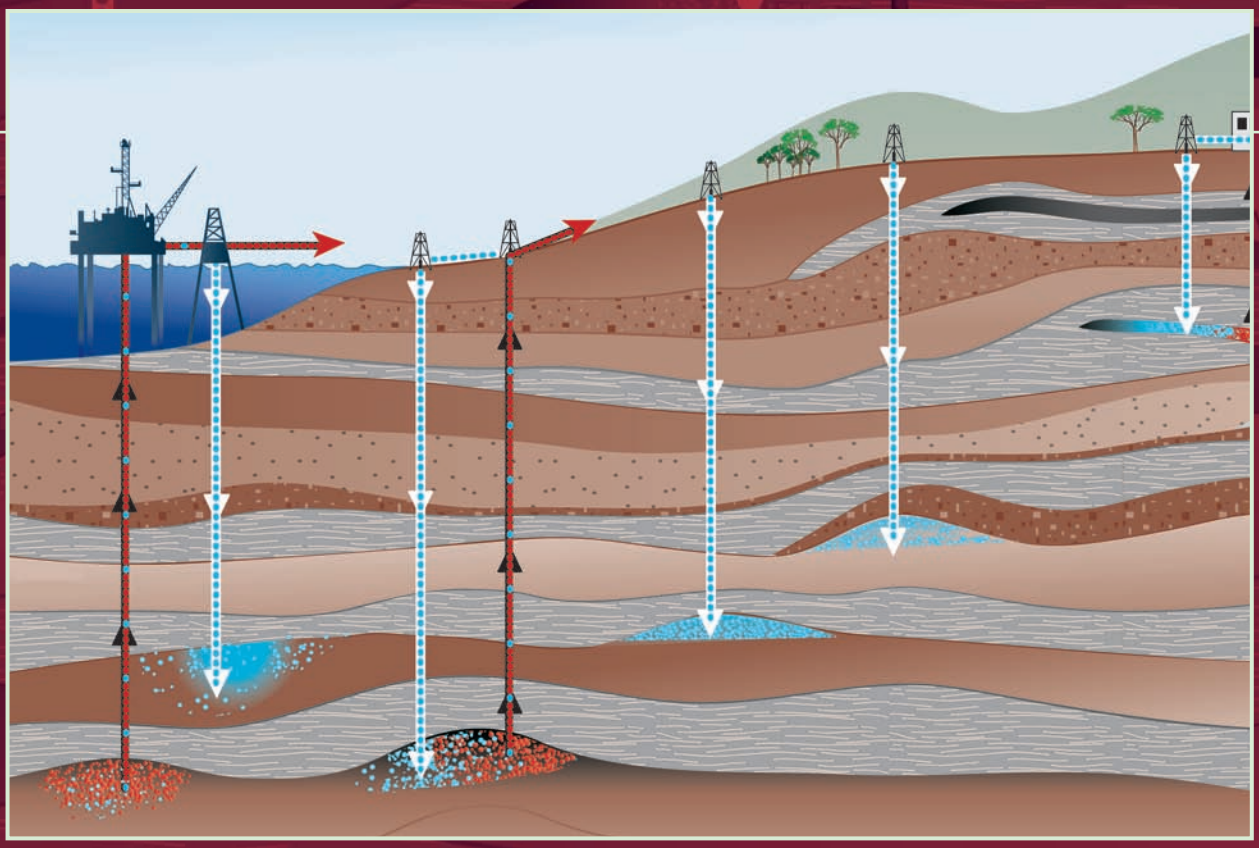
EXHIBIT 1

CARBON DIOXIDE CAPTURE AND STORAGE



WMO

Intergovernmental Panel on Climate Change

UNEP

IPCC Special Report on

Carbon Dioxide Capture and Storage

Edited by

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Prepared by Working Group III of the
Intergovernmental Panel on Climate Change

Published for the Intergovernmental Panel on Climate Change

CAMBRIDGE
UNIVERSITY PRESS

CAMBRIDGE UNIVERSITY PRESS
Cambridge, New York, Melbourne, Madrid, Cape Town, Singapore, Sào Paulo

Cambridge University Press
40 West 20th Street, New York, NY 10011–4211, USA

Published in the United States of America by Cambridge University Press, New York

www.cambridge.org
Information on this title:www.cambridge.org/9780521863360

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First published 2005

Printed in Canada

A catalogue record for this publication is available from the British Library

ISBN-13 978-0-521-86643-9 hardback
ISBN-10 0-521-86643-X hardback

ISBN-13 978-0-521-68551-1 paperback
ISBN-10 0-521-68551-6 paperback

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Please use the following reference to the whole report:
IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

Cover image: Schematic of geological storage options (Courtesy CO2CRC).

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5

Underground geological storage

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Table TS.1. Current maturity of CCS system components. An X indicates the highest level of maturity for each component. There are also less mature technologies for most components.

CCS component	CCS technology	Research phase [a]	Demonstration phase [b]	Economically feasible under specific conditions [c]	Mature market [d]
Capture	Post-combustion			X	
	Pre-combustion			X	
	Oxyfuel combustion		X		
	Industrial separation (natural gas processing, ammonia production)				X
Transportation	Pipeline				X
	Shipping			X	
Geological storage	Enhanced Oil Recovery (EOR)				X[e]
	Gas or oil fields			X	
	Saline formations			X	
	Enhanced Coal Bed Methane recovery (ECBM)[f]		X		
Ocean storage	Direct injection (dissolution type)	X			
	Direct injection (lake type)	X			
Mineral carbonation	Natural silicate minerals	X			
	Waste materials		X		
Industrial uses of CO_2					X

[a] Research phase means that the basic science is understood, but the technology is currently in the stage of conceptual design or testing at the laboratory or bench scale, and has not been demonstrated in a pilot plant.

[b] Demonstration phase means that the technology has been built and operated at the scale of a pilot plant, but further development is required before the technology is required before the technology is ready for the design and construction of a full-scale system.

[c] Economically feasible under specific conditions means that the technology is well understood and used in selected commercial applications, for instance if there is a favourable tax regime or a niche market, or processing on in the order of 0.1 $MtCO_2\ yr^{-1}$, with few (less than 5) replications of the technology.

[d] Mature market means that the technology is now in operation with multiple replications of the technology worldwide.

[e] CO_2 injection for EOR is a mature market technology, but when used for CO_2 storage, it is only economically feasible under specific conditions.

[f] ECBM is the use of CO_2 to enhance the recovery of the methane present in unminable coal beds through the preferential adsorption of CO_2 on coal. Unminable coal beds are unlikely to ever be mined, because they are too deep or too thin. If subsequently mined, the stored CO_2 would be released.

In this context, the availability of CCS in the portfolio of options for reducing greenhouse gas emissions could facilitate the achievement of stabilization goals. Other technological options, which have been examined more extensively in previous IPCC assessments, include: (1) reducing energy demand by increasing the efficiency of energy conversion and/or utilization devices; (2) decarbonizing energy supplies (either by switching to less carbon-intensive fuels (coal to natural gas, for example), and/or by increasing the use of renewable energy sources and/or nuclear energy (each of which, on balance, emit little or no CO_2); (3) sequestering CO_2 through the enhancement of natural sinks by biological fixation; and (4) reducing non-CO_2 greenhouse gases.

Model results presented later in this report suggest that use of CCS in conjunction with other measures could significantly reduce the cost of achieving stabilization and would increase flexibility in achieving these reductions . The heavy worldwide reliance on fossil fuels today (approximately 80% of global energy use), the potential for CCS to reduce CO_2 emissions over the next century, and the compatibility of CCS systems with current energy infrastructures explain the interest in this technology.

EXECUTIVE SUMMARY

Underground accumulation of carbon dioxide (CO_2) is a widespread geological phenomenon, with natural trapping of CO_2 in underground reservoirs. Information and experience gained from the injection and/or storage of CO_2 from a large number of existing enhanced oil recovery (EOR) and acid gas projects, as well as from the Sleipner, Weyburn and In Salah projects, indicate that it is feasible to store CO_2 in geological formations as a CO_2 mitigation option. Industrial analogues, including underground natural gas storage projects around the world and acid gas injection projects, provide additional indications that CO_2 can be safely injected and stored at well-characterized and properly managed sites. While there are differences between natural accumulations and engineered storage, injecting CO_2 into deep geological formations at carefully selected sites can store it underground for long periods of time: it is considered likely that 99% or more of the injected CO_2 will be retained for 1000 years. Depleted oil and gas reservoirs, possibly coal formations and particularly saline formations (deep underground porous reservoir rocks saturated with brackish water or brine), can be used for storage of CO_2. At depths below about 800–1000 m, supercritical CO_2 has a liquid-like density that provides the potential for efficient utilization of underground storage space in the pores of sedimentary rocks. Carbon dioxide can remain trapped underground by virtue of a number of mechanisms, such as: trapping below an impermeable, confining layer (caprock); retention as an immobile phase trapped in the pore spaces of the storage formation; dissolution in the *in situ* formation fluids; and/or adsorption onto organic matter in coal and shale. Additionally, it may be trapped by reacting with the minerals in the storage formation and caprock to produce carbonate minerals. Models are available to predict what happens when CO_2 is injected underground. Also, by avoiding deteriorated wells or open fractures or faults, injected CO_2 will be retained for very long periods of time. Moreover, CO_2 becomes less mobile over time as a result of multiple trapping mechanisms, further lowering the prospect of leakage.

Injection of CO_2 in deep geological formations uses technologies that have been developed for and applied by, the oil and gas industry. Well-drilling technology, injection technology, computer simulation of storage reservoir dynamics and monitoring methods can potentially be adapted from existing applications to meet the needs of geological storage. Beyond conventional oil and gas technology, other successful underground injection practices – including natural gas storage, acid gas disposal and deep injection of liquid wastes – as well as the industry's extensive experience with subsurface disposal of oil-field brines, can provide useful information about designing programmes for long-term storage of CO_2. Geological storage of CO_2 is in practice today beneath the North Sea, where nearly 1 $MtCO_2$ has been successfully injected annually at Sleipner since 1996 and in Algeria at the In-Salah gas field. Carbon dioxide is also injected underground to recover oil. About 30 Mt of non-anthropogenic CO_2 are injected annually, mostly in west Texas, to recover oil from over 50 individual projects, some of which started in the early 1970s. The Weyburn Project in Canada, where currently 1–2 $MtCO_2$ are injected annually, combines EOR with a comprehensive monitoring and modelling programme to evaluate CO_2 storage. Several more storage projects are under development at this time.

In areas with suitable hydrocarbon accumulations, CO_2-EOR may be implemented because of the added economic benefit of incremental oil production, which may offset some of the costs of CO_2 capture, transport and injection. Storage of CO_2 in coal beds, in conjunction with enhanced coal bed methane (ECBM) production, is potentially attractive because of the prospect of enhanced production of methane, the cleanest of the fossil fuels. This technology, however, is not well developed and a better understanding of injection and storage processes in coals is needed. Carbon dioxide storage in depleted oil and gas reservoirs is very promising in some areas, because these structures are well known and significant infrastructures are already in place. Nevertheless, relatively few hydrocarbon reservoirs are currently depleted or near depletion and CO_2 storage will have to be staged to fit the time of reservoir availability. Deep saline formations are believed to have by far the largest capacity for CO_2 storage and are much more widespread than other options.

While there are uncertainties, the global capacity to store CO_2 deep underground is large. Depleted oil and gas reservoirs are estimated to have a storage capacity of 675–900 $GtCO_2$. Deep saline formations are very likely to have a storage capacity of at least 1000 $GtCO_2$ and some studies suggest it may be an order of magnitude greater than this, but quantification of the upper range is difficult until additional studies are undertaken. Capacity of unminable coal formations is uncertain, with estimates ranging from as little as 3 $GtCO_2$ up to 200 $GtCO_2$. Potential storage sites are likely to be broadly distributed in many of the world's sedimentary basins, located in the same region as many of the world's emission sources and are likely to be adequate to store a significant proportion of those emissions well into the future.

The cost of geological storage of CO_2 is highly site-specific, depending on factors such as the depth of the storage formation, the number of wells needed for injection and whether the project is onshore or offshore – but costs for storage, including monitoring, appear to lie in the range of 0.6–8.3 US$/$tCO_2$ stored. This cost is small compared to present-day costs of CO_2 capture from flue gases, as indicated in Chapter 3. EOR could lead to negative storage costs of 10–16 US$/$tCO_2$ for oil prices of 15–20 US$ per barrel and more for higher oil prices.

Potential risks to humans and ecosystems from geological storage may arise from leaking injection wells, abandoned wells, leakage across faults and ineffective confining layers. Leakage of CO_2 could potentially degrade the quality of groundwater, damage some hydrocarbon or mineral resources, and have lethal effects on plants and sub-soil animals. Release of CO_2 back into the atmosphere could also create local health and safety concerns. Avoiding or mitigating these impacts will require careful site selection, effective regulatory oversight, an appropriate monitoring programme that provides

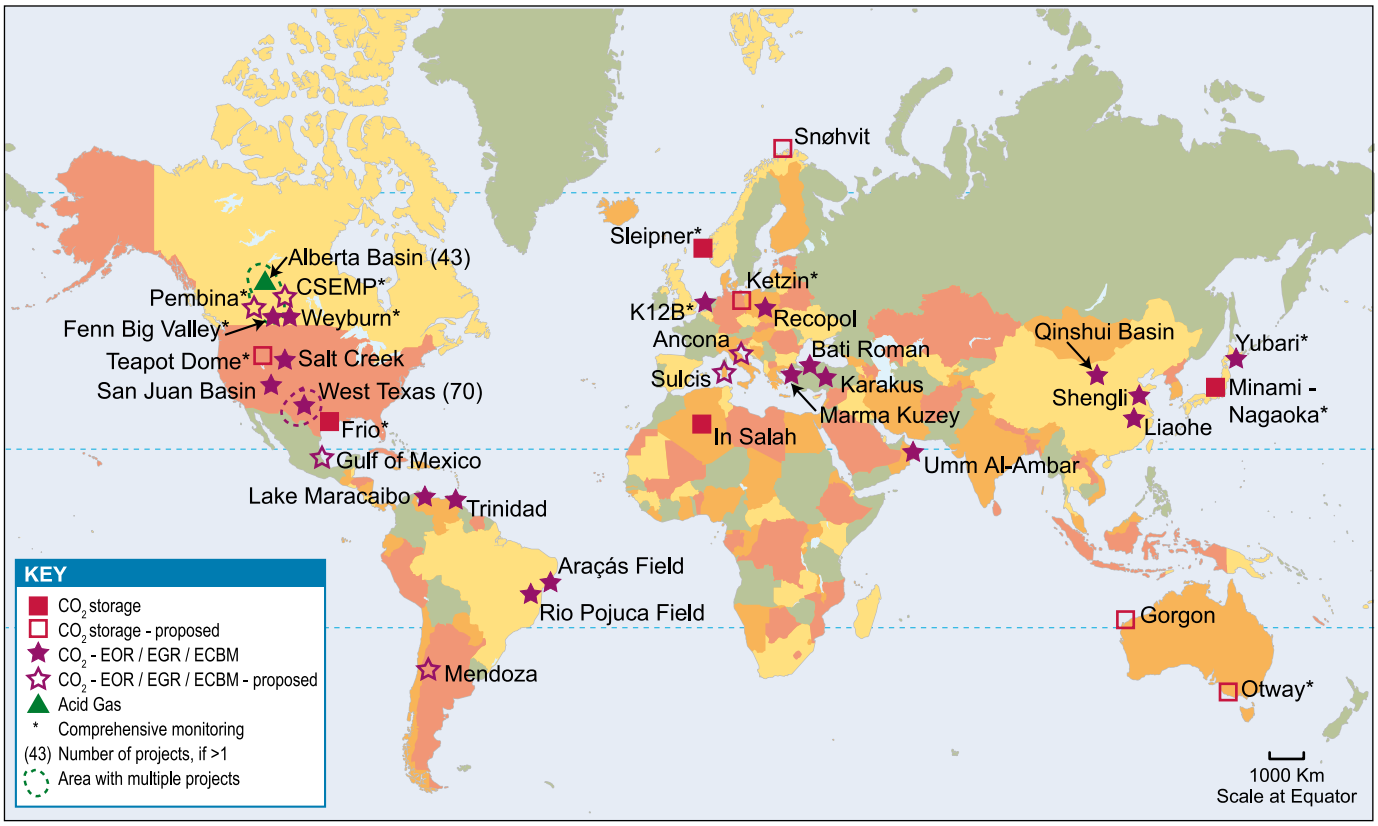

Figure 5.1 Location of sites where activities relevant to CO_2 storage are planned or under way.

early warning that the storage site is not functioning as anticipated and implementation of remediation methods to stop or control CO_2 releases. Methods to accomplish these are being developed and tested.

There are few, if any, national regulations specifically dealing with CO_2 storage, but regulations dealing with oil and gas, groundwater and the underground injection of fluids can in many cases be readily adapted and/or adopted. However, there are no regulations relating specifically to long-term responsibility for storage. A number of international laws that predate any consideration of CO_2 storage are relevant to offshore geological storage; consideration of whether these laws do or do not permit offshore geological storage is under way.

There are gaps in our knowledge, such as regional storage-capacity estimates for many parts of the world. Similarly, better estimation of leakage rates, improved cost data, better intervention and remediation options, more pilot and demonstration projects and clarity on the issue of long-term stewardship all require consideration. Despite the fact that more work is needed to improve technologies and decrease uncertainty, there appear to be no insurmountable technical barriers to an increased uptake of geological storage as an effective mitigation option.

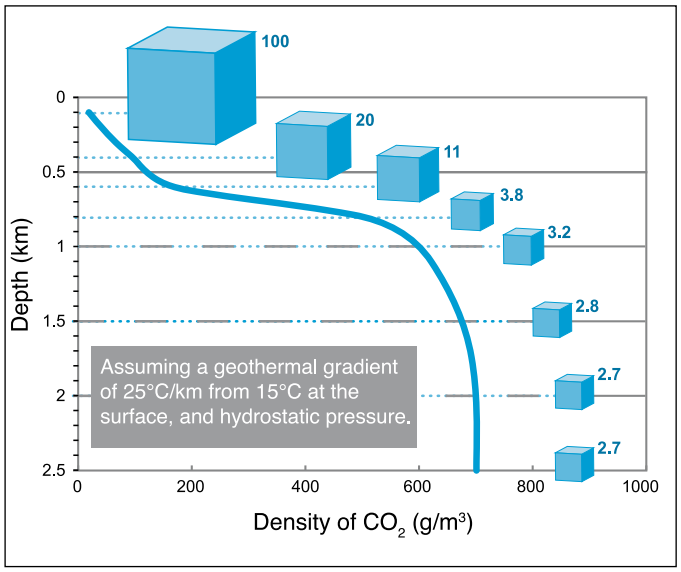

Figure 5.2 Variation of CO_2 density with depth, assuming hydrostatic pressure and a geothermal gradient of 25°C km^{-1} from 15°C at the surface (based on the density data of Angus *et al.*, 1973). Carbon dioxide density increases rapidly at approximately 800 m depth, when the CO_2 reaches a supercritical state. Cubes represent the relative volume occupied by the CO_2 and down to 800 m, this volume can be seen to dramatically decrease with depth. At depths below 1.5 km, the density and specific volume become nearly constant.

5.1 Introduction

5.1.1 What is geological storage?

Capture and geological storage of CO_2 provide a way to avoid emitting CO_2 into the atmosphere, by capturing CO_2 from major stationary sources (Chapter 3), transporting it usually by pipeline (Chapter 4) and injecting it into suitable deep rock formations. This chapter explores the nature of geological storage and considers its potential as a mitigation option.

The subsurface is the Earth's largest carbon reservoir, where the vast majority of the world's carbon is held in coals, oil, gas organic-rich shales and carbonate rocks. Geological storage of CO_2 has been a natural process in the Earth's upper crust for hundreds of millions of years. Carbon dioxide derived from biological activity, igneous activity and chemical reactions between rocks and fluids accumulates in the natural subsurface environment as carbonate minerals, in solution or in a gaseous or supercritical form, either as a gas mixture or as pure CO_2. The engineered injection of CO_2 into subsurface geological formations was first undertaken in Texas, USA, in the early 1970s, as part of enhanced oil recovery (EOR) projects and has been ongoing there and at many other locations ever since.

Geological storage of anthropogenic CO_2 as a greenhouse gas mitigation option was first proposed in the 1970s, but little research was done until the early 1990s, when the idea gained credibility through the work of individuals and research groups (Marchetti, 1977; Baes *et al*., 1980; Kaarstad, 1992; Koide *et al*., 1992; van der Meer, 1992; Gunter *et al*., 1993; Holloway and Savage, 1993; Bachu *et al*., 1994; Korbol and Kaddour, 1994). The subsurface disposal of acid gas (a by-product of petroleum production with a CO_2 content of up to 98%) in the Alberta Basin of Canada and in the United States provides additional useful experience. In 1996, the world's first large-scale storage project was initiated by Statoil and its partners at the Sleipner Gas Field in the North Sea.

By the late 1990s, a number of publicly and privately funded research programmes were under way in the United States, Canada, Japan, Europe and Australia. Throughout this time, though less publicly, a number of oil companies became increasingly interested in geological storage as a mitigation option, particularly for gas fields with a high natural CO_2 content such as Natuna in Indonesia, In Salah in Algeria and Gorgon in Australia. More recently, coal mining companies and electricity-generation companies have started to investigate geological storage as a mitigation option of relevance to their industry.

In a little over a decade, geological storage of CO_2 has

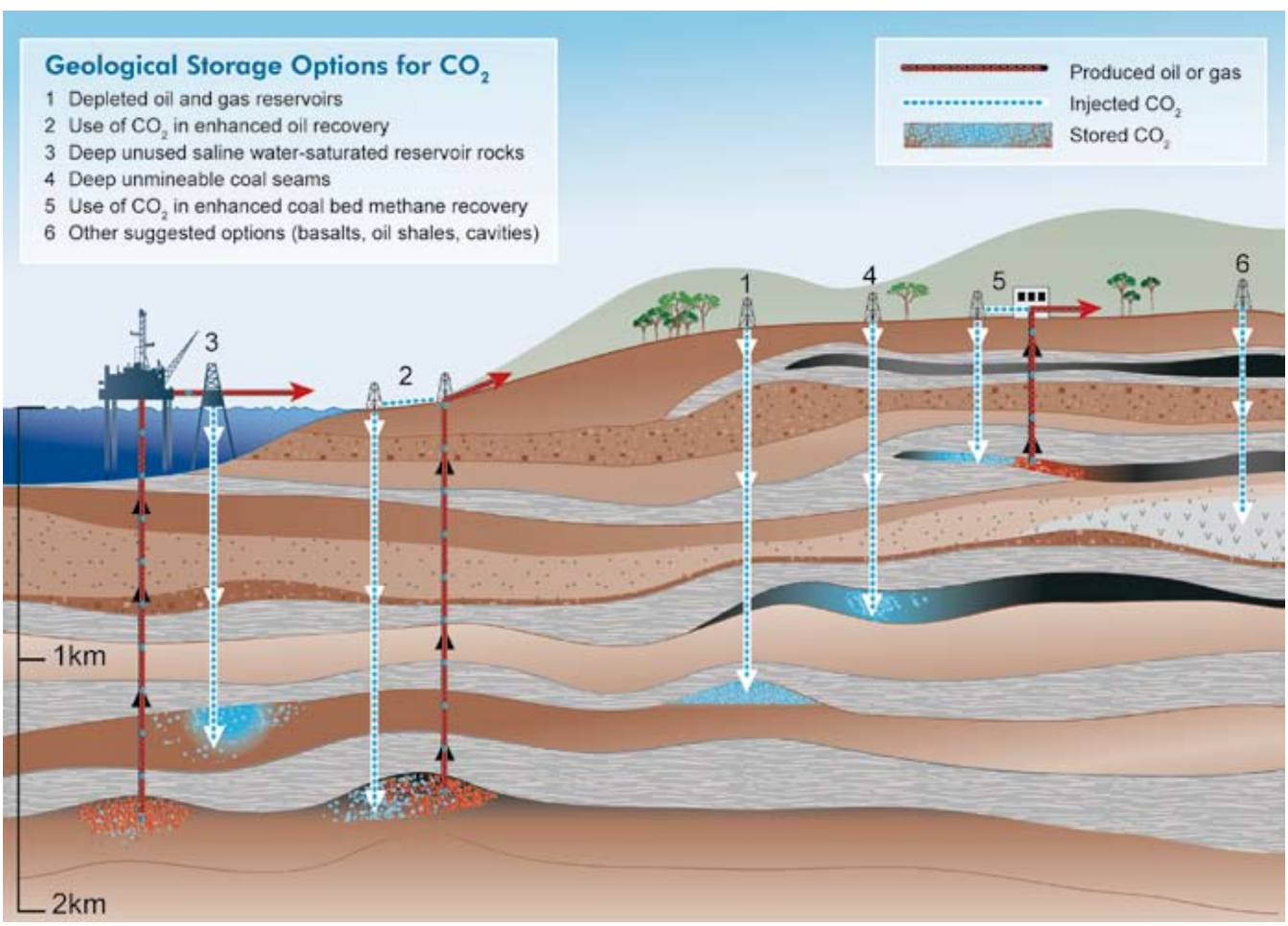

Figure 5.3 Options for storing CO_2 in deep underground geological formations (after Cook, 1999).

grown from a concept of limited interest to one that is quite widely regarded as a potentially important mitigation option (Figure 5.1). There are several reasons for this. First, as research has progressed and as demonstration and commercial projects have been successfully undertaken, the level of confidence in the technology has increased. Second, there is consensus that a broad portfolio of mitigation options is needed. Third, geological storage (in conjunction with CO_2 capture) could help to make deep cuts to atmospheric CO_2 emissions. However, if that potential is to be realized, the technique must be safe, environmentally sustainable, cost-effective and capable of being broadly applied. This chapter explores these issues.

To geologically store CO_2, it must first be compressed, usually to a dense fluid state known as 'supercritical' (see Glossary). Depending on the rate that temperature increases with depth (the geothermal gradient), the density of CO_2 will increase with depth, until at about 800 m or greater, the injected CO_2 will be in a dense supercritical state (Figure 5.2).

Geological storage of CO_2 can be undertaken in a variety of geological settings in sedimentary basins. Within these basins, oil fields, depleted gas fields, deep coal seams and saline formations are all possible storage formations (Figure 5.3).

Subsurface geological storage is possible both onshore and offshore, with offshore sites accessed through pipelines from the shore or from offshore platforms. The continental shelf and some adjacent deep-marine sedimentary basins are potential offshore storage sites, but the majority of sediments of the abyssal deep ocean floor are too thin and impermeable to be suitable for geological storage (Cook and Carleton, 2000). In addition to storage in sedimentary formations, some consideration has been given to storage in caverns, basalt and organic-rich shales (Section 5.3.5).

Fluids have been injected on a massive scale into the deep subsurface for many years to dispose of unwanted chemicals, pollutants or by-products of petroleum production, to enhance the production of oil and gas or to recharge depleted formations (Wilson *et al.*, 2003). The principles involved in such activities are well established and in most countries there are regulations governing these activities. Natural gas has also been injected and stored in the subsurface on a large scale in many parts of the world for many years. Injection of CO_2 to date has been done at a relatively small scale, but if it were to be used to significantly decrease emissions from existing stationary sources, then the injection rates would have to be at a scale similar to other injection operations under way at present.

But what is the world's geological storage capacity and does it occur where we need it? These questions were first raised in Chapter 2, but Section 5.3.8 of this chapter considers geographical matching of CO_2 sources to geological storage sites in detail. Not all sedimentary basins are suitable for CO_2 storage; some are too shallow and others are dominated by rocks with low permeability or poor confining characteristics. Basins suitable for CO_2 storage have characteristics such as thick accumulations of sediments, permeable rock formations saturated with saline water (saline formations), extensive covers of low porosity rocks (acting as seals) and structural simplicity. While many basins show such features, many others do not.

Is there likely to be sufficient storage capacity to meet the world's needs in the years ahead? To consider this issue, it is useful to draw parallels with the terms 'resources' and 'reserves' used for mineral deposits (McKelvey, 1972). Deposits of minerals or fossil fuels are often cited with very large resource figures, but the 'proven' reserve is only some fraction of the resource. The resource figures are based on the selling price of the commodity, the cost of exploiting the commodity, the availability of appropriate technologies, proof that the commodity exists and whether the environmental or social impact of exploiting the commodity is acceptable to the community. Similarly, to turn technical geological storage capacity into economical storage capacity, the storage project must be economically viable, technically feasible, safe, environmentally and socially sustainable and acceptable to the community. Given these constraints, it is inevitable that the storage capacity that will actually be used will be significantly less than the technical potential. Section 5.3 explores this issue. It is likely that usable storage capacity will exist in many areas where people live and where CO_2 is generated from large stationary sources. This geographical congruence of storage-need and storage-capacity should not come as a surprise, because much of the world's population is concentrated in regions underlain by sedimentary basins (Gunter *et al.*, 2004).

It is also important to know how securely and for how long stored CO_2 will be retained – for decades, centuries, millennia or for geological time? To assure public safety, storage sites must be designed and operated to minimize the possibility of leakage. Consequently, potential leakage pathways must be identified and procedures must be established, to set appropriate design and operational standards as well as monitoring, measurement and verification requirements. Sections 5.4, 5.6 and 5.7 consider these issues.

In this chapter, we primarily consider storage of pure or nearly pure, CO_2. It has been suggested that it may be economically favourable to co-store CO_2 along with H_2S, SO_2 or NO_2. Since only a few scientific studies have evaluated the impacts of these added constituents on storage performance or risks, they are not addressed comprehensively here. Moreover, the limited information gained from practical experience with acid gas injection in Canada is insufficient to assess the impacts of the added components on storage security.

5.1.2 Existing and planned CO_2 projects

A number of pilot and commercial CO_2 storage projects are under way or proposed (Figure 5.1). To date, most actual or planned commercial projects are associated with major gas production facilities that have gas streams containing CO_2 in the range of 10–15% by volume, such as Sleipner in the North Sea, Snohvit in the Barents Sea, In Salah in Algeria and Gorgon in Australia (Figure 5.1), as well as the acid gas injection projects in Canada and the United States. At the Sleipner Project, operated by Statoil, more than 7 $MtCO_2$ has been injected into a deep sub-sea saline formation since 1996 (Box 5.1). Existing and planned

Table 5.1 A selection of current and planned geological storage projects.

Project	Country	Scale of Project	Lead organizations	Injection start date	Approximate average daily injection rate	Total storage	Storage type	Geological storage formation	Age of formation	Lithology	Monitoring
Sleipner	Norway	Commercial	Statoil, IEA	1996	3000 t day^{-1}	20 Mt planned	Aquifer	Utsira Formation	Tertiary	Sandstone	4D seismic plus gravity
Weyburn	Canada	Commercial	EnCana, IEA	May 2000	3-5000 t day^{-1}	20 Mt planned	CO_2-EOR	Midale Formation	Mississippian	Carbonate	Comprehensive
Minami-Nagoaka	Japan	Demo	Research Institute of Innovative Technology for the Earth	2002	Max 40 t day^{-1}	10,000 t planned	Aquifer (Sth. Nagoaka Gas Field)	Haizume Formation	Pleistocene	Sandstone	Crosswell seismic + well monitoring
Yubari	Japan	Demo	Japanese Ministry of Economy, Trade and Industry	2004	10 t day^{-1}	200 t Planned	CO_2-ECBM	Yubari Formation (Ishikari Coal Basin)	Tertiary	Coal	Comprehensive
In Salah	Algeria	Commercial	Sonatrach, BP, Statoil	2004	3-4000 t day^{-1}	17 Mt planned	Depleted hydrocarbon reservoirs	Krechba Formation	Carboniferous	Sandstone	Planned comprehensive
Frio	USA	Pilot	Bureau of Economic Geology of the University of Texas	4-13 Oct. 2004	Approx. 177 t day^{-1} for 9 days	1600t	Saline formation	Frio Formation	Tertiary	Brine-bearing sandstone-shale	Comprehensive
K12B	Netherlands	Demo	Gaz de France	2004	100-1000 t day^{-1} (2006+)	Approx 8 Mt	EGR	Rotleigendes	Permian	Sandstone	Comprehensive
Fenn Big Valley	Canada	Pilot	Alberta Research Council	1998	50 t day^{-1}	200 t	CO_2-ECBM	Mannville Group	Cretaceous	Coal	P, T, flow
Recopol	Poland	Pilot	TNO-NITG (Netherlands)	2003	1 t day^{-1}	10 t	CO_2-ECBM	Silesian Basin	Carboniferous	Coal	
Qinshui Basin	China	Pilot	Alberta Research Council	2003	30 t day^{-1}	150 t	CO_2-ECBM	Shanxi Formation	Carboniferous-Permian	Coal	P, T, flow
Salt Creek	USA	Commercial	Anadarko	2004	5-6000 t day^{-1}	27 Mt	CO_2-EOR	Frontier	Cretaceous	Sandstone	Under development
Planned Projects (2005 onwards)											
Snøhvit	Norway	Decided Commercial	Statoil	2006	2000 t day^{-1}		Saline formation	Tubaen Formation	Lower Jurassic	Sandstone	Under development
Gorgon	Australia	Planned Commercial	Chevron	Planned 2009	Approx. 10,000 t day^{-1}		Saline formation	Dupuy Formation	Late Jurassic	Massive sandstone with shale seal	Under development
Ketzin	Germany	Demo	GFZ Potsdam	2006	100 t day^{-1}	60 kt	Saline formation	Stuttgart Formation	Triassic	Sandstone	Comprehensive
Otway	Australia	Pilot	CO2CRC	Planned late 2005	160 t day^{-1} for 2 years	0.1 Mt	Saline fm and depleted gas field	Waarre Formation	Cretaceous	Sandstone	Comprehensive
Teapot Dome	USA	Proposed Demo	RMOTC	Proposed 2006	170 t day^{-1} for 3 months	10 kt	Saline fm and CO_2-EOR	Tensleep and Red Peak Fm	Permian	Sandstone	Comprehensive
CSEMP	Canada	Pilot	Suncor Energy	2005	50 t day^{-1}	10 kt	CO_2-ECBM	Ardley Fm	Tertiary	Coal	Comprehensive
Pembina	Canada	Pilot	Penn West	2005	50 t day^{-1}	50 kt	CO_2-EOR	Cardium Fm	Cretaceous	Sandstone	Comprehensive

storage projects are also listed in Table 5.1.

At the In Salah Gas Field in Algeria, Sonatrack, BP and Statoil inject CO_2 stripped from natural gas into the gas reservoir outside the boundaries of the gas field (Box 5.2). Statoil is planning another project in the Barents Sea, where CO_2 from the Snohvit field will be stripped from the gas and injected into a geological formation below the gas field. Chevron is proposing to produce gas from the Gorgon field off Western Australia, containing approximately 14% CO_2. The CO_2 will be injected into the Dupuy Formation at Barrow Island (Oen, 2003). In The Netherlands, CO_2 is being injected at pilot scale into the almost depleted K12-B offshore gas field (van der Meer *et al*., 2005).

Forty-four CO_2-rich acid gas injection projects are currently operating in Western Canada, ongoing since the early 1990s (Bachu and Haug, 2005). Although they are mostly small scale, they provide important examples of effectively managing injection of CO_2 and hazardous gases such as H_2S (Section 5.2.4.2).

Box 5.1 The Sleipner Project, North Sea.

The Sleipner Project, operated by Statoil in the North Sea about 250 km off the coast of Norway, is the first commercial-scale project dedicated to geological CO_2 storage in a saline formation. The CO_2 (about 9%) from Sleipner West Gas Field is separated, then injected into a large, deep, saline formation 800 m below the seabed of the North Sea. The Saline Aquifer CO_2 Storage (SACS) project was established to monitor and research the storage of CO_2. From 1995, the IEA Greenhouse Gas R&D Programme has worked with Statoil to arrange the monitoring and research activities. Approximately 1 $MtCO_2$ is removed from the produced natural gas and injected underground annually in the field. The CO_2 injection operation started in October 1996 and, by early 2005, more than 7 $MtCO_2$ had been injected at a rate of approximately 2700 t day^{-1}. Over the lifetime of the project, a total of 20 $MtCO_2$ is expected to be stored. A simplified diagram of the Sleipner scheme is given in Figure 5.4.

The saline formation into which the CO_2 is injected is a brine-saturated unconsolidated sandstone about 800–1000 m below the sea floor. The formation also contains secondary thin shale layers, which influence the internal movement of injected CO_2. The saline formation has a very large storage capacity, on the order of 1–10 $GtCO_2$. The top of the formation is fairly flat on a regional scale, although it contains numerous small, low-amplitude closures. The overlying primary seal is an extensive, thick, shale layer.

This project is being carried out in three phases. Phase-0 involved baseline data gathering and evaluation, which was completed in November 1998. Phase-1 involved establishment of project status after three years of CO_2 injection. Five main project areas involve descriptions of reservoir geology, reservoir simulation, geochemistry, assessment of need and cost for monitoring wells and geophysical modelling. Phase-2, involving data interpretation and model verification, began in April 2000.

The fate and transport of the CO_2 plume in the storage formation has been monitored successfully by seismic time-lapse surveys (Figure 5.16). The surveys also show that the caprock is an effective seal that prevents CO_2 migration out of the storage formation. Today, the footprint of the plume at Sleipner extends over an area of approximately 5 km^2. Reservoir studies and simulations covering hundreds to thousands of years have shown that CO_2 will eventually dissolve in the pore water, which will become heavier and sink, thus minimizing the potential for long-term leakage (Lindeberg and Bergmo, 2003).

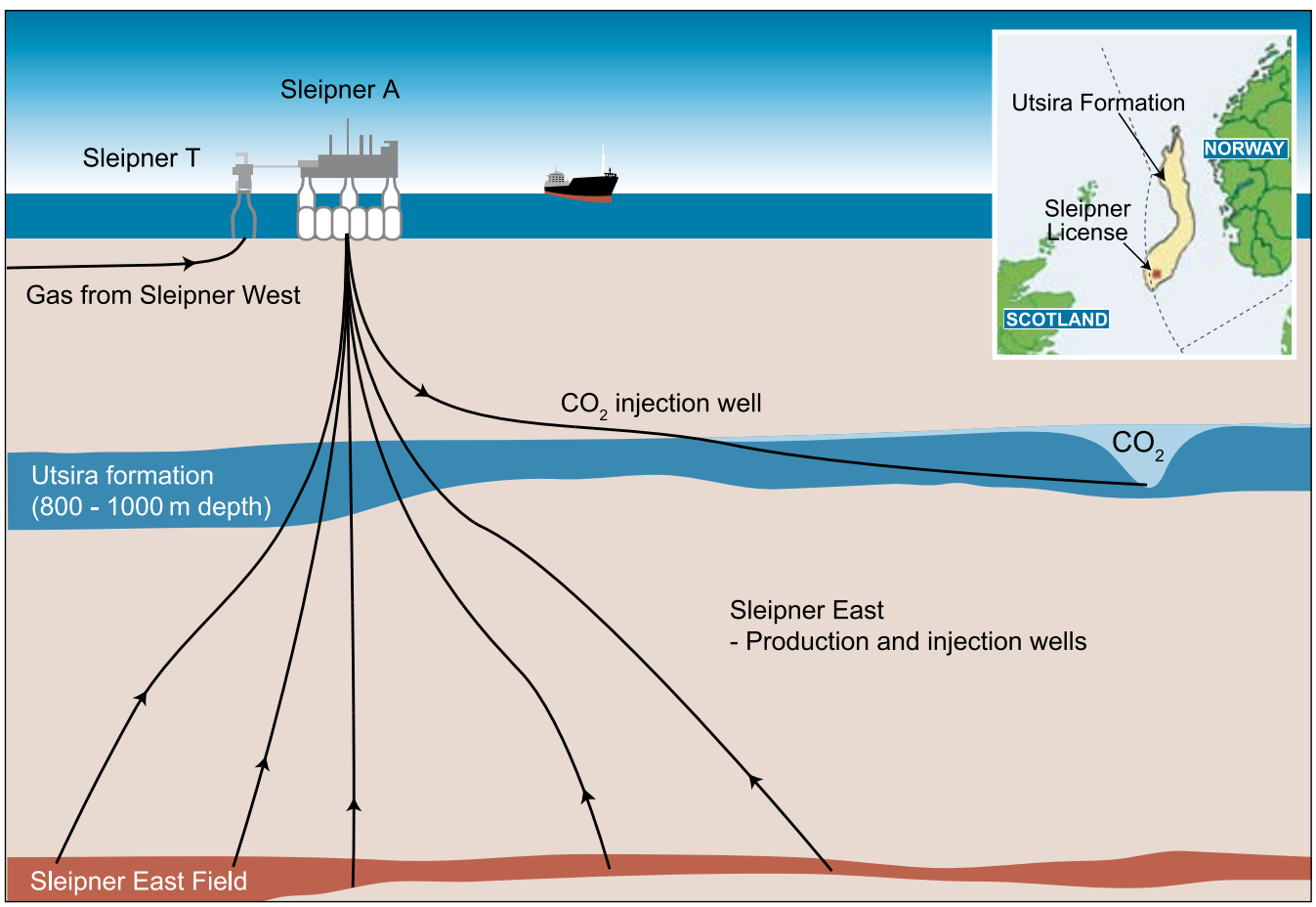

Figure 5.4 Simplified diagram of the Sleipner CO_2 Storage Project. Inset: location and extent of the Utsira formation.

Box 5.2 The In Salah, Algeria, CO_2 Storage Project.

The In Salah Gas Project, a joint venture among Sonatrach, BP and Statoil located in the central Saharan region of Algeria, is the world's first large-scale CO_2 storage project in a gas reservoir (Riddiford *et al.*, 2003). The Krechba Field at In Salah produces natural gas containing up to 10% CO_2 from several geological reservoirs and delivers it to markets in Europe, after processing and stripping the CO_2 to meet commercial specifications. The project involves re-injecting the CO_2 into a sandstone reservoir at a depth of 1800 m and storing up to 1.2 $MtCO_2$ yr^{-1}. Carbon dioxide injection started in April 2004 and, over the life of the project, it is estimated that 17 $MtCO_2$ will be geologically stored. The project consists of four production and three injection wells (Figure 5.5). Long-reach (up to 1.5 km) horizontal wells are used to inject CO_2 into the 5-mD permeability reservoir.

The Krechba Field is a relatively simple anticline. Carbon dioxide injection takes place down-dip from the gas/water contact in the gas-bearing reservoir. The injected CO_2 is expected to eventually migrate into the area of the current gas field after depletion of the gas zone. The field has been mapped with three-dimensional seismic and well data from the field. Deep faults have been mapped, but at shallower levels, the structure is unfaulted. The storage target in the reservoir interval therefore carries minimal structural uncertainty or risk. The top seal is a thick succession of mudstones up to 950 m thick.

A preliminary risk assessment of CO_2 storage integrity has been carried out and baseline data acquired. Processes that could result in CO_2 migration from the injection interval have been quantified and a monitoring programme is planned involving a range of technologies, including noble gas tracers, pressure surveys, tomography, gravity baseline studies, microbiological studies, four-dimensional seismic and geomechanical monitoring.

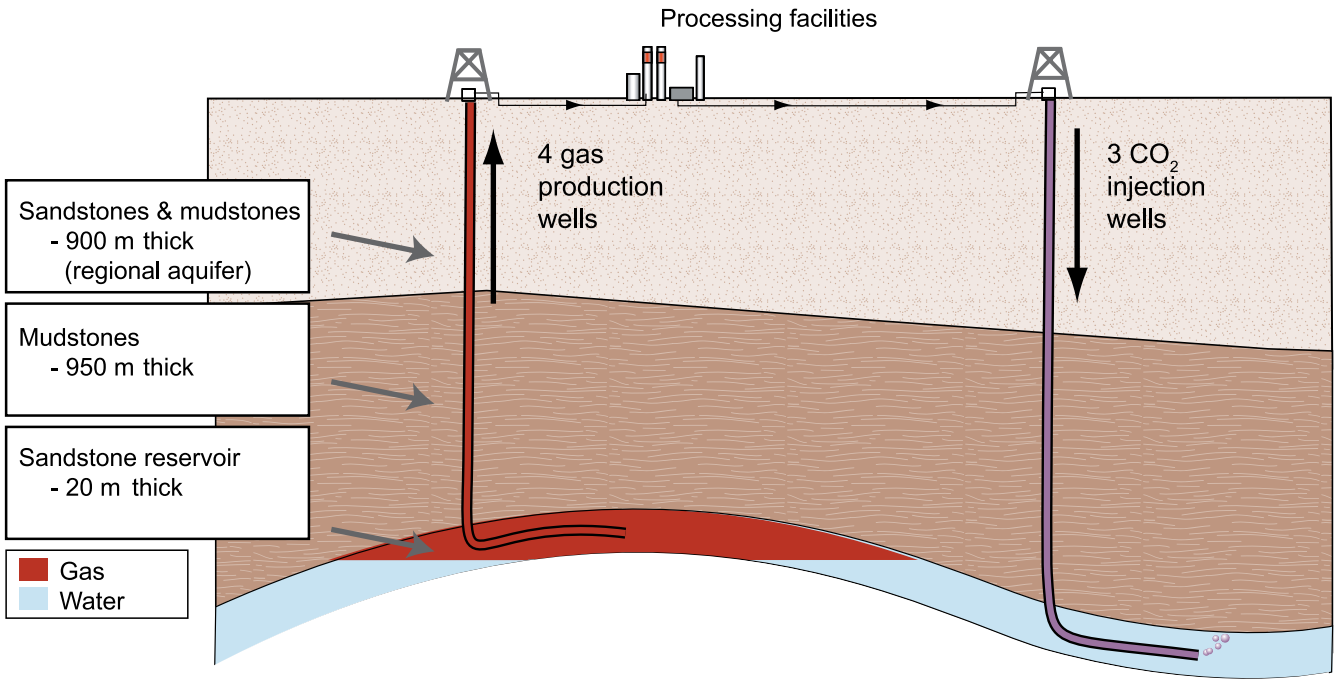

Figure 5.5 Schematic of the In Salah Gas Project, Algeria. One $MtCO_2$ will be stored annually in the gas reservoir. Long-reach horizontal wells with slotted intervals of up to 1.5 km are used to inject CO_2 into the water-filled parts of the gas reservoir.

Opportunities for enhanced oil recovery (EOR) have increased interest in CO_2 storage (Stevens *et al.*, 2001b; Moberg *et al.*, 2003; Moritis, 2003; Riddiford *et al.*, 2003; Torp and Gale, 2003). Although not designed for CO_2 storage, CO_2-EOR projects can demonstrate associated storage of CO_2, although lack of comprehensive monitoring of EOR projects (other than at the International Energy Agency Greenhouse Gas (IEA-GHG) Weyburn Project in Canada) makes it difficult to quantify storage. In the United States, approximately 73 CO_2-EOR operations inject up to 30 $MtCO_2$ yr^{-1}, most of which comes from natural CO_2 accumulations – although approximately 3 $MtCO_2$ is from anthropogenic sources, such as gas processing and fertiliser plants (Stevens *et al.*, 2001b). The SACROC project in Texas was the first large-scale commercial CO_2-EOR project in the world. It used anthropogenic CO_2 during the period 1972 to 1995. The Rangely Weber project (Box 5.6) injects anthropogenic CO_2 from a gas-processing plant in Wyoming.

In Canada, a CO_2-EOR project has been established by EnCana at the Weyburn Oil Field in southern Saskatchewan (Box 5.3). The project is expected to inject 23 $MtCO_2$ and extend the life of the oil field by 25 years (Moberg *et al.*,

Box 5.3 The Weyburn CO_2-EOR Project.

The Weyburn CO_2-enhanced oil recovery (CO_2-EOR) project is located in the Williston Basin, a geological structure extending from south-central Canada into north-central United States. The project aims to permanently store almost all of the injected CO_2 by eliminating the CO_2 that would normally be released during the end of the field life.

The source of the CO_2 for the Weyburn CO_2-EOR Project is the Dakota Gasification Company facility, located approximately 325 km south of Weyburn, in Beulah, North Dakota, USA. At the plant, coal is gasified to make synthetic gas (methane), with a relatively pure stream of CO_2 as a by-product. This CO_2 stream is dehydrated, compressed and piped to Weyburn in southeastern Saskatchewan, Canada, for use in the field. The Weyburn CO_2-EOR Project is designed to take CO_2 from the pipeline for about 15 years, with delivered volumes dropping from 5000 to about 3000 t day^{-1} over the life of the project.

The Weyburn field covers an area of 180 km^2, with original oil in place on the order of 222 million m^3 (1396 million barrels). Over the life of the CO_2-EOR project (20–25 years), it is expected that some 20 MtCO_2 will be stored in the field, under current economic conditions and oil recovery technology. The oil field layout and operation is relatively conventional for oil field operations. The field has been designed with a combination of vertical and horizontal wells to optimize the sweep efficiency of the CO_2. In all cases, production and injection strings are used within the wells to protect the integrity of the casing of the well.

The oil reservoir is a fractured carbonate, 20–27 m thick. The primary upper seal for the reservoir is an anhydrite zone. At the northern limit of the reservoir, the carbonate thins against a regional unconformity. The basal seal is also anhydrite, but is less consistent across the area of the reservoir. A thick, flat-lying shale above the unconformity forms a good regional barrier to leakage from the reservoir. In addition, several high-permeability formations containing saline groundwater would form good conduits for lateral migration of any CO_2 that might reach these zones, with rapid dissolution of the CO_2 in the formation fluids.

Since CO_2 injection began in late 2000, the EOR project has performed largely as predicted. Currently, some 1600 m^3 (10,063 barrels) day^{-1} of incremental oil is being produced from the field. All produced CO_2 is captured and recompressed for reinjection into the production zone. Currently, some 1000 tCO_2 day^{-1} is reinjected; this will increase as the project matures. Monitoring is extensive, with high-resolution seismic surveys and surface monitoring to determine any potential leakage. Surface monitoring includes sampling and analysis of potable groundwater, as well as soil gas sampling and analysis (Moberg *et al.*, 2003). To date, there has been no indication of CO_2 leakage to the surface and near-surface environment (White, 2005; Strutt *et al.*, 2003).

2003; Law, 2005). The fate of the injected CO_2 is being closely monitored through the IEA GHG Weyburn Project (Wilson and Monea, 2005). Carbon dioxide-EOR is under consideration for the North Sea, although there is as yet little, if any, operational experience for offshore CO_2-EOR. Carbon dioxide-EOR projects are also currently under way in a number of countries including Trinidad, Turkey and Brazil (Moritis, 2002). Saudi Aramco, the world's largest producer and exporter of crude oil, is evaluating the technical feasibility of CO_2-EOR in some of its Saudi Arabian reservoirs.

In addition to these commercial storage or EOR projects, a number of pilot storage projects are under way or planned. The Frio Brine Project in Texas, USA, involved injection and storage of 1900 tCO_2 in a highly permeable formation with a regionally extensive shale seal (Hovorka *et al.*, 2005). Pilot projects are proposed for Ketzin, west of Berlin, Germany, for the Otway Basin of southeast Australia and for Teapot Dome, Wyoming, USA (Figure 5.1). The American FutureGen project, proposed for late this decade, will be a geological storage project linked to coal-fired electricity generation. A small-scale CO_2 injection and monitoring project is being carried out by RITE at Nagoaka in northwest Honshu, Japan. Small-scale injection projects to test CO_2 storage in coal have been carried out in Europe (RECOPOL) and Japan (Yamaguchi *et al.*, 2005). A CO_2-enhanced coal bed methane (ECBM) recovery demonstration project has been undertaken in the northern San Juan Basin of New Mexico, USA (Reeves, 2003a) (Box 5.7). Further CO_2-ECBM projects are under consideration for China, Canada, Italy and Poland (Gale, 2003). In all, some 59 opportunities for CO_2-ECBM have been identified worldwide, the majority in China (van Bergen *et al.*, 2003a).

These projects (Figure 5.1; Table 5.1) demonstrate that subsurface injection of CO_2 is not for the distant future, but is being implemented now for environmental and/or commercial reasons.

5.1.3 Key questions

In the previous section, the point is made that deep injection of CO_2 is under way in a number of places (Figure 5.1). However, if CO_2 storage is to be undertaken on the scale necessary to make deep cuts to atmospheric CO_2 emissions, there must be hundreds, and perhaps even thousands, of large-scale geological storage projects under way worldwide. The extent to which this is or might be, feasible depends on the answers to the key questions outlined below and addressed subsequently in this chapter:

- How is CO_2 stored underground? What happens to the CO_2 when it is injected? What are the physico-chemical and chemical processes involved? What are the geological

controls? (Sections 5.2 and 5.3)
- How long can CO_2 remain stored underground? (Section 5.2)
- How much and where can CO_2 be stored in the subsurface, locally, regionally, globally? Is it a modest niche opportunity or is the total storage capacity sufficient to contain a large proportion of the CO_2 currently emitted to the atmosphere? (Section 5.3)
- Are there significant opportunities for CO_2-enhanced oil and gas recovery? (Section 5.3)
- How is a suitable storage site identified and what are its geological characteristics? (see Section 5.4)
- What technologies are currently available for geological storage of CO_2? (Section 5.5)
- Can we monitor CO_2 once it is geologically stored? (Section 5.6)
- Will a storage site leak and what would be the likely consequences? (Sections 5.6 and 5.7)
- Can a CO_2 storage site be remediated if something does go wrong? (Sections 5.6 and 5.7)
- Can a geological storage site be operated safely and if so, how? (Section 5.7)
- Are there legal and regulatory issues for geological storage and is there a legal/regulatory framework that enables it to be undertaken? (Section 5.8)
- What is the likely cost of geological storage of CO_2? (Section 5.9)
- After reviewing our current state of knowledge, are there things that we still need to know? What are these gaps in knowledge? (Section 5.10).

The remainder of this chapter seeks to address these questions.

5.2 Storage mechanisms and storage security

Geological formations in the subsurface are composed of transported and deposited rock grains organic material and minerals that form after the rocks are deposited. The pore space between grains or minerals is occupied by fluid (mostly water, with proportionally minute occurrences of oil and gas). Open fractures and cavities are also filled with fluid. Injection of CO_2 into the pore space and fractures of a permeable formation can displace the *in situ* fluid or the CO_2 may dissolve in or mix with the fluid or react with the mineral grains or there may be some combination of these processes. This section examines these processes and their influence on geological storage of CO_2.

5.2.1 CO_2 flow and transport processes

Injection of fluids into deep geological formations is achieved by pumping fluids down into a well (see Section 5.5). The part of the well in the storage zone is either perforated or covered with a permeable screen to enable the CO_2 to enter the formation. The perforated or screened interval is usually on the order of 10–100 m thick, depending on the permeability and thickness of the formation. Injection raises the pressure near the well, allowing CO_2 to enter the pore spaces initially occupied by the *in situ* formation fluids. The amount and spatial distribution of pressure buildup in the formation will depend on the rate of injection, the permeability and thickness of the injection formation, the presence or absence of permeability barriers within it and the geometry of the regional underground water (hydrogeological) system.

Once injected into the formation, the primary flow and transport mechanisms that control the spread of CO_2 include:
- Fluid flow (migration) in response to pressure gradients created by the injection process;
- Fluid flow in response to natural hydraulic gradients;
- Buoyancy caused by the density differences between CO_2 and the formation fluids;
- Diffusion;
- Dispersion and fingering caused by formation heterogeneities and mobility contrast between CO_2 and formation fluid;
- Dissolution into the formation fluid;
- Mineralization;
- Pore space (relative permeability) trapping;
- Adsorption of CO_2 onto organic material.

The rate of fluid flow depends on the number and properties of the fluid phases present in the formation. When two or more fluids mix in any proportion, they are referred to as miscible fluids. If they do not mix, they are referred to as immiscible. The presence of several different phases may decrease the permeability and slow the rate of migration. If CO_2 is injected into a gas reservoir, a single miscible fluid phase consisting of natural gas and CO_2 is formed locally. When CO_2 is injected into a deep saline formation in a liquid or liquid-like supercritical dense phase, it is immiscible in water. Carbon dioxide injected into an oil reservoir may be miscible or immiscible, depending on the oil composition and the pressure and temperature of the system (Section 5.3.2). When CO_2 is injected into coal beds, in addition to some of the processes listed above, adsorption and desorption of gases (particularly methane) previously adsorbed on the coal take place, as well as swelling or shrinkage of the coal itself (Section 5.3.4).

Because supercritical CO_2 is much less viscous than water and oil (by an order of magnitude or more), migration is controlled by the contrast in mobility of CO_2 and the *in situ* formation fluids (Celia *et al*., 2005; Nordbotten *et al*., 2005a). Because of the comparatively high mobility of CO_2, only some of the oil or water will be displaced, leading to an average saturation of CO_2 in the range of 30–60%. Viscous fingering can cause CO_2 to bypass much of the pore space, depending on the heterogeneity and anisotropy of rock permeability (van der Meer, 1995; Ennis-King and Paterson, 2001; Flett *et al*., 2005). In natural gas reservoirs, CO_2 is more viscous than natural gas, so the 'front' will be stable and viscous fingering limited.

The magnitude of the buoyancy forces that drive vertical flow depends on the type of fluid in the formation. In saline formations, the comparatively large density difference (30–50%) between CO_2 and formation water creates strong buoyancy forces that drive CO_2 upwards. In oil reservoirs, the density

careful characterization to be good candidates for CO_2 storage, unless the faults and fractures are sealed and CO_2 injection will not open them (Holloway, 1997; Zarlenga *et al.*, 2004).

The pressure and flow regimes of formation waters in a sedimentary basin are important factors in selecting sites for CO_2 storage (Bachu *et al.*, 1994). Injection of CO_2 into formations overpressured by compaction and/or hydrocarbon generation may raise technological and safety issues that make them unsuitable. Underpressured formations in basins located mid-continent, near the edge of stable continental plates or behind mountains formed by plate collision may be well suited for CO_2 storage. Storage of CO_2 in deep saline formations with fluids having long residence times (millions of years) is conducive to hydrodynamic and mineral trapping (Section 5.2).

The possible presence of fossil fuels and the exploration and production maturity of a basin are additional considerations for selection of storage sites (Bachu, 2000). Basins with little exploration for hydrocarbons may be uncertain targets for CO_2 storage because of limited availability of geological information or potential for contamination of as-yet-undiscovered hydrocarbon resources. Mature sedimentary basins may be prime targets for CO_2 storage because: (1) they have well-known characteristics; (2) hydrocarbon pools and/or coal beds have been discovered and produced; (3) some petroleum reservoirs might be already depleted, nearing depletion or abandoned as uneconomic; (4) the infrastructure needed for CO_2 transport and injection may already be in place. The presence of wells penetrating the subsurface in mature sedimentary basins can create potential CO_2 leakage pathways that may compromise the security of a storage site (Celia and Bachu, 2003). Nevertheless, at Weyburn, despite the presence of many hundreds of existing wells, after four years of CO_2 injection there has been no measurable leakage (Strutt *et al.*, 2003).

5.3.2 Oil and gas fields

5.3.2.1 Abandoned oil and gas fields

Depleted oil and gas reservoirs are prime candidates for CO_2 storage for several reasons. First, the oil and gas that originally accumulated in traps (structural and stratigraphic) did not escape (in some cases for many millions of years), demonstrating their integrity and safety. Second, the geological structure and physical properties of most oil and gas fields have been extensively studied and characterized. Third, computer models have been developed in the oil and gas industry to predict the movement, displacement behaviour and trapping of hydrocarbons. Finally, some of the infrastructure and wells already in place may be used for handling CO_2 storage operations. Depleted fields will not be adversely affected by CO_2 (having already contained hydrocarbons) and if hydrocarbon fields are still in production, a CO_2 storage scheme can be optimized to enhance oil (or gas) production. However, plugging of abandoned wells in many mature fields began many decades ago when wells were simply filled with a mud-laden fluid. Subsequently, cement plugs were required to be strategically placed within the wellbore, but not with any consideration that they may one day be relied upon to contain a reactive and potentially buoyant fluid such as CO_2. Therefore, the condition of wells penetrating the caprock must be assessed (Winter and Bergman, 1993). In many cases, even locating the wells may be difficult and caprock integrity may need to be confirmed by pressure and tracer monitoring.

The capacity of a reservoir will be limited by the need to avoid exceeding pressures that damage the caprock (Section 5.5.3). Reservoirs should have limited sensitivity to reductions in permeability caused by plugging of the near-injector region and by reservoir stress fluctuations (Kovscek, 2002; Bossie-Codreanu *et al.*, 2003). Storage in reservoirs at depths less than approximately 800 m may be technically and economically feasible, but the low storage capacity of shallow reservoirs, where CO_2 may be in the gas phase, could be problematic.

5.3.2.2 Enhanced oil recovery

Enhanced oil recovery (EOR) through CO_2 flooding (by injection) offers potential economic gain from incremental oil production. Of the original oil in place, 5–40% is usually recovered by conventional primary production (Holt *et al.*, 1995). An additional 10–20% of oil in place is produced by secondary recovery that uses water flooding (Bondor, 1992). Various miscible agents, among them CO_2, have been used for enhanced (tertiary) oil recovery or EOR, with an incremental oil recovery of 7–23% (average 13.2%) of the original oil in place (Martin and Taber, 1992; Moritis, 2003). Descriptions of CO_2-EOR projects are provided in Box 5.3 and Box 5.6, and an illustration is given in Figure 5.15.

Many CO_2 injection schemes have been suggested, including continuous CO_2 injection or alternate water and CO_2 gas injection (Klins and Farouq Ali, 1982; Klins, 1984). Oil displacement by CO_2 injection relies on the phase behaviour of CO_2 and crude oil mixtures that are strongly dependent on reservoir temperature, pressure and crude oil composition. These mechanisms range from oil swelling and viscosity reduction for injection of immiscible fluids (at low pressures) to completely miscible displacement in high-pressure applications. In these applications, more than 50% and up to 67% of the injected CO_2 returns with the produced oil (Bondor, 1992) and is usually separated and re-injected into the reservoir to minimize operating costs. The remainder is trapped in the oil reservoir by various means, such as irreducible saturation and dissolution in reservoir oil that it is not produced and in pore space that is not connected to the flow path for the producing wells.

For enhanced CO_2 storage in EOR operations, oil reservoirs may need to meet additional criteria (Klins, 1984; Taber *et al.*, 1997; Kovscek, 2002; Shaw and Bachu, 2002). Generally, reservoir depth must be more than 600 m. Injection of immiscible fluids must often suffice for heavy- to-medium-gravity oils (oil gravity 12–25 API). The more desirable miscible flooding is applicable to light, low-viscosity oils (oil gravity 25–48 API). For miscible floods, the reservoir pressure must be higher than the minimum miscibility pressure (10–15 MPa) needed for achieving miscibility between reservoir oil and CO_2, depending on oil composition and gravity, reservoir temperature and CO_2 purity (Metcalfe, 1982). To achieve effective removal of the

Box 5.6 The Rangely, Colorado, CO_2-EOR Project.

The Rangely CO_2-EOR Project is located in Colorado, USA and is operated by Chevron. The CO_2 is purchased from the Exxon-Mobil LaBarge natural gas processing facility in Wyoming and transported 283 km via pipeline to the Rangely field. Additional spurs carry CO_2 over 400 km from LaBarge to Lost Soldier and Wertz fields in central Wyoming, currently ending at the Salt Creek field in eastern Wyoming.

The sandstone reservoir of the Rangely field has been CO_2 flooded, by the water alternating gas (WAG) process, since 1986. Primary and secondary recovery, carried out between 1944 and 1986, recovered 1.9 US billion barrels (302 million m^3) of oil (21% of the original oil in place). With use of CO_2 floods, ultimate tertiary recovery of a further 129 million barrels (21 million m^3) of oil (6.8% of original oil in place) is expected. Average daily CO_2 injection in 2003 was equivalent to 2.97 $MtCO_2$ yr^{-1}, with production of 13,913 barrels oil per day. Of the total 2.97 Mt injected, recycled gas comprised around 2.29 Mt and purchased gas about 0.74 Mt. Cumulative CO_2 stored to date is estimated at 22.2 Mt. A simplified flow diagram for the Rangely field is given in Figure 5.15.

The Rangely field, covering an area of 78 km^2, is an asymmetric anticline. A major northeast-to-southwest fault in the eastern half of the field and other faults and fractures significantly influence fluid movement within the reservoir. The sandstone reservoirs have an average gross and effective thickness of 160 m and 40 m, respectively and are comprised of six persistent producing sandstone horizons (depths of 1675–1980 m) with average porosity of 12%. Permeability averages 10 mD (Hefner and Barrow, 1992).

By the end of 2003, there were 248 active injectors, of which 160 are used for CO_2 injection and 348 active producers. Produced gas is processed through two parallel single-column natural-gas-liquids recovery facilities and subsequently compressed to approximately 14.5 MPa. Compressed-produced gas (recycled gas) is combined with purchased CO_2 for reinjection mostly by the WAG process.

Carbon dioxide-EOR operation in the field maintains compliance with government regulations for production, injection, protection of potable water formations, surface use, flaring and venting. A number of protocols have been instituted to ensure containment of CO_2 – for example, pre-injection well-integrity verification, a radioactive tracer survey run on the first injection, injection-profile tracer surveys, mechanical integrity tests, soil gas surveys and round-the-clock field monitoring. Surface release from the storage reservoir is below the detection limit of 170 t yr^{-1} or an annual leakage rate of less than 0.00076% of the total stored CO_2 (Klusman, 2003). Methane leakage is estimated to be 400 t yr^{-1}, possibly due to increased CO_2 injection pressure above original reservoir pressure. The water chemistry portion of the study indicates that the injected CO_2 is dissolving in the water and may be responsible for dissolution of ferroan calcite and dolomite. There is currently no evidence of mineral precipitation that may result in mineral storage of CO_2.

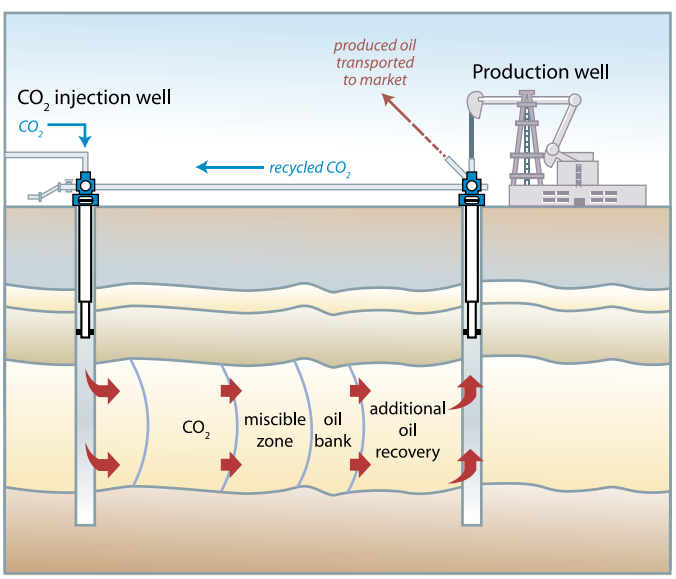

Figure 5.15 Injection of CO_2 for enhanced oil recovery (EOR) with some storage of retained CO_2 (after IEA Greenhouse Gas R&D Programme). The CO_2 that is produced with the oil is separated and re-injected back into the formation. Recycling of produced CO_2 decreases the amount of CO_2 that must be purchased and avoids emissions to the atmosphere.

oil, other preferred criteria for both types of flooding include relatively thin reservoirs (less than 20 m), high reservoir angle, homogenous formation and low vertical permeability. For horizontal reservoirs, the absence of natural water flow, major gas cap and major natural fractures are preferred. Reservoir thickness and permeability are not critical factors.

Reservoir heterogeneity also affects CO_2 storage efficiency. The density difference between the lighter CO_2 and the reservoir oil and water leads to movement of the CO_2 along the top of the reservoir, particularly if the reservoir is relatively homogeneous and has high permeability, negatively affecting the CO_2 storage and oil recovery. Consequently, reservoir heterogeneity may have a positive effect, slowing down the rise of CO_2 to the top of the reservoir and forcing it to spread laterally, giving more complete invasion of the formation and greater storage potential (Bondor, 1992; Kovscek, 2002; Flett *et al.*, 2005).

5.3.2.3 Enhanced gas recovery

Although up to 95% of original gas in place can be produced, CO_2 could potentially be injected into depleted gas reservoirs to enhance gas recovery by repressurizing the reservoir (van der Burgt *et al.*, 1992; Koide and Yamazaki, 2001; Oldenburg *et al.*, 2001). Enhanced gas recovery has so far been implemented only at pilot scale (Gaz de France K12B project, Netherlands,

Table 5.1) and some authors have suggested that CO_2 injection might result in lower gas recovery factors, particularly for very heterogeneous fields (Clemens and Wit, 2002).

5.3.3 Saline formations

Saline formations are deep sedimentary rocks saturated with formation waters or brines containing high concentrations of dissolved salts. These formations are widespread and contain enormous quantities of water, but are unsuitable for agriculture or human consumption. Saline brines are used locally by the chemical industry and formation waters of varying salinity are used in health spas and for producing low-enthalpy geothermal energy. Because the use of geothermal energy is likely to increase, potential geothermal areas may not be suitable for CO_2 storage. It has been suggested that combined geological storage and geothermal energy may be feasible, but regions with good geothermal energy potential are generally less favourable for CO_2 geological storage because of the high degree of faulting and fracturing and the sharp increase of temperature with depth. In very arid regions, deep saline formations may be considered for future water desalinization.

The Sleipner Project in the North Sea is the best available example of a CO_2 storage project in a saline formation (Box 5.1). It was the first commercial-scale project dedicated to geological CO_2 storage. Approximately 1 $MtCO_2$ is removed annually from the produced natural gas and injected underground at Sleipner. The operation started in October 1996 and over the lifetime of the project a total of 20 $MtCO_2$ is expected to be stored. A simplified diagram of the Sleipner scheme is given in Figure 5.4.

The CO_2 is injected into poorly cemented sands about 800–1000 m below the sea floor. The sandstone contains secondary thin shale or clay layers, which influence the internal movement of injected CO_2. The overlying primary seal is an extensive thick shale or clay layer. The saline formation into which CO_2 is injected has a very large storage capacity.

The fate and transport of the Sleipner CO_2 plume has been successfully monitored (Figure 5.16) by seismic time-lapse surveys (Section 5.6). These surveys have helped improve the conceptual model for the fate and transport of stored CO_2. The vertical cross-section of the plume shown in Figure 5.16 indicates both the upward migration of CO_2 (due to buoyancy forces) and the role of lower permeability strata within the formation, diverting some of the CO_2 laterally, thus spreading out the plume over a larger area. The survey also shows that the caprock prevents migration out of the storage formation. The seismic data shown in Figure 5.16 illustrate the gradual growth of the plume. Today, the footprint of the plume at Sleipner extends over approximately 5 km^2. Reservoir studies and simulations (Section 5.4.2) have shown that the CO_2-saturated brine will eventually become denser and sink, eliminating the potential for long-term leakage (Lindeberg and Bergmo, 2003).

5.3.4 Coal seams

Coal contains fractures (cleats) that impart some permeability to the system. Between cleats, solid coal has a very large number of micropores into which gas molecules from the cleats can diffuse and be tightly adsorbed. Coal can physically adsorb many gases and may contain up to 25 normal m^3 (m^3 at 1 atm and 0°C) methane per tonne of coal at coal seam pressures. It has a higher affinity to adsorb gaseous CO_2 than methane (Figure 5.17). The volumetric ratio of adsorbable CO_2:CH_4 ranges from as low as one for mature coals such as anthracite, to ten or more for younger, immature coals such as lignite. Gaseous CO_2 injected through wells will flow through the cleat system of the coal, diffuse into the coal matrix and be adsorbed onto the coal micropore surfaces, freeing up gases with lower affinity to coal (i.e., methane).

The process of CO_2 trapping in coals for temperatures and pressures above the critical point is not well understood (Larsen, 2003). It seems that adsorption is gradually replaced by absorption and the CO_2 diffuses or 'dissolves' in coal. Carbon dioxide is a 'plasticizer' for coal, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure (coal softening). In one case, the transition temperature was interpreted to drop from about 400ºC at 3 MPa to <30ºC at 5.5 MPa CO_2 pressure (Larsen, 2003). The transition temperature is dependent on the maturity of the coal, the maceral content, the ash content and the confining stress and is not easily extrapolated to the field. Coal plasticization or softening, may adversely affect the permeability that would allow CO_2 injection. Furthermore, coal swells as CO_2 is adsorbed and/or absorbed, which reduces permeability and injectivity by orders of magnitude or more (Shi and Durucan, 2005) and which may be counteracted by increasing the injection pressures (Clarkson and Bustin, 1997; Palmer and Mansoori, 1998; Krooss *et al.*, 2002; Larsen, 2003). Some studies suggest that the injected CO_2 may react with coal (Zhang *et al.*, 1993), further highlighting the difficulty in injecting CO_2 into low-permeability coal.

If CO_2 is injected into coal seams, it can displace methane, thereby enhancing CBM recovery. Carbon dioxide has been injected successfully at the Allison Project (Box 5.7) and in the Alberta Basin, Canada (Gunter *et al.*, 2005), at depths greater than that corresponding to the CO_2 critical point. Carbon dioxide-ECBM has the potential to increase the amount of produced methane to nearly 90% of the gas, compared to conventional recovery of only 50% by reservoir-pressure depletion alone (Stevens *et al.*, 1996).

Coal permeability is one of several determining factors in selection of a storage site. Coal permeability varies widely and generally decreases with increasing depth as a result of cleat closure with increasing effective stress. Most CBM-producing wells in the world are less than 1000 m deep.

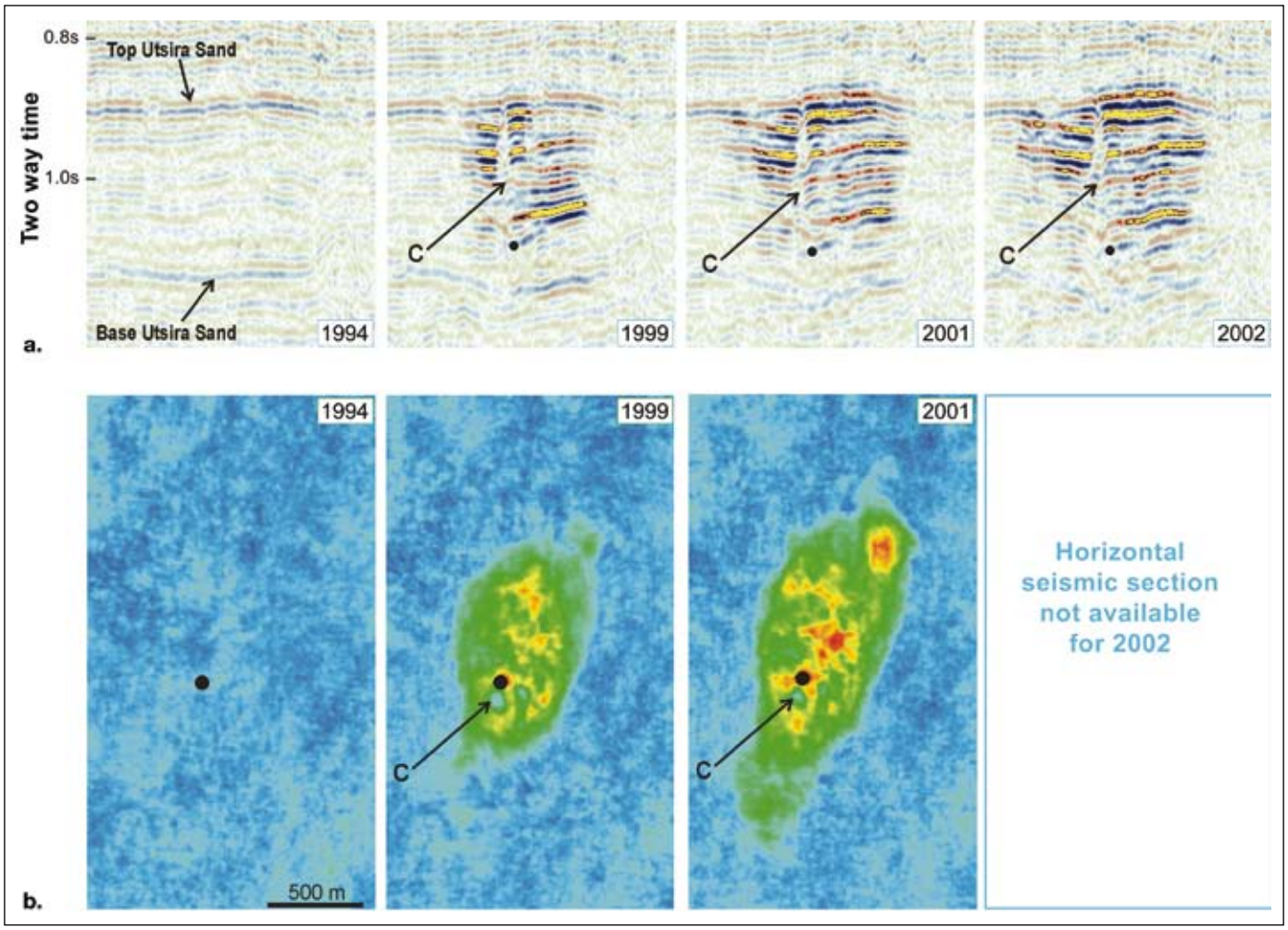

Figure 5.16 (a) Vertical seismic sections through the CO_2 plume in the Utsira Sand at the Sleipner gas field, North Sea, showing its development over time. Note the chimney of high CO_2 saturation (c) above the injection point (black dot) and the bright layers corresponding to high acoustic response due to CO_2 in a gas form being resident in sandstone beneath thin low-permeability horizons within the reservoir. (b) Horizontal seismic sections through the developing CO_2 plume at Sleipner showing its growth over time. The CO_2 plume-specific monitoring was completed in 2001; therefore data for 2002 was not available (courtesy of Andy Chadwick and the CO2STORE project).

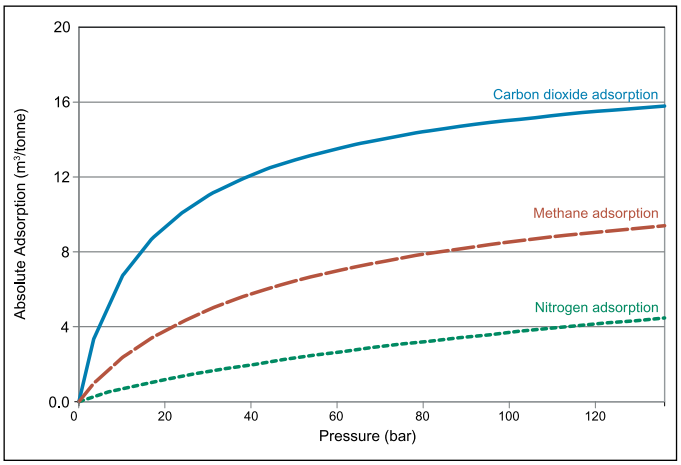

Figure 5.17 Pure gas absolute adsorption in standard cubic feet per tonne (SCF per tonne) on Tiffany Coals at 55ºC (after Gasem et al., 2002).

Original screening criteria proposed in selecting favourable areas for CO_2 ECBM (IEA-GHG, 1998) include:

- Adequate permeability (minimum values have not yet been determined);
- Suitable coal geometry (a few, thick seams rather than multiple, thin seams);
- Simple structure (minimal faulting and folding);
- Homogeneous and confined coal seam(s) that are laterally continuous and vertically isolated;
- Adequate depth (down to 1500 m, greater depths have not yet been studied);
- Suitable gas saturation conditions (high gas saturation for ECBM);
- Ability to dewater the formation.

However, more recent studies have indicated that coal rank may play a more significant role than previously thought, owing to the dependence on coal rank of the relative adsorptive capacities

Box 5.7 The Allison Unit CO_2-ECBM Pilot.

The Allison Unit CO_2-ECBM Recovery Pilot Project, located in the northern New Mexico portion of the San Juan Basin, USA, is owned and operated by Burlington Resources. Production from the Allison field began in July 1989 and CO_2 injection operations for ECBM recovery commenced in April 1995. Carbon dioxide injection was suspended in August 2001 to evaluate the results of the pilot. Since this pilot was undertaken purely for the purposes of ECBM production, no CO_2 monitoring programme was implemented.

The CO_2 was sourced from the McElmo Dome in Colorado and delivered to the site through a (then) Shell (now Kinder-Morgan) CO_2 pipeline. The Allison Unit has a CBM resource of 242 million m^3 km^{-2}. A total of 181 million m^3 (6.4 Bcf) of natural CO_2 was injected into the reservoir over six years, of which 45 million m^3 (1.6 Bcf) is forecast to be ultimately produced back, resulting in a net storage volume of 277,000 tCO_2. The pilot consists of 16 methane production wells, 4 CO_2 injection wells and 1 pressure observation well. The injection operations were undertaken at constant surface injection pressures on the order of 10.4 MPa.

The wells were completed in the Fruitland coal, which is capped by shale. The reservoir has a thickness of 13 m, is located at a depth of 950 m and had an original reservoir pressure of 11.5 MPa. In a study conducted under the Coal-Seq Project performed for the US Department of Energy (www.coal-seq.com), a detailed reservoir characterization and modelling of the pilot was developed with the COMET2 reservoir simulator and future field performance was forecast under various operating conditions.

This study provides evidence of significant coal-permeability reduction with CO_2 injection. This permeability reduction resulted in a two-fold reduction in injectivity. This effect compromised incremental methane recovery and project economics. Finding ways to overcome and/or prevent this effect is therefore an important topic for future research. The injection of CO_2 at the Allison Unit has resulted in an increase in methane recovery from an estimated 77% of original gas in place to 95% of the original gas in place within the project area. The recovery of methane was in a proportion of approximately one volume of methane for every three volumes of CO_2 injected (Reeves *et al.*, 2004).

An economic analysis of the pilot indicated a net present value of negative US$ 627,000, assuming a discount rate of 12% and an initial capital expenditure of US$ 2.6 million, but not including the beneficial impact of any tax credits for production from non-conventional reservoirs. This was based on a gas price of 2.09 US$ GJ^{-1} (2.20 US$/MMbtu) (at the time) and a CO_2 price of 5.19 US$ t^{-1} (0.30 US$/Mcf). The results of the financial analysis will change, depending on the cost of oil and gas (the analysis indicated that the pilot would have yielded a positive net present value of US$2.6 million at today's gas prices) and the cost of CO_2. It was also estimated that if injectivity had been improved by a factor of four (but still using 2.09 US$ GJ^{-1} (2.20 US$/MMbtu)), the net present value would have increased to US$ 3.6 million. Increased injectivity and today's gas prices combined would have yielded a net present value for the pilot of US$ 15 million or a profit of 34 US$/$tCO_2$ retained in the reservoir (Reeves *et al.*, 2003).

of methane and CO_2 (Reeves *et al.*, 2004).

If the coal is never mined or depressurized, it is likely CO_2 will be stored for geological time, but, as with any geological storage option, disturbance of the formation could void any storage. The likely future fate of a coal seam is, therefore, a key determinant of its suitability for storage and in storage site selection and conflicts between mining and CO_2 storage are possible, particularly for shallow coals.

5.3.5 Other geological media

Other geological media and/or structures – including basalts, oil or gas shale, salt caverns and abandoned mines – may locally provide niche options for geological storage of CO_2.

5.3.5.1 Basalts

Flows and layered intrusions of basalt occur globally, with large volumes present around the world (McGrail *et al.*, 2003). Basalt commonly has low porosity, low permeability and low pore space continuity and any permeability is generally associated with fractures through which CO_2 will leak unless there is a suitable caprock. Nonetheless, basalt may have some potential for mineral trapping of CO_2, because injected CO_2 may react with silicates in the basalt to form carbonate minerals (McGrail *et al.*, 2003). More research is needed, but in general, basalts appear unlikely to be suitable for CO_2 storage.

5.3.5.2 Oil or gas rich shale

Deposits of oil or gas shale or organic-rich shale, occur in many parts of the world. The trapping mechanism for oil shale is similar to that for coal beds, namely CO_2 adsorption onto organic material. Carbon dioxide-enhanced shale-gas production (like ECBM) has the potential to reduce storage costs. The potential for storage of CO_2 in oil or gas shale is currently unknown, but the large volumes of shale suggest that storage capacity may be significant. If site-selection criteria, such as minimum depth, are developed and applied to these shales, then volumes could be limited, but the very low permeability of these shales is likely to preclude injection of large volumes of CO_2.

5.3.5.3 Salt caverns

Storage of CO_2 in salt caverns created by solution mining could use the technology developed for the storage of liquid natural gas and petroleum products in salt beds and domes in Western Canada and the Gulf of Mexico (Dusseault *et al.*, 2004). A single salt cavern can reach more than 500,000 m^3. Storage of CO_2 in salt caverns differs from natural gas and compressed air storage because in the latter case, the caverns are cyclically pressurized and depressurized on a daily-to-annual time scale, whereas CO_2 storage must be effective on a centuries-to-millennia time scale. Owing to the creep properties of salt, a cavern filled with supercritical CO_2 will decrease in volume, until the pressure inside the cavern equalizes the external stress in the salt bed (Bachu and Dusseault, 2005). Although a single cavern 100 m in diameter may hold only about 0.5 Mt of high density CO_2, arrays of caverns could be built for large-scale storage. Cavern sealing is important in preventing leakage and collapse of cavern roofs, which could release large quantities of gas (Katzung *et al.*, 1996). Advantages of CO_2 storage in salt caverns include high capacity per unit volume ($kgCO_2\ m^{-3}$), efficiency and injection flow rate. Disadvantages are the potential for CO_2 release in the case of system failure, the relatively small capacity of most individual caverns and the environmental problems of disposing of brine from a solution cavity. Salt caverns can also be used for temporary storage of CO_2 in collector and distributor systems between sources and sinks of CO_2.

5.3.5.4 Abandoned mines

The suitability of mines for CO_2 storage depends on the nature and sealing capacity of the rock in which mining occurs. Heavily fractured rock, typical of igneous and metamorphic terrains, would be difficult to seal. Mines in sedimentary rocks may offer some CO_2-storage opportunities (e.g., potash and salt mines or stratabound lead and zinc deposits). Abandoned coal mines offer the opportunity to store CO_2, with the added benefit of adsorption of CO_2 onto coal remaining in the mined-out area (Piessens and Dusar, 2004). However, the rocks above coal mines are strongly fractured, which increases the risk of gas leakage. In addition, long-term, safe, high-pressure, CO_2-resistant shaft seals have not been developed and any shaft failure could result in release of large quantities of CO_2. Nevertheless, in Colorado, USA, there is a natural gas storage facility in an abandoned coal mine.

5.3.6 Effects of impurities on storage capacity

The presence of impurities in the CO_2 gas stream affects the engineering processes of capture, transport and injection (Chapters 3 and 4), as well as the trapping mechanisms and capacity for CO_2 storage in geological media. Some contaminants in the CO_2 stream (e.g., SO_x, NO_x, H_2S) may require classification as hazardous, imposing different requirements for injection and disposal than if the stream were pure (Bergman *et al.*, 1997). Gas impurities in the CO_2 stream affect the compressibility of the injected CO_2 (and hence the volume needed for storing a given amount) and reduce the capacity for storage in free phase, because of the storage space taken by these gases. Additionally, depending on the type of geological storage, the presence of impurities may have some other specific effects.

In EOR operations, impurities affect the oil recovery because they change the solubility of CO_2 in oil and the ability of CO_2 to vaporize oil components (Metcalfe, 1982). Methane and nitrogen decrease oil recovery, whereas hydrogen sulphide, propane and heavier hydrocarbons have the opposite effect (Alston *et al.*, 1985; Sebastian *et al.*, 1985). The presence of SO_x may improve oil recovery, whereas the presence of NO_x can retard miscibility and thus reduce oil recovery (Bryant and Lake, 2005) and O_2 can react exothermally with oil in the reservoir.

In the case of CO_2 storage in deep saline formations, the presence of gas impurities affects the rate and amount of CO_2 storage through dissolution and precipitation. Additionally, leaching of heavy metals from the minerals in the rock matrix by SO_2 or O_2 contaminants is possible. Experience to date with acid gas injection (Section 5.2.4.2) suggests that the effect of impurities is not significant, although Knauss *et al.* (2005) suggest that SO_x injection with CO_2 produces substantially different chemical, mobilization and mineral reactions. Clarity is needed about the range of gas compositions that industry might wish to store, other than pure CO_2 (Anheden *et al.*, 2005), because although there might be environmental issues to address, there might be cost savings in co-storage of CO_2 and contaminants.

In the case of CO_2 storage in coal seams, impurities may also have a positive or negative effect, similar to EOR operations. If a stream of gas containing H_2S or SO_2 is injected into coal beds, these will likely be preferentially adsorbed because they have a higher affinity to coal than CO_2, thus reducing the storage capacity for CO_2 (Chikatamarla and Bustin, 2003). If oxygen is present, it will react irreversibly with the coal, reducing the sorption surface and, hence, the adsorption capacity. On the other hand, some impure CO_2 waste streams, such as coal-fired flue gas (i.e., primarily N_2 + CO_2), may be used for ECBM because the CO_2 is stripped out (retained) by the coal reservoir, because it has higher sorption selectivity than N_2 and CH_4.

5.3.7 Geographical distribution and storage capacity estimates

Identifying potential sites for CO_2 geological storage and estimating their capacity on a regional or local scale should conceptually be a simple task. The differences between the various mechanisms and means of trapping (Sections 5.2.2) suggest in principle the following methods:

- For volumetric trapping, capacity is the product of available volume (pore space or cavity) and CO_2 density at *in situ* pressure and temperature;
- For solubility trapping, capacity is the amount of CO_2 that can be dissolved in the formation fluid (oil in oil reservoirs, brackish water or brine in saline formations);
- For adsorption trapping, capacity is the product of coal volume and its capacity for adsorbing CO_2;

Table 5.9 Compilation of CO_2 storage cost estimates for different options.

Option type	On or offshore	Location	US$/t$CO_2$ stored			Comments	Nature of Midpoint value
			Low	Mid	High		
Saline formation	Onshore	Australia	0.2	0.5	5.1	Statistics for 20 sites[a]	Median
Saline formation	Onshore	Europe	1.9	2.8	6.2	Representative range[b]	Most likely value
Saline formation	Onshore	USA	0.4	0.5	4.5	Low/base/high cases for USA[c]	Base case for average parameters
Saline formation	Offshore	Australia	0.5	3.4	30.2	Statistics for 34 sites[a]	Median
Saline formation	Offshore	N. Sea	4.7	7.7	12.0	Representative range[b]	Most likely value
Depleted oil field	Onshore	USA	0.5	1.3	4.0	Low/base/high cases for USA[c]	Base case for average parameters
Depleted gas field	Onshore	USA	0.5	2.4	12.2	Low/base/high cases for USA[c]	Base case for average parameters
Disused oil or gas field	Onshore	Europe	1.2	1.7	3.8	Representative range[b]	Most likely value
Disused oil or gas field	Offshore	N. Sea	3.8	6.0	8.1	Low/base/high cases for USA[c]	Most likely value

Note: The ranges and low, most likely (mid), high values reported in different studies were calculated in different ways. The estimates exclude monitoring costs.

a. Figures from Allinson *et al.*, (2003) are statistics for multiple cases from different sites in Australia. Low is the minimum value, most likely is median, high is maximum value of all the cases. The main determinants of storage costs are rate of injection and reservoir characteristics such as permeability, thickness, reservoir depth rather than reservoir type (such as saline aquifer, depleted field, etc.). The reservoir type could be high or low cost depending on these characteristics. The figures are adjusted to exclude compression and transport costs.

b. Figures from Hendriks *et al.*, (2002) are described as a representative range of values for storage options 1000-3000 m depth. The full range of costs is acknowledged to be larger than shown. The figures are converted from Euros to US$.

c. Bock *et al.*, (2003) define a base case, low- and high-cost cases from analysis of typical reservoirs for US sites. Each case has different depth, reservoir, cost and oil/gas price parameters. The figures are adjusted to exclude compression and transport costs.

Table 5.10 Investment costs for industry CO_2 storage projects.

Project	Sleipner	Snøhvit
Country	Norway	Norway
Start	1996	2006
Storage type	Aquifer	Aquifer
Annual CO_2 injection rate ($MtCO_2\ yr^{-1}$)	1	0.7
Onshore/Offshore	Offshore	Offshore
Number of wells	1	1
Pipeline length (km)	0	160
Capital Investment Costs (US$ million)		
Capture and Transport	79	143
Compression and dehydration	79	70
Pipeline	none	73
Storage	15	48
Drilling and well completion	15	25
Facilities	[a]	12
Other	[a]	11
Total capital investment costs (US$ million)	94	191
Operating Costs (US$ million)		
Fuel and CO_2 tax	7	
References	Torp and Brown, 2005	Kaarstad, 2002

[a] No further breakdown figures are available. Subset of a larger system of capital and operating costs for several processes, mostly natural gas and condensate processing.

5.9.3 Cost estimates for CO_2 geological storage

This section reviews storage costs for options without benefits from enhanced oil or gas production. It describes the detailed cost estimates for different storage options.

5.9.3.1 Saline formations

The comprehensive review by Allinson *et al.,* (2003), covering storage costs for more than 50 sites around Australia, illustrates the variability that might occur across a range of sites at the national or regional scale. Onshore costs for 20 sites have a median cost of 0.5 US$/t$CO_2$ stored, with a range of 0.2–5.1 US$/t$CO_2$ stored. The 37 offshore sites have a median value of 3.4 US$/t$CO_2$ stored and a range of 0.5–30.2 US$/t$CO_2$ stored. This work includes sensitivity studies that use Monte Carlo analyses of estimated costs to changes in input parameters. The main determinants of storage costs are reservoir and injection characteristics such as permeability, thickness and reservoir depth, that affect injection rate and well costs rather than option type (such as saline formation or depleted field).

Bock *et al*. (2003) have made detailed cost estimates on a series of cases for storage in onshore saline formations in the United States. Their assumptions on geological characteristics are based on a statistical review of more than 20 different formations. These formations represent wide ranges in depth (700–1800 m), thickness, permeability, injection rate and well numbers. The base-case estimate for average characteristics has a storage cost of 0.5 US$/t$CO_2$ stored. High- and low-cost cases representing a range of formations and input parameters are 0.4–4.5 US$/t$CO_2$ stored. This illustrates the variability resulting from input parameters.

Onshore storage costs for saline formations in Europe for depths of 1000–3000 m are 1.9–6.2 US$/t$CO_2$, with a most likely value of 2.8 US$/t$CO_2$ stored (Hendriks *et al*., 2002). This study also presents estimated costs for offshore storage over the same depth range. These estimates cover reuse of existing oil and gas platforms (Hendriks *et al*., 2002). The range is 4.7–12.0 US$/t$CO_2$ stored, showing that offshore costs are higher than onshore costs.

5.9.3.2 Disused oil and gas reservoirs

It has been shown that storage costs in disused oil and gas fields in North America and Europe are comparable to those for saline formations (Hendriks *et al*., 2002; Bock *et al*., 2003). Bock *et al*. (2003) present costs for representative oil and gas reservoirs in the Permian Basin (west Texas, USA). For disused gas fields, the base-case estimate has a storage cost of 2.4 US$/t$CO_2$ stored, with low and high cost cases of 0.5 and 12.2 US$/t$CO_2$ stored. For depleted oil fields, the base-case cost estimate is 1.3 US$/t$CO_2$ stored, with low- and highcost cases of 0.5 and 4.0 US$/t$CO_2$ stored. Some reduction in these costs may be possible by reusing existing wells in these fields, but remediation of abandoned wells would increase the costs if required.

In Europe, storage costs for onshore disused oil and gas fields at depths of 1000–3000 m are 1.2–3.8 US$/t$CO_2$ stored. The most likely value is 1.7 US$/t$CO_2$ stored. Offshore oil and gas fields at the same depths have storage costs of 3.8–8.1 US$/t$CO_2$ stored (most likely value is 6.0 US$/t$CO_2$ stored). The costs depend on the depth of the reservoir and reuse of platforms. Disused fields may benefit from reduced exploration and monitoring costs.

5.9.3.3 Representative storage costs

The different studies for saline formations and disused oil and gas fields show a very wide range of costs, 0.2–30.0 US$/t$CO_2$ stored, because of the site-specific nature of the costs. This reflects the wide range of geological parameters that occur in any region or country. In effect, there will be multiple sites in any geographic area with a cost curve, providing increasing storage capacity with increasing cost.

The extensive Australian data set indicates that storage costs are less than 5.1 US$/t$CO_2$ stored for all the onshore sites and more than half the offshore sites. Studies for USA and Europe also show that storage costs are generally less than 8 US$/t$CO_2$, except for high-cost cases for offshore sites in Europe and depleted gas fields in the United States. A recent study suggests that 90% of European storage capacity could be used for costs less that 2 US$/t$CO_2$ (Wildenborg *et al*., 2005b).

Assessment of these cost estimates indicates that there is significant potential for storage at costs in the range of 0.5–8 US$/t$CO_2$ stored, estimates that are based on the median, base case or most likely values presented for the different studies (Table 5.9). These exclude monitoring costs, well remediation and longer term costs.

5.9.3.4 Investment costs for storage projects

Some information is available on the capital and operating costs of industry capture and storage projects (Table 5.10). At Sleipner, the incremental capital cost for the storage component comprising a horizontal well to inject 1 MtCO_2 yr^{-1} was US$ 15 million (Torp and Brown, 2005). Note that at Sleipner, CO_2 had to be removed from the natural gas to ready it for sale on the open market. The decision to store the captured CO_2 was at least in part driven by a 40 US$/t$CO_2$ tax on offshore CO_2 emissions. Details of the energy penalty and levelized costs are not available. At the planned Snohvit project, the estimated capital costs for storage are US$ 48 million for injection of 0.7 MtCO_2 yr^{-1} (Kaarstad, 2002). This data set is limited and additional data on the actual costs of industry projects is needed.

5.9.4 Cost estimates for storage with enhanced oil and gas recovery

The costs of CO_2 geological storage may be offset by additional revenues for production of oil or gas, where CO_2 injection and storage is combined with enhanced oil or gas recovery or ECBM. At present, in commercial EOR and ECBM projects that use CO_2 injection, the CO_2 is purchased for the project and is a significant proportion of operating costs. The economic benefits from enhanced production make EOR and ECBM potential early options for CO_2 geological storage.

5.9.4.1 Enhanced oil recovery

The costs of onshore CO_2-flooding EOR projects in North America are well documented (Klins, 1984; Jarrell *et al.*, 2002). Carbon dioxide EOR projects are business ventures to increase oil recovery. Although CO_2 is injected and stored, this is not the primary driver and EOR projects are not optimized for CO_2 storage.

The commercial basis of conventional CO_2-EOR operations is that the revenues from incremental oil compensate for the additional costs incurred (including purchase of CO_2) and provide a return on the investment. The costs differ from project to project. The capital investment components are compressors, separation equipment and H_2S removal, well drilling and well conversions and completions. New wells are not required for some projects. Operating costs are the CO_2 purchase price, fuel costs and field operating costs.

In Texas, the cost of CO_2 purchase was 55–75% of the total cost for a number of EOR fields (averaging 68% of total costs) and is a major investment uncertainty for EOR. Tax and fiscal incentives, government regulations and oil and gas prices are the other main investment uncertainties (e.g., Jarrell *et al.*, 2002).

The CO_2 price is usually indexed to oil prices, with an indicative price of 11.7 US$/t$CO_2$ (0.62 US$/Mscf) at a West Texas Intermediate oil price of 18 US$ per barrel, 16.3 US$/t$CO_2$ at 25 US$ per barrel of oil and 32.7 US$/t$CO_2$ at 50 US$ per barrel of oil (Jarrell *et al.*, 2002). The CO_2 purchase price indicates the scale of benefit for EOR to offset CO_2 storage costs.

5.9.4.2 Cost of CO_2 storage with enhanced oil recovery

Recent studies have estimated the cost of CO_2 storage in EOR sites (Bock *et al.*, 2003; Hendriks *et al.*, 2002). Estimates of CO_2 storage costs for onshore EOR options in North America have been made by Bock *et al.* (2003). Estimates for a 2-MtCO_2 yr^{-1} storage scenario are based on assumptions and parameters from existing EOR operations and industry cost data. These include estimates of the effectiveness of CO_2-EOR, in terms of CO_2 injected for each additional barrel of oil. The methodology for these estimates of storage costs is to calculate the break-even CO_2 price (0.3 tCO_2).

Experience from field operations across North America provides information about how much of the injected CO_2 remains in the oil reservoir during EOR. An average of 170 standard m^3 CO_2 of new CO_2 is required for each barrel of enhanced oil production, with a range of 85 (0.15 tCO_2) to 227 (0.4 tCO_2) standard m^3 (Bock *et al.*, 2003). Typically, produced CO_2 is separated from the oil and reinjected back underground, which reduces the cost of CO_2 purchases.

The base case for a representative reservoir at a depth of 1219 m, based on average EOR parameters in the United States with an oil price of 15 US$ per barrel, has a net storage cost of –14.8 US$/t$CO_2$ stored. Negative costs indicate the amount of cost reduction that a particular storage option offers to the overall capture and storage system. Low- and high-cost cases representing a range of CO_2 effectiveness, depth, transport distance and oil price are –92.0 and +66.7 US$/t$CO_2$ stored. The low-cost case assumes favourable assumptions for all parameters (effectiveness, reservoir depth, productivity) and a 20 US$ per barrel oil price. Higher oil prices, such as the 50 US$ per barrel prices of 2005, will considerably change the economics of CO_2-EOR projects. No published studies are available for these higher oil prices.

Other estimates for onshore EOR storage costs all show potential at negative net costs. These include a range of –10.5 to +10.5 US$/t$CO_2$ stored for European sites (Hendriks *et al.*, 2002). These studies show that use of CO_2 enhanced oil recovery for CO_2 storage can be a lower cost option than saline formations and disused oil and gas fields.

At present, there are no commercial offshore EOR operations and limited information is available on CO_2 storage costs for EOR options in offshore settings. Indicative storage cost estimates for offshore EOR are presented by Hendriks *et al.* (2002). Their range is –10.5 to +21.0 US$/t$CO_2$ stored. For the North Sea Forties Field, it has been shown that CO_2-flooding EOR is technically attractive and could increase oil recovery, although at present it is not economically attractive as a stand-alone EOR project (Espie *et al.*, 2003). Impediments are the large capital requirement for adapting facilities, wells and flowlines, as well as tax costs and CO_2 supply. It is noted that the economics will change with additional value for storage of CO_2.

The potential benefit of EOR can be deduced from the CO_2 purchase price and the net storage costs for CO_2-EOR storage case studies. The indicative value of the potential benefit from enhanced oil production to CO_2 storage is usually in the range of 0–16 US$/t$CO_2$. In some cases, there is no benefit from EOR. The maximum estimate of the benefit ranges up to $92 per tonne of CO_2 for a single case study involving favourable parameters. In general, higher benefits will occur at high-oil-price scenarios similar to those that have occurred since 2003 and for highly favourable sites, as shown above. At 50 US$ per barrel of oil, the range may increase up to 30 US$/t$CO_2$.

5.9.4.3 Cost of CO_2 storage with enhanced gas recovery

CO_2-enhanced gas recovery is a less mature technology than EOR and it is not in commercial use. Issues are the cost of CO_2 and infrastructure, concerns about excessive mixing and the high primary recovery rates of many gas reservoirs. Cost estimates show that CO_2-EGR (enhanced gas recovery) can provide a benefit of 4–16 US$/t$CO_2$, depending on the price of gas and the effectiveness of recovery (Oldenburg *et al.*, 2002).

5.9.4.4 Cost of CO_2 storage with enhanced coal bed methane

The injection of CO_2 for ECBM production is an immature technology not yet in commercial use. In CO_2-ECBM, the revenues from the produced gas could offset the investment costs and provide a source of income for investors. Cost data are based on other types of CBM operations that are in use.

There is significant uncertainty in the effectiveness of CO_2 storage in coal beds in conjunction with ECBM, because there

is no commercial experience. The suggested metric for CO_2 retention is 1.5–10 m^3 of CO_2 per m^3 of produced methane. The revenue benefit of the enhanced production will depend on gas prices.

Well costs are a major factor in ECBM because many wells are required. In one recent study for an ECBM project (Schreurs, 2002), the cost per production well was given as approximately US$750,000 per well, plus 1500 US$ m^{-1} of in-seam drilling. The cost of each injection well was approximately US$430,000.

The IEA-GHG (1998) developed a global cost curve for CO_2-ECBM, with storage costs ranging from –20 to +150 US$/t$CO_2$. It concluded that only the most favourable sites, representing less than 10% of global capacity, could have negative costs. Estimates of onshore CO_2-ECBM storage costs in the United States have been made by using the approach described for EOR (Bock *et al.*, 2003). They estimate the effectiveness of ECBM in terms of CO_2 injected for incremental gas produced, ranging from 1.5 to 10 units (base case value of 2) of CO_2 per unit of enhanced methane. Other key inputs are the gas well production rate, the ratio of producers to injectors, well depth and the number of wells. The base case, storing 2.1 MtCO_2 per year for a representative reservoir at 610 m depth in a newly built facility, requires 270 wells. The assumed gas price is US$1.90 per GJ (US$2.00 per Mbtu). It has a net storage cost of –8.1 US$/t$CO_2$ stored. Low- and high-cost cases representing a range of parameters are –26.4 and +11.1 US$/t$CO_2$ stored. The range of these estimates is comparable to other estimates – for example, those for Canada (Wong *et al.*, 2001) and Europe (Hendriks *et al.*, 2002), 0 to +31.5 US$/t$CO_2$. Enhanced CBM has not been considered in detail for offshore situations and cost estimates are not available.

Only one industrial-scale CO_2-ECBM demonstration project has taken place to date, the Allison project in the United States and it is no longer injecting CO_2 (Box 5.7). One analysis of the Allison project, which has extremely favourable geological characteristics, suggests the economics of ECBM in the United States are dubious under current fiscal conditions and gas prices (IEA-GHG, 2004). The economic analyses suggest this would be commercial, with high gas prices about 4 US$ per GJ) and a credit of 12–18 US$/t$CO_2$. Alternatively, Reeves (2005) used detailed modelling and economic analysis to show a break-even gas price of US$2.44 per GJ (US$2.57 per Mbtu), including costs of 5.19 US$/t$CO_2$ for CO_2 purchased at the field.

5.9.5 Cost of monitoring

While there has been extensive discussion of possible monitoring strategies in the literature and technologies that may be applicable, there is limited information on monitoring costs. These will depend on the monitoring strategy and technologies used and how these are adapted for the duration of storage projects. Some of the technologies likely to be used are already in widespread use in the oil and gas and CBM industries. The costs of individual technologies in current use are well constrained.

Repeated use of seismic surveys was found to be an effective monitoring technology at Sleipner. Its applicability will vary between options and sites. Seismic survey costs are highly variable, according to the technology used, location and terrain and complexity. Seismic monitoring costs have been reviewed for an onshore storage project for a 1000 MW power plant with a 30-year life (Myer *et al.*, 2003). Assuming repeat surveys at five-year intervals during the injection period, monitoring costs are estimated as 0.03 US$/t$CO_2$, suggesting that seismic monitoring may represent only a small fraction of overall storage costs. No discounting was used to develop this estimate.

Benson *et al.* (2005) have estimated life-cycle monitoring costs for two scenarios: (1) storage in an oil field with EOR and (2) storage in a saline formation. For these scenarios, no explicit leakage was considered. If leakage were to occur, the 'enhanced' monitoring programme should be sufficient to detect and locate the leakage and may be sufficient to quantify leakage rates as well. For each scenario, cost estimates were developed for the 'basic' and 'enhanced' monitoring package. The basic monitoring package included periodic seismic surveys, microseismicity, wellhead pressure and injection-rate monitoring. The enhanced package included all of the elements of the 'basic' package and added periodic well logging, surface CO_2 flux monitoring and other advanced technologies. For the basic monitoring package, costs for both scenarios are 0.05 US$/t$CO_2$, based on a discount rate of 10% (0.16–0.19 US$/t$CO_2$ undiscounted). The cost for the enhanced monitoring package is 0.069–0.085 US$/t$CO_2$ (0.27–0.30 US$/t$CO_2$ undiscounted). The assumed duration of monitoring includes the 30-year period of injection, as well as further monitoring after site closure of 20 years for EOR sites and 50 years for saline formations. Increasing the duration of monitoring to 1000 years increased the discounted cost by 10%. These calculations are made assuming a discount rate of 10% for the first 30 years and a discount rate of 1% thereafter.

5.9.6 Cost of remediation of leaky storage projects

No estimates have been made regarding the costs of remediation for leaking storage projects. Remediation methods listed in Table 5.7 have been used in other applications and, therefore, could be extrapolated to CO_2 storage sites. However, this has not been done yet.

5.9.7 Cost reduction

There is little literature on cost-reduction potential for CO_2 geological storage. Economies of scale are likely to be important (Allinson *et al.*, 2003). It is also anticipated that further cost reduction will be achieved with application of learning from early storage projects, optimization of new projects and application of advanced technologies, such as horizontal and multilateral wells, which are now widely used in the oil and gas industry.

5.10 Knowledge gaps

Knowledge regarding CO_2 geological storage is founded on basic knowledge in the earth sciences, on the experience of the oil and gas industry (extending over the last hundred years or more) and on a large number of commercial activities involving the injection and geological storage of CO_2 conducted over the past 10–30 years. Nevertheless, CO_2 storage is a new technology and many questions remain. Here, we summarize what we know now and what gaps remain.

1. Current storage capacity estimates are imperfect:
   - There is need for more development and agreement on assessment methodologies.
   - There are many gaps in capacity estimates at the global, regional and local levels.
   - The knowledge base for geological storage is for the most part based on Australian, Japanese, North American and west European data.
   - There is a need to obtain much more information on storage capacity in other areas, particularly in areas likely to experience the greatest growth in energy use, such as China, Southeast Asia, India, Russia/Former Soviet Union, Eastern Europe, the Middle East and parts of South America and southern Africa.

2. Overall, storage science is understood, but there is need for greater knowledge of particular mechanisms, including:
   - The kinetics of geochemical trapping and the long-term impact of CO_2 on reservoir fluids and rocks.
   - The fundamental processes of CO_2 adsorption and CH_4 desorption on coal during storage operations.

3. Available information indicates that geological storage operations can be conducted without presenting any greater risks for health and the local environment than similar operations in the oil and gas industry, when carried out at high-quality and well-characterized sites. However, confidence would be further enhanced by increased knowledge and assessment ability, particularly regarding:
   - Risks of leakage from abandoned wells caused by material and cement degradation.
   - The temporal variability and spatial distribution of leaks that might arise from inadequate storage sites.
   - Microbial impacts in the deep subsurface.
   - Environmental impact of CO_2 on the marine seafloor.
   - Methods to conduct end-to-end quantitative assessment of risks to human health and the local environment.

4. There is strong evidence that storage of CO_2 in geological storage sites will be long term; however, it would be beneficial to have:
   - Quantification of potential leakage rates from more storage sites.
   - Reliable coupled hydrogeological-geochemical-geo–mechanical simulation models to predict long-term storage performance accurately.
   - Reliable probabilistic methods for predicting leakage rates from storage sites.
   - Further knowledge of the history of natural accumulations of CO_2.
   - Effective and demonstrated protocols for achieving desirable storage duration and local safety.

5. Monitoring technology is available for determining the behaviour of CO_2 at the surface or in the subsurface; however, there is scope for improvement in the following areas:
   - Quantification and resolution of location and forms of CO_2 in the subsurface, by geophysical techniques.
   - Detection and monitoring of subaquatic CO_2 seepage.
   - Remote-sensing and cost-effective surface methods for temporally variable leak detection and quantification, especially for dispersed leaks.
   - Fracture detection and characterization of leakage potential.
   - Development of appropriate long-term monitoring approaches and strategies.

6. Mitigation and remediation options and technologies are available, but there is no track record of remediation for leaked CO_2. While this could be seen as positive, some stakeholders suggest it might be valuable to have an engineered (and controlled) leakage event that could be used as a learning experience.

7. The potential cost of geological storage is known reasonably well, but:
   - There are only a few experience-based cost data from non-EOR CO_2 storage projects.
   - There is little knowledge of regulatory compliance costs.
   - There is inadequate information on monitoring strategies and requirements, which affect costs.

8. The regulatory and responsibility or liability framework for CO_2 storage is yet to be established or unclear. The following issues need to be considered:
   - The role of pilot and demonstration projects in developing regulations.
   - Approaches for verification of CO_2 storage for accounting purposes.
   - Approaches to regulatory oversight for selecting, operating and monitoring CO_2 storage sites, both in the short and long term.
   - Clarity on the need for and approaches to long-term stewardship.
   - Requirements for decommissioning a storage project.

Additional information on all of these topics would improve technologies and decrease uncertainties, but there appear to be no insurmountable technical barriers to an increased uptake of geological storage as a mitigation option.