%	25-30	100-120
OECD Pacific	10%	7-8	30-40
China & India	15%	10-12	280-300
Other	5%	3-4	60-70

	Global deployment share 2030	RDD&D inv. cost USD bn 2005-2030	Commercial inv. cost* USD bn 2030-2050
OECD NA	35%	30-35	350-400
OECD Europe	35%	30-35	150-200
OECD Pacific	10%	10-12	70-80
China & India	15%	12-14	400-450
Other	5%	4-5	250-300

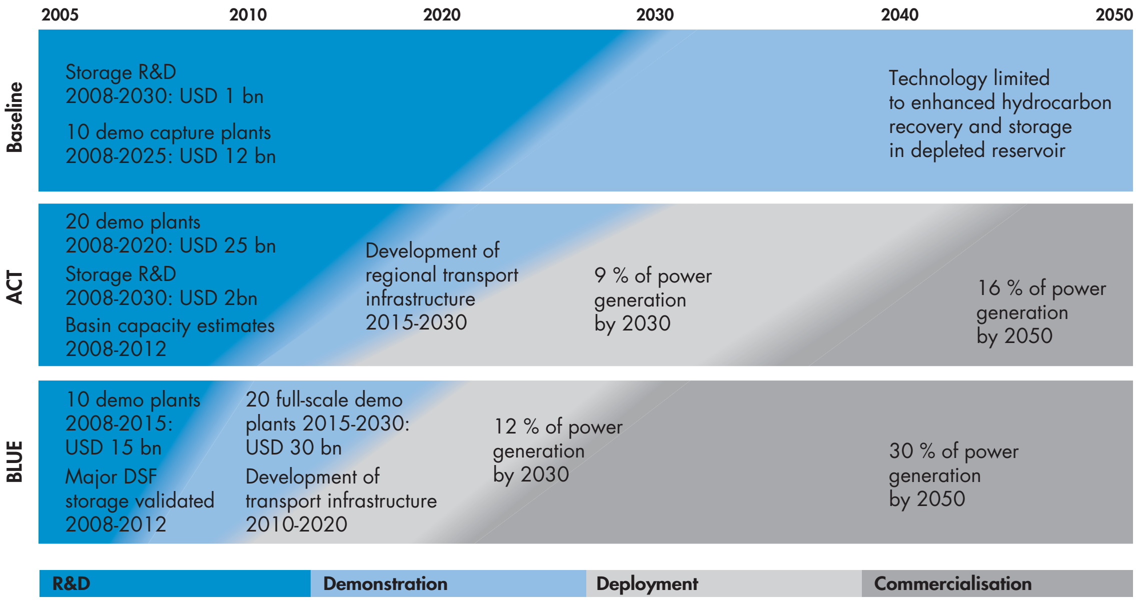
* Excludes operating costs. Total including OPEX is USD 1.3-1.5 trillion for ACT and USD 4.0-4.5 trillion for BLUE.

Technology Targets

	ACT: emissions stabilisation	BLUE: 50% emissions reduction
RD&D		
Capture technologies for three main options (post-combustion, pre-combustion, and oxy-fuelling)	Technologies tested in small- and large-scale plants. Cost of CO_2 avoided around USD 50/t by 2020. Chemical looping tested	
Demonstration targets	20 large-scale demo plants with a range of CCS options, including fuel type (coal/gas/biomass) by 2020	30 large-scale demo plants with a range of CCS options, including fuel type (coal/gas/biomass) by 2020
New gas-separation technologies: membranes & solid adsorption	New capture concepts: next-generation processes, such as membranes, solid absorbers and new thermal processes	
Technology transfer	Technology transfer to China and India	Technology transfer to all transition and developing countries
Deployment		
Regional pipeline infrastructure for CO_2 transport	Major transportation pipeline networks developed and CO_2 maritime shipping	
Deployment targets	Early commercial large-scale plants by 2015 (ZEP, ZeroGen, GreenGen)	30% of electricity generated from CCS power plant by 2050

Source: IEA, Energy Technology Perpectives 2008.

Technology Timeline



In this roadmap, commercialisation assumes an incentive of USD 50/t CO_2 saved.

Key Actions Needed

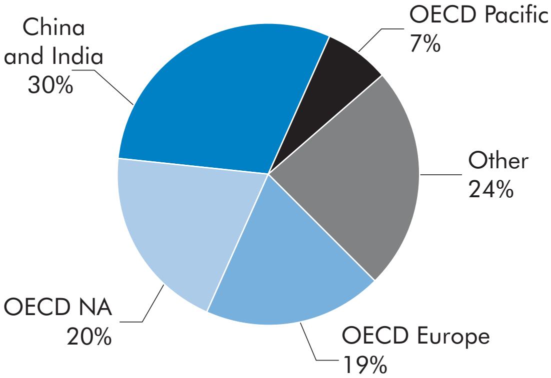
- Develop and enable legal and regulatory frameworks for CCS at the national and international levels, including long-term liability regimes and classification of CO_2.
- Incorporate CCS into emission trading schemes and post-Kyoto instruments.
- RD&D to reduce capture cost and improve overall system efficiencies.
- RD&D for storage integrity and monitoring. Validation of major storage sites. Monitor and valuation methods for site review, injection and closure periods.
- Raise public awareness and education on CCS.
- Assessment of storage capacity using Carbon Sequestration Leadership Forum methodology at the national, basin and field levels.
- Governments and private sector should address the financial gaps for early CCS projects to enable widespread deployment of CCS for 2020.
- New power plants to include capture/storage readiness considerations within design by 2015.

Key Areas for International Collaboration

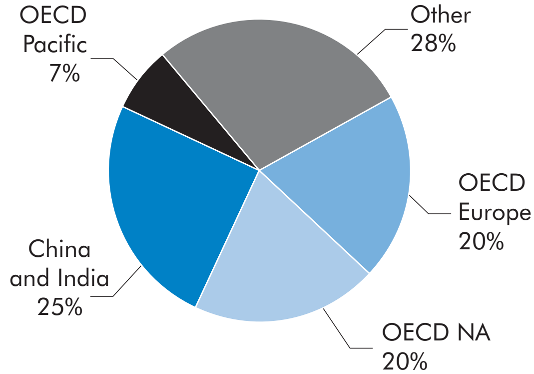
- Development and sharing of legal and regulatory frameworks.
- Develop international, regional and national instruments for CO_2 pricing, including CDM and ETS.
- Raise public awareness and education.
- Sharing best practices and lessons learnt from demonstration projects (pilot and large-scale).
- Joint funding of large-scale plants in developing countries by multi-lateral lending institutions, industry and governments.
- Development of standards for national and basin storage estimates and their application.
- Organisations: CSLF, IEA GHG, IEA CCC, IPCC.

CO_2 Capture and Storage: Industry, H_2 & Fuel Transformation

ACT 2.0 Gt savings 2050



Blue 4.3 Gt savings 2050



	Global deployment share 2050	RD&D inv. cost USD bn 2005-2030	Commercial inv. cost* USD bn 2030-2050
OECD NA	20%	10-12	125-150
OECD Europe	19%	8-10	125-150
OECD Pacific	7%	2-5	60-70
China & India	30%	6-8	200-300
Other	24%	3-4	150-200

	Global deployment share 2050	RD&D inv. cost USD bn 2005-2030	Commercial inv. cost* USD bn 2030-2050
OECD NA	20%	15-20	350-400
OECD Europe	20%	10-14	350-400
OECD Pacific	7%	5-7	150-200
China & India	25%	10-12	300-400
Other	28%	10-12	250-300

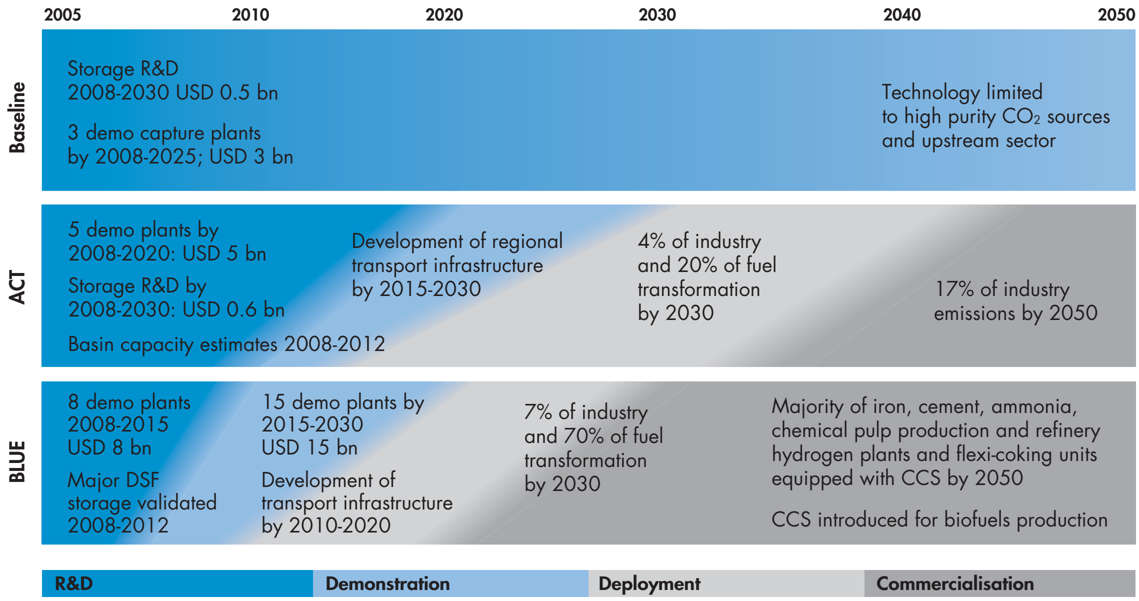
*Excludes operating costs. Total including OPEX is approximately USD 1.0–1.2 trillion for ACT and USD 4–4.5 trillion for BLUE.

Technology Targets

	ACT: emissions stabilisation	BLUE: 50% emissions reduction
RD&D		
Development of various industry applications	Nitrogen free blast furnace and smelt reduction processes (enabling tech.), CCS demo for iron production processes, cement kilns with oxy-fuelling, black-liquor IGCC, fluid catalytic crackers equipped with high-temp. CHP and CO_2 capture. Cost of CO_2 avoided at a range of 50-100 USD/tonne by 2020	
Demonstration targets	5 large scale demo plants in various sectors by 2020	12 large scale demo plants in a range of capture and storage options, including fuel type (coal/gas/biomass) by 2020
New gas separation and capture technologies	Including next-generation processes, such as membranes, solid adsorbers and new thermal processes	
Technology transfer	Technology transfer to China and India	Technology transfer to all transition and developing countries
RD&D		
Development of a regional pipeline infrastructure for CO_2 transport	Major transportation pipeline networks developed, and CO_2 maritime shipping	

Source: IEA, Energy Technology Perpectives 2008.

Technology Timeline



In this roadmap, commercialisation assumes an incentive of USD 50/t CO_2 saved.

Key Actions Needed

- Develop and enable legal and regulatory frameworks for CCS at the national and international levels, including long-term liability regimes and classification of CO_2.
- Monitoring and verification methods for site assessment, injection and closure periods.
- Incorporate CCS into Emission Trading Schemes and Clean Development Mechanisms.
- RD&D to reduce capture cost and improve overall system efficiencies.
- RD&D for storage integrity and monitoring.
- Raise public awareness and increase education about CCS.
- Assessment of storage capacity using CSLF methodology at the national, basin and field levels.
- Develop 5 large scale demonstration plants by 2020 with public-private partnerships.

Key Areas for International Collaboration

- Develop and sharing of legal and regulatory frameworks.
- Develop international, regional and national instruments for CO_2 pricing, including CDM and ETS.
- Raise public awareness and education.
- Sharing best practices and lessons learned pilot and large scale from demonstration projects.
- Joint funding of large-scale plants in developing countries by multilateral lending institutions, industry and governments.
- Develop standards for national and basin storage estimates and their application.
- Organisations: Carbon Sequestration Leadership Forum, IEA GHG.

Updating the CCS Roadmaps

Clearly the sample CCS Roadmaps on the preceding pages are only a start. This book seeks to take a next step by updating cost and performance figures, reviewing in more detail the global status of government investment in CCS policy and demonstration, and identifying regional potentials for CO_2 capture and storage.

Technology Options for CCS

A variety of different technology options for CCS are currently being developed in the power generation, fuel transformation and industrial sectors. Most of these technologies still need to be demonstrated on a large scale. Others such as chemical looping represent more innovative options which may or may not materialise in the future. Table 7.1 lists the various technology options which are covered in the IEA's CCS Roadmap analysis.

Table 7.1 Technology Options for CCS in Power Generation, Fuel Transformation and Industry

Power generation			
Current technology development		***Innovative options - post 2025***	
Coal	IGCC - physical absorption (P.A.)	Coal	chemical looping
	USCSC - chemical absorption (C.A.)	Gas	NGCC - chemical looping
	Oxyfueling for steam cycles	Biomass	BIGCC - physical absorption
	retrofit options		
Gas	NGCC – CA		
Fuel transformation			
Gas processing - chemical absorption			
Gas, coal and biomass to liquids			
Heavy oil / Oil sands cracking			
Hydrogen production - physical absorption			
Industry			
Current technology development		***Innovative options - post 2030***	
Nitrogen-free blast furnace - physical absorption		cement rotary kiln - chemical looping	
Smelt reduction – chemical/physical absorption			
DRI			
Cement rotary kiln - chemical absorption, oxyfueling			
Ammonia - chemical absorption			
Black liquor gasifier			

Early opportunities. Early CCS projects will pave the way for large-scale deployment. Such projects will provide the early learning needed to facilitate CCS for the power generation and industrial sectors. There are a variety of early opportunities for CCS demonstration, including the expansion of existing CO_2 capture in natural gas processing, or in ammonia or hydrogen manufacturing and existing gas and coal-to liquids facilities where the CO_2 is already separated; and expanding CO_2 use for EOR, where transport distances are short and storage can generate revenue.

CCS Timeline

Expanding on the ETP 2008 roadmaps for CCS, the timeline in Figure 7.1 aims to outline a potential pathway to achieve the level of CCS deployment needed under the BLUE Map scenario, *i.e.* 9.2 Gt of CO_2 savings in 2050 from various CCS technologies. The timeline includes more detailed targets on CCS R&D, demonstration and deployment needs for power generation, fuel transformation and industry. Cross cutting issues such as CO_2 transport and storage together with financing, legal and public acceptance needs are also outlined in the timeline.

CCS Roadmap Indicators

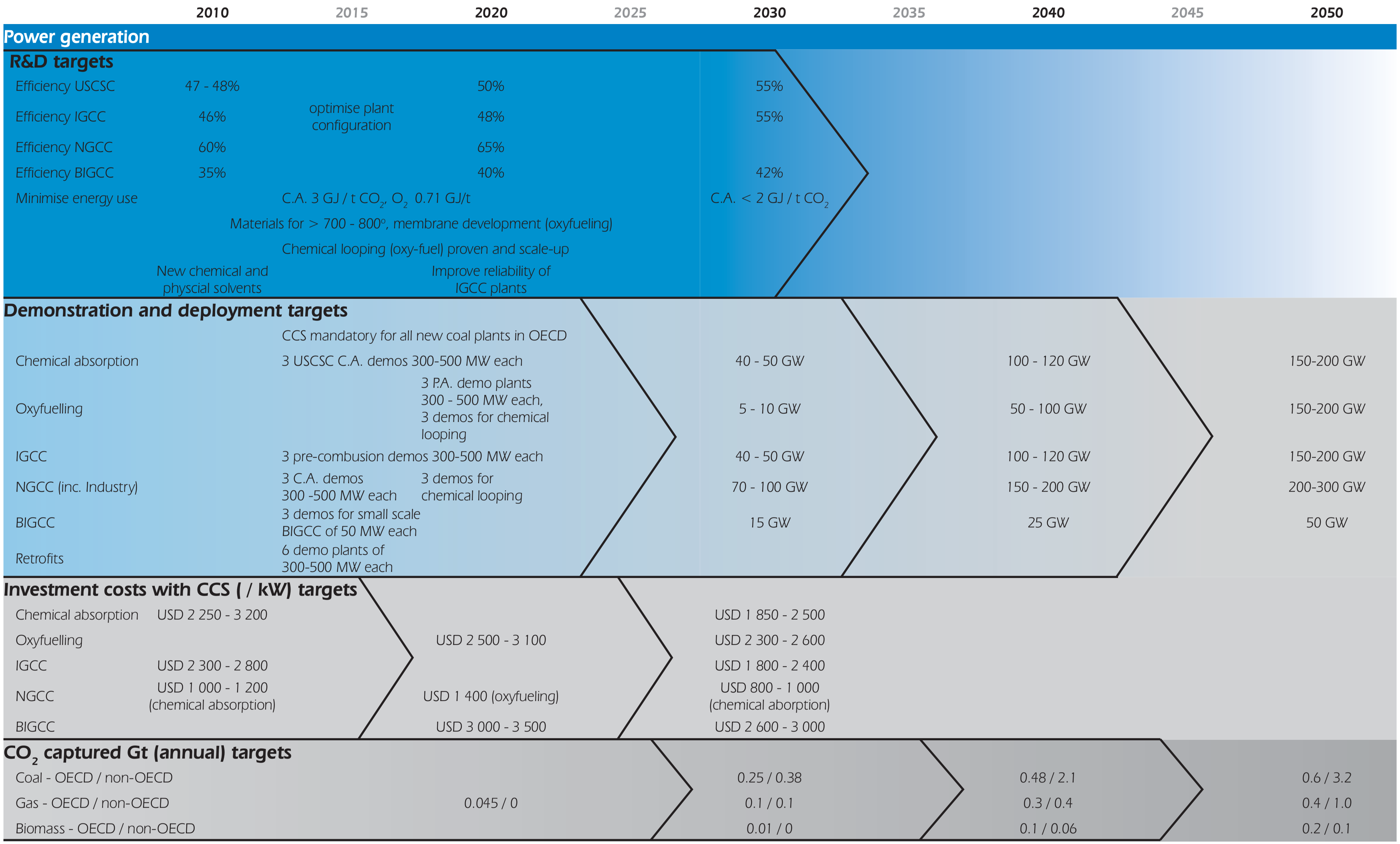
Indicators have been identified to help track progress against the CCS roadmap. Although it is difficult to develop such indicators as technologies advance at different speeds, it is nevertheless helpful to develop technology milestones for the purpose of future technology planning. The indicators outlined in Table 7.2 cover capture demonstration and deployment, transport network

Table 7.2 Need for CCS Demonstration and Deployment Consistent with the BLUE Map Scenario

	2012	2015	2020	2025	2030
No. of demo plants approved (licensed and financed)					
Power	9 coal	3 gas, 3 coal	3 biomass, 3 gas		
Industry	2 ammonia	2 cement, 2 I&S, 2 P&P	2 cement, 2 I&S, 2 P&P		
No. of demo plants operating					
Power		9 coal	3 gas, 3 coal	3 biomass, 3 gas	
Industry			4 cement, 4 I&S, 4 P&P		
No. of commercial plants operational					
Power			10 coal, 2 gas	70 coal, 10 gas	300 coal, 100 gas
Industry			20 ammonia plants, 10 cement kilns, 2 blast furnaces/ smelt reduction plants		50 ammonia plants, 100 cement kilns, 50 blast furnaces, 10 black liquor boilers
km of pipeline approved (licensed and financed)	1 100	3 000	10 000		
km of pipeline under construction	400	1 500	5 000	10 000	
km of pipeline operational	100	500	5 000	15 000	40 000
Gt CO_2 stored	0.036	0.105	0.31	0.85	1.8
EOR	0.025	0.05	0.2	0.4	0.7
ECBM	0.001	0.005	0.01	0.05	0.1
Aquifers	0.01	0.05	0.1	0.4	1
Gt captured	0.036	0.105	0.31	0.85	2
Power	0.005	0.02	0.05	0.3	1.2
Industry	0.015	0.03	0.05	0.25	0.5
Fuel transformation	0.016	0.055	0.21	0.3	0.3

Note: I&S = Iron and steel
P&P = Pulp and paper

Figure 7.1 Proposed CCS Timeline



Note: C.A. = chemical absorption
P.A. = physical absorption

	2010	2015	2020	2025	2030	2035	2040	2045	2050
Industry									
R&D - oxyfueling, gas cleaning									
Iron and steel		Oxyfuel for blast furnaces - gas flow optimized and gas cleaning to be solved							
Cement		Develop oxyfueling and chemical looping			C.A. energy use to fall to 2.2 GJ / t				
Pulp and paper		Improve reliability of gasifier and demonstre use of gasifier with gas turbine							
Demonstration and deployment									
Iron and Steel			2 demo blast furnace plants, 2 demo smelt reduction plants, 2 demo DRI plants		25 - 30 blast furnaces, 50 - 60 DRI, 8 - 10 smelt reduction plants				75 - 100 blast furnaces, 150 - 250 DRI, 100 - 150 smelt reduction plants
Cement		2 demo C.A.	5 demo oxyfuel, 5 demo chemical looping		100 - 150 cement kilns				450 - 500 cement kilns
Ammonia	deployment in ammonia plants		20 ammonia plants		40 - 50 ammonia plants				100 - 150 ammonia plants
Pulp and paper		2 demo plants of 300MW black liquor gasifiers			10 black liquor boilers				100 black liquor boilers
Mitigation costs t CO_2*									
Iron and Steel (blast furnase / smelt reduction / DRI)		100/75/25 - 50			40 - 60 / 30 - 50 / 20 - 40				40 - 60 / 20 - 40 / 20 - 40
Cement (post combustion / oxyfueling)		125/na		na / 60	100 / 50				75 / 40
Ammonia		25			20				20
Pulp and paper (black liquor boilers / gasifiers)		50/na		na / 30	40 / 30				35 / 25
Gt captured ; % CO_2 produced									
Iron and steel					0.2 Gt; 8 - 10%				1.25 Gt; 30%
Cement					0.15 Gt; 8 - 10%				0.8 - 1.0 Gt; 30%
Ammonia					0.1 Gt; 20 - 30%				0.3 Gt; 80 - 100%
Pulp and paper									0.1 Gt; 15%
Cross cutting (transport, storage, legal, finance and public acceptance)									
Legal framework	Estabilished legal and regulatory framework for storage and transportation of CO_2								
		Clear licensing and permitting systems for storage projects							
		Established monitoring and valuation procedures							
Pipeline network									
size of network - km	5 000 - 7 000		15 000 - 25 000		32 000 - 50 000		60 000 - 90 000		
investment costs - USD bn	3 to 4.2		9 to 15		24 to 36		45 to 75		
Storage									
		Consistent assessment of storage potentials globally							
EOR Gt stored		10 - 1 Mt projects committed	5 - 10 Gt						
Gt stored				50 Gt, 50% DSF 50% EOR + DOGF			250 Gt, 75% DSF		
CO_2 incentive									
OECD				50		100			
non-OECD						50	100		
Financing									
Inv. cost USD bn		60 - 80		400 - 500		1 300 - 1 500		1 200 - 1 400	
		CDM incentive in place							
Public acceptance									
			National campaigns to educate public on benefits of CCS and role in combating climate change						

Note: DSF = deep saline formation. DOGF = depleted oil and gas fields. DRI = direct reduced iron needs and storage needs to 2030. These indicators are intended to be illustrate what is needed for CCS development under the ETP 2008 analysis. They can be used as a general guideline for setting technology targets under an international technology collaboration framework. The figures below are ambitious and highlight the urgency of actions needed on the demonstration and deployment phases of CCS development in power generation, but also for fuel transformation and industry.

Financial, Legal and Public Acceptance Issues and Recommendations

A number of non-technical challenges must also be overcome in order to achieve CCS's full potential. The most critical are financing near-term demonstration projects, enacting a long-term enabling framework particularly through CO_2 mitigation policies, the development of legal and regulatory frameworks governing CO_2 storage and transport, and increased public awareness and support.

Financing CCS

CCS adds significant cost to power generation and industrial processes. Therefore, CCS will only become commercially viable if there are suitable financial incentives and/or regulatory mandates. An area of particular concern is the financial gap and risks facing the critical early CCS demonstration projects. It is clear that GHG market mechanisms alone will not be sufficient to incentivise the needed CCS demonstration projects.[78] Equally important is the need to establish a predictable, long-term price for CO_2.

Legal and Regulatory Frameworks

While governments are making important progress in developing suitable CCS policy frameworks, much additional work needs to be done to formalise standardised international guidelines for site selection, monitoring and verification, to address long-term liability concerns, and to ensure clear, transparent permitting processes for the full chain of CCS infrastructure investments, including transportation via pipeline.

Public Awareness and Acceptance

Public awareness and support for CCS is critical if it is to achieve its potential as a GHG mitigation solution. Effective communication strategies need to be developed and implemented, especially for CCS early opportunities.

Recommendations

- Fiscal and trading frameworks that will create a sufficient price for CO_2 are required if industry is to invest in CCS. An incentive of USD 50/t CO_2 is needed by 2020 in OECD countries and by 2035 in non-OECD countries. This incentive needs to rise to approximately USD 100/t CO_2 by 2035 in OECD countries and by 2040 in non-OECD countries to enable the wide scale deployment of more expensive CCS options in industry.
- Inclusion of CCS in the Kyoto Protocol flexibility mechanisms, as well as any future post-Kyoto flexibility mechanisms, could provide significant impetus for CCS as a carbon abatement option.

78. The G8 Energy Ministers in June 2008 called for 20 full-scale CCS demonstrations to be launched by 2010. To date, only 4 full-scale projects exist.

- The Clean Development Mechanism in particular could foster the process of involving developing economies in implementing CCS.
- Similarly, the comprehensive inclusion of CCS in the European Union Emissions Trading Scheme by 2013, and in other emerging emissions trading schemes as quickly as possible, would provide a means for facilitating the commercial viability of CCS in the medium to long term.
- Government support will also encourage project developers to share their technology and their experience with others. Public-private partnerships are a tool that should be more widely utilised.
- Governments should lead the demonstration process by providing necessary near-term regulatory and liability frameworks and financial incentives to cover the additional costs of CCS and to mitigate potential risks. These regulatory and legal frameworks should cover standards for well drilling, pipeline siting and access, the assignment of liability, environmental and safety risks, and the monitoring and verification of CO_2 retention.
- Governments must take a leading role in ameliorating the perception of risks associated with CCS by establishing clear regulatory responsibility for CCS project evaluation, approval and monitoring. Governments should actively engage the insurance industry to help identify products and services to address risk.
- Governments and project developers must deploy effective risk communication techniques to engage and educate the public, and pay special attention to developing guidelines for local community consultation on proposed CCS projects.

Regional CCS Development

Chapter 6 provides a detailed review of regional prospects and progress towards CCS implementation, including policy and regulatory developments, investments in R&D and demonstration, and estimates of CO_2 storage potential. Table 7.3 aims to provide a synopsis of the current state of play in CCS development.[79] Although many countries/regions have invested significant resources in CCS research, development and initial deployment, including evaluation of CO_2 storage potential, many other countries and regions critical to future CCS development have much work to do. In particular, there are sharp contrasts in the state of policy development for CCS regulation and financial incentives for CCS demonstration. There is a mismatch between those regions that have made significant investments in CCS and those countries that will require wide-scale CCS implementation in order to mitigate the CO_2 emissions from their expected fossil fuel utilisation. Additionally, there is a further need to address labour skills, educational differences, needed to transfer the technology globally.

CCS deployment will require a co-ordinated global effort if it is to make a meaningful contribution to CO_2 mitigation efforts by 2050. Wide-scale deployment must begin in 2025-30 in order to reach global diffusion by 2050. Figures 7.2 and 7.3 map out a global vision for CCS deployment in 2030 and 2050 based on ETP 2008 scenario analysis. These maps show the scale of CCS demonstration and deployment in power generation and industry, as well as the size of the transportation network, and the potential for annual CCS for each region. In 2030, demonstration and early deployment is likely to be focused predominately in OECD countries and China and India. By 2050, CCS will need to be applied globally with annual capture of CO_2 in non-OECD countries estimated to be 1.8 times that of OECD countries.

79. *This table does not attempt to capture all of the CCS project announcements around the world; for updated information, visit the IEA GHG Implementing Agreement's list of projects at* http://www.co2captureandstorage.info/co2db.php, *or the Massachusetts Institute of Technology's CCS Project Database at* http://sequestration.mit.edu/tools/projects/index.html.

Table 7.3 Regional CCS Development

	Total CO_2 emissions Mt 2004	Capture potential Blue 2050 Mtpa	Estimated storage potential - Gt	Proposed demonstration projects	Policy proposals
Europe	3 700	600	·	12 proposed demo plants by 2015 for coal & gas-fired plants; approx. 20 demo plants under consideration in France, Italy, Germany, UK, Poland, the Netherlands and Ireland	Creation of legal framework; qualifying CCS under EU-ETS
Russia	2 600	400	•		
China	4 800	2 000	●	Yantai 300-400 MW IGCC plant (2010) with 2nd phase CCS option; ECBM micro-pilot project; GreenGen natgas with CCS	CCS integrated into 11th 5-year plan via National high technologies programme and in National Science and Technology Plan to 2020; 2005-06 MOST memorandum of understanding on gov't led CCS research
India	1 100	900	•	Pilot project development for CO_2 capture	
Japan	1 300	150-250	·	Offshore storage	Offshore storage legislation developed - linked to London Convention and Protocol and MARPOL
Australia & New Zealand	500	200-400	●	CO2CRC Otway project (storage) AUD 40m; ZeroGen - IGCC demo AUD 1bn; Monash CTL project (AUD 6 bn - 10 Mt/yr CO_2); Gorgon off-shore gas stream; Callide Oxyfuel project (30 MW); Coolimba power 2*200 MW oxyfuel coal plant	Further legislation at federal and state level necessary. Certain States have legislation that provides for transport and storage of CO_2 in some instances; federal bill for offshore storage and transport; further legislation under development in some states
ODA	2 000	900	●	Gas processing; EOR; fertiliser plants	
US	6 000	1 700	⬤	Weyburn project; DF2 project; AEP project (Phase I 30 MWth 2008 and Phase II 200 Mwe 600 MWth 2011); FutureGen (300 MW IGCC)	Further legislation at federal and state level necessary. Regulation on CO_2 storage to be proposed by US EPA; US DoT to regulate CO_2 transport
Canada	650	850	●	EPCOR IGCC plant; Weyburn project; boundary dam CCS - 1 Mt/yr 2015; EPCOR - 500 MW IGCC; HARP (storage demo in water-saturated Redwater reef); ASAP (storage - aquifer); WASP (storage - aquifer)	Further legislation at federal and provincial level necessary. CCS for new coal-fired power plants and oil sands by 2018; some provincial policies address CCS; some federal and provincial legislation covering capture and transport of CO_2 in oil and gas fields; storage and liability issues still to be addressed
Brazil	1 250	400	●		
Middle East & North Africa			●	CO_2 capture from sour gas (1 Mt pa)- Algeria	

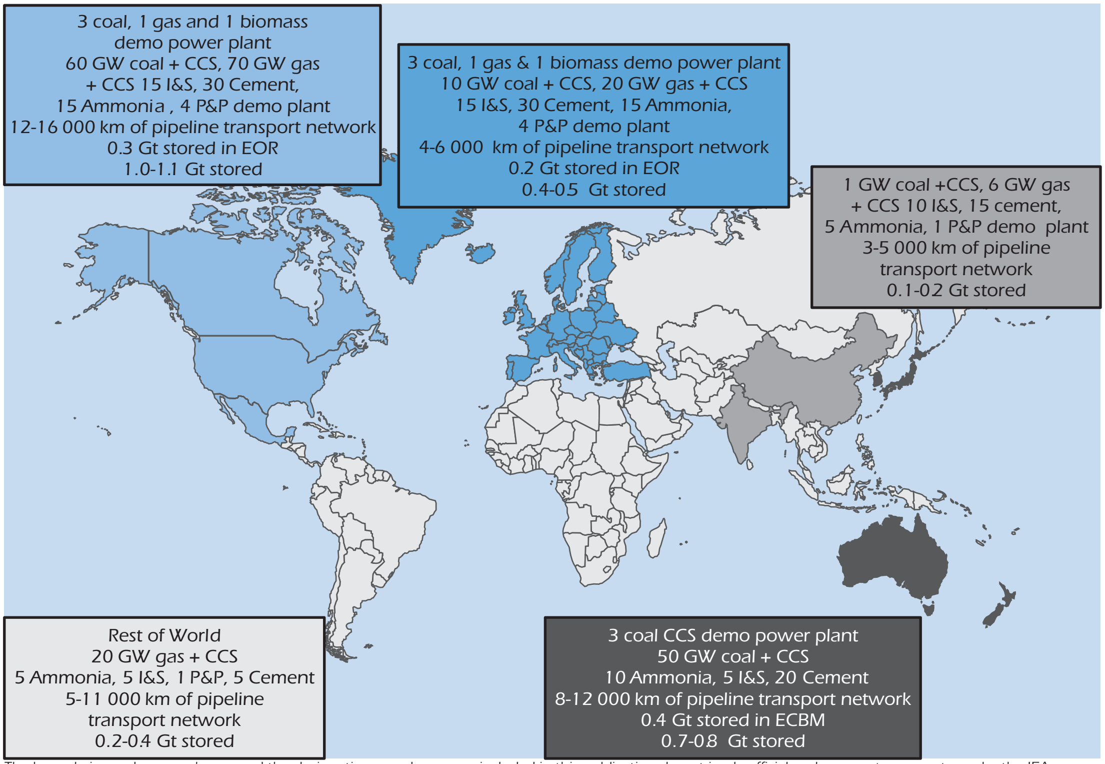
· < 500 Gt, • 500–1 000 Gt, ● 1 000-2 000 Gt, ⬤ > 2 000 Gt ODA: other developing Asia.

Early CCS opportunities	Initiatives	International collaboration
Fertiliser plants; gas processing; ECBM France and Poland ; Sleipner monitoring project Norway; EOR Turkey	EU zero emissions platform (ZEP) the Flagship Programme on CCS; 7th EU Framework Programme (€120m) proposed; CCS Directive - EU wide framework to encourage CCS	IEA Greenhouse Gas R&D; IEA Clean Coal Centre; CSLF; EU-China partnership; EU-India initiative; GOSAC; various other initiatives by individual member states
Various ECBM projects; various IGCC plants; fertiliser and chemical plants; EOR		CSLF; US Future Gen; US-China Energy and Environment Technology Centre; Near Zero Emissions Coal EU-China; EU Framework Programme 6; China-UK Mo; APEC Energy Working Group; APP Clean Development and Climate
EOR; various coal-fired power plants; fertiliser plants	Indian CO_2 Sequestration Applied Research Network	CSLF; EU-India initiative; US FutureGen; APP Clean Development and Climate; US Big Sky CCS partnership
Chemical plants	Clean coal technology roadmap (CCS by 2020)	IEA Greenhouse Gas R&D; IEA; CSLF
Gas processing	National clean coal fund - AUD 500 m; CO_2CRC (Otway)	IEA Greenhouse Gas R&D; IEA; CSLF
EOR; chemical and fertiliser plants; ECBM	Carbon Sequestration Regional Partnerships; DoE technology roadmap for CCS; Stanford Global Climate and Energy Project; CMI - Princeton, MIT CCS programme; ZERT; GTSP	IEA Greenhouse Gas R&D; CSLF; APEC Energy Working Group; APP Clean Development and Climate Initiative
EOR; various power plants; oil sands	Canada CCS Roadmap - gasification technology in oil sands; Weyburn-Midale Final Phase; 300-400 MW coal demo plant and early implementation of CO_2 transport infrastructure	IEA Greenhouse Gas R&D; CSLF; APEC Energy Working Group; APP Clean Development and Climate
EOR	CARBMAP (mapping source and sinks); Carbometano Brazil (ECMB); CEPAC (storage R&D)	IEA co-ordination; IEA Greenhouse Gas R&D
EOR; gas processing	R&D for EOR potential; CO_2 capture from hydrogen power production; CCS in GTL	

Figure 7.2 Global CCS Vision 2030

Key point

Demonstration and early deployment will take place mainly in OECD countries.



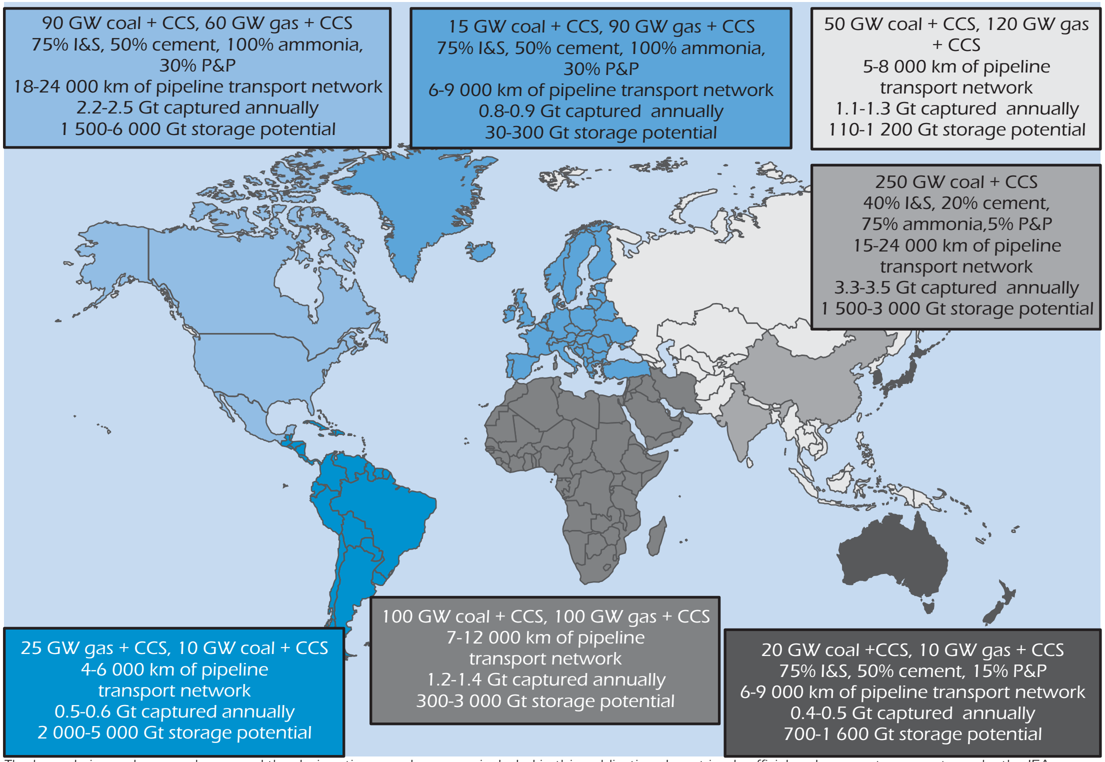
The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA estimates.

Figure 7.3 Global CCS Vision 2050

Key point

Rapid deployment and uptake in non-OECD countries will be needed from 2030 to 2050 for CCS to reach the CO_2 emissions reduction potential under the BLUE Map Scenario.



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.

Source: IEA estimates.

Conclusion: Recommendations for International Collaboration

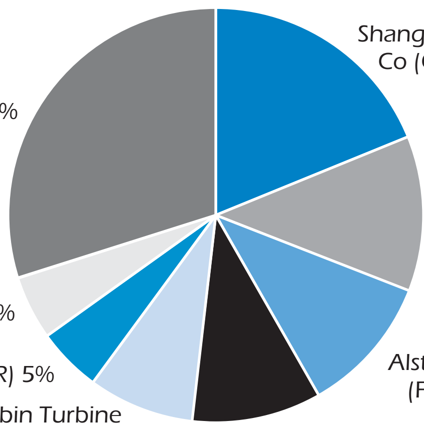
Energy Technology Perspectives 2008 showed that CCS development is critical to reducing CO_2 emissions. It is the priority technology for combating climate change, providing potentially the largest contribution to both the emissions stabilisation and the emissions halving scenarios in 2050. Under the ETP 2008 BLUE Map scenario, CCS provides 19% of the CO_2 savings, a reduction of 9.2 Gt in power generation, fuel transformation and industry. To achieve the BLUE Map outcome, 30% of all power plants and almost 80% of all fossil power plants will need to be equipped with CCS. In industry, approximately half of the iron and steel, cement, pulp and paper and ammonia plants need to apply CCS.

In order to achieve such a high level of CCS penetration by 2050, a massive increase is needed in CCS R&D and demonstration over the next 10–15 years to support wide-scale deployment starting in 2020-25. A comparison of the regional status of CCS development around the world (Table 7.3) and the expanded CCS roadmap in Table 7.2 show the need to rapidly accelerate CCS demonstration. On its face, the status of CCS demonstration appears promising, with 28 coal and gas fired demonstration projects proposed worldwide. However these projects urgently need to be approved and financed over the next 5 years if CCS is to be successfully demonstrated by 2020. Demonstration projects are also needed for biomass power generation and for industrial applications. A great deal of political will and industry commitment is required to meet the tight deadlines outlined in our roadmap. Governments and industry must act now to implement this timeline.

Figure 7.4 Market Share of Steam Turbines 2006 (83.1 GW)

Key point

Seven producers cover two-thirds of the market.



Source: METI, 2008.

Figure 7.4 shows the current market share for manufactures of steam turbines, while Table 7.4 lists the largest manufacturers of boilers. These manufacturers will also be market players for CCS technology in power generation. Any international framework for technology collaboration in CCS must include these organisations and specifically those from rapidly growing China and India.

Table 7.4: Leading Boiler Manufacturers

Bharat Heavy Industries (India)
Dongfang Boiler Co (China) / Mitsubishi Heavy Industries (Japan)
Doosan Heavy Industries (Korea)
Harbin Boiler Co (China)
Mitsu Babcock (Japan/UK)
Siemens (Germany)
Wuhan Boiler Co (China) / Alstom (France)

Source: IEA data.

Greater international collaboration is needed in the following areas, in order to achieve CCS development.

R&D

- Continued improvement of chemical absorbents;
- Improvements in efficiency and economics for all three capture technologies (pre-combustion, post-combustion and oxyfuel capture);
- A fully-funded, robust programme of research to develop second and third generation capture technologies (*e.g.* advanced solvents, sorbents, membranes, chemical looping and oxyfuel turbines);
- Further development of advanced options that are still in the R&D stage (chemical looping, Kimberlina cycle, cryogenic CO_2 separation);
- Capture systems for iron & steel making processes, cement kilns and black liquor boilers/gasifiers;
- Enhanced analysis of process conditions, flow analysis and materials development for oxyfuel combustion; and
- Improvements in efficiency and economics for CO_2 filtering and compression prior to transportation.

Demonstration

- Global co-ordination to assure that a portfolio of CO_2 storage projects moves through the demonstration phase to commercial application (it is likely that more than one demonstration of each technology needs to be funded to take into account the variable of coal types, sorbents, and other issues);
- Regional and national co-ordination on CO_2 transport pipelines to assess infrastructure needs, costs, and legal/regulatory issues;
- Co-ordinated CO_2 storage projects to cover the widest range of geological conditions in order to improve the understanding of storage site feasibilities; and
- Banning the use of natural CO_2 for new EOR projects by 2010 and gradually raising the tax on natural CO_2 extraction.

Industrial Manufacturing Base

- More detailed evaluations of the cost escalation of coal-fired power plants and identification of solutions to price rises that have resulted from bottlenecks in the equipment supply chain;
- Engagement of boiler, gas turbine and steam turbine manufacturers to make their equipment suitable for the different gas compositions that result from CCS;
- Establishing a CO_2-EOR/storage portfolio standard, or similar market-based incentive, and guaranteeing a minimum oil price for CO_2-EOR/storage projects; and
- Establishing turn-key fossil fuel power plant technology with CCS.

Work with Oxygen Suppliers

- Improving international co-operation between universities and research institutes to integrate membranes into air separation processes for oxygen production.

Policy Framework for Commercial Investments

- Establishment of credible long-term CO_2 reduction incentives in enough countries and regions to generate a market of sufficient size; and
- Development of a uniform global standard or set of characteristics for CO_2 for storage monitoring and verification and site selection to enable harmonisation of technologies and pratices and to accelerate deployment.

Financing

- Leadership by governments and industry to identify and pledge the estimated USD 20-30 billion that will be required to finance the demonstration plants needed for the power sector, and the additional USD 10-15 billion that will be needed for CCS demonstration in industry and fuel transformation; and
- Establishing more robust, co-ordinated public-private partnerships to bridge financing gaps for CCS demonstration.

Participation of Developing Countries

- Establishing a mechanism, working with international multilateral institutions, national governments and industry, to enhance and Finance international CCS technology collaboration to developing countries.

ANNEX 1

Regional Investment Costs And Discount Rates

Regional Investment Costs

The ETP model covers 15 regions. The database is set up as one reference database with cost data for the United States. Costs in other regions are calculated by multiplying US cost data by a region-specific factor. Region-specific cost multipliers are listed in Table A1.1. These multipliers are applied to all processes.

This detailed, but still rather crude, representation of the world energy system poses certain limitations:

- Exchange rates fluctuate. Changing exchange rates affect relative investment costs. Exchange rates for developing countries can fluctuate widely, *e.g.* by a factor of two or more.
- Project system boundaries differ by region and by site. For example in developing countries it may be necessary to build roads, new power lines or other infrastructure for new power plants.
- The regions in the model are very large. Any cost factor is an average. Actual costs may differ considerably for locations (and countries) within regions.

Table A1.1 Region-Specific Cost Multipliers

	Investment cost	Annual fixed O&M costs	Annual variable O&M costs
AFR	125	90	85
AUS	125	90	90
CAN	100	100	100
CHI	90	80	80
CSA	125	90	85
EEU	100	90	85
FSU	125	90	85
IND	90	80	80
JPN	140	100	100
MEA	125	90	85
MEX	100	90	90
ODA	125	80	80
SKO	100	90	90
USA	100	100	100
WEU	110	100	95

USA = 100

Source: IEA, 2008.

- Particularly in developing countries, some technologies require imported equipment, while others are based on locally produced equipment. Such differences can impact investment costs significantly.
- In developing countries, the availability of skilled labour may be a limiting factor. If workers have to be hired from abroad, this will affect labour costs. Operating and maintenance costs consist of 50% labour costs that are region specific and 50% materials and auxiliary costs that are assumed to be the same in all regions. Multipliers for fixed and variable costs are shown in Table A1.1.[80]

Discount Rates: Liberalisation, Risk and Time Preferences

The discount rates in the model vary by region and by sector, depending on capital availability and perceived risk. Discount rates aim to reflect real world discount rates, excluding inflation (Table A1.2). These discount rates are usually significantly higher than the long-term social discount rate. Economists' opinions differ as to which discount rates should be applied for CO_2 policy analysis (Portney and Weyant, 1999).

Money supply can be divided into loans and own capital and equity. The long-term return on investment for equity is several percent higher than for loans, because the owner of the equity is exposed to the risk of the company going bankrupt, in which case loans are paid back first and usually the equity owner gets nothing. In situations where electricity supply is determined by government, the lending rate may apply.

In liberalised markets, it is more accurate to use equity rates. The ETP figures are based on the 30-year government bond rate (for the main country in the region, if applicable), corrected for

Table A1.2 *Region- and Sector-Specific Discount Rates in the ETP Model*

	Real bond yield (%/yr)	Industry/Electricity lending (%/yr)	Industry/Electricity equity (%/yr)
AFR	8.2	9.2	13.7
AUS	2.6	3.6	8.1
CAN	3.7	4.7	9.3
CHI	5.2	6.2	10.7
CSA	7.2	8.2	12.7
EEU	5.7	6.7	11.3
FSU	8.7	9.7	14.3
IND	8.0	9.0	13.5
JPN	2.0	3.0	7.5
MEA	5.6	6.6	11.1
MEX	7.2	8.2	12.7
ODA	8.2	9.2	13.7
SKO	5.6	6.6	11.1
USA	4.2	5.2	9.7
WEU	3.7	4.7	9.3

Source: IEA, 2008.

80. These multipliers do not apply to energy and materials inputs that are modelled as physical flows. The regional price of these flows is calculated by the model.

inflation. For developing countries, Moody's country ranking has been used as a measure of creditworthiness. Industry financing has been split into lending and equity. Company borrowing rates are taken to be 1% higher than government bond rates, in order to reflect the average incremental risk associated with lending to companies. 5.5% has been added to the government bond rate for industrial equity risk (NYU Stern, 2002).

ANNEX 2

GDP Projections

GDP growth is an important driver of future emissions and therefore of the demand for CCS technologies. The GDP projections in the ETP model's reference scenario are in line with the IEA 2007 *World Energy Outlook* Baseline Scenario. The growth projections by period and by region are shown in Table A2.1.

Table A2.1 GDP Growth 2005-2050

	GDP	Growth	%/yr	GDP index	2005=100	
	2005-15	2015-30	2030-50	2015	2030	2050
OECD	2.5	1.9	1.3	128.0	169.8	219.8
North America	2.6	2.2	1.5	129.3	179.2	241.3
USA	2.6	2.2	1.5	129.3	179.2	241.3
Europe	2.3	2.4	0.7	125.5	179.2	206.0
Pacific	2.2	1.6	1.6	124.3	157.7	216.7
Japan	1.6	1.3	1.3	117.2	142.3	184.2
Transition Eco	4.7	2.9	3.4	158.3	243.1	474.4
Russia	4.3	2.8	3.0	152.4	230.5	416.4
Developing Asia	6.9	4.8	3.6	194.9	393.7	798.7
China	7.7	4.9	3.8	210.0	430.3	907.3
India	7.2	5.8	3.6	200.4	466.9	947.2
Middle East	4.5	4.9	3.4	155.3	318.6	621.2
Africa	4.5	3.6	3.6	155.3	264.0	535.5
Latin America	3.8	2.8	2.7	145.2	219.7	374.4
Brazil	3.5	2.8	2.6	141.1	213.5	356.7
World	4.2	3.3	2.6	150.9	245.6	410.3
European Union	2.3	1.8	0.7	125.5	164.0	188.6

Source: IEA, 2007.

ANNEX 3

Websites with Information on CCS

Bellona Foundation: *http://www.bellona.org/.*

BRGM: *http://www.brgm.fr/brgm/CO2/default.htm.*

Canada's Capture & Storage Technology Network (CCSTN):
http://www.nrcan.gc.ca/es/etb/cetc/combustion/co2network/htmldocs/aboutus_e.html.

Canada International Test Centre for CO_2 Capture: *http://www.co2-research.ca/.*

Carbon Sequestration Leadership Forum: *http://www.cslforum.org/.*

CO_2 Capture and Storage Association (CCSA): *http://www.ccsassociation.org.uk/.*

Climate Action Network Europe: *http://www.climnet.org/.*

CO_2 Analyst Hub: *http://www.theco2hub.com/analystshub.aspx.*

CO_2GeoNet: *http://www.co2geonet.com/.*

CO_2NET: *http://www.co2net.com.*

CO2CRC: *http://www.co2crc.com.au/.*

European Union Zero Emissions Technology Platform:
http://www.zero-emissionplatform.eu/website/.

European Union CCS Information: *http://ec.europa.eu/environment/climat/ccs/work_en.htm.*

French Ministry CO_2 Website: *http://www.industrie.gouv.fr/energie/co2.htm.*

Global Climate and Energy Project (GCEP): *http://gcep.stanford.edu/.*

Global Carbon Project (GCP): *http://www.globalcarbonproject.org/.*

Greenfacts: *http://www.greenfacts.org/en/co2-capture-storage/links/index.htm.*

Greenhouse Gas Online: *http://www.ghgonline.org/.*

Greenpeace's CCS Web Pages:
http://www.greenpeace.org/international/press/reports/technical-brifing-ccs.

International Energy Agency (IEA) Secretariat:
http://www.iea.org/Textbase/subjectqueries/cdcs.asp.

IEA Clean Coal Centre: *http://www.iea-coal.co.uk/site/index.htm.*

IEA GHG R&D Programme:
http://www.ieagreen.org.uk/; http://www.co2captureandstorage.info/.

IEA GHG Programme R&D Project Database:
http://script3.ftech.net/~ieagreen/co2sequestration.htm.

Institut Français de Pétrole (IFP): *http://www.ifp.fr/IFP/en/ifp/ab12.htm.*

International Maritime Organisation (IMO) Website (with London Protocol and OSPAR information on CCS): *http://www.imo.org/includes/blastdataonly.asp/data_id=17361/7.pdf.*

Intergovernmental Panel on Climate Change (IPCC): *www.ipcc.ch.*

International Petroleum Industry Environmental Conservation Association (IPIECA) Website: *http://www.ipieca.org/activities/climate_change/climate_about.php.*

Massachusetts Institute of Technology (MIT) CCS Website:
http://sequestration.mit.edu/index.html.

Natural Resources Canada (NRCan):
http://www.nrcan.gc.ca/es/etb/cetc/combustion/co2trm/htmldocs/technical_reports_e.html.
http://www.nrcan.gc.ca/es/etb/cetc/combustion/co2network/htmldocs/frontpage_e.html.

National Energy Technology Laboratory (NETL) Clean Power Coal Initiative:
http://www.netl.doe.gov/technologies/coalpower/cctc/.

NETL FutureGen Website: *http://www.netl.doe.gov/technologies/coalpower/futuregen/.*

NOVEM Overview of CCS Projects: *http://www.cleanfuels.novem.nl/projects/international.asp.*

Pew Center on Global Climate Change, Technology Solutions Pages:
http://www.pewclimate.org/technology-solutions

Princeton University Carbon Mitigation Initiative: *http://www.princeton.edu/%7Ecmi/.*

Schlumberger SEED on Climate Change and CCS:
http://www.seed.slb.com/en/scictr/watch/climate_change/capture.htm.

StatoilHydro:
http://www.statoil.com/STATOILCOM/SVG00990.nsf/Attachments/co2MagasinAugust2007/$FILE/CO2_eng.pdf.

The Carbon Trust: *http://www.carbontrust.co.uk/default.ct.*

UK Energy Research Centre (UKERC): *http://www.co2capture.org.uk/.*

US Carbon Sequestration Regional Partnerships:
http://fossil.energy.gov/programs/sequestration/partnerships/.

US Department of Energy Carbon Sequestration Website: *http://carbonsequestration.us/.*
http://cdiac2.esd.ornl.gov/index.html.

US Environmental Protection Agency CCS Website:
http://www.epa.gov/climatechange/emissions/co2_geosequest.html.

University College London, Carbon Capture Legal Programme: *http://www.ucl.ac.uk/cclp/.*

World Business Council for Sustainable Development: *http://www.wbscd.org/.*

World Coal Institute: *http://www.worldcoal.org/.*

World Energy Council: *http://www.worldenergy.org/.*

World Resources Institute: *http://www.wri.org/.*

ANNEX 4

Definitions, Abbreviations, Acronyms and Units

Definitions

Readers interested in obtaining more detailed information should consult annual IEA publications such as *Energy Balances of OECD Countries*, *Energy Balances of Non-OECD Countries*, *Coal Information*, *Oil Information*, *Gas Information* and *Electricity Information.*

API Gravity

Specific gravity measured in degrees on the American Petroleum Institute scale. The higher the number, the lower the density. 25° API equals 0.904 kg/m^3. 42° API equals 0.815 kg/m^3.

Aquifer

An underground water reservoir. If the water contains large quantities of minerals it is a saline aquifer.

Associated Gas

Natural gas found in a crude oil reservoir, either separate from or in solution with the oil.

Biomass

Biological material that can be used as fuel or for industrial production. It includes solid biomass such as wood and plant and animal products, gases and liquids derived from biomass, industrial waste and municipal waste.

Black Liquor

A by-product from chemical pulping processes which consists of the lignin residue combined with water and the chemicals used for the extraction of the lignin.

Brown Coal

Sub-bituminous coal and lignite. Sub-bituminous coal is defined as non-agglomerating coal with a gross calorific value between 4 165 kcal/kg and 5 700 kcal/kg. Lignite is defined as non-agglomerating coal with a gross calorific value less than 4 165 kcal/kg.

Clean Coal Technologies (CCT)

Technologies designed to enhance the efficiency and the environmental acceptability of coal extraction, preparation and use.

Carbon Sequestration Enhanced Gas Recovery (CSEGR)

Enhanced Gas recovery is a speculative technology where CO_2 is injected into a gas reservoir in order to increase the pressure in the reservoir so that more gas can be extracted.

Coal

Unless stated otherwise, coal includes both coal primary products (including hard coal and lignite, or as it is sometimes called "brown coal") and derived fuels (including patent fuel, coke oven coke, gas coke, coke oven gas and blast-furnace gas). Peat is also included.

Coal-to-Liquids (CTL)

The production of synthetic crude from coal using processes such as Fischer-Tropsch synthesis *(q.v.).*

Electricity Production

Electricity production is the total amount of electricity generated by a power plant. It includes own-use and transmission and distribution losses.

Enhanced Coal-Bed Methane Recovery (ECBM)

Enhanced Coal-Bed Methane Recovery is a technology for the recovery of methane (natural gas) by injecting CO_2 into uneconomic coal seams. The technology has been applied in a demonstration project in the United States, and is being tested elsewhere.

Enhanced Oil Recovery (EOR)

Enhanced oil recovery is also known as tertiary oil recovery. It follows primary recovery (oil produced by the natural pressure in the reservoir) and secondary recovery (using water injection). Various EOR technologies exist, such as steam injection, hydrocarbon injection, underground combustion and CO_2 flooding.

Fischer-Tropsch (FT) Synthesis

A process for the catalytic production of synthetic fuels from natural gas, coal and biomass feedstocks.

Fuel Cell

A device that can be used to convert hydrogen or natural gas into electricity. Various types exist that can be operated at temperatures ranging from 80°C to 1 000°C. Their efficiency ranges from 40% to 60%. Their application is currently limited to niche markets and demonstration projects due to their high cost and the immature status of the technology, but their use is growing fast.

Gas

Gas includes natural gas (both associated and non-associated, but excluding natural gas liquids) and gas-works gas.

Gas-to-Liquids (GTL)

The production of synthetic crude from natural gas using a Fischer-Tropsch process.

Heat

In IEA energy statistics, heat refers to the heat produced for sale only. Most heat included in this category comes from the combustion of fuels, although some small amounts are produced from geothermal sources, electrically-powered heat pumps and boilers.

Hydro

Hydro refers to the energy content of the electricity produced in hydropower plants assuming 100% efficiency.

Integrated Gasification Combined Cycle (IGCC)

Integrated Gasification Combined Cycle is a technology in which a solid or liquid fuel (coal, heavy oil or biomass) is gasified, followed by combustion of the resulting gas to produce electricity in a combined–cycle power plant.

Liquefied Natural Gas (LNG)

LNG is natural gas which has been liquefied by lowering its temperature to -162°C at atmospheric pressure, reducing the space requirements for storage and transport by a factor over 600.

Non-Conventional Oil

Non-conventional oil includes oil shale, oil sands-based extra heavy oil and bitumen, derivatives such as synthetic crude products, and liquids derived from natural gas (GTL).

Nuclear

Nuclear refers to the primary heat equivalent of the electricity produced by a nuclear plant with an assumed average thermal efficiency of 33%.

Oil

Oil includes crude oil, natural gas liquids, refinery feedstocks and additives, other hydrocarbons and petroleum products (such as refinery gas, ethane, liquefied petroleum gas, aviation gasoline, motor gasoline, jet fuel, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, paraffin waxes, petroleum coke and petroleum coke).

Renewable Energy Sources

Renewable energy sources are those where the energy is derived from natural processes that are replenished constantly. They include geothermal, solar, hydro, wind, tide, and wave energy for electricity generation and the direct use of geothermal and solar heat.

Other Transformation, Own Use and Losses

Other transformation, own use and losses covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes energy use and loss by gas works, petroleum refineries, coal and gas transformation and liquefaction. It also includes energy used in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category.

Purchasing Power Parity (PPP)

The rate of currency conversion that equalises the purchasing power of different currencies. It makes allowance for the differences in price levels and spending patterns between different countries.

Scenario

An analysis dataset based on a consistent set of assumptions.

REGIONAL GROUPINGS

Africa

Africa is defined as: Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, the Central African Republic, Chad, Comoros, Congo, the Democratic Republic of Congo, Côte d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Réunion, Rwanda, São Tomé and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, the United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe.

Central and South America

Central and South America is defined as: Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominica, the Dominican Republic, Ecuador, El Salvador, French Guiana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts-Nevis-Anguilla, Saint Lucia, St. Vincent-Grenadines and Suriname, Trinidad and Tobago, Uruguay and Venezuela.

China

China refers to the People's Republic of China.

Developing Countries

Developing countries is defined as: China, India and other developing Asia, Central and South America, Africa and the Middle East.

Eastern Europe

Eastern Europe is defined as: Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Kosovo, the former Yugoslav Republic of Macedonia, Montenegro, Poland, Romania, Serbia, Slovakia, and Slovenia.

Former Soviet Union (FSU)

The FSU is defined as: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Ukraine, Uzbekistan, Tajikistan, Turkmenistan.

Group of Eight (G8)

The Groupf of Eight is defined as: Canada, France, Germany, Italy, Japan, Russia, the United Kingdom and the United States.

G8+5 Countries

The G8 nations (Canada, France, Germany, Italy, Japan, Russia, the United Kingdom and the United States), plus the five leading emerging economies – Brazil, China, India, Mexico and South Africa.

Middle East

The Middle East is defined as: Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates and Yemen. For oil and gas production it includes the neutral zone between Saudi Arabia and Iraq.

OECD Europe

OECD Europe is defined as: Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

Organisation of Petroleum Exporting Countries (OPEC)

OPEC is defined as: Algeria, Angola, Ecuador, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela.

Other Developing Asia (ODA)

Other Developing Asia is defined as: Afghanistan, Bangladesh, Bhutan, Brunei, Chinese Taipei, Fiji, French Polynesia, Indonesia, Kiribati, Democratic People's Republic of Korea, Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Papua New Guinea, the Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Vietnam and Vanuatu.

Western Europe

Western Europe is defined as: Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

Abbreviations and Acronyms

AFR	Africa
APFBC	Advanced Pressurised Fluidised Bed Combustion
APEC	Asia-Pacific
API	American Petroleum Institute
ASU	Air Separation Unit
AUD	Australian Dollar
AUS	Australia and New Zealand
BKB	Brown Coal Briquettes
CA	Chemical Absorption
$CaCO_3$	Calcium Carbonate
CAD	Canadian Dollar
CAN	Canada
CaO	Calcium Oxide
CAPEX	Capital Expenditures
CaS	Calcium Sulphide
$CaSO_4$	Calcium Sulphate
CAT	Carbon Abatement Technologies
CC	Combined Cycle
CCC	Clean Coal Centre
CCGT	Combined Cycle Gas Turbine
CCS	CO_2 Capture and Storage
CCT	Clean Coal Technologies
CEPAC	Brazilian Carbon Storage Research Center
CFBC	Circulating Fluidised Bed Combustion
CDM	Clean Development Mechanism
CENS	CO_2 for EOR in the North Sea
CERT	Committee on Energy Research and Technology
CFB	Circulating Fluid Bed
CHI	China

CHP	Combined Heat and Power
CLC	Chemical Looping Combustion
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CRUST	CO_2 Re-use through Underground Storage
CSA	Central and South America
CSLF	Carbon Sequestration Leadership Forum
CUCBM	China United Coal-bed Methane Corporation
DME	Dimethyl Ether
DOE	Department of Energy
DOGF	Depleted Oil and Gas Fields
DRI	Direct Reduced Iron
DSF	Deep Saline Formations
ECBM	Enhanced Coal-bed Methane Recovery
EEU	Eastern Europe
EGR	Enhanced Gas Recovery
EOH	Ethanol
EOR	Enhanced Oil Recovery
EPR	European Pressurised Water Reactor
ESPOO	ECE Convention on Transboundary Impact Assessment
ETP	Energy Technology Perspectives
ETS	Emissions Trading Scheme
ETSAP	Energy Technology Systems Analysis Programme
EU	European Union
EUR	Euro
FCC	Fluid Catalytic Cracker
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurisation
FSU	Former Soviet Union
FT	Fischer-Tropsch

GB	Governing Board
GCV	Gross Calorific Value
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GIS	Geographical Information System
GTL	Gas-to-Liquids
H_2	Hydrogen
HHV	Higher Heating Value
HTGR	High Temperature Gas Cooled Reactor
IEA	International Energy Agency
IEKP	Integrated Energy and Climate Programme
IET	International Emissions Trading
IGCC	Integrated Gasification Combined Cycle
IGFC	Integrated Gasification-fuel Cell Combined Cycle
IND	India
IPCC	Intergovernmental Panel on Climate Change
ISCC	In Situ CO_2 Capture Technology from Solid Fuel Gasification
JI	Joint Implementation
JPN	Japan
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LTF	Low Temperature Flash
MCMPR	Ministerial Council on Mineral and Petroleum Resources
MEA	Middle East
MEA	Mono Ethanol Amine
MeOH	Methanol
MEX	Mexico
$MgCl_2$	Magnesium Chloride
MgO	Magnesium Oxide

MRG	Monitoring and Reporting Guidelines
M&V	Monitoring and Verification
NETL	National Energy Technology Laboratory (US DOE)
NGCAS	Next Generation Technology for the Capture and Geological Storage of CO_2
NGO	Non-Governmental Organisation
NLECI	National Low Emissions Coal Initiative
NOK	Norwegian Krone
NOx	Nitrogen Oxides
NUC	Nuclear
ODA	Other Developing Asia
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of Petroleum Exporting Countries
OSPAR	Oslo Convention and Paris Convention for the Protection of the Marine Environment of the North-East Atlantic
OxF	OxyFueling
PA	Physical Absorption
PC	Pulverised Coal
PCC	Post Carbon Capture
PFBC	Pressurised Fluidised Bed Combustion
PM_{10}	Particulate Matter of less than 10 micron diameter
PPP	Purchasing Power Parity
PV	Photovoltaics
R&D	Reasearch and Development
RD&D	Research, Development and Demonstration
REN	Renewables
RGGI	Regional Greenhouse Gas Initiative (US)
SACS	Saline Aquifer CO_2 Storage
SC	Supercritical
SKO	South Korea
SMR	Steam Methane Reforming

SO	Sulphur Oxide
SOFC	Solid Oxide Fuel Cells
SO_2	Sulphur Dioxide
SO_x	Oxides of Sulphur
UAE	United Arab Emirates
UGS	Underground Natural Gas Storage
ULCOS	Ultra-Low CO_2 Steelmaking
UNCLOS	United Nations Convention for the Law of the Sea
UNFCCC	United Nations Framework Convention on Climate Change
US/USA	United States of America
USC	Ultra Supercritical
USCSC	Ultra Supercritical Steam Cycle
USD	United States Dollar
USDOE	United States Department of Energy
WAG	Water Alternated Gas
WCSB	Western Canada Sedimentary Basin
WEO	World Energy Outlook
WEU	Western Europe
WPFF	IEA Working Party on Fossil Fuels

UNITS

Atm	atmosphere (unit of pressure). Normal atmospheric pressure is defined as 1 Atm.
bar	a unit of pressure nearly identical to an atmosphere unit. 1 bar = 0.9869 Atm.
bbl	barrel
Bcf	billion cubic feet
bcm	billion cubic metres
bpd	barrels per day
BOE	Barrels of Oil Equivalent. 1 BOE = 41.868 GJ.
°C	degrees Celsius
cm	centimetre

EJ	exajoule = 10^{18} joules
GJ	gigajoule = 10^{9} joules
Gt	gigatonne = 10^{9} tonnes
Gtpa	gigatonne per annum
GW	gigawatt = 10^{9} watts
GWh	gigawatt hour
ha	hectare
hr	hour
kg	kilogramme
km	kilometre
kt	kilotonnes
ktpa	kilotonnes per annum
kW	kilowatt = 10^{3} watts
kWh	kilowatt hour
l	litre
m	metre
m^2	square metre
m^3	cubic metre
mb	million barrels
mbd	million barrels per day
Mcf	million cubic feet
mg	milligramme
Mio	million
MJ	megajoule = 10^{6} joules
MPa	megapascal = 10^{6} Pa
mpg	miles per gallon
mtpa	megatonne per year
Mt	megatonne = 10^{6} tonnes
Mtpa	megatonne per year
Mtoe	million tonnes of oil equivalent

MW	megawatt = 10^6 watts
Nm^3	Normal cubic metre. Measured at 0°C and a pressure of 1.013 bar.
pa	per annum (year)
Pa	Pascal
PJ	petajoule = 10^{15} joules
ppm	parts per million
t	tonne = metric ton = 1 000 kilogrammes
Tcf	trillion cubic feet
tpa	tonne per year
TW	terawatt = 10^{12} watts
TWh	terawatt hour

ANNEX 5

Current CO_2 Capture and Storage Projects

The IEA GHG R&D Programme maintains an on-line database of CCS projects (R&D, pilot, and commercial) with extensive links to reference materials from individual projects. The database can be accessed at: *http://www.co2captureandstorage.info/co2db.php.*

In addition, the Massachusetts Institute of Technology has a regularly updated projects website at *http://sequestration.mit.edu/tools/projects/index.html.* Other websites (see Annex 3) also maintain lists.

The four largest current projects are outlined below.

The Sleipner CCS Project

The first commercial CCS project in the world was implemented in Sleipner, one of the largest gas fields in the North Sea, 230 km off the coast of Norway. The field is managed by StatoilHydro (58.4% financial interest), with Esso Norge and Total Fina Elf owning respecting 32.2% and 9.4%. The gas produced contains up to 9% CO_2. The commercial export specifications for the gas supplied require less than 2.5% CO_2 content. The amount of CO_2 produced was nearly 3% of Norway's total emissions in 1990.

In 1990, a team from Statoil proposed to use a deep saline formation for CO_2 storage from the Sleipner Vest field. The repository selected was the Utsira saline sandstone formation located 800 m and more below the seabed. Without CO_2 storage, licensees of the field would have had to pay more than NOK 1 million/day in Norway's upstream CO_2 tax. The project has injected over 1 Mt CO_2 a year since October 1996.

The Sleipner Vest platform consists of 2 main modules: a wellhead platform and a treatment platform. Amine scrubbing technology, with a solution containing Methyl Diethanolamine (MDEA) and water, is used to separate CO_2 from high pressure gas. Energy released by the amine treatment process generates 6 MW of power which is used on the platform.

The Utsira saline sand is 200 m thick. A horizontal well injects CO_2 at a depth of 1 012 m below sea level. During the planning phase, a detailed characterisation programme was designed to determine the structure of the strata overlaying the Utsira formation, including the identification of faults in the reservoir and cap rock and the determination of reservoir properties, such as porosity, thickness and permeability and their vertical and lateral variation. The potential geochemical interaction between the CO_2, the minerals and fluids was also analysed. Information obtained from core samples in the injection zone and adjacent layers, along with wellbore logging, was used to determine the potential for mineral dissolution, which was found to be limited due to the low carbonate content.

With funding from the Norwegian government, the EU, the licensees and partners in the Saline Aquifer CO_2 Storage (SACS), $SACS_2$ and CO_2STORE projects, initial site assessment and time-lapse monitoring during the injection of CO_2 has been conducted, allowing a mapping of the movement of the CO_2 front with time. In addition to repeated seismic surveys, other monitoring technologies (micro-seismic, gravity surveys, multi-component seismic, wellbore logging) have been used to complement and improve the accuracy of the surveys. Accumulations of CO_2 with thicknesses of less than 1 m were detected, far better than the typical accuracy of seismic surveys, *e.g.* 7-10 m (Arts, *et al.*, 2004; Freund, 2007). Extensive modelling was performed using commercial and reservoir simulators, and the predicted fluid movements were compared with the results of monitoring surveys. The lessons learnt from Sleipner have been captured in a "Best Practice Manual" (Chadwick, *et al.*, 2006) with an extensive description of the monitoring and simulation.

The cost of underground injection in Sleipner has been documented by Torp (2005). The annualised CAPEX-related costs (at a 10% discount rate) were USD 9.6 million, while OPEX costs were updated to include the CO_2 tax on the gas turbine driver for the CO_2 compressor as well as other costs such as monitoring, etc. The corrected OPEX is therefore about USD 16 per tonne of CO_2 injected.

The IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Weyburn Project

In September 2000, PanCanadian Resources (now EnCana, Canada's largest oil company), began operating a CO_2 miscible enhanced oil recovery (EOR) project at their Weyburn field in Southeastern Saskatchewan, Canada. The project followed a pilot project conducted by Shell in the Midale field (with a similar geological setup) in the late 1980s, where CO_2 was injected to enhance recovery. The Weyburn EOR project currently injects 6 500 tonnes per day of CO_2, along with approximately 3 000 tonnes per day of recycled CO_2. The CO_2 is purchased from a coal gasification plant in North Dakota, United States, and transported through a 320 km pipeline to Weyburn. The Saskachewan provincial authorities provided a fiscal stimulus to improve the economics of the project under a USD 20 per barrel scenario. The field covers 210 km^2 (53 000 acres): The amount of original oil in place is estimated at 1.4 billion barrels, and with CO_2-EOR, the total amount of incremental oil recovery is projected to be 155 million barrels. At the conclusion of the project, some 30 million tonnes of CO_2 will have been stored. In 2005, Apache Canada started a CO_2 miscible flood at their Midale oilfield. CO_2 is being injected at a rate of 1 300 tonnes per day, along with 400 tonnes per day of recycled CO_2. The amount of original oil in place is 515 million barrels, and the total amount of incremental oil recovery is projected at 60 million barrels. At project completion (also 30 years), over 10 million tonnes of CO_2 are projected to have been stored in the Midale field.

Weyburn is also the host site of an international research project on CO_2 storage (Wilson and Brown, 2007). Operated in parallel with the commercial EOR operations under the auspices of the IEA GHG R&D Programme, an international consortium of governments and industry has been working with researchers from around the world to develop effective measurement, monitoring, verification and risk assessment techniques. Results from Phase I of this research project (2000-2004) concluded that storage of CO_2 in an oil reservoir is viable and safe over the long term. A Final Phase of the project, which was expanded to include the Midale oilfield as well, is currently (2008) underway and will run until 2011. The goal of the Final Phase is to build on the success of Phase I and compile a Best Practices Manual to provide guidance to all aspects of future CO_2 storage projects in both technical and policy areas (regulatory, public communications and business environment). The Final Phase is supported by six government and nine industry sponsors. The Petroleum Technology Research Centre (Regina, Saskatchewan) is coordinating the technical programme, while Natural Resources Canada is coordinating the policy activities and providing overall project integration.

The In Salah CCS Project

In Salah Gas is a joint venture project, with BP, Sonatrach and StatoilHydro in central Algeria. It was designed to test the commercial viability of CO_2 storage as a CO_2 mitigation option. The first phase of the project began in 2004, and involves the injection of up to 4 000 tonnes a day of CO_2. Gas from the Reg and Tiggentour fields is dehydrated on-site, transported via pipeline over 100 km and then mixed with gas produced from the Krechba field. The CO_2 (up to 10% by content) is extracted from the gas at the Krechba facility, using an amine process. Processed gas with less than 0.3% CO_2 is then transported via pipeline to the Hassi R'Mel network.

The CO_2 is compressed and injected in 3 re-injection wells in a saline formation underlying the gas reservoir 2.4 km underground. 1 Mtpa CO_2 is injected with a planned total storage of 17 million tonnes of CO_2. Given the additional CAPEX and OPEX costs of USD 100 million, the cost of CO_2 avoided is close to USD 6 per tonne, significantly lower than offshore gas processing costs. Despite the very remote environment, extensive monitoring, including seismic acquisition and wellbore measurements, is being carried out by the partners with partial support from the EU CO_2ReMoVe project (Wright, 2007).

The Snøhvit CCS Project

The Norwegian Snøhvit CCS project in the Barents Sea is similar in a number of ways to the Sleipner project (Freund, 2007). The field, operated by StatoilHydro, has Petoro, Total, Amerada Hess Norge, RWE-DEA Norge and Svenska Petroleum Exploration as partners. Snøhvit is a subsea development remotely operated from onshore. Due to its remoteness from gas markets, it has been developed as a LNG project. Natural gas containing CO_2 is transported via a 145 km multiphase pipeline to the receiving liquefaction plant onshore near the city of Hammerfest, where it is separated into gas and condensates. CO_2 is removed from gas prior to its liquefaction, using an amine process at high pressure. Another 145 km pipeline has been built to transport this CO_2 offshore back to the Snøhvit field where it is injected into a 45-75 m thick formation called Tubasen lying 2 500 m below the seabed. The cost of the pipeline and injection is estimated at EUR 125 million. First CO_2 was injected into the offshore geological storage site in April 2008. The project monitoring is partly funded under EU R&D programmes, such as CO_2ReMoVe (Frederiksen and Torp, 2007).

ANNEX 6

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